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INDIANA UTILITY REGULATORY COMMISSION

VERIFIED JOINT PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC ("NIPSCO") AND ROSEWATER WIND GENERATION LLC (THE "JOINT VENTURE") FOR (1) ISSUANCE TO NIPSCO OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE PURCHASE AND ACQUISITION OF A 102 MW WIND FARM ("THE ROSEWATER PROJECT"); (2) APPROVAL OF THE ROSEWATER PROJECT AS A CLEAN ENERGY PROJECT UNDER IND. CODE § 8-1-8.8-11; (3) APPROVAL OF RATEMAKING AND ACCOUNTING TREATMENT ASSOCIATED WITH THE ROSEWATER PROJECT; (4) AUTHORITY TO ESTABLISH AMORTIZATION RATES FOR NIPSCO'S INVESTMENT IN THE JOINT VENTURE; (5) APPROVAL PURSUANT TO IND. CODE § 8-1-2.5-6 OF AN ALTERNATIVE REGULATORY PLAN INCLUDING ESTABLISHMENT OF JOINT VENTURE THROUGH WHICH THE ROSEWATER PROJECT WILL SUPPORT NIPSCO'S GENERATION FLEET AND THE REFLECTION IN NIPSCO'S NET ORIGINAL COST RATE BASE OF ITS INVESTMENT IN JOINT VENTURE; (6) APPROVAL OF PURCHASED POWER AGREEMENTS THROUGH WHICH NIPSCO WILL RECEIVE THE ENERGY GENERATED BY THE ROSEWATER PROJECT, INCLUDING TIMELY COST RECOVERY PURSUANT TO IND. CODE § 8-1-8.8-11 THROUGH NIPSCO'S FUEL ADJUSTMENT CLAUSE; (7) AUTHORITY TO DEFER AMORTIZATION AND TO ACCRUE POST-IN SERVICE CARRYING CHARGES ON NIPSCO'S INVESTMENT IN JOINT VENTURE; (8) TO THE EXTENT GENERALLY ACCEPTED ACCOUNTING PRINCIPLES WOULD TREAT ANY ASPECT OF JOINT VENTURE AS DEBT ON NIPSCO'S FINANCIAL STATEMENTS, APPROVAL OF FINANCING; (9) APPROVAL OF AN ALTERNATIVE REGULATORY PLAN FOR NIPSCO IN ORDER TO FACILITATE THE IMPLEMENTATION OF THE ROSEWATER PROJECT; AND (10) TO THE EXTENT NECESSARY, ISSUANCE OF AN ORDER PURSUANT TO IND. CODE § 8-1-2.5-5 DECLINING TO EXERCISE JURISDICTION OVER JOINT VENTURE AS A PUBLIC UTILITY.	)	**CAUSE NO. 45194** **APPROVED:** AUG 07 2019

ORDER OF THE COMMISSION

Presiding Officers:
James F. Huston, Chairman
David L. Ober, Commissioner
David E. Veleta, Senior Administrative Law Judge

On February 1, 2019, Joint Petitioners Northern Indiana Public Service Company LLC ("NIPSCO") and RoseWater Wind Generation LLC ("RoseWater" or "Joint Venture") (collectively, the "Joint Petitioners") filed their Verified Joint Petition with the Indiana Utility Regulatory Commission ("Commission") in this Cause for (1) issuance to NIPSCO of a certificate of public convenience and necessity ("CPCN") to purchase and acquire indirectly through Joint Venture a wind farm that will have an aggregate nameplate capacity of approximately 102 megawatt ("MW") ("Rosewater Project"); (2) approval of the Rosewater Project as a clean energy project under Ind. Code § 8-1-8.8-11; (3) approval of associated ratemaking and accounting treatment for the Rosewater Project; (4) establishment of amortization rates for NIPSCO's investment in the Rosewater Project through Joint Venture; (5) approval pursuant to Ind. Code § 8-1-2.5-6 of an alternative regulatory plan ("ARP") to implement the Rosewater Project, including establishment of Joint Venture and the reflection in NIPSCO's net original cost rate base of its investment in Joint Venture; (6) approval of purchased power agreements ("PPAs") through which NIPSCO will acquire the energy generated by the Rosewater Project, including timely cost recovery pursuant to Ind. Code § 8-1-8.8-11 through a rate adjustment mechanism administered through NIPSCO's Fuel Adjustment Clause ("FAC"); (7) authorization for NIPSCO to defer amortization and to accrue post-in-service carrying charges ("PISCC") on NIPSCO's capital investments in Joint Venture; (8) to the extent generally accepted accounting principles ("GAAP") would treat any aspect of Joint Venture as debt on NIPSCO's financial statements, grant of necessary financing approval; (9) approval of an ARP for NIPSCO in order to facilitate the implementation of the Rosewater Project; and (10) to the extent necessary, pursuant to Ind. Code § 8-1-2.5-5, a declination to exercise jurisdiction over Joint Venture as a public utility. On February 1, 2019, Joint Petitioners filed their prepared testimony and exhibits constituting their case-in-chief. Joint Petitioners also filed a Motion for Protection and Nondisclosure of Confidential and Proprietary Information, which the Presiding Officers granted in a docket entry dated April 25, 2019.

On February 5, 2019, Citizens Action Coalition of Indiana, Inc. ("CAC") filed its Petition to Intervene, which the Presiding Officers granted in a docket entry dated February 18, 2019. On February 28, 2019, the Indiana Coal Council ("ICC") filed its Petition to Intervene, which the Presiding Officers granted in a docket entry dated March 8, 2019. On March 1, 2019, Dennis Rackers filed his Petition to Intervene, which the Presiding Officers granted in a docket entry dated March 14, 2019. On March 11, 2019, NIPSCO Industrial Group filed its Petition to Intervene, which the Presiding Officers granted in a docket entry dated March 25, 2019.[1] On March 20, 2019, the Indiana Coalition for Affordable and Reliable Electricity filed its Petition to Intervene, which the Presiding Officers granted in a docket entry dated April 8, 2019. On April 9, 2019, the Indiana Municipal Utility Group ("IMUG") filed its Petition to Intervene, which the Presiding Officers granted in a docket entry dated April 25, 2019. On April 22, 2019, the Board of Commissioners of LaPorte County, Indiana ("LaPorte") filed its Petition to Intervene, which the Presiding Officers granted in a docket entry dated May 3, 2019.

In accordance with the February 18, 2019 docket entry setting the procedural schedule for this Cause, the Indiana Office of Utility Consumer Counselor ("OUCC") and Intervenors filed testimony and exhibits constituting their respective cases-in-chief on April 29, 2019. Joint Petitioners filed rebuttal testimony on May 8, 2019.

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[1] The companies that comprise the NIPSCO Industrial Group are ArcelorMittal USA, Cargill, Inc., Praxair, Inc., and USG Corporation.

The Commission held an evidentiary hearing in this Cause on May 22, 2019 at 9:30 a.m., in Room 222 of the PNC Center, 101 W. Washington Street, Indianapolis, Indiana. At such time, the evidence of the respective parties was admitted into the record and cross-examination was conducted of witnesses.

Having considered the evidence presented and the applicable law, the Commission finds:

1. **Notice and Commission Jurisdiction.** Notice of the evidentiary hearing in this Cause was given and published by the Commission as required by law. NIPSCO is a public utility within the meaning of that term as used in Ind. Code § 8-1-2-1 and is subject to the jurisdiction of the Commission in the manner and to the extent provided by the Public Service Commission Act, as amended, and other pertinent laws of the State of Indiana. NIPSCO is also an "eligible business" as that term is defined in Ind. Code § 8-1-8.8-6. NIPSCO is also an "energy utility" within the meaning of Ind. Code § 8-1-2.5-2 and provides "retail energy service" as that term is defined by Ind. Code § 8-1-2.5-3. NIPSCO is also subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC"). Therefore, the Commission has jurisdiction over NIPSCO and the subject matter of this proceeding.

2. **NIPSCO's Characteristics.** NIPSCO is a limited liability company organized and existing under the laws of the State of Indiana with its principal office and place of business at 801 East 86th Avenue, Merrillville, Indiana. NIPSCO is authorized by the Commission to provide electric utility service to the public in all or part of Benton, Carroll, DeKalb, Elkhart, Fulton, Jasper, Kosciusko, LaGrange, Lake, LaPorte, Marshall, Newton, Noble, Porter, Pulaski, Saint Joseph, Starke, Steuben, Warren and White Counties in northern Indiana. NIPSCO owns, operates, manages and controls electric generating, transmission and distribution plant and equipment and related facilities, which are used and useful in the production, transmission, distribution and furnishing of electric energy, heat, light and power to the public. Pursuant to the Commission's Order dated September 24, 2003 in Cause No. 42349, NIPSCO has transferred functional control of its transmission facilities to the Midcontinent Independent System Operator, Inc. ("MISO"), a regional transmission organization operated under the authority of FERC, which administers the use of NIPSCO's transmission system and the economic dispatching of NIPSCO's generating units pursuant to MISO's FERC approved tariff provisions. NIPSCO also engages in power purchase transactions through MISO as necessary to meet the demands of its customers.

3. **RoseWater's Characteristics.** NIPSCO formed RoseWater Wind Generation LLC under the laws of Delaware on December 11, 2018 to serve as the Joint Venture. The members of the Joint Venture are (1) NIPSCO, (2) EDP Renewables North America LLC ("EDPR" or "Developer"), which is building the Rosewater Project through a special purpose entity known as Rosewater Wind Farm LLC ("Rosewater ProjectCo"), which will own the Rosewater Project, and (3) a Tax Equity Partner ("TEP"), which will be a financial investor that will not have any operational rights in the Joint Venture.

4. **Requested Relief.** In its Verified Joint Petition, Joint Petitioners requested the Commission enter a Final Order (1) making findings as to the best estimate for the cost of the Rosewater Project; (2) making findings that the purchase and acquisition of the Rosewater Project is consistent with the Commission's plan for expansion of electric generating capacity and/or

NIPSCO's 2018 Integrated Resource Plan ("IRP"); (3) making findings that public convenience and necessity require or will require the construction, purchase and acquisition of the Rosewater Project pursuant to the Build Transfer Agreement ("BTA") as proposed; (4) granting NIPSCO a CPCN for the purchase and acquisition of the Rosewater Project pursuant to Ind. Code ch. 8-1-8.5; (5) making findings that the Rosewater Project is an eligible clean energy project pursuant to Ind. Code § 8-1-8.8-11(d); (6) approving the Joint Venture structure and approving NIPSCO's proposed ARP; (7) approving the BTA PPA, which will be in effect if all the conditions precedent to the BTA are met, (the "BTA PPA") and the Back-Stop Wind Energy Purchase Agreement between NIPSCO and Rosewater ProjectCo (the "Back-Stop PPA"), which will be in effect if all the conditions precedent to the BTA are not met, and authorizing NIPSCO's timely recovery of its costs through periodic rate adjustments pursuant to Ind. Code § 8-1-8.8-11; (8) authorizing NIPSCO to defer amortization and to accrue PISCC at NIPSCO's weighted average cost of capital on each of NIPSCO's investments in Joint Venture, with such amounts recorded in Account 182.3, included in NIPSCO's rate base, and amortized over the remaining life of the Rosewater Project; (9) approving financing to the extent required by GAAP; (10) approving amortization rates for NIPSCO's investment in the Rosewater Project through the Joint Venture; (11) as necessary, declining to exercise jurisdiction over Joint Venture as a public utility pursuant to Ind. Code § 8-1-2.5-5; and (12) making such further orders and providing such further relief to Joint Petitioners as may be appropriate.

5. **<u>Statutory Framework</u>.** Ind. Code § 8-1-8.5-5 sets forth the conditions for receiving a CPCN. Ind. Code § 8-1-8.8-2 concerns the development of alternative energy sources, including renewable "energy projects." Per Ind. Code § 8-1-8.8-10, the definition of "renewable energy resource" includes energy from wind. Pursuant to Ind. Code § 8-1-8.8-11, an energy project is eligible for timely recovery of costs. This framework provides the basis for the requested Commission assurance of purchased power cost recovery through the full terms of the BTA PPA and the Back-Stop PPA. Ind. Code § 8-1-2-42(a) ("Section 42(a)") authorizes rate adjustment mechanisms which would include recovery of purchased electricity costs. Finally, Ind. Code § 8-1-2.5-6, which authorizes ARPs, provides a basis for approval to invest in the Rosewater Project, including establishment of the Joint Venture and the reflection in NIPSCO's net original cost rate base of its investment in Joint Venture.

With regard to Joint Petitioners' requested relief pursuant to Ind. Code ch. 8-1-8.8, the Commission has previously granted comparable relief to NIPSCO, Duke Energy, Vectren South and Indiana Michigan Power Company, and in those cases we found wind power developments to be renewable resource projects. We approved the purchase agreements and timely cost recovery through a rate adjustment mechanism to be administered with the FAC proceedings.

6. **<u>Joint Petitioners' Case-in-Chief</u>.** Joint Petitioners presented the testimony of five witnesses in its case-in-chief: Andrew S. Campbell, Director of Regulatory Support and Planning for NIPSCO; Michael D. McCuen, Director of Income Taxes for NiSource Corporate Services Company; Angela Camp, Controller for NIPSCO; Patrick N. Augustine, Principal in Charles River Associates' Energy Practice; and Robert Lee, Vice President of CRA International d/b/a Charles River Associates, Inc. ("CRA").

(a) **<u>Campbell Direct Testimony</u>.** Mr. Campbell provided a broad overview of the proposed transactions; discussed how NIPSCO will integrate the wind into NIPSCO's and MISO's operations; discussed the viability of wind energy resources generally discussed the terms of the BTA and the BTA PPA, outlining NIPSCO's rights to the wind energy project's production, capacity, and environmental attributes, and the benefits associated with the environmental attributes in the form of Renewable Energy Credits ("RECs"). He described that the Back-Stop PPA will only come into play if the conditions precedent to the BTA are not met, and discussed NIPSCO's proposal for recovering the costs associated with the Joint Venture and the BTA PPA, which will be in effect if all the conditions precedent to the BTA are met.

Mr. Campbell explained NIPSCO's generation transition plan. He testified the 2018 IRP included a Short Term Action Plan consisting of the actions NIPSCO will take for the period 2019-2021. The short-term plan focuses on initiating the retirement process for all of the coal-fired units at R.M. Schahfer Generation Station ("Schahfer") and selecting/acquiring replacement projects to fill the capacity gap. In connection with the 2018 IRP, NIPSCO conducted an all-source request for proposals ("All-Source RFP"), which generated a robust response. The responses indicated there are more than enough diverse resources and projects to meet NIPSCO's supply needs in 2023. Ninety proposals supported by 59 projects across five states were received. Each proposal was evaluated and scored independently from NIPSCO. The projects scoring the highest were short-listed and proceeded to negotiation of definitive agreements. The Rosewater Project was one of the short-listed proposals. The other two responses, which are the subject of petitions filed in other dockets, are PPAs between NIPSCO and Jordan Creek Wind Farm LLC and between NIPSCO and Roaming Bison Wind, LLC. The three filings together request authority to obtain a total of 800 MW of wind capacity. All three wind projects are projected to have a 2020 in-service date and are all located in western Indiana north of Indianapolis.

Mr. Campbell testified that wind is a renewable, local, and clean energy source. He stated that wind energy projects do not use fossil or nuclear fuel in operation, which means no mining or drilling for fuel, no radioactive or hazardous wastes, no use of water for steam or cooling, and no emissions of greenhouse gases or other pollutants. He said the absence of fossil or nuclear fuel also means the price of wind power is not impacted by the volatility of commodities. He stated that due to meteorological and resource diversity of the MISO footprint, the location of these wind projects influences the capacity accreditation and available wind energy for NIPSCO's customers. Mr. Campbell stated that all three projects being proposed by NIPSCO at this time are located in Indiana, more specifically the part of Indiana with advantageous meteorological and resource diversity conditions in the MISO footprint. He said that for these reasons, and with advances in wind technology in areas such as wind turbine availability, capacity factor, design and size, and wind mapping,[2] wind energy has become a viable source of renewable energy resources on a per megawatt-hour ("MWh") basis.

Mr. Campbell testified the Rosewater Project is being implemented through a series of agreements – the BTA, a BTA PPA, a Back-Stop PPA (in the event the parties do not close), as well as two more agreements to be executed in late 2019 or early 2020. EDPR, through Rosewater ProjectCo, is building an approximately 25 turbine wind farm and associated electric transmission line in White County, Indiana (utilizing MISO interconnect request J513), which will have an

[2] Mapping refers to the process of assessing impacts of existing wind resources, restrictions on land use, and other sensitivities that may affect wind energy.

aggregate nameplate capacity of approximately 102 MW, and is commonly referred to as the Rosewater Project. The Rosewater Project is expected to achieve commercial operation in the fourth quarter of 2020. The size of the project may change slightly as engineering and technical specifications are finalized.

Pursuant to the BTA, and as explained in the Example Term Sheet (Confidential Attachment 1-E), Joint Venture will purchase 100% of the equity interest in Rosewater ProjectCo from Developer. As a pre-condition to the transaction, a Joint Venture Operating Agreement (the "LLC Agreement"), which stipulates that Joint Venture will be owned initially by three members, must be executed. The first member is a TEP, a financial investor which will not be responsible for project operations. The TEP has not yet been identified. The second member is Developer, which is the entity that is constructing the Rosewater Project through Rosewater ProjectCo. Third is NIPSCO, which will manage the Rosewater Project at the closing of the transaction under the BTA. NIPSCO is the managing member and will initially own approximately 1% of Joint Venture. Developer will build the Rosewater Project through Rosewater ProjectCo, and Rosewater ProjectCo will own the Rosewater Project. The Developer will transfer 100% of Rosewater ProjectCo to Joint Venture pursuant to the BTA when the Rosewater Project begins operating in late 2020. Immediately prior to the transfer, Developer will invest a portion of the proceeds to be paid by Joint Venture, pursuant to the BTA, into the Joint Venture in return for an ownership share of the Joint Venture, which it will hold until 2023. For its share, the TEP will invest a percentage of the amount needed to pay Joint Venture's obligation under the BTA. NIPSCO will invest the remaining amount needed under the BTA in return for its share of Joint Venture. In 2023, NIPSCO will purchase Developer's interest in Joint Venture for cash. TEP's interest in Joint Venture will enable it to receive a specific percent of the Production Tax Credits ("PTCs") and tax losses generated by the Rosewater Project along with distributions of up to a specific percent of any excess cash generated by the Rosewater Project. Once TEP has attained an internal rate of return ("IRR") as specified in the LLC Agreement, the allocation of taxable income, loss, gain and deductions drops to a specific percent. At this point, NIPSCO will have the option to acquire the TEP interest for fair market value as defined in the LLC Agreement. Lastly, NIPSCO can consolidate the wind project and eliminate the need for the BTA PPA.

NIPSCO does not anticipate a need for additional investment beyond what is contemplated in the agreements. However, situations such as, but not limited to, force majeure or extended forced outages where the Rosewater Project is unable to produce for an extended period of time, could result in a need for additional investment. NIPSCO seeks authority in this case to include any such additional payments as an increase of its investment in the Joint Venture.

Mr. Campbell testified that NIPSCO will enter a traditional PPA with Rosewater ProjectCo, the owner of the Rosewater. NIPSCO is requesting the necessary approvals to purchase the electrical energy output from the Rosewater Project either through a Wind Energy Purchase Agreement between NIPSCO and Rosewater ProjectCo (after transfer of Rosewater ProjectCo's equity to the Joint Venture) – which has been delineated as the BTA PPA, or a Back-Stop Wind Energy Purchase Agreement between NIPSCO and Rosewater ProjectCo (without transfer of ownership to the Joint Venture) – which has been delineated as the Back-Stop PPA. Both PPAs have a term of 15 years. If all the conditions precedent to the BTA are satisfied, EDPR will sell its equity in Rosewater ProjectCo to the Joint Venture.

Mr. Campbell described that during the commercial negotiations between NIPSCO and EDPR, the prices for both the BTA PPA and the Back-Stop PPA were offered as a revised proposal from EDPR, which contemplates the Joint Venture structure. Mr. Campbell testified that the prices for both PPAs are in line with other proposals received through the All-Source RFP and are considered to be market-based prices at a level in which the transaction will attract a TEP's investment. The market price was based upon an open and competitive RFP. Mr. Campbell explained that attracting the TEP is a key component of the transaction whether the BTA and BTA PPA is in full effect or the Back-Stop PPA is employed.

Mr. Campbell testified that prior to the closing of the Equity Capital Contribution Agreement ("ECCA") and the LLC Agreement, the Joint Venture will be a shell corporation. Both of these agreements must be executed as a condition to closing in the BTA. It is anticipated that the ECCA will be entered into in January 2020, when a form of the LLC Agreement will be agreed to between the parties to the ECCA. The LLC Agreement will be executed in connection with the closing of the sale of the Rosewater ProjectCo to the Joint Venture. The ECCA will obligate NIPSCO, EDPR and the TEP to contribute funds to the Joint Venture to fund the purchase of Rosewater ProjectCo. The LLC Agreement will govern the operation and management of the Joint Venture after the purchase of Rosewater ProjectCo. As noted above, NIPSCO will be the managing member of the Joint Venture. The LLC Agreement will also require NIPSCO to purchase EDPR's interest in the Joint Venture in 2023. Mr. Campbell stated that NIPSCO may purchase the TEP's interest in the Joint Venture subsequently.

Mr. Campbell stated that EDPR develops, constructs, owns, and operates wind and solar renewable energy projects throughout the United States. He also stated that EDPR's parent, EDP Renováveis SA, is the fourth largest developer of renewable energy projects in the world, and EDPR is the largest generator of wind energy in Indiana.[3] EDPR develops projects internally through experienced in-house teams of project developers, project managers, energy assessment engineers, design engineers, construction engineers, and supportive staff. EDPR has permitted and constructed over 600 MW in White County, Indiana, and another 200 MW in Randolph County, Indiana, and, in Mr. Campbell's opinion, is extremely familiar with permitting requirements associated with wind farm development.

Mr. Campbell testified that EDPR's financial ability to complete construction of the wind project and transfer it to the Joint Venture is key to NIPSCO and the Joint Venture. NIPSCO has taken this into consideration by including adequate assurance provisions in the BTA. Furthermore, as part of NIPSCO's due diligence when evaluating the creditworthiness of potential counterparties, NIPSCO gathered and reviewed credit information during the pre-qualification process in the All-Source RFP. He stated counterparties that were investment grade based on their unsecured senior debt rating met the credit requirements and that if a bidder did not meet the debt rating requirement or did not have a rating, they were required to post collateral upon executing a definitive agreement. Mr. Campbell testified that EDPR met this requirement.

Mr. Campbell explained that the role of the TEP(s) is to contribute cash to the Joint Venture under the terms of the BTA. The TEP(s) will be a party to the Joint Venture because it will be able

[3] Information obtained from EDPR's response to the All-Source RFP.

to fully use the PTCs that the project will receive. Mr. Campbell explained that the BTA requires EDPR to construct the Rosewater Project through Rosewater ProjectCo and then sell 100% of the equity interest in Rosewater ProjectCo to the Joint Venture in 2020, when it is anticipated that all of the conditions precedent will be met.

Mr. Campbell explained that the BTA requires EDPR to provide by September 2019 either a guaranty or a letter of credit from a qualified guarantor or a qualified financial institution. After the closing date, the amount of the guaranty or letter of credit remains in effect until the earlier of the date when all of EDPR's obligations have been satisfied or the third anniversary of the closing of the BTA. In the event that EDPR is in default of any of its obligations under the BTA or the Joint Venture, and by extension NIPSCO, is otherwise entitled to indemnification or damages under the BTA, then the Joint Venture has a right to access the credit support directly to reimburse the Joint Venture, and by extension NIPSCO, for any damages or costs incurred as a result of EDPR's failure to comply with its obligations under the BTA. The BTA PPA provides NIPSCO with 100% of the electrical energy output of the Rosewater Project, the unforced capacity ("UCAP"), which represents the percentage of installed capacity ("ICAP") available after a unit's forced outage rate is taken into account as shown in the BTA PPA, and any environmental attributes of the project for 15 years.

Mr. Campbell explained that in the first quarter of 2018, NIPSCO retained CRA to assist in the design, administration, and bid evaluation of a RFP. The purpose of the RFP was to solicit binding bids to cover an anticipated capacity shortfall starting in 2023 and to obtain market-based information on the cost and performance of alternative resource options to inform and improve NIPSCO's 2018 IRP. Through the process, NIPSCO received bids supported by renewable facilities, fossil resources, energy storage, and demand response options. Bids for both standalone assets and integrated facilities comprised of different resource types or supported by storage were submitted. Bidders offered assets under PPAs and offered assets for sale.

Mr. Campbell's role in the RFP process was to ensure that the process conformed to NIPSCO's intent to competitively bid and secure additional electric energy and capacity in the amount needed to serve NIPSCO's retail customers in the future, and that CRA conducted the process in a fair and transparent manner.

Mr. Campbell stated that once the preferred plan within the IRP was chosen and the RFP results were reviewed, NIPSCO, in conjunction with CRA, negotiated with developers of the most viable wind energy projects. During the negotiations, the number of potential wind projects was reduced to four. After completion of negotiations over the terms, conditions and price, NIPSCO executed three wind agreements for a total purchase of approximately 800 MW of wind power. The size of each project may change slightly as engineering and technical specifications are finalized.

Mr. Campbell testified that the decision to contract for the wind in 2020 was based upon NIPSCO's and CRA's analysis that NIPSCO's customers, over the life of the projects, would save approximately $500 million due to the declining value of the PTC. He stated that the Rosewater Project plays a role in satisfying NIPSCO's electric planning goals and objectives.

Mr. Campbell explained that congestion risks were assessed using MISO's future year ProMod models which are capable of simulating hourly market operations for a given study year. The output was then used to determine the expected curtailments, total revenue and congestion and loss charges for each site under consideration. Sites with greater congestion risk have been appropriately discounted in NIPSCO site analysis.

Mr. Campbell stated that the wind project's general interconnection agreement has been completed and is in the MISO queue. The point of interconnection is NIPSCO's 138 kilovolt Reynolds Substation. To facilitate the project's interconnection, upgrades are required at the Reynolds Substation and work is to be completed in August of 2020 by NIPSCO as the interconnecting utility.

Mr. Campbell testified NIPSCO will take delivery of the wind energy from Rosewater ProjectCo at a specified metering point. He stated NIPSCO will be the Market Participant and will make the energy available in the MISO energy market. He testified NIPSCO will be paying the Joint Venture (through the Rosewater ProjectCo) the contract price per MWh and counting this wind energy as used in the NIPSCO system. He stated that NIPSCO will "settle" the sale price for the wind energy sold into MISO against the price paid for the wind energy. Mr. Campbell explained that NIPSCO offers its generation and bids its load into the MISO energy markets daily, along with other sales and purchases, in the end "settling" the costs against revenues. He said MISO treats wind energy projects as dispatchable intermittent resources and, as such, Rosewater ProjectCo will be subject to real-time Revenue Sufficiency Guarantee and Uninstructed Deviation charges assessed under the Open Access Transmission, Energy and Operating Reserve Markets Tariff.

Mr. Campbell explained that the generator interconnection agreement that Rosewater ProjectCo will be receiving from MISO will have network resource interconnection service ("NRIS") available for its full injection once any required transmission system upgrades at Reynolds substation are complete. Having NRIS will allow NIPSCO to designate this generation facility as a network resource to receive Network Integration Transmission Service without further study.

Mr. Campbell testified that if all of the BTA's conditions precedent are met, the BTA PPA will provide NIPSCO's customers with a more affordable and cleaner energy resource and that this is supported by the analysis performed in NIPSCO's 2018 IRP.

Mr. Campbell testified that if all of the BTA's conditions precedent are not met, the Back-Stop PPA will provide NIPSCO's customers with a more affordable and cleaner energy resource and that this is supported by the analysis performed in NIPSCO's 2018 IRP.

Mr. Campbell described the alternative practices, procedures and mechanisms NIPSCO is seeking under the ARP. He stated that NIPSCO is requesting approval of the following four alternative practices, procedures and mechanisms in connection with the Joint Venture: (1) Since the Rosewater Project arose out of the All-Source RFP, NIPSCO seeks to be relieved of or otherwise found to have complied with the obligations to receipt of a CPCN established under Ind. Code § 8-1-8.5-5(e); (2) NIPSCO will not be the owner of the generating assets that make up the

Rosewater Project. Instead, NIPSCO will own an interest in Joint Venture. NIPSCO seeks approval of the Joint Venture and the joint venture structure. NIPSCO further seeks to record its interest in the Joint Venture as a regulatory asset in Account 182.3 and to amortize the amounts so recorded using the amortization rates sought to be approved for the Rosewater Project. Mr. Campbell said that NIPSCO requests to include in net original cost rate base and in the value of its utility property for purposes of Ind. Code § 8-1-2-6 and for ratemaking purposes the balance of the regulatory asset NIPSCO has recorded for the Joint Venture; (3) As noted, NIPSCO seeks to recover its payments made to Rosewater ProjectCo pursuant to the BTA PPA and the Back-Stop PPA, through the FAC without regard to Ind. Code § 8-1-2-42(d)(1) through (4) ("Section 42(d)") and without regard to any benchmarks established by the Commission for PPAs; and (4) To the extent necessary, NIPSCO is seeking approval of financing. To the extent financing approval is sought and obtained herein, NIPSCO seeks to be relieved of the technical requirements set forth in Ind. Code §§ 8-1-2-79 and -80. According to Mr. Campbell, these include corporate officer signatures and verifications, the elements in Ind. Code § 8-1-2-79(a)(1) through (6), and the specific provisions to be set forth in the Commission's certificate of authority set forth in Ind. Code § 8-1-2-80(a) and (b).

Mr. Campbell testified NIPSCO's proposed Joint Venture and participation in the Rosewater Wind Project is in the public interest as required for an ARP as set forth in Ind. Code ch. 8-1-2.5. He opined that the creation of Joint Venture is in the public interest in that it allows NIPSCO to obtain less expensive energy for its customers by maximizing the benefit of the wind project's PTCs. It thus enhances for NIPSCO's customers the value of NIPSCO's retail services. According to Mr. Campbell, the 2018 IRP shows that the most viable path for NIPSCO's customers involves accelerating the retirement of a majority of NIPSCO's remaining coal-fired generation in the next five years and all coal within the next ten years, with replacement generation provided by lower-cost renewable energy resources such as wind, solar, and battery storage. To maximize the benefit for NIPSCO's customers of that lower-cost renewable energy, NIPSCO must find the path to monetizing the tax benefits described by Witness McCuen. Mr. Campbell testified that NIPSCO also recognizes the value for its customers from NIPSCO being in control of its generation and minimizing the risk from relying too heavily on counterparties to PPAs. Mr. Campbell stated that the Joint Venture structure provides full control of the renewable energy project by NIPSCO with a much lower investment and lower risk profile that more efficiently monetizes the tax benefits of the renewable energy project. If NIPSCO were not to employ the Joint Venture and outright purchase the project, the value of the tax benefits associated with the renewable project would be greatly reduced. He said the Joint Venture also allows NIPSCO's customers to receive the value of the tax benefits associated with the project as they are realized. In short, it is this Joint Venture structure that makes the implementation of NIPSCO's 2018 IRP possible. Mr. Campbell also provided the confidential value of structuring the transaction through the Joint Venture.

Mr. Campbell identified five benefits of the Joint Venture structure to NIPSCO's customers: (1) NIPSCO will have full control of the wind project, which will allow it to operate the project efficiently; (2) the levelized cost of the power from the project over the project's lifetime will be less than if NIPSCO built the project or just signed a PPA with a project developer; (3) NIPSCO's power portfolio will be more diversified because it will eventually include an owned, renewable asset; (4) NIPSCO will not have to bear the counterparty risk that exists in a traditional PPA; and (5) NIPSCO will have the option to repower the project at the end of its life or to retire it, whichever provides its customers the best value.

Mr. Campbell noted that there are certain competitive procurement requirements set forth in Ind. Code § 8-1-8.5-5(e) and since the Rosewater Project arose out of the All-Source RFP, NIPSCO seeks to be relieved of or otherwise found to have complied with those requirements. Mr. Campbell opined that based on the unique circumstances of this case, additional competitive procurement requirements would not only be unnecessary but would jeopardize the implementation of the 2018 IRP.

Mr. Campbell explained that without the ability to earn a return on its investment in the Joint Venture, there would be no incentive for NIPSCO to pursue the Joint Venture. NIPSCO must create the Joint Venture structure to capture the value of the tax benefits from the Rosewater Project for the benefit of NIPSCO's customers. He stated that if traditional ratemaking would deny NIPSCO the ability to earn a return on the investment that is needed to capture the value of those benefits, then NIPSCO cannot make that investment. Mr. Campbell opined that approving this aspect of NIPSCO's ARP is in the public interest because it enhances the value of NIPSCO's services for its customers and allows NIPSCO to implement the 2018 IRP.

Mr. Campbell explained that to the extent Ind. Code §§ 8-1-2-79 and -80 might apply because the Commission might view the Joint Venture as a financing mechanism, NIPSCO seeks to be relieved from its requirements because NIPSCO is not issuing new debt, nor is it selling any securities. He opined that the requirements of Ind. Code §§ 8-1-2-79 and -80 are unnecessary in this context.

Mr. Campbell concluded that Ind. Code § 8-1-2.5-6(a)(1) authorizes the adoption of alternative regulatory practices, procedures and mechanisms if they are in the public interest (after considering the factors set forth in Ind. Code § 8-1-2.5-5) and if they will enhance or maintain the value of NIPSCO's retail energy services or property. The Joint Venture and each of the elements of NIPSCO's proposed ARP are in the public interest. By implementing the Rosewater Project through the Joint Venture structure, NIPSCO is reducing the overall cost of the Rosewater Project to NIPSCO and to NIPSCO's customers. This enhances the value of NIPSCO's retail energy services and property. Mr. Campbell stated that two of the factors in Ind. Code § 8-1-2.5-5 are especially applicable here because approval of the Joint Venture and the proposed ARP will be beneficial to NIPSCO, NIPSCO's customers, and the State of Indiana. Further, by reducing overall cost, approval of the ARP promotes energy utility efficiency.

Mr. Campbell explained that because the Joint Venture will not be the title owner of the Rosewater Project, Joint Venture will not own electric generation facilities that provide electricity that NIPSCO will use to serve the public. Instead, NIPSCO will purchase 100% of the electrical energy output of the Rosewater Project at market-based rates from Rosewater ProjectCo under the BTA PPA. As such, Joint Venture is not a "public utility." He said that the Joint Venture will own Rosewater ProjectCo, which will own facilities that only provide service to NIPSCO on a wholesale basis. He noted the unique circumstances of this arrangement, the Commission's exercise of jurisdiction over NIPSCO and the regulation by FERC, render the exercise of jurisdiction by this Commission over Joint Venture as a public utility unnecessary. Further, declining to exercise jurisdiction will be beneficial to Joint Venture, NIPSCO, NIPSCO's customers and the State of Indiana. Mr. Campbell said declining to exercise jurisdiction will also promote energy utility efficiency. In addition, the exercise of the Commission's jurisdiction over Joint Venture as a public utility would inhibit the implementation of NIPSCO's generation transition plan as set forth in its 2018 IRP. Accordingly, Mr. Campbell opined that the Commission should proceed to issue an order declining to exercise its jurisdiction over Joint Venture as a public utility. Mr. Campbell also requested that the Commission confirm that once Rosewater ProjectCo becomes an affiliated interest of NIPSCO, it will maintain the declination of jurisdiction, assuming such is granted, in the proceeding initiated by Rosewater ProjectCo seeking a declination of Commission jurisdiction.

Mr. Campbell also noted that NIPSCO is seeking a CPCN pursuant to Ind. Code § 8-1-8.5-2 to purchase and acquire the Rosewater Project through the Joint Venture. He stated that the Rosewater Project is consistent with the 2018 IRP. He also noted that the purchase and acquisition of the Rosewater Project through the Joint Venture is consistent with the Commission's 2018 Report on the Statewide Analysis of Future Resource Requirements for Electricity that was issued by the Commission in the fall of 2018.

Mr. Campbell testified that if all of the BTA's conditions precedent are met, NIPSCO is proposing to timely recover the costs in accordance with Ind. Code §§ 8-1-8.5-6 and 8-1-8.8-11 through a rate adjustment mechanism approved pursuant to Section 42(a) on the basis of energy concurrent with its FAC filings. Furthermore, Mr. Campbell stated that NIPSCO is seeking approval of power purchases pursuant to the BTA PPA as reasonable throughout the entire term of the agreement and therefore confirmation that the costs thereof are recoverable through the FAC filing without regard to the Section 42(d) tests or any other FAC benchmark.

Mr. Campbell testified that if all of the BTA's conditions precedent are not met, NIPSCO is proposing to timely recover the costs through a rate adjustment mechanism approved pursuant to Section 42(a) on the basis of energy concurrent with its FAC filings. Furthermore, Mr. Campbell stated that NIPSCO is seeking approval of power purchases pursuant to the Back-Stop PPA as reasonable throughout the entire term of the agreement and therefore confirmation that the costs thereof are recoverable through the FAC filing without regard to the Ind. Code § 8-1-2-42(d) tests or any other FAC benchmark.

Mr. Campbell explained that as used in the BTA PPA and the Back-Stop PPA, the term "Environmental Attribute" is intended to capture any changes to governmental rules, regulations or law, or changes to registration systems put in place over the term of the BTA PPA and Back-Stop PPA. He said NIPSCO anticipates the RECs it receives will be tracked through the Midwest Renewable Energy Tracking System ("M-RETS"). Mr. Campbell explained M-RETS is a database that tracks relevant information about renewable energy produced and delivered in the Upper Midwest, including the MISO footprint, to verify for subscribers in states with mandatory or voluntary renewable portfolio standards, or for utility and other participants, the RECs made available to them through REC purchases and sales. M-RETS will track the ownership of RECs and generation attributes that result from the generation of renewable electricity.

(b) **<u>McCuen Direct Testimony</u>.** Mr. McCuen described the structure of the

Joint Venture and how it provides value to NIPSCO's customers. He testified there are two wind projects being negotiated with developers that anticipate utilizing the Joint Venture structure, one of which is presented in this proceeding.

Mr. McCuen testified the joint venture will be a limited liability company that will own and operate the wind generation assets. He stated that 100% of the energy and capacity of the project will be sold to NIPSCO through a PPA. He testified there will be three members in the joint venture – NIPSCO, the Developer, and the TEP. He explained there will be two documents that control the joint venture – the LLC Agreement and an ECCA.

Mr. McCuen stated that Confidential Attachment 1-E is an Example Term Sheet of a joint venture agreement. He stated this Term Sheet has not been negotiated between parties and is intended only as an example of the material terms that are typically addressed in joint venture agreements for renewable energy wind projects. He stated the Example Term Sheet outlines all the material items that would be in an LLC Agreement. He testified that when the LLC Agreement is finalized, a copy will be shared with all parties and can be submitted to the Commission.

Mr. McCuen noted the LLC Agreement will set forth the terms applicable to: (1) the operation and management of joint venture and Rosewater ProjectCo; (2) the allocation of tax items; (3) the distribution of net cash flow by the joint venture after the Funding Date; (4) managing members; (5) milestones for investor returns; (6) condition precedents; (7) relationship to other related documents; (8) representations and warranties of parties; (9) purchase price option; and (10) governance.

Mr. McCuen testified the ECCA is the document that binds the TEP to invest in the Joint Venture if all conditions precedent in it are met. He stated the ECCA is the document that causes the joint venture to issue Class A Interests to the Member and Class B Interests to the Investors, in each case, in accordance with the terms of the LLC Agreement. He stated that on the financial closing date, the joint venture will acquire all of the outstanding membership interests of the Rosewater ProjectCo for the purchase price. He stated that when the ECCA is finalized, a copy will be provided to all parties and can be submitted to the Commission. Mr. McCuen testified NIPSCO will be the managing member of the Joint Venture.

Mr. McCuen noted that the Joint Venture was formed on December 11, 2018 with NIPSCO as the sole member. He stated the other members of the Joint Venture will be added when the Rosewater Project is completed and indirectly sold to Joint Venture. He testified the project is expected to be completed and in-service no later than December 31, 2020. He explained that the significance of the date of completion is that the Rosewater Project is expected to qualify for Section 45 PTCs as provided under the Internal Revenue Code. He testified that if the project is completed and in-service by December 31, 2020, it will qualify for 100% of the PTC, a significant source of value to the project.

Mr. McCuen identified the dollar amount of PTCs provided by the Internal Revenue Code the Rosewater Project is anticipated to generate over the 10-year period. The actual amount of PTCs generated can vary based upon the output of the facility. The projections reflect a capacity factor using the historic wind data for this region.

Mr. McCuen explained that under current legislation, the owner of a wind project will receive 100% of the PTC if it started the project in 2016 and finished the project within a 4-year window (before 2021). He stated that projects that begin after 2019, or go into service after 2023, are not eligible for the PTC. He testified that the Internal Revenue Service ("IRS") will consider construction as having begun if the taxpayer paid or incurred 5% or more of the total cost of the facility in a particular taxable year, and thereafter made continuous efforts to advance towards completion of the facility. He stated that generally, the continuous construction and continuous efforts requirements will be deemed satisfied if a facility is placed in service by the calendar year that is no more than four calendar years after the calendar year during which construction of the facility began. Mr. McCuen testified that the wind developer in this proceeding, EDPR, obtained in 2016, project equipment valued at more than 5% of the cost of the project. Therefore, the project will be eligible for 100% of the wind PTC in 2021 – 2030 (i.e., ten years) if it is placed into service by December 31, 2020.

Mr. McCuen testified the PTC amount is $0.015/kilowatt hour ("kWh") in 1993 dollars adjusted for inflation using the inflation adjustment factor published each year by the IRS in the Federal Register. He stated that in 2018, the factor was 1.5792 and therefore the PTC was approximately 2.4¢/kWh.

Mr. McCuen testified the Rosewater Project is being developed by EDPR through its wholly owned subsidiary, Rosewater ProjectCo. He stated that when the project is completed and ready to be placed in service, Joint Venture will purchase Rosewater ProjectCo's equity from EDPR. He testified that each member of the Joint Venture will contribute the requisite amount of cash for their membership interest in order to have the cash available to purchase the project from EDPR.

Mr. McCuen stated that Rosewater ProjectCo will enter into a PPA with NIPSCO as the exclusive off-taker of power and capacity from the project. He explained that NIPSCO will make payments under the terms of the PPA to Rosewater ProjectCo. Out of the proceeds of the PPA payments, Rosewater ProjectCo will pay for all of the operation and maintenance ("O&M") expenses of the project along with any other expenses, including property taxes. He stated that any cash remaining after the payment of expenses will be distributed to the tax equity investor and NIPSCO. He said that based upon the projections, the tax equity partner is expected to take no more than a specific percent of this excess cash from the project, with the remainder flowing to NIPSCO.

Mr. McCuen noted that under the terms of an anticipated LLC Agreement, a specific percent of the PTCs and tax losses of the Rosewater Project will be allocated to the tax equity partner until such time as the tax equity partner has achieved the negotiated IRR. He stated that when this IRR is achieved, the allocation of profits and losses to the tax equity investor will drop to a specific percent. He testified that NIPSCO projects that 100% of the PTCs will have been generated and distributed prior to reaching this point.

Mr. McCuen explained that cash investments will be made when the project is completed and ready to go into service, which is expected to be on or before December 31, 2020. He stated that no later than mid-2023, NIPSCO will be required to purchase the ownership interest of EDPR for a fixed price as negotiated under the terms of the BTA. He indicated this is anticipated to coincide with the retirement of Schahfer and at that point, NIPSCO will have invested a specific amount of cash in the Joint Venture.

Mr. McCuen testified that other than accounts payable and operating lines of credit, the Joint Venture will not have any short or long term debt on its balance sheet. He testified that tax equity partner brings financial efficiency to the project by virtue of its ability to utilize the tax attributes on a more accelerated basis than the other members in the Joint Venture. In essence, the tax equity partner is monetizing the tax attributes of the Rosewater Project and thereby reducing the cost to the NIPSCO customer.

Mr. McCuen explained why the tax equity partner is able to utilize the tax attributes more efficiently than the other members in the Joint Venture. He testified that EDPR typically employs tax equity partners in projects that EDPR develops and owns as EDPR does not have an appetite for the tax attributes. He stated NIPSCO is similarly constrained in the use of tax attributes due to previous and anticipated accelerated tax deductions that will limit its utilization of losses and credits over the next several years. He stated that the TEP, on the other hand, is not involved in a capital intensive industry and not subject to the tax incentives (i.e. accelerated depreciation) provided by Congress for electric utility infrastructure investing and therefore has the capacity to immediately utilize tax credits as they are generated by the project. He stated that this ability of the TEP to more efficiently utilize the tax attributes is reflected in the upfront cash investment, which reduces the overall investment of NIPSCO in the project (and ultimately the cost to the customer) while still allowing NIPSCO to obtain 100% of the non-tax ownership attributes of the project.

Mr. McCuen testified that under the terms of the LLC Agreement, NIPSCO will have the option to acquire the tax equity partner's remaining ownership interest after the tax equity partner has achieved its negotiated IRR. He stated that this buyout option provides for a fair market value purchase price of that remaining ownership interest, determined on the discounted future cash flows of the project for the remaining 5% ownership interest.

(c) <u>Camp Direct Testimony</u>. Ms. Camp explained NIPSCO's proposed accounting treatment for its investment in Joint Venture. She testified NIPSCO proposes that its investment in Joint Venture be recorded as a regulatory asset, which would be included in its rate base in subsequent rate case proceedings, including a return of and return on. In addition, NIPSCO requests that any investments made in Joint Venture, which are recorded as a regulatory asset, would be amortized over the life of the Rosewater Project, which is currently estimated to be 30 years. She stated amortization of the regulatory asset would begin as of the closing on the BTA.

Ms. Camp described the authority sought with respect to the deferral of amortization. She explained that the regulatory asset will consist of NIPSCO's investment in the Joint Venture. Over time, NIPSCO will make different capital contributions to the Joint Venture. For instance, one contribution will be made at or about the closing on the BTA. Another will be made in 2023 when NIPSCO buys out EDPR's interest. She noted that there could be others. Ms. Camp explained that amortization of the regulatory asset will commence as of the in-service date of the Rosewater

Project. She said that, with respect to each capital contribution it makes to the Joint Venture, NIPSCO requests authorization to defer amortization of the regulatory asset corresponding to that contribution until such time as the recovery of the amortization of that portion of the regulatory asset balance is reflected in NIPSCO's rates and charges. Ms. Camp testified that NIPSCO requests authority to record the deferral in Account 182.3 and that the amounts so recorded be included in NIPSCO's rate base for ratemaking purposes and amortized over the remaining life of the Rosewater Project.

Ms. Camp stated that similar to the deferral of amortization, NIPSCO seeks to accrue PISCC with respect to each capital investment that it makes to the Joint Venture, with such PISCC accrued at NIPSCO's weighted average cost of capital ("WACC") until a return on that particular investment is recovered through NIPSCO's rates and charges. Again, she said the amount so accrued would be recorded in Account 182.3, included in NIPSCO's rate base for ratemaking purposes, and amortized over the remaining life of the Rosewater Project.

Ms. Camp testified the accounting and ratemaking treatment for NIPSCO's investment in the Joint Venture, including the deferral of amortization and accrual of PISCC, is similar to the regulatory treatment that would be afforded NIPSCO if NIPSCO were the initial owner of the asset. She said the transaction is being pursued through the Joint Venture to provide value to customers by monetizing the PTCs, which can only be done by structuring the transaction in this fashion, but it will result in NIPSCO having an investment in the Joint Venture rather than in utility plant. She explained NIPSCO needs the opportunity to earn a full return on its investment in order for this to be possible. Otherwise, NIPSCO would purchase the generation the traditional way, which would undoubtedly be used and useful utility plant, but the value of the PTCs would be significantly diminished. NIPSCO's investment in the Rosewater Project under the traditional approach would be higher, reflecting the full purchase price under the BTA.

Ms. Camp testified that NIPSCO requests that the retail jurisdictional portion of the costs incurred pursuant to the Wind PPAs be recovered on a timely basis through retail rates over the term of the Wind PPAs. Witness Campbell explained that NIPSCO will receive payments as an owner of the Joint Venture. NIPSCO requests authority to defer such payments it receives as a regulatory liability that will offset the costs that NIPSCO incurs pursuant to the Wind PPAs through the FAC. She said NIPSCO requests the Commission authorize NIPSCO to recover the costs of the Wind PPAs, including all associated MISO costs, from retail customers through the full term of the Wind PPAs via a rate adjustment mechanism in accordance with Section 42(a) and Ind. Code § 8-1-8.8-11. NIPSCO proposes this recovery be accomplished through the tracking provision of Section 42(a) by treating the costs of the Wind PPAs as a cost to be recovered in a fashion similar to the FAC mechanism, where the cost is recovered based on the estimated cost for a particular quarter and trued-up in a subsequent quarter. She stated that initially, NIPSCO proposes to seek recovery of the costs of the Wind PPAs in conjunction with and contemporaneous with its quarterly FAC proceedings. The quarterly FAC filings would show, on both a projected and actual basis, costs associated with the Wind PPAs as a separate line item for easy identification. She explained that although NIPSCO is initially proposing to have the cost recovery administered through its FAC, this cost recovery should not be subject to the Section 42(d) tests or any FAC benchmarks, including benchmarks set forth in Cause No. 43526. Essentially, NIPSCO proposes the same recovery mechanism as the Commission approved for NIPSCO in Cause No. 43393. To the extent necessary to be relieved of these conditions, this is part of NIPSCO's proposed ARP.

Ms. Camp stated that NIPSCO currently has no plans to change the recovery mechanism, but acknowledges that such a change would be possible in a subsequent electric rate case.

Ms. Camp testified it is possible that GAAP will require the Joint Venture's financial statements to be consolidated with NIPSCO's and that, in consolidation, debt will be created on the consolidated financial statements as a result of the Joint Venture. NIPSCO seeks Commission approval of such financing to the extent it results purely from GAAP requirements, but the statutes under which financing approval is obtained, Ind. Code §§ 8-1-2-79 and -80, include several requirements that are unnecessary to this particular transaction. She stated these include corporate officer signatures and verifications, the elements in Ind. Code § 8-1-2-79(a)(1) through (6), and the specific provisions to be set forth in the Commission's certificate of authority.

Ms. Camp concluded that each of the proposals presented are in the public interest. She testified that granting approval will be beneficial for NIPSCO to be able to implement its 2018 IRP and will thereby enhance value for NIPSCO's customers.

(d) **Augustine Direct Testimony.** Mr. Augustine discussed the preferred portfolio from NIPSCO's 2018 IRP and how the assumptions associated with the new wind resource options modeled in the 2018 IRP compared with the cost of the BTA and Back-Stop PPAs.

Mr. Augustine provided an overview of NIPSCO's preferred portfolio from the 2018 IRP and described how it was developed. He said NIPSCO's preferred portfolio retires all four coal units at Schahfer in 2023 and retires the Michigan City Generating Station coal plant in 2028. Mr. Augustine stated the preferred portfolio includes the following capacity replacements over time: 125 MW of energy efficiency and demand side management peak load savings by 2023, growing to 370 MW by 2038; approximately 1,100 MW of ICAP wind representing 157 MW of UCAP 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. He noted that Section 9.3 of the 2018 IRP provides additional detail associated with the preferred replacement portfolio.

Mr. Augustine testified the plan was developed through substantial quantitative and qualitative analysis, including the use of the All-Source RFP solicitation to identify the most relevant types of resources available in the market, along with their associated costs. He stated that 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. He stated that NIPSCO also evaluated the impact each of the retirement and replacement alternatives would have on local communities and NIPSCO's employees.

Mr. Augustine provided an overview of the 2018 IRP's Short Term Action Plan as it relates to the replacement resources in the preferred portfolio. He stated that part of the Short Term Action Plan 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. Furthermore, he stated that, in the Short Term Action Plan, NIPSCO identified a phased-in approach to selecting and acquiring these replacement resources. Mr. Augustine said 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. He stated the prioritized replacement resources are wind projects looking to qualify for the PTC, which is expiring over the next few years. Mr. Augustine testified that 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.

Mr. Augustine testified the preferred portfolio included two wind resource additions: an asset acquisition of 600 MW of ICAP (90 MW of UCAP) in 2020, and a PPA of 501 MW of ICAP (67 MW of UCAP) in 2021.

Mr. Augustine described how NIPSCO used the All-Source RFP to determine the cost and operational performance assumptions of wind resources in its IRP. He said 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. Mr. Augustine testified that this approach allowed for the efficient development of planning-level assumptions that could be transparently shared with stakeholders and deployed in the 2018 IRP models. He stated 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.

Mr. Augustine described the specific assumptions used for the wind tranches that were selected in the preferred plan in the 2018 IRP. He said 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. He stated the PPA of 501 MW of ICAP (67 MW of UCAP) was assumed to enter into service in the middle of 2021 with a 20-year contract duration, a fixed nominal PPA price of $25.54/MWh, and a capacity factor of approximately 42%.

Mr. Augustine testified he was able to compare the total cost of the BTA PPA and Back-Stop PPA with the total costs of these tranche-level inputs used in the 2018 IRP modeling. He stated he 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 MWh Joint Venture. Mr. Augustine said the LCOE develops a levelized, all-in cost of a given resource option over a pre-defined analysis period on a per MWh basis and that 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.

Mr. Augustine explained the inputs that are required to perform an LCOE calculation. He stated that 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 WACC and capital structure projected as of December 31, 2019; the expected FOM costs and ongoing capital expenditures over the 30-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.

Mr. Augustine testified that 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 30-year planning horizon. He said 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.

Mr. Augustine described the LCOE values calculated for the two wind resource tranches incorporated in the 2018 IRP's preferred portfolio. He said the 30-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 30-year project life. He said the 30-year LCOE of the 2021 wind PPA was calculated to be $32.63/MWh based on the 30-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. Mr. Augustine testified that the 30-year LCOE of the Joint Venture was calculated based on an acquisition cost, a capacity costs factor, and a 30-year project life. He illustrated how the LCOE values for the wind resource tranches incorporated in the 2018 IRP's preferred portfolio compare with the LCOE of the Joint Venture.

Mr. Augustine testified 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 of wind additions in the 2020-2021 time period. He stated that 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 net present value of revenue requirement that is far less than the savings projected for NIPSCO's customers in the 2018 IRP's preferred portfolio. In addition, Mr. Augustine said the generation-weighted average LCOE of the three wind projects currently being pursued by NIPSCO is lower than the generation-weighted average of the two wind tranches used in the 2018 IRP ($36.07/MWh). He stated 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, Mr. Augustine testified, 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.

(e) Lee Direct Testimony. Mr. Lee explained the analysis NIPSCO used to evaluate its various options for wind energy and why NIPSCO's investment in the Joint Venture is an economic choice for helping meet NIPSCO's retail electric load. He described the key findings outlined in the opinion letter provided from CRA to NIPSCO following the RFP. He testified that through the opinion letter and its attachments, CRA recommended certain assets as potential projects to advance to a definitive agreement phase and that the assets recommended for advancement were selected based on the preferred portfolio in NIPSCO's 2018 IRP and the RFP scoring criteria developed in advance of the RFP process.

Mr. Lee sponsored Confidential Attachment 3-D, which includes the detailed scoring results for each project bid into the RFP. He stated that consistent with the All-Source RFP process rules, each project was evaluated based on development risk, reliability, asset-specific risk, and the estimated net present value ("NPV") of facility revenues and costs.

Mr. Lee provided an overview of NIPSCO's 2018 IRP and All-Source RFP process. He said in 2016, NIPSCO conducted an integrated resource planning process that identified a potential capacity shortfall at or around 2023 and included tentative conclusions as to future resource options. He then noted that in 2018, NIPSCO updated the 2016 IRP to ensure that resource planning reflected the most current outlook for key market drivers. Mr. Lee testified that on May 14, 2018, NIPSCO issued a news release announcing its intent to explore potential options to meet the future needs of its residential, commercial and industrial electric customers. He explained the All-Source RFP process was a component of NIPSCO's broader resource planning and analysis having a dual purpose. He said the first objective of the All-Source RFP was to solicit bids to cover NIPSCO's anticipated capacity shortfall starting in 2023. The second objective was to secure market-based information on the cost and performance of alternative resource options to inform and improve NIPSCO's 2018 IRP.

Mr. Lee described his involvement in NIPSCO's 2018 IRP process, which began in February 2018 after the 2018 IRP process had been initiated. He explained that the All-Source RFP was intended to inform NIPSCO's resource planning and identify potential capacity assets to meet NIPSCO's needs. He stated the All-Source RFP was conducted as part of an integrated IRP and RFP process and that his role was to help design and administer the All-Source RFP process.

Mr. Lee said through the All-Source RFP, NIPSCO sought to identify the discrete capacity resources best positioned to satisfy the anticipated capacity shortfall consistent with both the 2018 IRP analysis and the All-Source RFP bid selection criteria. He said NIPSCO considered a wide range of asset types, including physical generating assets, PPAs and demand response resources. Mr. Lee stated that through the process, NIPSCO received bids supported by renewable facilities, fossil resources, energy storage, and demand response options and that bids for both standalone assets and integrated facilities comprised of different resource types or supported by energy storage were submitted. He stated that bidders offered assets under PPA arrangements and assets for sale. In addition, he said, while the 2016 IRP identified an anticipated capacity shortfall starting in 2023, NIPSCO considered bids with transfer dates or PPA start dates in advance of the identified need in 2023. Mr. Lee stated CRA served as an independent third party managing the RFP process.

Mr. Lee testified the All-Source RFP was issued on May 14, 2018 and CRA conducted a bidder conference on May 16, 2018. He said prospective bidders were required to provide a Notice of Intent, Bi-lateral Confidentiality Agreement and Pre-Qualification Application due on May 29, 2018, with final proposals due on June 29, 2018.

Mr. Lee provided an overview of the All-Source RFP design and execution. He stated that prior to issuing the All-Source RFP, CRA worked with the NIPSCO team to define the process objectives and requirements. He testified that NIPSCO advised CRA that in order to ensure adequate, reliable capacity supplies to meet customer needs, it intended to acquire dispatchable, semi-dispatchable or renewable resources that, at a minimum, would meet established industry-wide reliability and performance criteria for electric generation facilities and that had physical deliverability into MISO Local Resource Zone 6 ("LRZ6"). He said CRA worked with NIPSCO to prepare the RFP documentation, ensuring the product requested was clearly defined and the evaluation criteria were clearly specified in the RFP documentation.

Mr. Lee explained how CRA and NIPSCO informed interested parties about the All-Source RFP. He stated that CRA managed the outreach to potential bidders interested in the process and worked with NIPSCO to identify existing assets and projects in-development located within LRZ6 as well as potential demand response providers. He said representatives from potential bidders were contacted via electronic mail notices and phone calls, informing them of the RFP and relevant due dates and that both NIPSCO and CRA participated in public stakeholder sessions to inform interested parties about the process and the integrated IRP/RFP approach. In addition, he explained NIPSCO published a press release related to this RFP on its website on May 14, 2018 and CRA ran trade press advertising in Megawatt Daily on May 14, 2018.

Mr. Lee testified that throughout the All-Source RFP process, CRA maintained a public Information Website that warehoused all key documents related to the All-Source RFP. He explained that through that Information Website, interested parties could submit questions and comments related to the process, and the documents or the All-Source RFP requirements. When appropriate, those questions and answers were posted to the RFP Information Website to ensure all bidders had equal access to information. He said all interested parties were allowed to submit Proposals in the All-Source RFP. Mr. Lee testified that ultimately, CRA approved all pre-qualification applications submitted and notified the applicants of their pre-qualification status.

Mr. Lee stated the All-Source RFP generated substantial interest from bidders. He said NIPSCO received more bids in response to its All-Source RFP than any capacity RFP he had participated in to date. Mr. Lee noted CRA received 90 proposals supported by 59 projects across five states and that many of the PPA proposals included fixed or variable pricing arrangements or options on the start date and contract term. He stated that several proposals included multiple options for facility configuration and resource sizes.

Mr. Lee noted that in total, nearly 15 gigawatts ("GW") of UCAP were offered into the RFP, providing a wide range of capacity choices across technologies and deal structures.

Mr. Lee explained that CRA evaluated the economics and other scoring considerations related to each Proposal independent of NIPSCO or any NIPSCO affiliates. He said CRA reserved the right, in its sole and exclusive discretion, to reject any and all Proposals on the grounds that such Proposal did not conform to the terms and conditions of the RFP or on the grounds that the bidder did not comply with the provisions of the RFP.

Mr. Lee described how RFP bids were used to inform IRP modeling. He said the proposals received in response to the RFP were used to develop "tranches" or bundles of assets comprised of individual facilities with similar cost, performance and overall economics. He said the bid tranches were used by the NIPSCO IRP team to develop a preferred capacity plan that included a range of asset types and that the preferred plan, which set the capacity needs by asset type, was announced at a public stakeholder session conducted on October 19, 2018. He stated the RFP selected individual proposals for advancement to a potential definitive agreement phase consistent with the IRP preferred plan and based on the RFP's scoring criteria. Mr. Lee described the Proposal review and evaluation.

Mr. Lee stated that CRA reviewed all proposals that met pre-determined qualifying criteria set forth in the RFP documentation and evaluated each based on certain pre-specified evaluation criteria. He said for physical generating assets and storage assets offered under either a PPA or an asset sales structure, the evaluation considered: (1) estimated NPV of expected market revenues and costs from the present through 2043 (20 years beyond the 2023 anticipated need date); (2) asset reliability and deliverability; (3) development risk; and (4) asset-specific risk factors. He explained that Demand Response proposals were evaluated across four categories: (1) cost; (2) demonstrated performance; (3) response time; and (4) proposal-specific risk factors.

Mr. Lee testified CRA evaluated the bids independent of NIPSCO. He said NIPSCO was not directly involved in the evaluation of proposals nor was NIPSCO aware of bidder identities as part of the process. He stated NIPSCO was provided general information about the level of interest in the RFP, the MW of capacity offered by asset type and the deal structure. He explained that CRA also provided NIPSCO indications of the general level and range of prices received for various asset categories in order to facilitate communication with stakeholders and others interested in the NIPSCO process. He stated that during the evaluation, NIPSCO was only made generally aware of CRA's progress and was only involved with bidder-specific issues if those issues required policy or technical guidance from NIPSCO subject matter experts.

Mr. Lee discussed the IRP process conclusions and NIPSCO's preferred plan. He testified that the 2018 IRP considered a range of options around the potential retirement of existing NIPSCO fossil generation facilities and developed an optimal portfolio of assets based on detailed scenario and risk analysis and informed by comprehensive market modeling. He explained that the magnitude of the 2023 resource need was directly dependent on the conclusions derived from the 2018 IRP.

Mr. Lee stated that NIPSCO's 2018 IRP results indicate that the optimal path forward includes the medium-term retirement of Schahfer Units 14, 15, 17, and 18 by 2023 and the retirement of Michigan City Unit 12 by year end 2028.

Mr. Lee testified that, given the retirement analysis conclusions included in the 2018 IRP, NIPSCO's resource requirements are greater than the approximately 600 MW initially identified in the 2016 IRP. He said that as a direct result of the expanded resource requirements, the level of capacity and the count of projects designated for advancement to the definitive agreement stage of the RFP was broader than initially anticipated.

Mr. Lee testified CRA recommended that NIPSCO advance a set of assets consistent with the IRP preferred plan to the definitive agreement phase of the process. He stated process bidders were asked to hold firm bids though December 31, 2018 and CRA's recommendations on advancement to the definitive agreement phase were subject to any potential resource constraints NIPSCO may have with respect to initiating commercial negotiations with counterparties in advance of that date. He testified the RFP was performed in a transparent, fair and nondiscriminatory manner and the process used to solicit and evaluate proposals was executed consistent with the process as defined and envisioned by NIPSCO and CRA at the outset and that no bidder was given an undue advantage or preference in the All-Source RFP.

Mr. Lee described the first step in the two-party negotiations with the developers. He explained that after CRA identified the assets recommended for advancement to the definitive agreement phase of the process, CRA communicated with each bidder, notifying them of the process status and next steps, and then NIPSCO prioritized certain short-listed projects and initiated commercial negotiations with the highest priority counterparties.

Mr. Lee discussed his recommendation for NIPSCO with regard to the acquisition of wind power. He noted the IRP modeling indicated a preference for wind resources as part of the preferred portfolio. In addition, he said NIPSCO was advised that the sites amenable for wind development within Indiana may be limited, but that all project proposals supported by Indiana wind projects showed positive NPV contributions. Mr. Lee stated that, as a result, consistent with the IRP's preferred portfolio, all Indiana wind proposals submitted into the All-Source RFP process were recommended as assets to consider for advancement to the definitive agreement phase for further due diligence and analysis.

Mr. Lee testified all Indiana wind projects were not considered equal priority. He explained that part of the value offered by wind resources relates to PTC that are a function of a facility's in-service date. He said wind resources that can meet a 2020 in-service date qualify for the maximum tax credits and moving forward with those projects to ensure they meet the 2020 online deadline for maximum PTC qualification was considered the highest priority. Mr. Lee explained that even within the set of 2020 wind projects, certain assets were prioritized by NIPSCO due to the economics of the deal and capacity constraints NIPSCO faces for finalizing commercial negotiations. He stated that other projects including solar projects and wind projects targeting a 2021 online date were considered lower priority because the economics of those projects were less time sensitive.

Mr. Lee described the seven projects bid into the All-Source RFP with a target online date of 2020 – NextEra's Jasper Pulaski and Jordan Creek projects, EDPR's Rosewater project, Apex's Roaming Bison, EON's Clinton, RES White Post and Calpine's Big Blue River project. Of these seven projects, Mr. Lee explained that NIPSCO has focused to date on both NextEra projects as well as the EDPR and Apex projects.

Mr. Lee explained how NIPSCO evaluated the pricing with and without RECs and that CRA evaluated RECs qualitatively. He said certain proposals included the provision that RECs would accrue to the project developer rather than NIPSCO and that these proposals lost points in the evaluation versus projects where RECs were transferred to NIPSCO.

Mr. Lee explained why CRA valued the RECs qualitatively rather than quantitatively. He noted the value of renewable energy was incorporated into the IRP process through evaluation of portfolio costs, risks, and carbon dioxide emissions. He said given the large uncertainty associated with future regulation and the future costs of renewable resources, no explicit REC value was attributed to renewable projects in the IRP. He stated that the IRP's preferred portfolio was predominantly comprised of renewable resources even without considering the economic value RECs might provide. He said the RFP process then selected individual projects consistent with the IRP's preferred portfolio. Mr. Lee testified that as a result, the RFP process evaluated wind assets versus other wind assets and solar projects versus other solar projects. He said assuming a similar facility capacity factor for like assets, assets within the same asset class would generate a similar number of RECs per MW-year and therefore, similar REC values; however, in cases where RECs accrue to the developer rather than to NIPSCO, there is a different, but highly uncertain, value offered by one project versus another. He said that because CRA wanted that difference in value reflected in the bid evaluation, but there was not a specific REC valuation consistent with IRP modeling. Projects that did not include RECs lost points through the Proposal Specific Risk scoring category; however, in all but one instance, Indiana wind projects did include RECs as part of the bid.

Mr. Lee described how NIPSCO evaluated the relative economics of facilities offered for sale versus facilities offered under a PPA structure of different lengths. He said that as part of the evaluation of the economics of each bid received, CRA calculated the NPV per MW-month of each bid received and that the NPV valued each facility's expected energy and capacity output versus projections of the prevailing market value for energy and capacity in Indiana derived from IRP base case modeling. Mr. Lee said for PPA bids, these value streams were offset by the bid specific PPA price offered into the RFP and for BTA options, the market value of the output was offset by the asset purchase price and ongoing facility expenses. He said in cases where the projected value of the facility's output exceeded the price for that output included in the PPA or the BTA costs, the proposal would yield a positive NPV. He also explained that in cases where the projected value of the facility's output was less than the price for that output included in the PPA or BTA costs, the proposal NPV would be negative. He said the sum of the discounted annual values offered by a PPA would be the total NPV for the proposal and that this total NPV was divided by the UCAP MW for the project multiplied by the number of months in the PPA term or the asset's expected life to yield a NPV per MW-month. Finally, he said the NPV per MW-month captures the total value offered across bids normalized by the bid's term length.

Mr. Lee described how NIPSCO evaluated the difference in value offered through asset ownership versus a PPA. He stated that for assets offered under a BTA, the explicit NPV period was 20 years from the original anticipated date of capacity needs, a period ending at year end 2042. Assets offered under a BTA arrangement, however, would provide economic value to NIPSCO customer beyond that 20-year window. As a result, the NPV for BTA included a provision for a residual value intended to represent some measure of the economic value that remained as of 2042.

He testified that assets offered to NIPSCO under PPA term lengths that extended beyond 2042 also were credited with a residual value intended to represent some measure of the economic value that remained as of 2042.

Mr. Lee described CRA's consideration of the locational marginal price-related ("LMP") impacts of the wind Proposals. He explained the prices included in the All-Source RFP NPV evaluation of bids were based on a single Indiana Hub price derived from 2018 IRP base case modeling and that, as a result, for this phase of the analysis, there was no distinction on the LMP for assets within LRZ6. He said he was aware that NIPSCO has conducted a nodal analysis of bids as part of the due diligence process during the definitive agreement phase to understand any potential congestion risk.

Mr. Lee testified the proposed Joint Venture is an economic option for meeting NIPSCO's retail electric load. He stated the 2018 IRP identified that, based on the current market economics and outlook, wind power represents an excellent resource option for NIPSCO and its customers over the expected useful life of a new wind facility. He testified that the Rosewater project was among the highest scoring wind projects overall based on the evaluation criteria used for scoring the All-Source RFP bids. He stated the Rosewater Project achieved three of the five development milestones used as part of the All-Source RFP scoring. He noted that, while the facility did lose points in the reliability category because EDPR had not completed a full N-1-1 analysis of the facility, very few of the potential counterparties for in-development wind resources had conducted such a study as of the All-Source RFP bid date. He stated that there were no asset-specific concerns for Rosewater and the facility yielded a positive NPV score based on the resources costs and the value of its output.

7. **<u>OUCC's Case-in-Chief</u>.** The OUCC presented the testimony of Peter M. Boerger, Ph.D., Senior Utility Analyst; Lauren M. Aguilar, Utility Analyst; John E Haselden, Senior Utility Analyst; and Wes R. Blakley, Senior Utility Analyst, all in the Electric Division of the OUCC.

Dr. Boerger introduced the OUCC's position on the case and presented his economic analysis of the proposal. He identified that the OUCC accepts that obtaining the wind resource proposed in this proceeding comports with NIPSCO's most recently submitted 2018 IRP and that the OUCC is not opposed to innovative financing mechanisms when economically justified, but that NIPSCO's proposed use of tax equity financing in this case is less attractive than relying on the more traditional PPA for power from the proposed facility. He reached that conclusion by considering the economics of the proposal over two time horizons: 30 years and 15 years.

In his 30-year analysis, Dr. Boerger identified a number of technical inadequacies in NIPSCO's analysis which raised the LCOE above that of the Back-Stop PPA proposal for the facility. Dr. Boerger performed an additional 15-year analysis, motivated by the observation that NIPSCO's 30-year analysis relied heavily on projections of purchased power prices in years 16 through 30—projections which are difficult to make and thus, uncertain. Dr. Boerger's 15-year analysis showed that significant amounts of customer expenditures could be saved over this initial period—a period during which NIPSCO's customers would likely be paying for accelerated depreciation on the Company's coal-fired power plants. Additionally, not making a large capital investment would retain for NIPSCO and its customers the option to make an investment at the end of 15 years with the benefit of the knowledge of technologies and market prices that cannot be known today. For these reasons, as well as the uncertainty of the proposal presented by NIPSCO, Dr. Boerger recommended that the Commission decline NIPSCO's request to obtain power from the Rosewater Project through its proposed Joint Venture and instead allow NIPSCO to take advantage of expiring PTCs by authorizing NIPSCO to enter into the proposed alternative Back-Stop PPA.

Ms. Aguilar presented testimony supporting the OUCC's recommendation that the Commission approve the Back-Stop PPA, as presented by OUCC witness Dr. Boerger. Ms. Aguilar stated that Ind. Code § 8-1-2-0.5 shows the Indiana General Assembly's focus on the need for affordability when Indiana utilities plan for electric generation, which is relevant to the question of whether NIPSCO should purchase an interest in the Rosewater Project or enter into a traditional PPA as the most economic choice for electric generation. Ms. Aguilar recommended that the Commission include in its consideration the emphasis on affordability, and consider the impact on captive customers when evaluating the Joint Venture versus the traditional PPA. Ms. Aguilar further stated that, given the OUCC's recommendation that NIPSCO enter into the Back-Stop PPA, NIPSCO's request for ARP relief and the declination of jurisdiction is not necessary.

Ms. Aguilar commented that NIPSCO identified two agreements that govern its relationship with any potential TEP, the Equity Capital Contribution Agreement and the LLC Agreement. Ms. Aguilar stated that there is no guarantee the terms presented in NIPSCO's testimony will be included when executing the final agreements and that the Commission will not have the opportunity to review the fully executed agreements before the conclusion of this Cause. Ms. Aguilar argued that it is important to know the TEP's standing within the LLC in order to understand the authority the TEP has over operations of the Rosewater Project. Ms. Aguilar also pointed out other unknowns about the Joint Venture. For example, a PPA between the Joint Venture and NIPSCO would need to be negotiated if the Project were to continue in operation, and the fair market value required to be paid to the TEP cannot be determined until all conditions precedent are met.

In the event that the Commission approves the Joint Venture, Ms. Aguilar recommended that the Commission require NIPSCO to defer and file its proposed buyout of the TEP in a separate docketed proceeding after the terms of the ECCA and the LLC Agreement have been negotiated and the buyout amount is determined.

On the issue of renewable energy credits, Ms. Aguilar stated that NIPSCO intends to evaluate the marketability of RECs and pass back the proceeds of the sale of RECs to NIPSCO's customers. This approach will reduce costs to consumers, which is reasonable. Ms. Aguilar also noted that this approach will also negate the renewable nature of the wind generation, and that the OUCC does not take issue with this approach.

Mr. Haselden noted this proceeding, in conjunction with two pending PPA CPCN proceedings, are the initial steps in implementing NIPSCO's most recent IRP. Mr. Haselden stated that while the use of a TEP is common in the industry, NIPSCO's proposal is one of only a few in the nation wherein a utility would be involved in a facility ownership of the project with a tax equity partner due to the tax incentives for renewable energy projects and NIPSCO's inability to fully monetize those tax incentives. Because NIPSCO has indicated other projects using this financing structure will likely follow, the precedent this case sets is important in light of the fact over 3,300 MW of nameplate renewable energy capacity will be required by 2023 according to NIPSCO's 2018 IRP. Mr. Haselden estimated that the additions to rate base will total several billion dollars.

Mr. Haselden explained that there are risks to customers involved with the Joint Venture compared to a traditional PPA. Mr. Haselden recommended, should the BTA PPA be approved by the Commission, certain customer protections be implemented:

1. NIPSCO and its customers should equally share in the risk of additional expenses, subject to a cap, in the event revenues paid to the Joint Venture do not cover the Joint Venture's expenses;
2. NIPSCO's customers' portion of the shared risks, the BTA PPA adjustments, and the buyout of the TEP should be shared and capped at no more than $2 million;
3. The wind project revenues and expenses should be tracked;
4. Inclusion of Joint Venture's costs in future rate cases should identify the Joint Venture expenses that exceed revenues accrued since the immediately preceding rate case and that difference should be amortized over four years subject to the $2 million cap; and,
5. NIPSCO's retail customers should not pay in rates a return on or a return of NIPSCO's investment of the amount referenced in Dr. Boerger's testimony, for any amount in excess of the initial investment and the buyout of EDPR, nor any amount in excess of the shared risk cap.

Mr. Blakley addressed the accounting and ratemaking treatment proposed in the petition. In describing the proposed Joint Venture arrangement, Mr. Blakely stated that NIPSCO's ownership interest will be treated as a regulatory asset and accrue carrying charges until it is included in base rates at the time of its next expected base rate case in 2023. Ms. Blakely stated that, should the Commission approve the Joint Venture, it is important NIPSCO's investment in the joint venture remain as a regulatory asset because if the project is transferred to plant investment, it will be depreciated, and the depreciation expenses will be included as a deduction in NIPSCO's tax returns. Mr. Blakely argued that this should not be permitted because the depreciation on the Rosewater Project has already been included as a deduction on the TEP's tax returns. Because of this risk. Mr. Blakely recommended that all Joint Venture assets should be treated as a regulatory asset, which books amortization instead of depreciation.

8. <u>CAC's Case-in-Chief.</u> CAC presented the testimony of Elizabeth A. Stanton, PhD, Director and Senior Economist of the Applied Economics Clinic and a Senior Research Fellow at the Global Development and Environmental Institute at Tufts University. Dr. Stanton participated in the 2018 IRP stakeholder process and reviewed both NIPSCO's All-Source RFP and the responses to the All-Source RFP. She evaluated NIPSCO's final 2018 IRP and co-authored comments submitted on behalf of CAC as part of that stakeholder process. *See* Attachment EAS-2. For this proceeding, Dr. Stanton confirmed that both the cost of the Joint Venture and the timing for procuring wind resources were consistent with NIPSCO's 2018 IRP. Although Dr. Stanton voiced concern about some aspects of NIPSCO's 2018 IRP process, she found NIPSCO's 2018 IRP methodology and process to be a vast improvement relative to its 2016 IRP. She also commended NIPSCO for the substantial leadership demonstrated in its 2018 IRP analysis, including an array of best practices, including: (1) conducting an All-Source RFP to inform model inputs, which gave NIPSCO an unusual level of credibility from which to forecast the cost of utility scale, supply-side generators; (2) transparent inclusion of input forecasts, outputs and assumptions; (3) a thorough description of most aspects of screening and portfolio selection; and (4) fair consideration of a wide range of supply-side alternatives without arbitrary limitations on the amount of those resources that can be selected or unsupported cost additions. Dr. Stanton recommended approval of the Joint Venture.

9. **<u>IMUG's Case-in-Chief.</u>** IMUG presented the testimony of Theodore Sommer, a partner with the firm of LWG CPAs and Advisors. Mr. Sommer did not oppose NIPSCO's proposals in this Cause but recommended that going forward NIPSCO work hard to do more to create opportunities for renewable energy generation integration with its municipal customers, large land owning customers and community programs; thereby, increasing the economic and social benefits obtained from increasing reliance on renewable energy.

Mr. Sommer described the economic and social benefits to be gained from NIPSCO and its customers jointly participating in economy of scale renewable energy projects. He described IMUG's suggested Municipal Solar Program ("MSP") wherein participating municipalities would select qualifying sites for possible installation of solar panels based upon "total value." Considerations would include size, proximity to needed electric lines, use of vacant municipal land, municipal rooftops, blighted land, brownfield sites and other appropriate locations. Compensation to municipalities could include land lease payments, bill credits, payment for firm energy sold to NIPSCO or other mutually beneficial arrangements. He explained that such an integrated NIPSCO / municipal MSP effort would create many economic, environmental, stakeholder, and social benefits.

The first MSP benefit Mr. Sommer described is new employment and job training opportunities. He suggested that contractors designing and installing the solar panel arrays would have to use personnel who reside in the NIPSCO service area, thus enhancing area employment and economic benefits. He suggested creating a "sidewalk to employment" whereby the chosen solar panel array designers and installers would be required to offer job training and employment to some area unemployed or under employed people who have the talent and desire to learn solar design, equipment acquisition, and installation. He also described the Hoosier "homegrown grown" energy economic stimulus. MSP would have a focus on acquiring area made equipment when possible and employing area workers so that the economic benefits when possible stay in the NIPSCO area or at least in Indiana. Keeping the resulting revenues in Indiana promotes the financial wellbeing of people in northern Indiana. He also described how the resulting lower municipal purchased power costs would free up capital to be used to improve municipal services and the public municipal facilities. He also described how MSP would further enhance public convenience and necessity. He explained that municipalities are in essence closed loop public services businesses devoted to serving the public without profit. Municipal revenues generated or financial savings are used to improve the public wellbeing, not used to pay out dividends or profits. MSP would combine the public service mandate of NIPSCO to provide safe, reliable, reasonable cost renewable generation, with the participating area municipality's mandate of providing reliable public services to its citizens. He described the environmental and public awareness benefits of

MSP. He testified that there is public concern about environmental impacts from burning fossil fuels and interest in maintaining and improving the environment we leave our children and grandchildren. He explained that municipal solar installations in NIPSCO's service area will send a positive social and educational message about the availability, benefits and viability of renewable energy.

Mr. Sommer also described community solar programs, which often entail residential solar programs that promote rooftop installations, area solar gardens or solar farms for residential customer subscription. He testified that funding can differ but often includes utility investment and/or customer subscription payments. He stated the focus is generally on residential customer participation and sometimes entails low income participation. He suggested that NIPSCO integrate its renewable energy efforts with such community solar programs. He explained that program type details like solar garden or individual customer focus, are variables that can be considered and accommodated to fit expectations, needs and performance.

Mr. Sommer also described opportunities for NIPSCO to increase wind generation integration with area stakeholders. He documented that NIPSCO's service area includes areas of the best wind speed characteristics in Indiana. He suggested that there may be opportunity for NIPSCO to obtain wind generation rights from large farms in these areas under favorable terms, perhaps in exchange for electricity service to the land owner's farm facilities. Such agreement might favorably reduce the cost of land leases for wind generation. He also suggested NIPSCO may want to consider partnering with area rural electric membership cooperatives in joint ownership and operation of commercial size wind generation.

Mr. Sommer also detailed how his proposed integration of NIPSCO renewable generation with area municipalities and customers would be consistent with and support NIPSCO's customer efforts and vision as espoused by NIPSCO's President.

Mr. Sommer concluded by stating his proposals are an opportunity to make Hoosier dollars first create greater benefit in Indiana. Land lease payments, revenue, or electric credits to municipalities from such joint renewable energy efforts could help pay for improved municipal services in NIPSCO's service area. That helps everyone living and working in those NIPSCO areas. NIPSCO obtaining wind lease rights in exchange for bill credits provides economic development benefits and potentially lower commercial wind development costs. The effort and results would also be further justification for Clean Energy Project rate incentives. An "Indiana first" consideration in renewable energy additions is one of many reasonable design / benefit criteria to review.

10. <u>NIPSCO Industrial Group's Case-in-Chief.</u> NIPSCO Industrial Group presented the testimony of James R. Dauphinais, a consultant in the field of public utility regulation and a Managing Principal with the firm of Brubaker & Associates, Inc. Mr. Dauphinais raised concerns regarding recovering 100% of the cost of the PPA through NIPSCO's FAC. He indicated that when the Commission ruled with respect to whether and how renewable energy PPAs would be recoverable in a utility's FAC in Cause Nos. 43323 and 43393, utilities were just beginning to gain experience with the use of renewable resources, and circumstances have changed since that time. Mr. Dauphinais noted renewable resources are now expected to become a very large portion of utility resource portfolios in general and for NIPSCO in particular, much of this renewable generation will likely be acquired through PPAs. Mr. Dauphinais also noted that the contribution of these PPAs toward meeting NIPSCO's peak system demand will no longer be negligible and NIPSCO has mechanisms under which it could recover some or all of its renewable PPA costs.

Mr. Dauphinais explained that the Rosewater Project has no fuel costs and a negligible amount of variable O&M costs. He noted that while the PPA requires payment by NIPSCO based on the energy production by the Rosewater Project, the purpose of that contract structure under a renewable PPA is typically to maximize the performance of the seller under the contract rather than to reimburse the seller for the variable costs of its facility. He testified that, given this, for cost allocation purposes, the costs incurred under a renewable PPA such as those for the Rosewater Project should be considered the same as fixed transmission and production costs. He noted the costs incurred under the PPA should be allocated to customer classes on the basis of the contribution of each customer class to NIPSCO's peak system demand, particularly to the extent the facilities in question provide the same support toward meeting NIPSCO's peak system demand as NIPSCO's transmission facilities and conventional generation facilities.

Mr. Dauphinais further explained that while renewable generation facilities cannot be counted on to the same extent as transmission facilities and conventional generation facilities to support NIPSCO's peak system demand, they nevertheless can be counted on to some degree. He discussed how MISO currently provides an initial year unforced capacity accreditation of 15.2% of nameplate capability to new wind generation facilities and an initial unforced capacity accreditation of 50% of nameplate capability to new solar generation facilities. He also explained that these amounts should be grossed up to reflect that conventional generation facilities typically receive an unforced capacity accreditation equal to only 75 to 95% of their summer rated capability. Based on this, he concluded that, with respect to supporting peak system demand during its initial year of operation, a nameplate MW of wind generation capacity provides 16 to 20% of the same support that would be provided by a summer rated capability MW of conventional generation. He also testified that a nameplate MW of solar generation capacity provides 53 to 67% of the same support that would be provided by a summer rate capability MW of conventional generation.

Mr. Dauphinais recommended that for the first year of the Rosewater Project PPA, 16% of the total cost of the PPA should be deemed to be equivalent in providing support to meet NIPSCO's peak system demand as that provided by NIPSCO's conventional generation facilities and recovered through NIPSCO's Resource Adequacy Adjustment Mechanism ("RA Tracker") rather than NIPSCO's FAC. He also recommended that the remaining 84% of the cost of the PPA be recovered through NIPSCO's FAC. Mr. Dauphinais noted that for the first year of the PPA, this would result in 16% of the cost of the PPA being allocated through the RA Tracker to customer classes on the basis of their contribution to peak system demand and the remaining 84% of the PPA being allocated to customer classes through NIPSCO's FAC based on energy consumption. Mr. Dauphinais explained that there is Commission precedent for recovering the cost of purchased power arrangements through a combination of the NIPSCO's RA Tracker and FAC. Specifically, Mr. Dauphinais pointed out that in Cause No. 44155 RA 14, the Commission found it appropriate to recover a portion of NIPSCO's Rate 765 costs through NIPSCO's RA Tracker rather than NIPSCO's FAC.

For the succeeding years of the PPA, Mr. Dauphinais recommended that the actual MISO unforced capacity accreditation percentage for the Rosewater Project divided by 95% should be used as the percentage of the total cost of the PPA and should be deemed equivalent in providing support to meeting NIPSCO's peak system demand, as provided by NIPSCO's conventional generation and be recovered through NIPSCO's RA Tracker rather than through NIPSCO's FAC. Mr. Dauphinais testified the portion of the PPA that is not recovered through NIPSCO's RA Tracker would be recovered through NIPSCO's FAC.

11. LaPorte's Case-in-Chief. LaPorte presented the testimony of Vidya Kora, President of the LaPorte County Board of Commissioners. Dr. Kora discussed some concerns and broader factors that he believes the Commission should consider as part of the review process and public interest considerations included when reviewing these types of advance approval of large cost items and certificate of need requests. Dr. Kora did not make any specific recommendations relating to NIPSCO's request in this Cause.

12. ICC's Case-in-Chief. ICC presented the testimony of Charles S. Griffey, a consultant providing services to the electric and natural gas industries; and Emily S. Medine, Principal in the consulting firm of Energy Ventures Analysis, Inc.

Mr. Griffey opposed approval of the CPCN due to concerns with NIPSCO's IRP. He indicated that NIPSCO's proposed service structure in its pending rate case will reduce industrial load to 50 MW, and that the issues ICC had identified with NIPSCO's IRP were borne out in these filings. Specifically, Mr. Griffey stated that: (1) congestion cost is higher than assumptions from the IRP; (2) NIPSCO assumed 100% tax efficiency from tax equity financing; (3) the capacity factor of Rosewater Project is lower than the 41.8% as represented in the IRP; (4) the assumption of a carbon dioxide ("CO2") tax was unreasonable; (5) increased future maintenance capital and operations and maintenance costs for coal units were above historic levels; (6) burdened coal units with environmental capital when the need for it is uncertain; (7) the Company did not update generic costs for solar units based on market conditions; (8) assumed current levels of PTCs and investment tax credits ("ITCs") for replacement PPAs will be available in the future; and (9) NIPSCO ignored its proposed industrial rate structure in the 2018 IRP. He also said there were no curtailment costs included in NIPSCO's 2018 IRP. Mr. Griffey contended that running Michigan City and converting Schahfer Units 17 and 18 to gas would produce a lower net present value rate of return than the proposed Joint Venture.

Ms. Medine also alleged that the wind proceedings were premature because NIPSCO's 2018 IRP had been flawed and no Director's Report had been issued yet. She also contended that NIPSCO failed to demonstrate that the Rosewater Project is needed to meet system demand and that it is the lowest cost revenue choice. She said the information on the project is incomplete, so it cannot be fully evaluated. She also stated that the request to insulate the project from Section 42(d) and FAC benchmarks is inappropriate. She testified that the rate case would result in a reduction in demand associated with its largest customers to just 50 MW. ICC was critical of NIPSCO for not developing a 20-year load forecast with reduced industrial load and for only modeling a scenario for zero carbon costs with high coal prices as part of its IRP. Ms. Medine expressed concern regarding the value of long-term PPAs. She also noted that the cost of wind in

NIPSCO's latest FAC was more than double that of its coal units and combined cycle gas turbines and higher than the cost of its peaking units. Ms. Medine asserted that NIPSCO did not consider ways to reduce operating and closure costs of the coal plants.

13. <u>NIPSCO's Rebuttal Testimony</u>. Messrs. Campbell and Augustine filed testimony in rebuttal to the testimony of the OUCC and Intervenors.

(a) <u>Campbell Rebuttal</u>. In response to the testimony filed on behalf of the OUCC, Mr. Campbell testified that in an effort to accommodate the OUCC's concerns, NIPSCO agrees that cost recovery of NIPSCO's developer buyout will be capped at the product of the percentage of EDPR ownership in the Joint Venture times the contract cost escalated at a specific rate per year. This contract cost is based on the project cost, less NIPSCO's percentage of investment with the percentage based on the amount owned by the TEP. Therefore, NIPSCO's cost recovery of payment to EDPR at the time EDPR's portion of the project is purchased in 2023 will be limited to the product of the percentage of EDPR's ownership and the cost of the project escalated by a specific percent return per year on the Developer's contribution. However, the cost recovery for the EDPR payment shall be no more than $89,227,285, as shown in Confidential Attachment 1-R-A. Mr. Campbell testified NIPSCO also agrees not to seek approval in this proceeding of any amounts related to its purchase of the TEP's share of the project estimated to occur around 2030. Rather, once a determination has been made by NIPSCO to purchase the TEP's share of the project, NIPSCO will seek recovery of such costs in a separately docketed proceeding. NIPSCO will seek recovery of no more than the fair market value of the TEP's share of the Joint Venture. NIPSCO agrees to continue to treat its investment in the Joint Venture, even after such time as the TEP portion of the project has been acquired by NIPSCO, as a regulatory asset with NIPSCO booking amortization instead of depreciation. The value to be included in rate base shall be determined in a base rate case at the time of acquisition or in the next base rate proceeding following acquisition. NIPSCO agrees it will not record and accumulate on its books and records either the wind project revenues or the Joint Venture expenses, but rather those revenues and expenses shall be maintained by the Joint Venture, tracked and available for review by NIPSCO, the OUCC, and other stakeholders that have executed appropriate nondisclosure agreements, and subject to an independent audit. This is inclusive of any subsequent investments (cash contributions) NIPSCO makes into the Joint Venture. NIPSCO agrees that the cap of cost recovery related to any additional investments (cash contributions as referred to on Page 17 of his direct testimony) NIPSCO may make into the Joint Venture will be recoverable from ratepayers at an amount capped at $2 million net of revenues. During the term of the BTA PPA, to the extent sales revenue by the Joint Venture to NIPSCO exceed operating costs, NIPSCO's cash allocation will be returned to NIPSCO ratepayers as proposed by NIPSCO. To the extent revenues are less than operating costs, cash contributions by NIPSCO may be offset (netted against) by NIPSCO's cash allocations. At the time of the buyout of the TEP, the accrued balance of the additional portion of this regulatory asset to be recovered from ratepayers will be no more than a net $2 million. NIPSCO agrees to have good faith discussions with stakeholders on NIPSCO's REC strategy, including whether RECs should be retired or sold. NIPSCO's REC strategy is currently reviewed, and audited, as a part of its quarterly FAC tracker filing, which is an appropriate forum for ongoing discussions. NIPSCO agreed not to seek cost recovery from ratepayers of any other costs incurred by NIPSCO related to: (1) the buyout of EDPR; (2) the buyout of the TEP; or (3) the operation of the Joint Venture while either EDPR or TEP are still participants in the Joint Venture. Finally, NIPSCO agreed to remain the managing member of RoseWater Wind Generation LLC. Mr. Campbell responded to Mr. Griffey's contention that no curtailment costs were included in NIPSCO's 2018 IRP even though NIPSCO paid $14 million for curtailments under current wind contracts. He testified NIPSCO has taken into consideration that, from time to time, wind resources are curtailed from operating. He stated that after the conclusion of NIPSCO's 2018 IRP, NIPSCO evaluated possible curtailments of the Rosewater Wind Farm and concluded that curtailments are expected to be de minimis.

Mr. Campbell testified that with regard to the Commission's recent Order in Cause No. 45052, one of the primary examples mentioned was that the proposed asset was approximately 77% of Vectren's summer peak. He testified that the Rosewater Project is expected to contribute approximately 8 to 15 MW of peak capacity at the time of NIPSCO's peak representing less than one percent of NIPSCO's summer peak load requirements. He stated that it was clear that the Commission did not want an approach that was confined to one technology and furthermore one asset. Mr. Campbell testified that NIPSCO's 2018 IRP preferred portfolio shows NIPSCO's requiring approximately ten or more projects fulfill the 2023 capacity gap. He explained that this plan calls for a mix of demand side management, wind, solar, and solar paired with storage projects. He testified NIPSCO's plan uses multiple assets and multiple technologies to fulfill its projected capacity needs and NIPSCO believes this multifaceted approach represents a de-risked path forward that is in the best interest of its customers. Furthermore, he stated that NIPSCO anticipates a mixture of owned and purchase power agreement assets with varying in-service dates along with varying durations, which is evidenced by the first three wind agreements currently pending approval before the Commission.

Mr. Campbell explained the difference between NIPSCO's All-Source RFP to that in the Vectren Case. He testified that NIPSCO utilized its RFP for two purposes: (1) to inform its 2018 IRP, and (2) to have a qualified list of projects to choose from based on the preferred portfolio selected. He testified there are two key differences based on Vectren's RFP: (1) NIPSCO did not utilize its All-Source RFP to justify the cost of any self-build options, and (2) NIPSCO's All-Source RFP was much more encompassing because it covered all sources and represented an openness to many different constructs, whereas the Vectren RFP was more limited in its overall scope and what resources were allowed to be bid.

In response to concerns raised by Mr. Griffey, Mr. Campbell noted that the UCAP determination for wind resources, and for all intermittent resources, varies from year to year based on actual performance. He noted that there is a wide range of UCAP determinations for wind throughout the MISO footprint.

In response to Ms. Medine's recommendation that in the event the Commission approves the Joint Venture, the Commission should decline to insulate NIPSCO from the Section 42(d) Tests or FAC benchmarks, Mr. Campbell testified that NIPSCO proposed that purchases pursuant to the BTA PPA, or Back-Stop PPA, be exempt from the Company's FAC Purchase Power Benchmark. He stated this treatment is consistent with the ratemaking treatment granted for NIPSCO's existing wind agreements (approved in Cause No. 43393) and other renewable energy NIPSCO purchases pursuant to its Renewable Energy Feed-In Tariff (Rate 765) (approved in Cause Nos. 43922 and 44393). He indicated it is also consistent with the treatment approved for numerous other PPAs granted by the Commission for other utilities.[4] Mr. Campbell stated that NIPSCO views purchases made pursuant to PPAs as an alternative to other types of generation that NIPSCO would otherwise own, regardless of the technology, and much of the cost of those assets are recovered through base rates rather than the fully loaded costs being used to develop the Purchase Power Benchmark. He explained that the Purchase Power Benchmark is constructed in a manner meant to provide an incentive to a utility's generation portfolio (owned and contracted resources via PPAs) to be available at times of high hourly market prices to act as a physical hedge. Subjecting a long-term PPA that locks in a fully costed resource is neither consistent with past precedent nor consistent with the treatment of Company-owned resources.

Mr. Campbell testified the $/MWh figures from NIPSCO's most recent FAC filing (Cause No. 38706 FAC 122) quoted by Ms. Medine are accurate to the best of his knowledge but he did not agree with the context in which they were utilized by Ms. Medine. He testified that NIPSCO's FAC filings only include a portion of the costs associated with the operation of NIPSCO's coal and natural gas assets and that there are additional fixed and variable costs associated with the on-going operation of those assets not captured in the FAC because they are embedded in base rates. He stated that while the incremental wind cost is higher in the FAC, it represents the total cost associated with the generation and is more economic for customers when considering the total cost of production, which is supported by the retirement analysis within NIPSCO's 2018 IRP.

In response to Ms. Medine's concern for the value of long-term PPAs if the cost of wind decreases over time, effectively locking in a high price, Mr. Campbell testified NIPSCO believes it is prudent to lock-in the BTA PPA, or Back-Stop PPA, with the Rosewater Wind Farm for a 15-year term. He stated that in general, new projects require a long-term commitment to attract the financing required to build the project, which tend to be between 15 to 20 years. He testified this is supported by the bids received by NIPSCO in its All-Source RFP where there were, generally, very few short-term options available. He testified that through the IRP and the subsequent due diligence analysis, the expected LCOE associated with the BTA PPA represents a significant savings relative to NIPSCO's existing generation at a term that fits within the confines of the planning horizon.

In response to the testimony submitted on behalf of IMUG that there is value in exploring a MSP, Mr. Campbell testified NIPSCO will work with IMUG, the CAC, the OUCC, and other interested parties and will host at least two meetings to that end in the first three months following the approval of a final order in this proceeding. He testified NIPSCO will work collaboratively and in good faith with its stakeholders to develop a program for the installation of solar infrastructure of up to five megawatts and explore how economy of scale MSP solar output can best be considered and reflected in response to a need for energy and capacity. He stated that such a program would only be available following approval from the Commission. He explained that the MSP installations may use laborers who reside in NIPSCO's service territory when possible and practicable and, participating contractors may use some qualified unemployed or low income workers from the NIPSCO service area.

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[4] See, for example, Duke Energy Indiana, Inc. in Cause No. 43097, Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. in Cause No. 43259, and Indiana Michigan Power Company in Cause No. 43328.

Mr. Campbell testified that NIPSCO will arrange for, and in a timely manner provide, appropriate interconnection of resulting agreed-to municipal solar facilities to its distribution or sub-transmission system, including any required electric system studies, metering, communications equipment, modifications to protective relaying or fusing, and any required certifications.

Mr. Campbell testified that NIPSCO, IMUG, CAC, the OUCC, and other interested parties will in good faith work on details, feasibility and possible approval of a community Solar Program, including consideration of customer subscription in community solar farms targeted at residential customer participation. He stated that low income customer participation and benefits will be part of that collaborative effort.

Mr. Campbell indicated that it is possible that NIPSCO's net metering tariff may need to be revised to allow municipal customers accessibility to the megawatts designated for residential customers in its net metering tariff, which is constrained by Ind. Code § 8-1-40-12.

Mr. Campbell responded to Dr. Kora's concerns about NIPSCO committing to one type of large scale generation going forward. First, he noted that Dr. Kora does not recommend that the Commission deny NIPSCO's request in this proceeding. He testified NIPSCO agrees with Dr. Kora that it is inappropriate to put its eggs all in one basket in the context of selecting a preferred portfolio that is reliant on one asset or type of technology. For these reasons, in addition to cost, NIPSCO selected a portfolio representing a mix of demand side management, wind, solar, and solar paired with storage, to replace the capacity need from the retirement of the Company's coal units at Bailly and Schahfer generating stations. He explained that this approach fully addresses the concerns raised by Dr. Kora that NIPSCO should not place a bet on one type of technology or a single asset. He testified that NIPSCO's preferred portfolio also blends in a mix duration through various ownership and purchase power agreement structure.

Mr. Campbell disagreed with Dr. Kora's concerns about NIPSCO moving too abruptly with respect to its 2018 IRP preferred portfolio. In fact, he argued, through the Company's 2016 and 2018 IRP processes, NIPSCO undertook diligent and extensive analysis to support both the projected retirement of existing assets and the replacement decisions outlined in the preferred portfolio, which is evidenced by the nearly one year 2018 IRP process. He explained that the process was stakeholder driven through a series of stakeholder meetings where NIPSCO solicited input from interested parties. He indicated the Company also engaged in an All-Source RFP to seek out viable projects to validate retirement decisions and to determine the most reliable and economic replacement plan through its preferred portfolio. Further, he testified NIPSCO investigated a self-build combined cycle natural gas facility as a means of replacing the projected retirement of existing generating assets and engaged in an extensive siting analysis in which many potentially viable sites were investigated throughout Indiana. He stated that as a part of these efforts, NIPSCO met with select counties, including LaPorte County, to investigate potential economic incentives for siting of such generation. He indicated this practice is common when investigating potential generation asset siting. Mr. Campbell testified NIPSCO was not disingenuous throughout the economic incentive process. He also testified NIPSCO made it clear that there were no guarantees the project would ever come to fruition, which further emphasizes the diligence undertaken by NIPSCO throughout the IRP process that ultimately recommended a preferred portfolio comprised of demand side management, wind, solar, and solar paired with storage, spread over multiple projects. He stated NIPSCO agrees with Dr. Kora regarding not putting too much stake in one type of resource. He testified the facts demonstrate NIPSCO's efforts to ensure all options were considered as part of the development of the 2018 IRP. Further, he stated the multiple project approach embedded within the preferred portfolio will also drive economic benefits where they ultimately end up being sited. Mr. Campbell encouraged LaPorte County to make its county as attractive as possible for future investment as NIPSCO will be engaging in subsequent RFP processes to identify additional projects to meet the preferred portfolio outlined within its 2018 IRP.

In response to Dr. Kora's statement that early in 2018 NIPSCO was pursuing the possibility of investing in new generation in LaPorte County and then abruptly changed course, Mr. Campbell testified that early in 2018, NIPSCO was exploring the option of potentially constructing an electric generating facility in its service territory, including in LaPorte County. He stated that on September 19, 2018, NIPSCO advised LaPorte County that the analysis, when compared with what NIPSCO was seeing in its 2018 IRP, was demonstrating that an option involving the self-building construction of a natural gas-fired electric generating station was not cost-effective for its customers when compared with other available options. He stated NIPSCO advised LaPorte County that it had reached a decision to discontinue its search for a potential construction site at that time. NIPSCO stated that market conditions and advancements in technology continue to transform the electric industry, creating more competitive options for its customers. Mr. Campbell testified that NIPSCO did not abruptly change course, but rather, it made prudent business decisions based on the results of the All-Source RFP and the analysis completed through a stakeholder-assisted process in the 2018 IRP. He noted that LaPorte County was able to participate in that process, but to his knowledge, no one representing the County did.

(b) <u>Augustine Rebuttal</u>. Mr. Augustine responded to Mr. Griffey's broad concerns that NIPSCO's 2018 IRP contains flaws and does not demonstrate that early retirement of the coal fleet and replacement with renewables is prudent or economical for ratepayers. Mr. Augustine testified that he responded to each of those initial concerns in his rebuttal testimony in NIPSCO's currently pending rate case (Cause No. 45159) and incorporated that testimony as Confidential Attachment 4-R-A. He also sponsored NIPSCO's formal responses to stakeholder IRP comments, including those made by the ICC, as Attachment 4-R-D. Mr. Augustine testified Mr. Griffey's claims are all without merit and fail in any way to contradict NIPSCO's finding that new renewable additions are lower cost for customers than maintaining the current coal fleet. This conclusion was supported by NIPSCO's comprehensive dispatch and revenue requirement analysis in the 2018 IRP across a range of scenarios, including scenarios developed by the ICC. He explained that Mr. Griffey did not perform any independent analysis that would reach an alternative conclusion, and his efforts to adjust NIPSCO's cost savings projections were either filled with errors or based on false premises.

Mr. Augustine responded to Mr. Griffey's major concerns with the time horizon evaluated by NIPSCO in its 2018 IRP and in its analysis to support its application. He stated that he responded to those baseless claims in his rebuttal testimony in Case Nos. 45195 and 45196, and attached them as Confidential Attachment 4-R-B and Confidential Attachment 4-R-C. Mr. Augustine said Mr. Griffey now further claims in this proceeding that the savings NIPSCO has calculated in its preferred portfolio over the long-term "are invented by an assumption with no rational basis whatsoever." According to Mr. Augustine, Mr. Griffey based this claim on analyses he has performed that compare the costs of NIPSCO's Preferred Portfolio F[5] from the IRP with other portfolios developed in the IRP process.

In response to Mr. Griffey's comparison between Preferred Portfolio F and several different retirement portfolios developed in NIPSCO's 2018 IRP, Mr. Augustine testified this is an "apples-to-oranges" comparison since the replacement analysis evaluated different objectives beyond least cost and developed portfolios accordingly.

In response to Mr. Griffey's comparison between Preferred Portfolio F and Portfolio C from NIPSCO's 2018 IRP, Mr. Augustine agreed it is fair to compare these portfolio options because both were developed in NIPSCO's replacement analysis, which evaluated portfolios with different mixes of natural gas and renewable additions and different mixes of PPAs and ownership options. He testified that both portfolios were concentrated on renewable additions, namely wind, solar, and battery storage, to replace retiring coal plants. He testified that by 2023, Portfolio F added 660 MW of 20-year renewable PPA UCAP,[6] 642 MW of owned renewable UCAP, and 50 MW of short-term capacity purchases, and that Portfolio C added 660 MW of 20-year renewable PPA UCAP, 220 MW of 15-year renewable PPA UCAP, and 470 MW of short-term capacity purchases and demand response resources.[7] He stated that after the expiration of the 15-year renewable PPAs, new solar resources were added to Portfolio C.

In response to Mr. Griffey's comparison of Portfolios F and C and claims that the expected savings for NIPSCO's preferred Portfolio F from the 2018 IRP are "an artifact of NIPSCO's back-end plan assumptions" resulting in "artificially manufactured end effects for Portfolio F", Mr. Augustine testified there is nothing artificially manufactured in NIPSCO's analysis, which developed transparent and reasonable comparisons for a range of well-vetted portfolio options across a wide range of market scenarios and stochastics. He stated that long-term analysis is a critical part of any resource planning exercise, and any decisions made by NIPSCO today, including doing nothing or committing significantly to short-term PPAs, have both short-term and long-term implications. He noted that Mr. Griffey presents a reasonable summary of the potential long-term impacts of a significant reliance on short-term PPAs, but his attempt to dismiss these "back-end plan" elements as somehow unreasonable or not important elements of the planning exercise is completely without merit. He testified that for the 2018 IRP portfolios that relied heavily on PPAs that expire after fifteen years, NIPSCO's analysis concluded that the most economic resources at the time of future PPA expiration would be generic solar additions. He noted that Mr. Griffey rightly asserts that when compared to near-term renewable acquisitions, these resources are not expected to have the same tax benefits and that he also correctly notes that the "generic solar resources also have lower capacity factors than the wind PPAs, which means that the difference is likely made up with more expensive market purchases." He testified that

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[5] Preferred Portfolio F retires all four units at the Schahfer coal plant in 2023 and retires the Michigan City coal plant in 2028 and replaces capacity with a mix of owned and contracted renewable resources, including wind, solar, and battery storage. *See* Section 9.2 and Section 9.3 of NIPSCO's 2018 IRP for more detail.

[6] UCAP represents the expected capacity available during the system peak.

[7] The detailed portfolio composition is documented in the "Replacement Mix by Portfolio" tab in Confidential Appendix D to NIPSCO's 2018 IRP.

instead of dismissing these considerations as mere artifacts of NIPSCO's plan assumptions, Mr. Griffey should realize that these are reasonable consequences of portfolio strategies that avoid longer-term commitments for resource options like the Joint Venture that can take full advantage of current tax incentives and generate larger amounts of energy to provide a long-term hedge against MISO market uncertainty.

Mr. Augustine disagreed with Mr. Griffey's dispute of NIPSCO's preferred portfolio selection on the basis of perceived flaws in the long-term analysis by stating that "the claimed thirty-year savings between preferred portfolio F and these other portfolios are due solely to the assumption that the PPAs are replicated in Preferred Portfolio F but are not extended in the other portfolios." He testified that as in Mr. Griffey's prior efforts to cast doubt on NIPSCO's 30-year NPV approach, he selectively isolates factors that he believes are concerns and ignores the same factors if they are not supportive of the case he is trying to make. He stated that in this instance he implies that 20-year PPAs were only extrapolated in NIPSCO's end-effects calculation in Portfolio F. Mr. Augustine testified this is completely false, as, by design, both Portfolio C and Portfolio F had identical amounts of 20-year PPA capacity (660 MW of UCAP), which were all treated the same. He noted that the portfolios differed in the remaining renewable resources, which comprised shorter-term (15-year duration) PPAs in Portfolio C and longer-duration owned assets like the Joint Venture in Portfolio F. He reiterated that there is a meaningful difference between 15-year PPAs and owned assets with longer lifetimes. He testified that Mr. Griffey's characterization of NIPSCO's analysis as one that "created the savings for Portfolio F... out of whole cloth" is completely unfounded. He testified NIPSCO performed a careful and deliberate portfolio development process to provide an even-handed analysis of the tradeoffs between long and short-duration options, and Mr. Griffey's efforts to suggest otherwise are completely without merit.

On redirect examination, Mr. Augustine further explained. In the IRP, all 20-year PPAs in Portfolios C and F were extrapolated to Year 30 using inflation, but 15-year PPAs were assumed to be replaced at Year 16 with an owned resource. Since both Portfolio C and Portfolio F have identical amounts of 20-year PPAs, changing the end effects analysis to replace those expiring PPAs with an owned resource at Year 21 would have had no relative effect on the results.

In response to Mr. Griffey's suggestion that NIPSCO should have used 20-year NPVs for comparison and in response to Dr. Boerger's suggestion that a 15-year analysis period could be used to evaluate resource options, Mr. Augustine testified the simple fact is that NIPSCO needs to consider both the short-term and the long-term, and ignoring potential customer costs after 20 years is not a reasonable way to conduct a long-term planning exercise. He stated that an owned project like the Joint Venture is a long-lived asset which can provide value to NIPSCO's customers for a longer period of time than the period over which Mr. Griffey and Dr. Boerger propose to evaluate. He emphasized, however, that the Rosewater project is just one part of a diverse preferred portfolio that includes both owned renewable resources and renewable resource PPAs, including two wind PPAs with 20-year durations totaling 700 MW that NIPSCO is currently pursuing.[8] He stated this application is consistent with the preferred portfolio and consistent with NIPSCO's objective to acquire a mix of project sizes, technology types, and commitment durations.

[8] *See* NIPSCO's petitions in Cause Nos. 45195 and 45196.

Mr. Augustine disagreed with Mr. Griffey's suggestion that an approach based on short-term flexibility "would favor extending coal plant lives until it is necessary to expend capital for environmental compliance." He testified NIPSCO's 2018 IRP found that the most flexible pathway forward is a staggered retirement of coal capacity and replacement with a diverse set of smaller renewable resources, with flexibility to change replacement strategy as technology and market rules evolve.[9] Furthermore, he stated that NIPSCO's decision to retire coal plants early is not at all contingent upon avoiding capital costs associated with future environmental compliance. In fact, NIPSCO demonstrated that the preferred portfolio of pursuing renewables like the Joint Venture and retiring coal early was lower cost for customers even with no carbon price for the full forecast horizon and with no new capital expenditures associated with environmental compliance.[10] He testified that the reality is that the all-in costs of maintaining and operating the coal fleet, regardless of any future environmental regulations, are higher than MISO market prices and alternative resources like the Joint Venture, and NIPSCO can achieve savings for customers immediately upon retirement. Mr. Augustine testified it is important to emphasize that NIPSCO's quantitative analysis of its preferred portfolio, one that includes owned wind such as the Joint Venture, is lower cost than maintaining existing coal across all time periods, including the near-term. He noted that Mr. Griffey provides no analysis that disputes this claim, and his efforts to show higher costs for Portfolio F against other alternatives over the short-term make comparisons against renewable PPAs rather than coal plants.

Mr. Augustine testified Mr. Griffey's claims that "NIPSCO now agrees it overstated the capacity value for Indiana wind resources in its IRP" is not fair because historical data in MISO indicates lower capacity credit for wind resources in Indiana than the system-wide average and because the Joint Venture does not have a guaranteed firm capacity. However, he stated that neither of these factors suggest that NIPSCO overstated the wind capacity credit in the 2018 IRP, since historical MISO data is not used to assign future capacity credit for new resources, and since MISO resources do not need pre-determined firm capacity guarantees in order to receive credit in the MISO market.

Mr. Augustine described how wind resources receive capacity credit in MISO. He explained that prior to actual operating history being available, new wind resources receive credit at the system-wide level. After sufficient operating history is available, MISO uses actual metered data in its calculation of capacity credit. He explained that as per MISO Business Practices Manual No. 011, "A wind farm with no commercial operation history during the Summer will receive a wind capacity credit equivalent to the MISO system wide wind capacity credit from the ELCC study for their initial Planning Year, and thereafter metered data will be used in order to calculate its future wind farm specific wind capacity credit."[11] Mr. Augustine testified that while Mr. Griffey claims that "it is unlikely that any of NIPSCO's presently proposed wind resources will after the first year of operation, be assigned a UCAP that approaches what NIPSCO assumed for modeling purposes" based on his historical review of capacity credit for wind resources in MISO Zone 6,

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[9] *See* pp. 176-177 of NIPSCO's 2018 IRP.

[10] *See* slides 49-50 of the presentation to stakeholders in a 2018 IRP meeting held on September 19, 2018 and slides 22-23 of the presentation to stakeholders in a 2018 IRP meeting held on October 18, 2018, which are provided in Appendix A to NIPSCO's 2018 IRP.

[11] ELCC refers to effective load carrying capability. *See* page 34 of 192 of the public version of MISO Business Practices Manual No. 11 for Resource Adequacy, effective February 20, 2019. The Manual is available at: https://www.misoenergy.org/legal/business-practice-manuals/

while historical data may provide some indicative information regarding regional trends, the performance of existing wind farms in Indiana will not dictate the future capacity credit of the Joint Venture.

In response to Mr. Griffey's cite to a Planning Year 2018/19 MISO wind report to support his claim that UCAP for wind resources will be lower in Indiana and that capacity credit is likely to decline over time,[12] Mr. Augustine testified that the report Mr. Griffey cites presents an historical view of realized wind capacity credit by zone, whereas the Business Practices Manual presents the actual process for calculating such credit, which will be based on the actual performance of a new project. Furthermore, he stated that the historical capacity credit for wind resources within Zone 6 has varied by year as a result of market and wind conditions and the fact that there are less than 300 MW of wind registered in Zone 6, a small sample size of data points to rely upon, a reality that Mr. Griffey ignores. He testified that Mr. Griffey presents last year's report, but in the report for Planning Year 2019/20, capacity credit values for Zone 6 wind resources have increased to 7.8%, with the system-wide capacity credit up to 15.7%. Zone 6 resources have realized capacity credits as high as 9.3%[13] in recent years.

With regard to Mr. Griffey's point about capacity credit declining in the future, Mr. Augustine testified MISO's estimate for this expectation has also changed dramatically over the last several years. He stated that in the Planning Year 2019/20 report, MISO's long-term expectation for wind capacity credit has increased by 0.4 percentage points compared with the number Mr. Griffey cites from last year, and this is a continuation of a trend. He continued that MISO's view on the long-term capacity credit for wind resources in the face of more wind penetration has consistently increased. For example, in the Planning Year 2013 report, MISO projected the wind capacity credit to be 10.6% with 30 GW of wind penetration. He testified that in the most recent Planning Year 2019/20 report, MISO projects a 13.5% capacity credit with 30 GW of wind penetration, which nearly 30% increase in the expected capacity credit is due to increased geographic diversity and better technological performance for wind plants. Furthermore, Mr. Augustine testified it is possible that the wind capacity credit could also increase over time if the penetration of solar resources shifts the effective peak hour of the day and hence the effective load carrying capability value of wind resources that perform better later in the evening. He noted that this phenomenon has already been seen in California (in the California ISO a methodology change to account for growing ELCC value for wind, as solar penetration increases, resulted in the August wind capacity credit jumping from an average of 17.65% from 2013 through 2017 to 26.5% in 2018 and 2019.)[14]

Mr. Augustine testified that he was not implying that there is no risk that the wind projects will realize capacity credits below the 15% and 13.5% assumptions used in the 2018 IRP; but, rather that he is trying to present a more balanced view of the current state of the market than Mr. Griffey does with his claim that 7.4% is the only reasonable planning assumption that NIPSCO should use. He stated that, in fact, NIPSCO has been transparent about capacity credit risk

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[12] *See* Griffey testimony, p. 26, lines 1-3.
[13] *See* MISO Planning Year 2015/16 Wind Capacity Credit Report: https://cdn.misoenergy.org/2015%20Wind%20Capacity%20Report124859.pdf
[14] *See* CAISO NQC summary: http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx

throughout the production of its 2018 IRP and stated explicitly in the 2018 IRP that it expects that "both wind and solar renewable capacity credit will change over time with increased renewable penetration levels"[15] and that, "if capacity credit rules or methodologies change, NIPSCO's 2018 IRP path can be cost-effectively scaled to adjust."[16] Mr. Augustine testified NIPSCO plans to pursue a geographically diverse set of different renewable resource types in a staged fashion to address this risk. He followed that as NIPSCO concluded in the 2018 IRP, "[b]y not committing to any single, large asset for the majority of UCAP needs, NIPSCO can flexibly adapt as rules and technologies change."[17] He testified that NIPSCO's request here is consistent with this approach and consistent with the clear finding that renewable resources are significantly lower cost than retaining the current coal fleet.

Mr. Augustine testified that Mr. Griffey's claim that other resources would have been chosen in NIPSCO's 2018 IRP analysis if wind resources were given a lower UCAP value, and states that it is "quite possible that Aurora could have selected a new CCGT or the coal-to-gas conversion of Schahfer 17/18" is purely speculative and not supported by any analysis. He stated that based on his knowledge of the 2018 IRP modeling, the more likely outcome would have been that additional, low cost wind and solar resources would have been the preferred resource additions. He stated that as demonstrated in NIPSCO's 2018 IRP, sufficient low cost renewable capacity and energy was available from the results of the All-Source RFP to retire all of NIPSCO's coal capacity by 2023 and generate significant savings for customers. He concluded that while Mr. Griffey focuses exclusively on capacity credit questions, he ignores the very large energy value that the wind resources will provide to NIPSCO's portfolio.

In response to Mr. Griffey's assertion that it was never reasonable to ignore congestion costs in the 2018 IRP, Mr. Augustine stated the IRP is a long-term planning exercise intended to develop directional resource guidance using a range of long-term assumptions for a large set of inputs, including market power prices. He noted it is standard practice in the industry to perform long-term assessments at the zonal level, while reserving the more detailed congestion and nodal pricing analysis for specific project evaluation. He stated that NIPSCO acknowledged the existence of congestion and nodal price risk for new resources in its 2018 IRP[18] and has now done significant due diligence around congestion risk in its selection of the preferred wind projects to carry out its Short Term Action Plan from the 2018 IRP. He testified that as demonstrated by NIPSCO's LCOE analysis, after including expected future congestion for the wind projects, the weighted average LCOE of the wind resources currently under consideration is lower than the weighted-average LCOE of the wind resources assumed in the 2018 IRP without congestion costs.

Mr. Augustine explained that NIPSCO performed a nodal price forecast analysis using its PROMOD model and transmission topology data available from the MISO Transmission Expansion Plan ("MTEP") process. He said NIPSCO used MTEP's Accelerated Fleet Change scenario, along with assumptions for NIPSCO fleet retirements and commodity prices that were consistent with those used in NIPSCO's 2018 IRP and noted the MTEP cases are provided for 2022, 2027, and 2032, and NIPSCO performed analysis for each year. He indicated that this

[15] *See* 2018 IRP, p. 177.
[16] *Ibid.*
[17] *Ibid.*
[18] *See* page 177 of the 2018 IRP.

analysis developed congestion costs between the Joint Venture's location and NIPSCO's load node, which were used in the LCOE analysis to compare the project to what was assumed in the 2018 IRP.

In response to Mr. Griffey taking issue with NIPSCO's use of the Accelerated Fleet Change scenario by claiming that it "assumes more far-flung renewable generation is built" and that it "would tend to favor generation located closer to loads," Mr. Augustine testified that, in fact, this is precisely why NIPSCO has analyzed this scenario. He stated it incorporates significant renewable additions and is designed to assess the potential for low prices for new renewable generation that is sited away from loads; therefore, NIPSCO's selection of this scenario is conservative in evaluating future congestion risk and that Mr. Griffey's implication otherwise is false.

Mr. Augustine disagreed with Mr. Griffey's criticism that NIPSCO did not perform any alternative nodal pricing analysis and claims that NIPSCO's fundamental congestion pricing analysis is not valid because NIPSCO's cost analysis did not incorporate the cost of new transmission. He stated that NIPSCO does not manage an isolated transmission system, where it is responsible for upgrades that are required as the system evolves over time. Instead, it is part of MISO. He noted that transmission upgrades on NIPSCO's system, such as the costs associated with upgrades necessary to facilitate the Schahfer retirement, have been included in NIPSCO's analysis. He indicated that other regional costs are less dependent on specific NIPSCO action since they are in other service territories or allocated more broadly across the system. Mr. Augustine noted that if NIPSCO customers are unable to realize the benefits of low-cost renewables, such as the wind project in this proceeding, it does not mean that the utility's customers would be absolved from paying for broader system upgrades associated with MISO's fleet evolution. Furthermore, he stated that project-level interconnection costs associated with the Joint Venture are embedded in the overall project costs. He stated that overall, Mr. Griffey's claim that transmission costs are missing from the analysis is baseless, and his dismissal of NIPSCO's long-term congestion pricing analysis for the same reason is equally unfounded. Mr. Augustine testified Mr. Griffey did not produce any analysis that would estimate the expected transmission costs that he claims are missing and he did not raise any questions regarding the well-vetted transmission assumptions that MISO itself develops for the nodal pricing congestion analysis NIPSCO performed.

Mr. Augustine responded to Mr. Griffey's suggestion that curtailment costs could be significant for the project. He testified NIPSCO also evaluated curtailment and that for the Joint Venture, NIPSCO's analysis found no curtailment in 2022 and 2027 and projected approximately 0.75% of the project's expected generation to be curtailed in 2032. He noted that this is an insignificant volume. He noted that Mr. Griffey did not perform any analysis that would demonstrate a larger risk of curtailment. Mr. Augustine testified that NIPSCO's approach with regard to congestion risk in the 2018 IRP and in this proceeding is very reasonable and appropriate. He indicated that as is standard practice in the industry, NIPSCO evaluated resource options on a zonal level in its 2018 IRP and that as part of its resource selection process, NIPSCO performed detailed congestion analysis to ensure that new projects would not introduce any cost risk beyond what was assumed in the 2018 IRP. He stated that this has now been confirmed, and Mr. Griffey has not provided any analysis that would refute NIPSCO's clear conclusion that the addition of the Joint Venture to NIPSCO's portfolio will be beneficial for customers and is consistent with the findings of the 2018 IRP.

Mr. Augustine disagreed with Mr. Griffey's claim that the tax equity assumptions used in the IRP are inconsistent with the tax equity assumptions used for the Joint Venture. He testified the tax equity assumptions used in the 2018 IRP were based on tranche-level data regarding capital costs and capacity factors for new wind resources, and the 2020 wind additions were assumed to have a 60% tax equity contribution.[19] He stated that, in reality, the specific parameters associated with a specific wind project such as the Joint Venture determine the ultimate tax equity contribution. He stated that in this case, NIPSCO now estimates that the tax equity contribution is broadly consistent with the IRP assumptions.

Mr. Augustine testified that Mr. Griffey's claim that the tax equity contribution for the Joint Venture is different is inaccurate. He indicated that Mr. Griffey is confusing two different elements associated with the Joint Venture. He stated that the initial partnership includes participation from a tax equity investor, NIPSCO, and the project developer, while NIPSCO proposes to buy out the Developer's stake in 2023 to align with the timing of the Schahfer retirement. He stated that NIPSCO will compensate the developer with a return on investment during this "hold" period, which will increase the total investment in the project. He stated that Mr. Griffey's effort to calculate an equivalent tax equity contribution as a result of this arrangement with the developer is misleading. He also emphasized that all elements of NIPSCO's partnership have been included in NIPSCO's cost modeling in this application, and when taken as a whole, the costs of the Joint Venture are well in line with the costs of the owned wind resource evaluated in the 2018 IRP as demonstrated in his direct testimony in this proceeding.

Mr. Augustine responded to Mr. Griffey's claims that NIPSCO has "eliminated any ongoing capital expenditures and lowered the O&M estimate compared to the IRP." He responded that all ongoing O&M cost estimates for the Joint Venture were provided by the project developer based on the specific wind project details, while the 2018 IRP assumptions for O&M costs and ongoing capital expenditures were based on generic values from a variety of public sources. He stated that although Mr. Griffey claims that NIPSCO has eliminated ongoing capital expenditures, the O&M budgets provided by the developer include large increases in spending throughout the forecast, in years 2026, 2029, 2036, and 2041. He noted that Mr. Griffey has not provided any data regarding ongoing wind plant costs that would suggest he has better information than the project developer.

In response to Mr. Griffey's belief that NIPSCO's LCOE analysis is not useful on a stand-alone basis and that the calculations contain unreasonable comparisons and Dr. Boerger's concern regarding the consistency of certain financial assumptions used in the calculation of the LCOE for the Joint Venture, Mr. Augustine summarized how NIPSCO performed its LCOE analysis and how it was related to the 2018 IRP. He testified that NIPSCO relied on its 2018 IRP to conclude that new wind additions would provide substantial savings to NIPSCO's customers. He stated that such savings were demonstrated against portfolios that preserved coal capacity and against a portfolio that retired coal plants, but replaced the capacity with non-wind renewable resources. He explained that the 2018 IRP analysis performed extensive dispatch analysis and detailed revenue

[19] *See* Section 4.10.2 of the 2018 IRP for more detail.

requirement calculations and provided clear evidence that wind resources acquired in the 2020-2021 time period are far less costly than maintaining NIPSCO's current coal fleet. He said that the LCOE analysis performed by NIPSCO in this proceeding was then conducted to ensure that the cost profile of the selected wind resource, in this case the Joint Venture, was similar to the assumptions used in the 2018 IRP, which were based on a combination of bids from NIPSCO's RFP.

Mr. Augustine disagreed with Mr. Griffey's claims that this analysis is not valid because an LCOE calculation can only be used to compare resources that are likely to operate at the exact same times. He explained that LCOE analysis is a standard tool used in the industry to compare the relative costs of different resource options on a per MWh basis and is used all the time to compare projects with different operational profiles, including different types of wind projects. He stated it is not a replacement for the more comprehensive dispatch and portfolio cost accounting analysis that NIPSCO has performed, but is a valid tool for comparing the costs of similar resource types, such as the Joint Venture wind project and the two wind tranches included in NIPSCO's preferred portfolio from the 2018 IRP.

Mr. Augustine disagreed with Dr. Boerger's assessment that the LCOE calculation is flawed because "NIPSCO uses two discount rates… one using NIPSCO's current return on equity ("ROE") value to calculate the discount rate and the other using the ROE proposed in NIPSCO's current rate case." Dr. Boerger noted that he calculates that the LCOE would be raised if the correct ROE is used. Mr. Augustine believes Dr. Boerger's assessment is complete. He testified that NIPSCO used different discount rates in its LCOE calculation to preserve general consistency with what was used in the 2018 IRP, while also reflecting a possible new capital structure for investment in the Joint Venture. He believes Dr. Boerger's position that NIPSCO should use one consistent ROE is reasonable, but his proposed adjustment only changed the discount rate and ignored the need to adjust the ROE assumed for the return on rate base. He stated that when the ROE is also adjusted, the future customer costs associated with the Joint Venture investment go down with a different LCOE, a number that is actually slightly lower than the original calculation, making Dr. Boerger's adjustment not complete.

Mr. Augustine stated he does not believe that any of Mr. Griffey's perceived concerns regarding the Joint Venture's attributes have merit, nor that Mr. Griffey's proposed alternative LCOE calculations are more appropriate than what NIPSCO has already calculated for the Joint Venture. Furthermore, he stated that Mr. Griffey's proposed set of alternative LCOEs for the Joint Venture still all fall below the LCOEs of continuing to operate NIPSCO's five existing coal units. He stated that although Mr. Griffey argues that NIPSCO's "comparison of the levelized cost of a wind project to the levelized cost of NIPSCO's coal units is completely without merit," whether the resources are compared through an LCOE calculation or through a full portfolio analysis that captures all costs of production and avoided costs of energy and capacity, wind options are lower cost for customers than maintaining the current coal fleet. He noted that Mr. Griffey has not offered any evidence or independent analysis that disputes this finding.

Mr. Augustine responded to Mr. Griffey's new perceived issue regarding carbon price assumptions noting that MISO's stakeholders only place a 20% weight on the future that includes a carbon tax, while NIPSCO includes a carbon price in three of the four scenarios that it developed in the 2018 IRP. Mr. Augustine testified that MISO's MTEP process serves a different purpose than NIPSCO's IRP process. The MTEP process is largely concerned with identifying the future supply and demand across the region in order to facilitate transmission planning, while NIPSCO is more focused on assessing future generation costs for customers in its IRP. He stated that although MISO may only assess one scenario with carbon prices, stakeholders in the MTEP planning process are still concerned with addressing coal retirements, renewable additions, and utility-specific carbon reduction targets in other ways.[20] He explained that within NIPSCO's IRP analysis, evaluating the costs of different potential carbon price outcomes was an important objective.

Mr. Augustine testified that, regarding the assumptions used in the 2018 IRP, it is likely that some form of meaningful carbon regulation will be present over a long-term planning horizon. He stated that contrary to Mr. Griffey's assertion that NIPSCO is "ignor[ing] current law" in its development of its carbon scenarios, NIPSCO has relied on the facts that the U.S. Supreme Court has ruled that the Clean Air Act gives the U.S. Environmental Protection Agency ("EPA") the authority to regulate emissions of CO2,[21] and that in 2009 the EPA made a finding that greenhouse gases endanger public health, requiring them to regulate CO2 emissions. He stated that while NIPSCO acknowledges that the current administration is not regulating emissions with a tax or emissions trading program and that federal regulation of CO2 emissions is a possible outcome for the entire planning horizon.[22] Therefore, NIPSCO believes that its long-term assumptions should also include the potential that a future administration could implement existing requirements differently or that separate legislation regulating carbon emissions could be passed by Congress.[23]

Mr. Augustine testified NIPSCO's finding in the 2018 IRP that customer costs can be lowered by retiring coal and adding renewables was not dependent on the assumption of a future price on carbon. He stated NIPSCO found that early retirement of coal and replacement with renewables was lower cost under its scenario without a carbon price. Furthermore, NIPSCO was open to stakeholder input on scenarios throughout its 2018 IRP process and evaluated one developed by the ICC with no carbon price, no future environmental capital expenditures for coal plants, low coal prices, and high natural gas prices. He stated that even in this scenario, NIPSCO found that renewable replacement resources are lower cost than the existing coal fleet.

Mr. Augustine responded to Mr. Griffey's note that a "discrepancy in approach" regarding NIPSCO's treatment of carbon prices versus the fact that "NIPSCO relies on current tax law to claim a need to act now based on the current expiration dates for ITCs and PTCs for solar and wind resources." He testified that with regard to the expected declines of federal tax credits over

[20] *See* the most recent MISO MTEP workshop materials for the 2020 planning year, which highlights stakeholder feedback, including comments regarding retirement assumptions, renewable penetration levels, and load serving entity renewable and carbon reduction goals on slide 3.
https://cdn.misoenergy.org/20190314%20MTEP20%20Futures%20Workshop%20Item%2002-03-04%20MTEP%20Futures%20Presentation327266.pdf
[21] *See* Massachusetts v. Environmental Protection Agency, 549 U.S. 497 (2007).
[22] NIPSCO's Challenged Economy scenario includes such an outlook.
[23] *See* Section 8 of NIPSCO's 2018 IRP for additional description of the rationale behind NIPSCO's carbon price scenarios.

time, the PTC is already in the fourth year of the planned phase down,[24] and there has been policy stability since the latest Congressional action in 2015. He said that at this time, there is no expectation that the tax credits will be extended, although a change in policy is always possible. In its 2018 IRP, NIPSCO consistently found that it is significantly lower cost for customers to bring PTC-eligible wind into the portfolio. Mr. Augustine explained that if the PTC expires prior to NIPSCO acquiring new wind resources, the 2018 IRP analysis demonstrated that customer costs will go up if alternative renewable resources need to be found.[25] This is a very different situation than the one associated with the potential for future carbon prices. He said in that case, NIPSCO found that retiring coal resources and replacing them with renewables is lower cost for customers with or without a future carbon price. He also noted that a major attribute of NIPSCO's preferred portfolio is the fact that it preserves significant flexibility regarding future resource acquisitions for additional capacity and energy needs in the coming years. If the PTC were to be extended, additional wind could be procured at a future date, and taking advantage of the tax incentives currently available to the Joint Venture does not prevent such future action.

Mr. Augustine disagreed with Mr. Griffey's representation of NIPSCO's stochastic distribution. He testified it is inaccurate to claim that the prices "stay" at certain prices across the various probability distributions presented. He stated that, as NIPSCO explained in detail in its IRP, "[t]he confidence intervals do not represent specific price trajectories, but instead indicate the probability of the price being at or below the specified level at any given point in time."[26] He stated that a representation of the 5th percentile, therefore, means that 5% of the data set is below this price level at the single point in time represented by the distribution (in this case, at the monthly level of granularity in the graphic referenced by Mr. Griffey). He stated that, as NIPSCO's 2018 IRP explained, "observations can come from different price paths over time, since each path is likely to be relatively volatile, moving up and down. He testified that, in fact, it is highly unlikely that a single path would be at [the representative] percentile for a sustained period of time."[27]

Mr. Augustine testified Mr. Griffey is incorrect in claiming that the prices in the distribution include NIPSCO's assumed step function change for CO2 taxes in 2026. He testified that as Mr. Griffey rightly pointed out in his own testimony, NIPSCO assigned a 75% likelihood of a CO2 price in 2026, meaning that 25% of the iterations in the stochastic distribution contained no CO2 price. He stated that NIPSCO's probability-weighting approach for the stochastic distribution development was explained on page 143 of the 2018 IRP and reviewed in detail during NIPSCO's May public advisory stakeholder meeting.[28] He testified that many of the low price observations noted by Mr. Griffey occur in situations where there is no price associated with carbon emissions.

Mr. Augustine testified that Mr. Griffey's misunderstanding of the stochastic prices completely invalidate his claim that "the Rosewater Project and the other wind PPAs are certainly much higher than the lower price outcome stochastics, particularly if the CO2 tax is removed in

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[24] Note that the phase-down started after 2016, with a safe harbor provision allowing projects with prior equipment purchases and project expenditures to still qualify with later in-service dates.
[25] *See* Section 9.3.1 of NIPSCO's 2018 IRP for additional detail regarding this conclusion.
[26] NIPSCO 2018 Integrated Resource Plan, p. 143.
[27] *Ibid.*
[28] *See* p. 16 of the May Public Advisory Meeting presentation, which is included in Appendix A to NIPSCO's 2018 IRP.

2026." He stated the CO2 price is already removed from many of the observations highlighted in the lower end of the distribution, and while it is certainly possible that market prices will be lower than the costs of the Joint Venture wind project or other wind PPAs for certain periods of time, NIPSCO's rigorous statistical analysis found that this is unlikely to be a persistent occurrence. Mr. Augustine added that low market prices pose a more significant risk to Mr. Griffey's preference of "extending coal plant lives," since low market prices expose coal-fired generating resource to both dispatch and MISO revenue risk. He testified NIPSCO has found that the price certainty offered by renewable resources mitigates cost risk for customers better than coal plants do across a wide range of outcomes evaluated in the stochastic analysis.

In response to Ms. Medine's concerns about the 2018 IRP process and assumptions, Mr. Augustine testified the IRP is a planning document and is not subject to a ruling or formal approval by the Commission and, in fact, by rule, the IRP Director's Report produced by the Commission "shall not comment on the desirability of the utility's preferred resource portfolio or a proposed resource action in the IRP."[29] Therefore, he testified that NIPSCO is not obligated to wait for any action from the Commission regarding its IRP submission before using its conclusions to support any resource decisions. He went on to explain that NIPSCO conducted a transparent IRP process, conducting six public advisory meetings over the course of 2018, along with many individual meetings with stakeholders to provide information and receive feedback on the methodologies and assumptions used in the 2018 IRP. He testified that as part of this process, NIPSCO performed several stakeholder-requested analyses prior to the submission of the 2018 IRP, including some requested by Ms. Medine and the ICC. Mr. Augustine testified NIPSCO consistently found that its preferred portfolio would provide significant savings, even in the scenarios developed by Ms. Medine.

Mr. Augustine testified that he responded to each of Ms. Medine's claims regarding the 2018 IRP in his rebuttal testimony in NIPSCO's currently pending rate case (Cause No. 45159) and incorporated that testimony as Confidential Attachment 4-R-A. He also sponsored NIPSCO's formal responses to stakeholder IRP comments, including those made by the ICC, as Attachment 4-R-D. He testified that as shown in the attachments, Ms. Medine's claims are all without merit and fail in any way to contradict NIPSCO's finding that new renewable additions are lower cost for customers than maintaining the current coal fleet.

Mr. Augustine responded to Ms. Medine's claims that in its 2018 IRP, NIPSCO failed to determine the impact to customer rate by considering only the NPVs and that labor and/or fuel intensive scenarios will have a more levelized rate impact than those with more new capital investments. He testified that while NIPSCO's "cost to customer" scorecard metric in the 2018 IRP reported the NPV of future projected revenue requirements, NIPSCO's IRP conclusions were based on the development of detailed annual projections for revenue requirements consistent with utility cost of service principles.[30] He stated that this analysis concluded that portfolios that replaced labor and fuel intensive resources like coal plants with renewable resources realized lower annual revenue requirements immediately. Therefore, Ms. Medine's implication that a different

[29] *See* 170 IAC 4-7-2.2.

[30] NIPSCO provided detailed annual revenue requirement projections and associated backup information for each portfolio across each scenario in the "DetailedFinOutput" tabs in Confidential Appendix D to the 2018 IRP.

cost metric would have changed NIPSCO's conclusion regarding retirement of coal plants and replacement with renewables is not supported at all by the analysis.

In response to Ms. Medine's suggestions that NIPSCO's 2018 IRP may have come to a different conclusion if it had more fully evaluated industrial load loss, Mr. Augustine testified NIPSCO did evaluate a low load scenario in the 2018 IRP, which was based on substantial industrial load leaving the system, and it found that retiring coal units provided savings to customers in this scenario. He was further asked about industrial load loss and the 5 largest users that would be eligible for NIPSCO's proposed Rate 831 in its pending rate case. While he testified on cross-examination that these users represent 800 MW of demand offset by interruptibles, he explained on redirect that much of this demand was in fact interruptible. He testified that the difference between the assumption of 194 MW subscription to Rate 831 and the level of demand from these five customers under the base case in the 2018 IRP was approximately 60 MW.

In response to Ms. Medine's suggestion that NIPSCO should not be locking into long-term commitments, including the PPA with the Rosewater Project, without evaluating industrial load loss risk in more detail, Mr. Augustine stated that it is important to note that since NIPSCO is part of the MISO market, the competitiveness of the existing coal fleet versus the alternative renewable resources in the preferred portfolio is not predominantly driven by NIPSCO's internal load obligations, but by the cost structure of the different resources and their position in the market. Furthermore, he explained that any future loss of firm load can be managed through NIPSCO's procurement of replacement resources, a strategy that is less risky than the one Ms. Medine advocates. He testified that investing in and maintaining the high-cost coal units, on the other hand, could result in NIPSCO having more high-cost capacity than it needs if load obligations were to fall significantly.

Mr. Augustine disagreed with Ms. Medine's claims that "[l]ocking into a 15-year wind contract exposes NIPSCO customers to potentially higher costs if the cost of wind generation declines." He testified NIPSCO's request includes a wind project that takes full advantage of the PTC, which will ramp down to zero over time after 2020. He testified that NIPSCO has found that the value of the PTC is greater than potential future cost declines in underlying wind technology, and Ms. Medine has provided no evidence to the contrary.

Mr. Augustine explained that Ms. Medine primarily references the fact that wind costs have declined since 2010 as per the International Renewable Energy Agency and the National Renewable Energy Laboratory ("NREL"), cites one footnote in an NREL report indicating that the WACC for wind projects is likely to decline over time as the PTC ramps down, and one footnote about future WACC for wind projects to assert that "NREL is not overly concerned about continued wind investment without the PTC." He stated that Ms. Medine also presents a summary of perceived problems that she believes have arisen with NIPSCO's current wind PPAs. Mr. Augustine testified that, while the historical cost declines she references are true, Ms. Medine's assertion that NREL is not "overly concerned" about continued wind investment is not based in any fact, nor does this statement actually say anything about the relative costs to NIPSCO's customers of wind entering into service in 2020 versus wind entering into service in the future.

Mr. Augustine testified that NREL produces an Annual Technology Baseline ("ATB") assessment of future technology costs, including for wind technology and that this is the primary source used by NIPSCO to project future cost declines for wind resources over time beyond the period of time that relied on the RFP bids. Mr. Augustine stated that Ms. Medine's use of NREL's ATB projections of future wind costs don't support her claim and that NREL's base case projections show annual declines of less than 1% in real dollars over time. The declines are offset by expected inflation growth, which is consistent with the long-term projections used in NIPSCO's 2018 IRP. Mr. Augustine noted that NREL also produces a low case with more aggressive cost declines, amounting to an approximate 32% reduction in nominal wind costs for projects coming online in 2031 (the lowest cost year in NREL's projections) relative to 2020. Mr. Augustine testified that this 32% cost decline for new wind in the NREL low case would not be sufficient to offset the loss of the PTC. He stated that NIPSCO's analysis has shown that the PTC is worth approximately 55% of the total installed costs of a project coming online in 2020 with a capacity factor in the range of the projects currently being pursued by NIPSCO. Mr. Augustine testified that even in NREL's low case, acquiring wind now would be the preferred, low-cost strategy versus waiting. He confirmed this was the finding in NIPSCO's 2018 IRP and is the primary reason why no additional wind resources beyond PTC-eligible RFP options were selected in the preferred portfolio.

Mr. Augustine concluded that Ms. Medine's claim that waiting for wind costs to decline could prevent NIPSCO from locking into higher cost wind is completely without merit. He testified that NIPSCO has found that replacing coal with renewable resources actually reduces risks substantially for customers. Mr. Augustine testified that NIPSCO's 2018 IRP analysis concluded that renewable additions, including wind, were far less risky than maintaining coal, since portfolios that retired coal early and replaced capacity with renewable resources were lower cost across all scenarios and performed best on all risk metrics from NIPSCO's stochastic analysis.

Mr. Augustine disagreed with Ms. Medine's assertion that, "the situation most analogous [to NIPSCO's] is the recent failed attempt by Southwestern Electric Power Company ("SWPECO") [sic] to obtain a CPCN for its ownership share (70%) of the 2000 MW Wind Catcher Project in Oklahoma." He presented multiple differences between that situation and NIPSCO's. He also provided numerous recent examples of utilities that are in situations far more relevant to NIPSCO's and received approvals to add wind to their portfolios, demonstrating that state commissions have found cause to approve wind applications in cases similar to NIPSCO's. He stated that even more important than these anecdotes, however, is the fact that NIPSCO has proven through extensive analysis that the Joint Venture wind addition is cost-effective for its customers.

Mr. Augustine responded to Dr. Kora's questions raised regarding the metrics NIPSCO used to evaluate portfolios in its 2018 IRP and notes that he is "concerned that the primary focus of public interest reviews have become too narrowly focused on what is the least cost option for the provision of electricity." He testified that NIPSCO conducted a highly collaborative and transparent IRP process in 2018 and incorporated many more metrics than least cost in its evaluation of portfolio options. He testified that NIPSCO presented its integrated scorecard approach in multiple public advisory meetings and fully documented the scorecard metrics and portfolio results for each metric in Section 9 of its 2018 IRP. He explained that consistent with Dr. Kora's suggestions, NIPSCO included metrics on its scorecard associated with local property tax revenues and employment at existing coal plants. In addition, NIPSCO evaluated reliability, environmental, cost risk, and fuel security metrics in arriving at its preferred portfolio. He stated that if NIPSCO would have focused solely on least cost, the IRP analysis would have concluded that retirement of all coal plants as soon as possible would have been preferred. Mr. Augustine testified that instead, NIPSCO evaluated a range of tradeoffs and selected a preferred portfolio with staggered coal retirements, a diverse set of renewable and storage replacements, and flexibility to adapt to changing market conditions over time.

In response to the other parties' use of the Vectren Order denying Vectren South a CPCN to construct a new natural gas combined cycle facility in an effort to criticize NIPSCO's IRP conclusion and its application in this proceeding, Mr. Augustine testified that broadly speaking, NIPSCO's preferred 2018 IRP portfolio aims to acquire a diverse set of resources, while leaving flexibility to adapt to changing market conditions over time, a plan that is very consistent with the spirit of the Vectren Order. He stated that the efforts by Mr. Griffey, Ms. Medine, and Dr. Kora to draw different conclusions are not reasonable nor are they based in an accurate understanding of NIPSCO's preferred portfolio. He noted that while Mr. Griffey believes the principles of the order "would favor extending coal plant lives," NIPSCO's analysis has clearly shown that retiring coal plants and replacing them with any number of short-term and long-term resource options is cost-effective immediately. He noted that while Ms. Medine references the Vectren Order to claim that NIPSCO has not fully evaluated options for its existing fleet and could be locking into long-term resources in the face of declining load, in its 2018 IRP, NIPSCO evaluated coal-to-gas conversion options and scenarios with no new environmental capital on its coal plants and still found that retirement and replacement with renewables was cost effective. He stated that, furthermore, NIPSCO's preferred portfolio explicitly recognizes future load uncertainty by not committing immediately to large resources, but instead taking a phased approach to resource acquisition over the next several years. Finally, he stated that while Dr. Kora references the Vectren Order and claims that "NIPSCO is rushing to commit...to just one type of new generation going forward – namely wind generation," this is a false assertion, as NIPSCO's preferred portfolio and Short Term Action Plan prioritizes the near-term acquisition of wind resources, followed by future evaluation and likely acquisition of solar and storage resources for anticipated capacity needs.

14. <u>Commission Discussion and Findings</u>.

A. <u>Clean energy project under Ind. Code ch. 8-1-8.8 and Financial Incentives</u>. Ind. Code § 8-1-8.8-11 provides that "[a]n eligible business must file an application to the commission for approval of a clean energy project" and that "[t]he commission shall encourage clean energy projects by creating financial incentives for clean energy projects, if the projects are found to be reasonable and necessary." An "eligible business" is an energy utility that "undertakes a project to develop alternative energy sources, including renewable energy projects." Ind. Code § 8-1-8.8-6(3). We have already found that NIPSCO is an "energy utility." A "clean energy project" includes "[p]rojects to develop alternative energy sources, including renewable energy projects." Ind. Code § 8-1-8.8-2(2). "[E]nergy from wind" is specifically listed as one of the clean energy resources in Ind. Code § 8-1-37-4(a)(1) through Ind. Code § 8-1-37-4(a)(16), thus making it a "renewable energy resource" under Ind. Code § 8-1-8.8-10. Through the Joint Venture and the associated PPAs with Rosewater ProjectCo, NIPSCO is undertaking a project to develop energy from wind and so is eligible for the relief provided in Ind. Code § 8-1-8.8-11.

In addition to timely cost recovery, which we will describe, NIPSCO seeks financial incentives including approval of the Joint Venture structure whereby NIPSCO will invest in the Joint Venture, as described by Witness Campbell, which will own Rosewater ProjectCo, which will build and own the Rosewater Project. NIPSCO seeks approval of the BTA between the Joint Venture and EDPR, the BTA PPA and the Back-Stop PPA. The Back-Stop PPA is effective if all conditions to the BTA are not satisfied, and so approval of both the BTA PPA and the Back-Stop PPA is sought and is necessary at this time. NIPSCO also seeks authority to record its investment as a regulatory asset in Account No. 182.3 and to amortize its investment over the life of the Rosewater Project (estimated to be 30 years). NIPSCO further seeks confirmation that the net balance of its investment recorded in Account No. 182.3 will be included in NIPSCO's net original cost rate base for ratemaking purposes. Further, with respect to each capital investment NIPSCO makes, NIPSCO seeks authority to defer amortization of the regulatory asset until such time as the recovery of the amortization expense on that portion is reflected in NIPSCO's rates and charges and to accrue PISCC with respect to that investment at NIPSCO's weighted average cost of capital until a return is recovered through NIPSCO's rates and charges.

There are a number of limitations on NIPSCO's requested financial incentives which it offered on rebuttal. These limitations are:

- NIPSCO agrees that cost recovery of NIPSCO's developer buyout will be capped at $89,227,285, as shown in Confidential Attachment 1-R-A.

- NIPSCO also agrees not to seek approval in this proceeding of any amounts related to its purchase of the TEP's share of the Joint Venture estimated to occur around 2030. Rather, once a determination has been made by NIPSCO to purchase the TEP's share of the Joint Venture, NIPSCO will seek recovery of such costs in a separately docketed proceeding. NIPSCO will seek recovery of no more than the fair market value of the TEP's share of the Joint Venture.

- NIPSCO agrees to continue to treat its investment in the Joint Venture, even after such time as the TEP portion of the project has been acquired by NIPSCO, as a regulatory asset with NIPSCO booking amortization instead of depreciation. The value of the TEP share to be included in rate base shall be determined in a base rate case at the time of acquisition or in the next base rate proceeding following acquisition.

- NIPSCO agrees it will not record and accumulate on its books and records either the wind project revenues or the Joint Venture expenses, but rather those revenues and expenses shall be maintained by the Joint Venture, tracked and available for review by NIPSCO, the OUCC, and other stakeholders that have executed appropriate nondisclosure agreements, and subject to an independent audit. This is inclusive of any subsequent investments (cash contributions) NIPSCO makes into the Joint Venture.

- NIPSCO agrees that the cap of cost recovery related to any additional investments (cash contributions as described by Mr. Campbell) NIPSCO may make into the Joint Venture will be recoverable from ratepayers at an amount capped at $2 million net of revenues. During the term of the BTA PPA, to the extent sales revenue by the Joint Venture to NIPSCO exceed operating costs, NIPSCO's cash allocation will be returned to NIPSCO ratepayers as proposed by NIPSCO. To the extent revenues are less than operating costs, cash contributions by NIPSCO may be offset (netted against) by NIPSCO's cash allocations. At the time of the buyout of the TEP, if any, the accrued balance of the additional portion of this regulatory asset to be recovered from ratepayers will be no more than a net $2 million.

- NIPSCO agrees to have good faith discussions with stakeholders on NIPSCO's REC strategy, including whether RECs should be retired or sold. NIPSCO's REC strategy is currently reviewed, and audited, as a part of its quarterly FAC tracker filing, which is an appropriate forum for ongoing discussions.

- Except as otherwise described above, NIPSCO will not seek cost recovery from ratepayers of any other costs incurred by NIPSCO related to: (1) the buyout of EDPR; (2) the buyout of the TEP; or (3) the operation of the Joint Venture while either EDPR or TEP are still participants in the Joint Venture.

- Finally, NIPSCO agrees to remain the managing member of the Joint Venture.

OUCC Witness Haselden testified at the evidentiary hearing that the customer protections contained in NIPSCO Witness Campbell's rebuttal testimony satisfy the conditions set out in Mr. Haselden's pre-filed testimony, and with those conditions, the OUCC can recommend approval of the Joint Venture.

According to Ind. Code § 8-1-8.8-11, the Commission shall encourage clean energy projects by creating financial incentives for such projects, if found to be reasonable and necessary. While Chapter 8.8 does not set forth specific factors the Commission should consider in determining the reasonableness and necessity of a clean energy project, the Commission has considered some of the factors outlined in Chapters 8.5 and 8.7 in other cases. *See Ind. Mich. Power Co.*, Cause No. 44511 at 7-8 (IURC Feb. 4, 2015); and *Ind. Mich. Power Co.*, Cause No. 44182, at 53-54 (IURC July 17, 2013).

As set forth further below, the evidence in this Cause supports a finding that the energy to be obtained from the Joint Venture and accompanying PPA (including the backup PPA) is needed by NIPSCO, is reasonably priced compared to other alternatives, and provides other material benefits. The evidence demonstrates that the Joint Venture will provide emission-free electric generation and allow for the development of another local renewable resource that will further diversify NIPSCO's generation resources.

NIPSCO has a demonstrated need for additional resources in 2023 and the 2018 IRP developed a multi-step process to be implemented over a few years that provides a reasonable transition to acquire replacement resources. The proposed Joint Venture also enables effective use of the PTC to reduce the cost of wind resources beyond those cost decreases that can be anticipated from technological improvements if the wind resources were instead to be acquired at a later date.

NIPSCO relies on its 2018 IRP to support its request for approval of the capacity and energy that will be provided by the Joint Venture. ICC Witness Medine argued that reliance on the

2018 IRP was premature because the Director's Report has yet to be issued. While the Director's Report has not yet been issued, we note that 170 IAC 4-7-2.2 specifically provides that the Director's Report neither approves nor disapproves an IRP. Nor do we need to approve NIPSCO's 2018 IRP and its preferred portfolio in this proceeding. Instead, we must determine whether to approve NIPSCO's chosen resource, the Joint Venture and associated PPA, and in doing so, consider whether that chosen resource is supported by a well-developed IRP.

As discussed further below, the evidence demonstrates that the acquisition of additional wind resources is consistent with NIPSCO's 2018 IRP and Short Term Action Plan. Both the OUCC and CAC noted the consistency of the acquisition of additional wind resources with NIPSCO's 2018 IRP. The CAC recommended the Rosewater Joint Venture be approved and the OUCC recommended approval of the Joint Venture subject to the limitations discussed above.

ICC argued that NIPSCO's 2018 IRP does not demonstrate that its preferred portfolio is the least cost portfolio by criticizing NIPSCO's performance of its 2018 IRP resource portfolio modeling. More specifically, Mr. Griffey stated that: (1) congestion cost is higher than assumptions from the IRP; (2) NIPSCO assumed 100% tax efficiency from tax equity financing; (3) the capacity factor of Rosewater Project is lower than the 41.8% as represented in the IRP; (c) the assumption of CO2 tax was unreasonable; (4) increased future maintenance capital and operations and maintenance costs for coal units were above historic levels; (5) burdened coal units with environmental capital when the need for it is uncertain; (6) the Company did not update generic costs for solar units based on market conditions; (7) assumed current levels of PTCs and ITCs for replacement PPAs will be available in the future; and (8) NIPSCO ignored its proposed industrial rate structure in the 2018 IRP. He also said there were no curtailment costs included in NIPSCO's 2018 IRP. Mr. Griffey contended that running Michigan City and converting Schahfer Units 17 and 18 to gas would produce a lower net present value rate of return than the proposed Joint Venture. NIPSCO's Witness Augustine, in rebuttal, adequately addressed those criticisms. This finding is consistent with the Commission's previous conclusions on an effectively similar fact set in Cause Nos. 45195 and 45196.

ICC also argued that because the cost of wind generation has been declining, NIPSCO's entering into a Joint Venture and the associated PPA exposes customers to potentially higher costs compared to the costs if a commitment is delayed for an unspecified period of time. While wind prices may or may not continue to decline, the likely phase-out or elimination of the PTC supports the acquisition of this wind resource now rather than later. Witness Augustine testified that the PTC is worth approximately 55% of the total installed costs of a project coming online in 2020 with a capacity factor in the range of the projects currently being pursued. Mr. McCuen testified that by contracting for wind resources now NIPSCO's customers, over the life of the projects, would save approximately $500 million due to the declining value of the production tax credits. As a result, acquiring wind resources now is preferable to waiting.

As the Commission has noted previously, "[a] key consideration in long-term resource planning is the need to retain maximum flexibility in utility resource decisions to minimize risks. . . . The credibility of the analysis is critical to the effort of Indiana utilities to maintain as many options as possible, which includes off-ramps to react quickly to changing circumstances and make appropriate changes in the resources." *S. Ind. Gas & Elec. Co.,* 2019 WL 1332234 at *24, Cause

No. 45086 (IURC Mar. 20, 2019). NIPSCO's proposal preserves optionality and flexibility and is consistent with the Commission's findings in *S. Ind. Gas and Elec. Co.,* Cause No. 45052 (IURC April 24, 2019). NIPSCO is not obligated to purchase and we are not asked to approve NIPSCO's potential future purchase of TEP's share. Accordingly, we find the Rosewater Project is a clean energy project under Ind. Code § 8-1-8.8-11 and NIPSCO's requested Joint Venture structure (and the associated BTA, BTA PPA, and Back-Stop PPA) is reasonable and necessary and should be approved. We further find that NIPSCO's requested financial incentives, as limited on rebuttal and set forth above, should be granted. We find the BTA, the BTA PPA, and, in the event that the BTA conditions are not satisfied, the Back-Stop PPA should be approved.

NIPSCO proposes the timely recovery of costs incurred pursuant to the BTA PPA and, if necessary, the Back-Stop PPA be administered through NIPSCO's FAC proceedings (or successor mechanism). We find that the costs to be incurred pursuant to the Rosewater Project are reasonable throughout the term of the BTA PPA and the Back-Stop PPA. Based on the record evidence, the Commission finds that the recovery of all of the purchased power costs related to the purchase over the full term of the BTA PPA and Back-Stop PPA should be approved. We further find that NIPSCO should recover the BTA PPA and, if necessary, Back-Stop PPA costs through a rate adjustment mechanism under Section 42(a) and administered through its FAC proceeding (or successor mechanism). Based upon the evidence presented and prior Commission precedent in other wind PPA proceedings, we find that NIPSCO's recovery of its BTA PPA costs and, if necessary, Back-Stop PPA costs should not be subject to the Section 42(d)(1) test or any other FAC benchmarks.

B. Approval of CPCN for NIPSCO's Acquisition of the Rosewater Project Through the Joint Venture. Ind. Code § 8-1-8.5-5 sets forth the criteria for approval of a utility specific generation proposal. The Commission must consider the items set forth in Ind. Code § 8-1-8.5-4, must make a finding as to the best estimate of cost of the project based on the evidence of record, must make a finding whether the proposal is consistent with our statewide analysis or a utility specific proposal, and must make a finding whether the public convenience and necessity requires the project.[31] We will address each of these provisions below.

(a) Best estimate of the cost. NIPSCO Witness Campbell testified to the cost of the Rosewater Project represented by the total price to the Joint Venture for the purchase of the equity interest in Rosewater ProjectCo. This number is confidential and set forth on page 23 of Mr. Campbell's direct testimony. NIPSCO will initially invest one percent of this total price. OUCC Witness Haselden testified that NIPSCO's investment in the Rosewater Project at the time of the EDPR buyout should be capped. In rebuttal NIPSCO agreed that cost recovery of NIPSCO's developer buyout would be capped at the product of the percentage of EDPR's ownership in the Joint Venture times the contract cost escalated at the rate of a specific percent per year. This represents a total cap on the purchase of EDPR's share of $89,227,285. Therefore, the cost recovery for the EDPR payment shall be no more than that shown in Confidential Attachment 1-R-A. The later purchase of TEP's share, should it be pursued, is no longer proposed in this proceeding. If NIPSCO should decide to complete that purchase, cost recovery will not be sought or proposed except as part of a separately docketed proceeding. That investment will be no more

[31] In addition, the Commission must make findings pursuant to Ind. Code § 8-1-8.5-5(e). This requirement is the subject of NIPSCO's proposed ARP, a matter we will address later.

than the fair market value of TEP's share at the time, which will consist of the discounted present value of TEP's share of the remaining payments left to be made over the remaining term of the BTA PPA. Petitioner's Exhibit No. 2, p. 13. Finally, NIPSCO has also agreed to a remaining cap of $2 million of cost recovery on any other capital investments it may be required to make in the Joint Venture net of revenues. No party offered any contrary evidence of the cost or disputed these numbers. It is critical that the cost estimate originated with a very competitive all-source RFP conducted at the direction of NIPSCO with the review of the responses performed by an experienced third party. Based upon the evidence and NIPSCO's agreement to cap the cost recovery for its purchase of EDPR's ownership in the Joint Venture, the Commission finds that NIPSCO has provided the best estimate for the cost of the project.

(b) Consistency with the Statewide Analysis or NIPSCO's Utility Specific Proposal. Ind. Code § 8-1-8.5-5(2) requires that the proposed construction, purchase, or lease be consistent with either the Commission's analysis for expansion of electric generating capacity or with a utility specific proposal that we approve. For the latter, we evaluate the proposal's consistency with the utility's IRP. The assumed capacity available from this BTA PPA would fill only a portion of the capacity shortfall anticipated in 2023. Witness Augustine, in rebuttal, also noted that despite the criticisms of NIPSCO's IRP, NIPSCO modeled every scenario requested by the stakeholders, and in each instance, the wind resources were more economic than other resources. The record reflects that within its IRP process, NIPSCO considered 90 proposals supported by 59 projects across five states with different generation resources for modeling, including natural gas, coal, wind, solar, battery storage, and demand response. The record also reflects that NIPSCO engaged and considered stakeholder input throughout the process. There is strong evidence in the record that NIPSCO utilized an array of best practices, including basing model inputs on its all-source RFP, which allowed for a more informed forecast of the cost of utility scale, supply-side generators than the Commission has seen in the past; transparent inclusion of input forecasts, outputs, and assumptions; a thorough description of most aspects of screening and portfolio selection; and fair consideration of a wide range of supply-side alternatives without arbitrary limitations on the amount of those resources that can be selected or unsupported cost additions. The evidence is uncontradicted that NIPSCO has a need for capacity at this point in time. Based upon the evidence presented, the Commission finds that NIPSCO has shown a need for the requested Rosewater Project. NIPSCO's IRP addresses each of the items set forth in Ind. Code § 8-1-8.5-4, which we have taken into account as required by statute. The Rosewater Project is consistent with NIPSCO's 2018 IRP, which, to the extent it addresses the short-term need for capacity that would be addressed by the Rosewater Project and to the extent it is necessary, we approve.

(c) Public Convenience and Necessity. The record establishes that the Rosewater Project is the result of a thorough RFP process and a quantitative and qualitative evaluation of the RFP responses. The record further demonstrates that the terms of the BTA PPA and Back-Stop PPA were reached after arms-length negotiations. NIPSCO will only pay for the energy it receives at a set price established by the PPAs.

We find that the energy provided through the Rosewater Project is a reasonable and necessary addition to NIPSCO's portfolio of generating resources necessary to meet the need for electricity within NIPSCO's service area, while also mitigating the risk through the diversification and use of an economic mix of capacity resources that provides flexibility. The record shows that the addition of the Rosewater Project to the resource mix will provide needed energy and capacity. NIPSCO's and CAC's evidence established that NIPSCO reasonably modeled the wind PPAs in its 2018 IRP. Mr. Lee demonstrated that the Net Present Value Utility Costs analysis showed that acquiring the wind energy from Rosewater was superior to other options available to NIPSCO, including not acquiring wind.

(d) <u>Conclusion</u>. Based upon the evidence of record, the Commission finds that NIPSCO has met the requirements of Ind. Code § 8-1-8.5-5. A CPCN for NIPSCO's acquisition of the Rosewater Project through the Joint Venture should be issued.

C. <u>Consideration of NIPSCO's Proposed ARP</u>. NIPSCO has proposed[32] an ARP as follows: because the Rosewater Project arose out of the All-Source RFP, NIPSCO seeks to be relieved of or otherwise found to have complied with the obligations for receipt of a CPCN established under Ind. Code § 8-1-8.5-5(e). NIPSCO will not be the owner of the generating assets that make up the Rosewater Project. Instead, NIPSCO will own an interest in Joint Venture. NIPSCO seeks approval of the Joint Venture and the Joint Venture structure. NIPSCO further seeks to record its interest in the Joint Venture as a regulatory asset in Account 182.3 and to amortize the amounts so recorded using the amortization rates sought to be approved for the Rosewater Project. NIPSCO requests to include in net original cost rate base, and in the value of its utility property for purposes of Ind. Code § 8-1-2-6 and for ratemaking purposes, the balance of the regulatory asset NIPSCO has recorded for the Joint Venture. As noted, NIPSCO seeks to recover its payments made to Rosewater ProjectCo pursuant to the BTA PPA and, if necessary, the Back-Stop PPA, through a rate adjustment mechanism administered through the FAC without regard to Section 42(d) and without regard to any benchmarks established by the Commission for PPAs.

To the extent necessary, NIPSCO is seeking approval of financing. To the extent financing approval is sought and obtained herein, NIPSCO seeks to be relieved of the technical requirements set forth in Ind. Code §§ 8-1-2-79 and -80. These include corporate officer signatures and verifications, the elements in Ind. Code § 8-1-2-79(a)(1) through (6), and the specific provisions to be set forth in the Commission's certificate of authority set forth in Ind. Code § 8-1-2-80(a) and (b).

Ind. Code § 8-1-2.5-6(a)(1) authorizes us to adopt alternative regulatory practices, procedures and mechanisms that are in the public interest and that enhance or maintain the value of NIPSCO's retail energy services or property. Our consideration of the public interest is to be guided by our review of the factors set forth in Ind. Code § 8-1-2.5-5. Of those four factors, the first three are applicable to all or some of NIPSCO's proposed ARP.

(a) <u>Relief from Ind. Code § 8-1-8.5-5(e)</u>. The purpose behind Ind. Code § 8-1-8.5-5(e) is twofold. First, to confirm the reasonableness and reliability of the cost estimates that form the basis for our finding for Ind. Code § 8-1-8.5-5(b)(1). Second, to assure that the actual costs that are incurred are, to the extent commercially practicable, based on competitive procurement. Here, the cost estimates – indeed the actual project – grew out of an All-Source RFP.

[32] NIPSCO submitted a verified petition wherein it elected to become subject to Ind. Code ch. 8-1-2.5.

Moreover, with the cap on costs to which NIPSCO agreed on rebuttal, the risk of cost overruns has been addressed. Accordingly, the requirements of Ind. Code § 8-1-8.5-5(e) would be unnecessary or wasteful and our declining to exercise those requirements will be beneficial to NIPSCO and NIPSCO's customers and will promote energy utility efficiency. Ind. Code § 8-1-2.5-5(b)(1) - (3).

(b) Investment Reflected in Net Original Cost Rate Base. NIPSCO's proposal in this proceeding is one of first impression for this Commission. In this proceeding, NIPSCO proposes to invest in Joint Venture, which will own Rosewater ProjectCo, which will own the "property . . . used and useful for the convenience of the public." Ind. Code § 8-1-2-6. Rosewater ProjectCo would then sell 100% of its output to NIPSCO pursuant to the BTA PPA. In this Cause, NIPSCO has provided evidence of the benefits of participation of a TEP and the Joint Venture in the development of renewable projects, so as to monetize the full value of the PTCs. NIPSCO has agreed to cap its investment in the Joint Venture and not to seek in this proceeding approval of any amounts related to the purchase of TEP's share or amounts related to any additional investment NIPSCO may make into the Joint Venture beyond the capped investment after the buyout of EDPR. Rather, once a determination has been made by NIPSCO to purchase TEP's share, NIPSCO will seek recovery of such costs in a separately docketed proceeding. As it pertains specifically to this element of NIPSCO's ARP, NIPSCO proposes to reflect in its net original cost rate base for ratemaking purposes the net balance of its investment in Joint Venture, which will be recorded in Account No. 182.3. NIPSCO witness Camp explained why this is needed. It is the Joint Venture structure that monetizes the PTC for the benefit of customers, and it is NIPSCO's investment of capital that will make the Joint Venture possible. If the requirements of Ind. Code § 8-1-2-6 would deny NIPSCO the opportunity to earn a return on its Joint Venture investment, then NIPSCO would simply invest in the physical utility assets themselves, which would diminish the value of the PTCs. Further, NIPSCO's investment under the traditional approach would be higher. Accordingly, the requirements of Ind. Code § 8-1-2-6 as applied to NIPSCO's investment reflected in Account 182.3 would be wasteful and our declining to apply those requirements will be beneficial to NIPSCO and NIPSCO's customers and will promote energy utility efficiency. Ind. Code §8-1-2.5-5(b)(1) - (3).

(c) Relief from FAC Purchased Power Benchmarks. As already explained, NIPSCO is not seeking to recover the costs to be incurred through the BTA PPA or, if necessary, the Back-Stop PPA "through" the FAC; rather, NIPSCO seeks to recover these costs through a rate adjustment mechanism in accordance with Section 42(a) and Ind. Code § 8-1-8.8-11, which is administered through the FAC. Accordingly, the specific requirements of Ind. Code § 8-1-2-42(d)(1) through (4) and our traditional purchased power benchmark test to implement (d)(1) would not apply. Nevertheless, and to the extent necessary, NIPSCO's ARP seeks to relieve the BTA PPA and Back-Stop PPA from these requirements. Such authority is not uncommon with PPAs that we approve in advance.[33] When we approve a PPA in advance pursuant to Ind. Code § 8-1-8.8-11, we are making a determination that the PPA is in the public interest and is reasonable over its term. Accordingly, the requirements set forth in Ind. Code § 8-1-2-42(d)(1) through (4) would be wasteful and our declining to apply those requirements will be beneficial to NIPSCO and NIPSCO's customers and will promote energy utility efficiency. Ind. Code § 8-1-2.5-5(b)(1)

[33] *See e.g., PSI Energy Inc.,* Cause No. 43097 (IURC Dec. 6, 2006); *S. Ind. Gas and Elec. Co.,* Cause No. 43259 (IURC Dec. 5, 2007); and *Ind. Mich. Power Co.,* Cause No. 43328 (IURC Nov. 28, 2007).

- (3).

(d) Technical Financing Requirements. As explained by Witness Camp, it is possible that GAAP would require aspects of the Joint Venture structure to be reflected on NIPSCO's financial statements as debt. To the extent it does, NIPSCO seeks any necessary financing authority. Ind. Code §§ 8-1-2-79 and -80 impose requirements on a petition seeking financing authority and on the certificate we ultimately issue. These include officer signatures and verifications and the specific elements of Ind. Code § 8-1-2-79(1) through (6). None of these requirements contemplate the limited contingent financing authority sought by NIPSCO. These requirements would be wasteful and our declining to apply those requirements will be beneficial to NIPSCO and NIPSCO's customers and will promote energy utility efficiency. Ind. Code § 8-1-2.5-5(b)(1) - (3).

(e) Conclusion. In conclusion, we find, after considering the factors set forth in Ind. Code § 8-1-2.5-5, that NIPSCO's proposed ARP is in the public interest and that it will enhance or maintain the value of NIPSCO's energy retail services and property. We therefore find that NIPSCO's proposed ARP as outlined in this paragraph should be approved.

D. Accounting and Finance Authority. As appropriate additional financial incentives under Ind. Code § 8-1-8.8-11, we find that NIPSCO should record its investments in the Joint Venture as a regulatory asset in Account No. 182.3 and that the investment should be amortized over the life of the Rosewater Project, estimated to be 30 years. NIPSCO shall also defer amortization with respect to each investment until such time as the recovery of the amortization of that portion is reflected in rates. NIPSCO should also be authorized to accrue PISCC with respect to each investment at NIPSCO's weighted average cost of capital until a return on that portion is reflected in NIPSCO's rates. Both of these deferrals should be recorded in Account 182.3 and amortized over the remaining life of the Rosewater Project. We further find, subject to the limitation agreed to by Mr. Campbell on rebuttal, that NIPSCO's balance in Account 182.3 related to the Rosewater Project should be included in net original cost rate base for ratemaking purposes. Finally, we find that to the extent GAAP would treat any aspect of the Joint Venture as debt on NIPSCO's financial statements, such financing is approved and that a certificate should therefore be issued.

E. Jurisdiction over Joint Venture. Because the Joint Venture will not be the title owner of the Rosewater Project, Joint Venture will not own electric generation facilities that provide electricity that NIPSCO will use to serve the public. As such, Joint Venture is not a "public utility." Joint Venture will own Rosewater ProjectCo, which will own facilities that only provide service to NIPSCO on a wholesale basis, and Joint Venture will not operate, manage, or control those electric generation facilities. To the extent the Joint Venture could be deemed a "public utility," Joint Venture seeks an order whereby we decline to exercise our jurisdiction and Joint Venture has elected to become subject to Ind. Code § 8-1-2.5-5. The unique circumstances of this arrangement, the Commission's exercise of jurisdiction of NIPSCO, and the regulation by FERC render the exercise of jurisdiction by this Commission over Joint Venture as a public utility unnecessary or wasteful. Further, declining to exercise jurisdiction will be beneficial to Joint Venture, NIPSCO, NIPSCO's customers and the State of Indiana. Declining to exercise jurisdiction will also promote energy utility efficiency. Finally, the exercise of the Commission's jurisdiction over Joint Venture as a public utility will inhibit the implementation of NIPSCO's generation transition plan as set forth in its 2018 IRP. Accordingly, to the extent necessary, the Commission finds that it should decline to exercise its jurisdiction over Joint Venture as a public utility.

F. Conclusion. We find the evidence of record in this proceeding supports approval of the Rosewater Project and the BTA PPA and Back-Stop PPA and the proposed method of cost recovery. The BTA PPA and the Back-Stop PPA terms and costs are reasonable, they provide needed energy, diversify NIPSCO's supply portfolio, provide environmental benefits, and defend against fuel cost volatility. We find the BTA PPA and Back-Stop PPA costs should be recovered through a Section 42(a) tracking mechanism to be administered through NIPSCO's quarterly FAC filings. We further find that: NIPSCO's proposed financial incentives as outlined above in Paragraph 14A should be granted; a CPCN should be issued for the acquisition of the Rosewater Project; NIPSCO's proposed ARP should be approved; and the Accounting and Finance Authority set forth above in Paragraph 14.D. should be granted.

15. Enhanced NIPSCO / Customer Renewable Energy Integration. The testimony of IMUG's Mr. Sommer and NIPSCO's Mr. Campbell provide ample evidence to support our approval of the proposed collaborative discussion, exploration, and promotion of future details on MSP and community solar programs. As renewable energy production in Indiana progresses and increases, it is appropriate that stakeholders look for reasonable ways to further capture the resulting economic and social benefits in Indiana. Potential benefits include: job creation; reduced municipal budgetary constraints because of reduced municipal energy use or revenue from solar power sales; job training for the unemployed or under employed; benefits to low income customers; public education; and participation in renewable energy production. We approve the renewable energy collaborative framework and topics proposed by Mr. Sommer and Mr. Campbell. An initial evaluation of at least 5 MW of MSP solar installations is reasonable. We recognize and appreciate the collaborative approach to such renewable energy programs taken by IMUG and NIPSCO in this Cause and encourage its successful completion.

16. Confidential Information. On February 1, 2019, NIPSCO filed a motion for protective order, which was supported by affidavit showing documents to be submitted to the Commission were trade secret information within the scope of Ind. Code §§ 5-14-3-4(a)(4) and (9) and Ind. Code § 24-2-3-2. On February 19, 2019, the Presiding Officers issued a Docket Entry finding the information described in the request for confidentiality to be confidential on a preliminary basis. After reviewing the designated confidential information, we find all such information qualifies as confidential trade secret information pursuant to Ind. Code § 5-14-3-4 and Ind. Code § 24-2-3-2. This information has independent economic value from not being generally known or readily ascertainable by proper means. NIPSCO takes reasonable steps to maintain the secrecy of the information and disclosure of such information would cause harm to NIPSCO. Therefore, we affirm the preliminary ruling and find this information should be exempted from the public access requirements contained in Ind. Code ch. 5-14-3 and Ind. Code § 8-1-2-29, and held confidential and protected from public disclosure by this Commission.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. The Rosewater Project, the Build Transfer Agreement, the BTA PPA, and the Back-Stop PPA are a clean energy project under Ind. Code § 8-1-8.8.3, and are reasonable and necessary under Ind. Code § 8-1-8.8-11.

2. The Build Transfer Agreement, the BTA PPA, and the Back-Stop PPA are approved.

3. The financial incentives, as modified in rebuttal, all as outlined in Paragraph 14.A. of this Order, are approved.

4. NIPSCO's costs incurred pursuant to the BTA PPA and/or the Back-Stop PPA shall be recovered through a rate adjustment mechanism pursuant to Ind. Code § 8-1-2-42(a) to be administered through NIPSCO's FAC proceeding (or successor mechanism). This recovery shall not be subject to any Ind. Code § 8-1-2-42(d) tests or FAC benchmarks.

5. A certificate of public convenience and necessity for NIPSCO's acquisition of the Rosewater Project though the Joint Venture is approved.

6. NIPSCO's alternative regulatory plan outlined in Paragraph 14.C. of this Order is approved.

7. NIPSCO shall record its investments in the Joint Venture as a regulatory asset in Account 182.3, and NIPSCO's investment therein shall be amortized over the life of the Rosewater Project. Subject to the caps agreed to on rebuttal, the balance of the regulatory asset shall be included in NIPSCO's net original cost rate base for ratemaking purposes.

8. NIPSCO is authorized to defer amortization with respect to each investment in the Joint Venture until such time as the recovery of the amortization of that portion is reflected in rates. NIPSCO is also authorized to accrue post-in-service carrying charges with respect to each investment at NIPSCO's then-approved weighted average cost of capital until a return on that portion is reflected in NIPSCO's rates. Both the deferral of amortization and accrual of PISCC shall be recorded in Account 182.3, and the unamortized balance thereof shall be included in NIPSCO's net original cost rate base for ratemaking purposes.

9. To the extent GAAP would treat any aspect of the Joint Venture as debt on NIPSCO's financial statement, such debt is approved, and this Order shall constitute the Commission's certificate therefore.

10. The Commission declines any jurisdiction over the Joint Venture.

11. The collaborative process proposed by IMUG and NIPSCO for evaluation of and details for municipal and customer renewable energy programs as described herein and in Mr. Sommer's and Mr. Campbell's testimony is approved. After completion of the collaborative meetings, IMUG should prepare and submit a joint report under this Cause advising of the results.

12. NIPSCO's request for confidential trade secret treatment is granted, and such Confidential Information shall be excepted from public disclosure.

13. This Order shall be effective on and after the date of its approval.

<u>HUSTON, OBER, AND ZIEGNER CONCUR; FREEMAN AND KREVDA ABSENT</u>:

APPROVED: AUG 07 2019

I hereby certify that the above is a true and correct copy of the Order as approved.

Regina K Sharper acting for

Mary M. Becerra
Secretary of the Commission