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March 1, 2021
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED JOINT PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC, DUNN'S BRIDGE I SOLAR GENERATION LLC, DUNN'S BRIDGE II SOLAR AND STORAGE GENERATION LLC, AND CAVALRY SOLAR AND STORAGE GENERATION LLC (THE "JOINT VENTURES") FOR (1) ISSUANCE TO NIPSCO OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE PURCHASE AND ACQUISITION OF (A) A 265 MW SOLAR PROJECT ("THE BRIDGE I PROJECT"), (B) A 435 MW SOLAR AND 75 MW ENERGY STORAGE PROJECT ("THE BRIDGE II PROJECT"), AND (C) A 200 MW SOLAR PROJECT AND 60 MW ENERGY STORAGE PROJECT ("THE CAVALRY PROJECT") (COLLECTIVELY, THE "SOLAR PROJECTS"); (2) APPROVAL OF THE SOLAR PROJECTS AS CLEAN ENERGY PROJECTS UNDER IND. CODE § 8-1-8.8-11; (3) APPROVAL OF RATEMAKING AND ACCOUNTING TREATMENT ASSOCIATED WITH THE SOLAR PROJECTS; (4) AUTHORITY TO ESTABLISH AMORTIZATION RATES FOR NIPSCO'S INVESTMENT IN THE JOINT VENTURES; (5) APPROVAL PURSUANT TO IND. CODE § 8-1-2.5-6 OF AN ALTERNATIVE REGULATORY PLAN INCLUDING ESTABLISHMENT OF JOINT VENTURES THROUGH WHICH THE SOLAR PROJECTS WILL SUPPORT NIPSCO'S GENERATION FLEET AND THE REFLECTION IN NIPSCO'S NET ORIGINAL COST RATE BASE OF ITS INVESTMENT IN JOINT VENTURES; (6) APPROVAL OF PURCHASED POWER AGREEMENTS AND CONTRACTS FOR DIFFERENCES THROUGH WHICH NIPSCO WILL PAY FOR THE ENERGY GENERATED BY THE SOLAR PROJECTS, 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 VENTURES; (8) TO THE EXTENT GENERALLY ACCEPTED ACCOUNTING PRINCIPLES WOULD TREAT ANY ASPECT OF JOINT VENTURES 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 SOLAR PROJECTS; AND (10) TO THE EXTENT NECESSARY, ISSUANCE OF AN ORDER PURSUANT TO IND. CODE § 8-1-2.5-5 DECLINING TO EXERCISE JURISDICTION OVER THE JOINT VENTURES AS PUBLIC UTILITIES.	)	**CAUSE NO. 45462**

JOINT PETITIONERS' AND CAC'S
JOINT SUBMISSION OF AGREED PROPOSED ORDER

Northern Indiana Public Service Company LLC, on behalf of Joint Petitioners and the Citizens Action Coalition of Indiana, Inc., by counsel, respectfully submit the attached agreed form of proposed order. For purposes of convenience, a Word version of the proposed order will be provided to the Administrative Law Judge via email transmission.

Respectfully submitted,

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CERTIFICATE OF SERVICE

The undersigned hereby certifies that the foregoing was served by email transmission upon T. Jason Haas, Indiana Office of Utility Consumer Counselor, PNC Center, Suite 1500 South, 115 W. Washington Street, Indianapolis, Indiana 46204 (thaas@oucc.in.gov, infomgt@oucc.in.gov) and Jennifer A. Washburn, Kerwin Olson, Reagan Kurtz, Citizens Action Coalition of Indiana, Inc., 1915 West 18th Street, Suite C, Indianapolis, Indiana 46204 (jwashburn@citact.org, kolson@citact.org, rkurtz@citact.org).

Dated this 1st day of March, 2021.

Bryan M. Likins

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED JOINT PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC, DUNN'S BRIDGE I SOLAR GENERATION LLC, DUNN'S BRIDGE II SOLAR AND STORAGE GENERATION LLC, AND CAVALRY SOLAR AND STORAGE GENERATION LLC (THE "JOINT VENTURES") FOR (1) ISSUANCE TO NIPSCO OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE PURCHASE AND ACQUISITION OF (A) A 265 MW SOLAR PROJECT ("THE BRIDGE I PROJECT"), (B) A 435 MW SOLAR AND 75 MW ENERGY STORAGE PROJECT ("THE BRIDGE II PROJECT"), AND (C) A 200 MW SOLAR PROJECT AND 60 MW ENERGY STORAGE PROJECT ("THE CAVALRY PROJECT") (COLLECTIVELY, THE "SOLAR PROJECTS"); (2) APPROVAL OF THE SOLAR PROJECTS AS CLEAN ENERGY PROJECTS UNDER IND. CODE § 8-1-8.8-11; (3) APPROVAL OF RATEMAKING AND ACCOUNTING TREATMENT ASSOCIATED WITH THE SOLAR PROJECTS; (4) AUTHORITY TO ESTABLISH AMORTIZATION RATES FOR NIPSCO'S INVESTMENT IN THE JOINT VENTURES; (5) APPROVAL PURSUANT TO IND. CODE § 8-1-2.5-6 OF AN ALTERNATIVE REGULATORY PLAN INCLUDING ESTABLISHMENT OF JOINT VENTURES THROUGH WHICH THE SOLAR PROJECTS WILL SUPPORT NIPSCO'S GENERATION FLEET AND THE REFLECTION IN NIPSCO'S NET ORIGINAL COST RATE BASE OF ITS INVESTMENT IN JOINT VENTURES; (6) APPROVAL OF PURCHASED POWER AGREEMENTS AND CONTRACTS FOR DIFFERENCES THROUGH WHICH NIPSCO WILL PAY FOR THE ENERGY GENERATED BY THE SOLAR PROJECTS, 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 VENTURES; (8) TO THE EXTENT GENERALLY ACCEPTED ACCOUNTING PRINCIPLES WOULD TREAT ANY ASPECT OF JOINT VENTURES 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 SOLAR PROJECTS; AND (10) TO THE EXTENT NECESSARY, ISSUANCE OF AN ORDER PURSUANT TO IND. CODE § 8-1-2.5-5 DECLINING TO EXERCISE JURISDICTION OVER THE JOINT VENTURES AS PUBLIC UTILITIES.	)	**CAUSE NO. 45462**

ORDER OF THE COMMISSION

Presiding Officers:
James F. Huston, Chairman
Stefanie Krevda, Commissioner
Brad J. Pope, Administrative Law Judge

On November 30, 2020, Joint Petitioners Northern Indiana Public Service Company LLC ("NIPSCO"), Dunn's Bridge I Solar Generation LLC ("Bridge I Joint Venture"), Dunn's Bridge II Solar Generation LLC ("Bridge II Joint Venture"), and Cavalry Solar Generation LLC ("Cavalry Joint Venture") (collectively referred to as the "Joint Ventures") filed their Verified Petition with the Indiana Utility Regulatory Commission ("Commission") in this Cause to authorize NIPSCO to continue implementation of its generation transition plan as set forth in its Integrated Resource Plan submitted October 31, 2018 ("2018 IRP") and to: (1) issue NIPSCO a certificate of public convenience and necessity ("CPCN") to purchase and acquire indirectly through Joint Ventures (a) a 265 megawatt ("MW") solar project ("Bridge I Project"), (b) a 435 MW solar and 75 MW energy storage project ("Bridge II Project"), and (c) a 200 MW solar and 60 MW energy storage project ("Cavalry Project") (collectively referred to as the "Solar Projects");[1] (2) approve the Solar Projects as clean energy projects under Ind. Code § 8-1-8.8-11; (3) approve associated ratemaking and accounting treatment for the Solar Projects; (4) establish amortization rates for NIPSCO's investment in the Solar Projects through Joint Ventures; (5) approve pursuant to Ind. Code § 8-1-2.5-6 an alternative regulatory plan to implement the Solar Projects as set forth herein, including establishment of Joint Ventures and the reflection in NIPSCO's net original cost rate base of its investment in Joint Ventures; (6) approve purchased power agreements and contracts for differences through which NIPSCO will pay for the energy generated by the Solar Projects, including timely cost recovery pursuant to Ind. Code § 8-1-8.8-11, which is anticipated to occur through NIPSCO's Fuel Adjustment Clause ("FAC"); (7) authorize NIPSCO to defer amortization and to accrue post-in service carrying charges ("PISCC") on NIPSCO's capital investments in Joint Ventures; (8) to the extent generally accepted accounting principles ("GAAP") would treat any aspect of Joint Ventures as debt on NIPSCO's financial statements, grant necessary financing approval; (9) approve an alternative regulatory plan for NIPSCO to facilitate the implementation of the Solar Projects; and (10) to the extent necessary, pursuant to Ind. Code § 8-1-2.5-5, decline to exercise jurisdiction over Joint Ventures as public utilities.[2] On November 30, 2020, Joint Petitioners filed their prepared testimony and exhibits constituting their case-in-chief.[3] 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 December 15, 2020.

On December 2, 2020, Citizens Action Coalition of Indiana, Inc. filed its Petition to Intervene, which the Presiding Officers granted in a docket entry dated December 15, 2020.

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[1] In this Petition, all nameplate capacity MW values for the Solar Projects are stated in alternating current. In various exhibits to the PPAs, MW values may be referenced in direct current which will appear higher than the alternating current equivalent. The Bridge I Project, Bridge II Project, and Cavalry Project are collectively referred to herein as the "Solar Projects" and are sometimes referred to individually as the "Project."

[2] Joint Petitioners' filed a Notice of Change of Legal Name for Bridge II and Cavalry on December 9, 2020.

[3] On February 24, 2021, NIPSCO filed Attachment 1-D to the Verified Direct Testimony of Erin E. Whitehead (certification of publication of notice).

In accordance with the December 16, 2020 Docket Entry setting the procedural schedule for this Cause, as amended January 22, 2021, the Indiana Office of Utility Consumer Counselor ("OUCC") filed testimony and exhibits constituting its case-in-chief on January 29, 2021. Joint Petitioners filed rebuttal testimony on February 9, 2021. On February 18, 2021, the OUCC also filed a correction to the testimony of Dr. Peter M. Boerger.

On February 25, 2021, Joint Petitioners and the OUCC filed exhibits to be offered into the record at the March 1, 2021 evidentiary hearing.

By docket entry issued on December 16, 2020, the Commission scheduled an evidentiary hearing in this Cause on March 1, 2021 at 1:30 p.m., in Room 222 of the PNC Center, 101 W. Washington Street, Indianapolis, Indiana. On February 254, 2021, a docket entry was issued advising that due to the ongoing COVID-19 pandemic, the hearing would be conducted via WebEx videoconferencing and providing related participation information. NIPSCO, the OUCC, and CAC participated in the evidentiary hearing via WebEx video or audio, and the testimony and exhibits of NIPSCO and the OUCC were admitted into the record without objection.

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

1. <u>Notice and Commission Jurisdiction.</u> 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. <u>NIPSCO's Characteristics.</u> 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. **Characteristics of Joint Ventures.** NIPSCO formed each of the LLCs under the laws of Delaware to serve as a Joint Venture. Prior to the closing of an Equity Capital Contribution Agreement ("ECCA") and a Joint Venture Operating Agreement ("LLC Agreement"), each Joint Venture will be a shell. Once those documents are executed, the members of each of the Joint Ventures will be NIPSCO (the managing member), and a Tax Equity Partner ("TEP") (a financial investor that will not have any operational rights in the Joint Venture).[4]

4. **The Bridge I Project.** The Bridge I Project is a 265 MW solar joint venture being implemented through a Build Transfer Agreement by and between Dunns Bridge Holdings I, LLC, as Seller ("Bridge I Seller"), and Dunn's Bridge I Solar Generation LLC, as Purchaser ("Bridge I Joint Venture") (the "Bridge I BTA")[5] using a series of agreements – a Contract for Differences between NIPSCO, as Purchaser, and Dunns Bridge Solar Center, LLC, as Seller ("Bridge I ProjectCo") (the "Bridge I CFD")[6] (or a Solar Generation BTA Energy Purchase Agreement between NIPSCO, as Purchaser, and Bridge I ProjectCo, as Seller (the "Bridge I BTA PPA")),[7] and a Solar Generation Energy Purchase Agreement between NIPSCO, as Purchaser, and Bridge I ProjectCo, as Seller (the "Bridge I Back-Stop PPA")[8] (in the event the parties do not close) (collectively referred to as the "Bridge I Solar Offtake Agreements") to pay for the energy and capacity, a Master Services Agreement ("Bridge I MSA") to support the operation and maintenance ("O&M") of the project,[9] and an Engineering, Procurement, and Construction Agreement ("Bridge I EPC Agreement"), as well as an ECCA ("Bridge I ECCA") and a LLC Agreement ("Bridge I LLC Agreement"). Bridge I Seller, through Bridge I ProjectCo, is developing the Bridge I Project in Jasper County, Indiana, which is expected to achieve commercial operation by December 31, 2022.

5. **The Bridge II Project.** The Bridge II Project is a 435 MW solar and 60 MW energy storage joint venture being implemented through the Build Transfer Agreement by and between Dunns Bridge Holdings II, LLC, as Seller ("Bridge II Seller") and Dunn's Bridge II Solar and Storage Generation LLC, as Purchaser ("Bridge II Joint Venture") (the "Bridge II BTA")[10] using a series of agreements – a Contract for Differences between NIPSCO, as Purchaser, and Dunns Bridge Energy Storage, LLC ("Bridge II ProjectCo") (the "Bridge II CFD")[11] (or a Solar Generation Energy Purchase Agreement between NIPSCO, as Purchaser, and Bridge II ProjectCo, as Seller (the "Bridge II BTA PPA")),[12] and a Solar Generation and Energy Storage BTA Energy Purchase Agreement between NIPSCO, as Purchaser, and Bridge I ProjectCo, as Seller (the "Bridge II Back-Stop PPA")[13] (in the event the parties do not close) (collectively referred to as the "Bridge II Solar Offtake Agreements") to pay for the energy and capacity, a Master Services Agreement (the Bridge II MSA") to support the O&M of the project,[14] and an Engineering,

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4 The Bridge I Joint Venture, Bridge II Joint Venture, and Cavalry Joint Venture are collectively referred to herein as the "Joint Ventures" and are sometimes referred to individually as the "Joint Venture."

5 The executed Bridge I BTA is included in Confidential Attachment 2-A-A.

6 A form of the Bridge I CFD is included in the Bridge I BTA at Exhibit L-3.

7 A form of the Bridge I BTA PPA is included in the Bridge I BTA at Exhibit L-2.

8 The executed Bridge I Back-Stop PPA is included in Confidential Attachment 2-B-A.

9 A form of the Bridge I MSA is included in the Bridge I BTA at Exhibit K.

10 The executed Bridge II BTA is included in Confidential Attachment 2-A-B.

11 A form of the Bridge II CFD is included in the Bridge II BTA at Exhibit L-3.

12 A form of the Bridge II BTA PPA is included in the Bridge II BTA at Exhibit L-2.

13 The executed Bridge II Back-Stop PPA is included in Confidential Attachment 2-B-B.

14 A form of the Bridge II MSA is included in the Bridge II BTA at Exhibit K.

Procurement, and Construction Agreement ("Bridge II EPC Agreement"), as well as an ECCA ("Bridge II ECCA") and a LLC Agreement ("Bridge II ECCA"). Bridge II Seller, through Bridge II ProjectCo, is developing the Bridge II Project in Jasper County, Indiana, which is expected to achieve commercial operation by December 31, 2023.

6. <u>The Cavalry Project.</u> The Cavalry Project is a 200 MW solar and 60 MW energy storage joint venture being implemented through the Build Transfer Agreement by and between Cavalry Energy Center Holdings, LLC, as Seller ("Cavalry Seller") and Cavalry Solar and Storage Generation LLC, as Purchaser ("Cavalry Joint Venture") (the "Cavalry BTA")[15] using a series of agreements – a Contract for Differences between NIPSCO, as Purchaser, and Cavalry ProjectCo, as Seller (the "Cavalry CFD")[16] (or a Solar Generation and Energy Storage BTA Energy Purchase Agreement (the "Cavalry BTA PPA"))[17] and a Solar Generation and Energy Storage Energy Purchase Agreement between NIPSCO, as Purchaser, and Cavalry ProjectCo, as Seller (the "Cavalry Back-Stop PPA")[18] (in the event the parties do not close) (collectively referred to as the "Cavalry Solar Offtake Agreements") to pay for the energy and capacity, a Master Services Agreement ("Cavalry MSA") to support the O&M of the project,[19] and an Engineering, Procurement, and Construction Agreement ("Cavalry EPC Agreement"), as well as an ECCA ("Cavalry ECCA") and a LLC Agreement ("Cavalry LLC Agreement"). Cavalry Seller, through Cavalry ProjectCo, is developing the Cavalry Project in White County, Indiana, which is expected to achieve commercial operation by December 31, 2023.

7. <u>Requested Relief.</u> 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 Solar Projects; (2) making findings that the purchase and acquisition of the Solar Projects is consistent with the Commission's plan for expansion of electric generating capacity and/or NIPSCO's 2018 IRP; (3) making findings that public convenience and necessity require or will require the construction, purchase and acquisition of the Solar Projects pursuant to the BTAs;[20] (4) granting NIPSCO a CPCN for the purchase and acquisition of the Solar Projects pursuant to Ind. Code ch. 8-1-8.5; (5) making findings that the Solar Projects are eligible clean energy projects pursuant to Ind. Code § 8-1-8.8-11(d); (6) approving the structure of the Joint Ventures and approving NIPSCO's proposed alternative regulatory plan; (7) approving the Solar Offtake Agreements[21] and authorizing NIPSCO's timely recovery of such 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 ("WACC") on each of NIPSCO's investments in Joint Ventures, with such amounts recorded in Account 182.3, included in NIPSCO's rate base, and amortized over the remaining life of the Solar Projects; (9) approval of financing to the extent required by GAAP; (10) approving amortization rates for NIPSCO's

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15 The executed Cavalry BTA is included in Confidential Attachment 2-A-C.

16 A form of the Cavalry CFD is included in the Cavalry BTA at Exhibit L-3.

17 A form of the Cavalry BTA PPA is included in the Cavalry BTA as Exhibit L-2.

18 The executed Cavalry Back-Stop PPA is included in Confidential Attachment 2-B-C.

19 A form of the Cavalry MSA is included in the Cavalry BTA as Exhibit K.

20 The Bridge I BTA, Bridge II BTA, and Cavalry BTA are collectively referred to herein as the BTAs and are sometimes referred to individually as the "BTA."

21 The Bridge I Solar Offtake Agreements, Bridge II Solar Offtake Agreements, and Cavalry Solar Offtake Agreements are collectively referred to herein as the Solar Offtake Agreements and are sometimes referred to individually as the "Solar Offtake Agreement."

investment in the Solar Projects through the Joint Ventures; (11) as necessary, declining to exercise jurisdiction over each 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.

8. Statutory Framework. 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 Solar Offtake Agreements. 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 an alternative regulatory plan ("ARP"), provides a basis for approval to invest in the Solar Projects, including establishment of the Joint Ventures and the reflection in NIPSCO's net original cost rate base of its investment in Joint Ventures.

We approved similar requests for relief under Ind. Code ch. 8-1-8.8 in our orders in Cause No. 45194 (the "Rosewater Order"),[22] and Cause No. 45310 (the "Crossroads Order"),[23] approving the requested wind purchases and acquisitions and the timely cost recovery for wind power developments and renewable resource projects through a quarterly rate adjustment mechanism to be administered with the FAC proceedings.

9. Joint Petitioners' Case-in-Chief. Joint Petitioners presented the testimony of seven witnesses in its case-in-chief: Erin E. Whitehead, Vice President of Regulatory Policy and Major Accounts for NIPSCO; Andrew S. Campbell, Director of Regulatory Support and Planning for NIPSCO; Patrick N. Augustine, Vice President of CRA International d/b/a Charles River Associates, Inc. ("CRA"); Robert Lee, Vice President of CRA; Jeff Plewes, Principal of CRA; Sandra E. Brummitt, Vice President and Chief Tax Officer for NiSource Corporate Services Company ("NCSC"); and Angela Camp, Director of Regulatory for NCSC.

(a) Whitehead Direct Testimony. Ms. Whitehead discussed NIPSCO's 2018 IRP and the preferred portfolio identified in the 2018 IRP, outlined implementation of NIPSCO's overall generation transition plan, which is rooted in the Short-Term Action Plan identified in the 2018 IRP to position NIPSCO to continue to reliably and affordably serve its customers when the R.M. Schahfer Generating Station ("Schahfer") retires in 2023, and described local support for the Solar Projects. Finally, Ms. Whitehead discussed NIPSCO's requests for approval of an ARP under Ind. Code § 8-1-2.5-6 and issuance of a CPCN.

Ms. Whitehead stated the Bridge I Project will include an estimated 900,000 solar panels capable of producing enough energy to power 79,500 homes; the Bridge II Project will include an estimated 1.5 million solar panels capable of producing enough energy to power 130,500 homes; and the Cavalry project will include an estimated 650,000 solar panels capable of producing enough energy to power 60,000 homes. She testified the Bridge I and Bridge II Projects are located

[22] *N. Ind. Pub. Serv. Co.*, Cause No. 45194 (IURC Aug. 7, 2019).
[23] *N. Ind. Pub. Serv. Co.*, Cause No. 45310 (IURC Feb. 19, 2020).

in Jasper County, Indiana, which is the county in which the retiring coal-fired Schahfer units are located. She stated that while reviewing projects bid into the Phase II RFPs, NIPSCO was very pleased that two competitive and economically-attractive projects were located in Jasper County. She said NIPSCO views the location of these projects as a positive for the Northwest Indiana economy generally and Jasper County specifically, noting that the Bridge I and Bridge II Projects are expected to provide approximately $59 Million in property taxes to Jasper County. Ms. Whitehead testified there has been no opposition or concern expressed from county officials about the Solar Projects and, in fact, county officials in both counties have expressed support for the Solar Projects. She testified local officials in Jasper County have expressed support for these projects, including one Jasper County commissioner, who was quoted in a press release as saying that "Jasper County is pleased to continue our long-term relationship with NIPSCO with the development of the Dunn's Bridge Solar Project, . . . As the county continues to search for additional economic development projects in light of the coming retirement of the Schahfer Generating Station, we look forward to this new opportunity to bring stability to our county's tax base."[24] She also explained that because NIPSCO will be the owner of the Solar Projects (initially as part of a Joint Venture and eventually as the outright owner), NIPSCO has made contractual arrangements with the developer so that some of the current NIPSCO employees at Schahfer will be offered continued employment opportunities with NIPSCO once Schahfer retires. She testified this is a qualitative benefit to the joint venture structure proposed in these proceedings, which would not be available under PPA arrangements.

Ms. Whitehead stated that NIPSCO is not asking for formal approval of its 2018 IRP, its generation transition plan, or the retirement of any particular generation asset, but rather NIPSCO is specifically requesting that the Commission approve the Solar Projects as reasonable and necessary resources that NIPSCO will use to serve its customers. She noted that the cost-effectiveness of the retirement of NIPSCO's coal-fired generation is not just an element of NIPSCO's preferred portfolio; instead, the analysis performed under the 2018 IRP demonstrated that under any potential future scenario the more coal-fired generation that was retained in NIPSCO's generation portfolio and the longer that coal-fired generation was retained, the more expensive and riskier the portfolio was for NIPSCO's customers. She stated that those portfolios that included more renewable resources were both more cost-effective and less risky for NIPSCO and its customers. Thus, it is not NIPSCO's proposal to pursue the Solar Projects presented in this proceeding that is leading to NIPSCO's coal-fired units being retired; it is the exact opposite—it is the 2018 IRP's conclusion that it is in the best interest of NIPSCO's customers to retire its coal-fired units that led NIPSCO to seek generation assets to replace the retiring assets, which has ultimately led NIPSCO to propose the Solar Projects as prudent choices to be part of NIPSCO's future generation portfolio.

Ms. Whitehead provided an overview of NIPSCO's preferred portfolio and how it was developed. She stated NIPSCO's preferred portfolio calls for the retirement of all of the coal-fired units at Schahfer by 2023 and the retirement of the Michigan City Generating Station ("Michigan City") by 2028. She said the preferred portfolio includes capacity replacements over a period of time, which include wind, solar, energy storage, and energy efficiency/demand response. She stated the preferred portfolio was developed through substantial analysis, including the use of an

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[24] Press release available at: https://www.nipsco.com/our-company/news-room/news-article/nipsco-announces-new-indiana-based-solar-projects-to-power-270-000-homes-by-2023.

all-source request for proposal ("All-Source RFP") to identify the most relevant types of resources available in the market, along with their associated costs. She explained that within the 2018 IRP, NIPSCO performed retirement and replacement assessments and scored the various portfolio alternatives against a number of cost, risk, environmental, and reliability metrics to arrive at the preferred portfolio, and evaluated the impact each of the retirement and replacement alternatives would have on local communities and NIPSCO's employees.

Ms. Whitehead identified the three key areas of benefits expected from NIPSCO's implementation of the preferred portfolio as (1) customer benefits, (2) environmental benefits, and (3) economic benefits. She stated that with regard to customer benefits, NIPSCO estimates that its generation transition will generate more than $4 Billion in cost savings over the next 30 years with NIPSCO's customers seeing these savings as early as 2023. She stated the primary environmental benefit will be the reduction of carbon emissions, which are expected to decrease by 90% by 2028 when compared to a 2005 baseline and, by retiring all coal-fired generation assets, all byproducts of burning coal will also be eliminated. She stated the economic benefits will accrue to the families, businesses, and industries NIPSCO serves, as well as to the economy of Northwest Indiana and the State of Indiana generally, as each of the Solar Projects is located in Indiana. She said the Solar Projects also will lead to significant incremental investment in Indiana that will benefit Indiana families, businesses, and industries noting that during construction these projects will lead to the creation of over 2,480 Full Time Equivalent ("FTE") jobs, $160 Million in earned wages, and contribute $230 Million to Indiana's Gross State Product ("GSP"). After construction, ongoing O&M, property taxes, and lease payments related to the Solar Projects over 30 years are expected to contribute more than $500 Million to Indiana's GSP.

Ms. Whitehead described details included in the Final Director's Report for Northern Indiana Public Service Company (NIPSCO's) 2018 Integrated Resource Plan dated February 10, 2020 ("Director's Report"), including that NIPSCO "submitted a very well developed IRP that includes a [RFP] from all types of resources without [predetermining] specific resources" and complimenting NIPSCO's combination of the IRP and RFP, by saying it "demonstrates an important evolution of state-of-the-art long-term resource planning" as it "enables NIPSCO to understand the uncertainties to help maintain a high degree of optionality and minimize adverse risks."[25] She stated the Director's Report was particularly complimentary of the All-Source RFP, stating:

> The RFP provided vast amounts of credible data on the cost of resource [alternatives]. This empirical information enhances the credibility of NIPSCO's IRP. More than any other Indiana utility to date, NIPSCO has conducted a robust and transparent analysis of the wholesale market opportunities, uncertainties, and risks that confront its company. NIPSCO's efforts to integrate the RFP information into its IRP was well done.[26]

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25 Attachment 1-B, p. 4. Later, the Director's Report also stated (p. 31), "[t]he resource costs from the actionable RFP were reasonably integrated into the IRP. This provided a more realistic valuation of resource costs and a good vehicle for minimizing NIPSCO's investment in capital intensive resources while maintaining adequate reliability."

26 Further, the Director's Report (p. 29) stated that "NIPSCO's integration of an actionable Request for Proposals was very farsighted and added significant credibility to the IRP. As a result of the combination IRP and

Ms. Whitehead stated that referring to the IRP process, the Director's Report continued by saying that "NIPSCO's transparent process was appropriate and sets a high standard for other utilities" and "commend[ed] NIPSCO for retaining outside experts and state-of-the-art planning tools to augment NIPSCO's expertise. The collaboration between NIPSCO and Charles River Associates in developing well-reasoned scenarios, sensitivities, portfolios, and the RFP, was particularly noteworthy."[27]

Ms. Whitehead stated that in NIPSCO's scenario and stochastic-based replacement analysis, it was determined that the portfolios that included more renewable resources were more cost-effective and less risky than the alternatives; therefore, NIPSCO's generation mix was projected to shift significantly from coal to renewables over time. She provided an overview of the Short-Term Action Plan saying NIPSCO identified a phased approach to selecting and acquiring replacement resources needed to fill the capacity gap that develops as a result of the planned retirements in 2023 in the preferred portfolio, with the plan calling for initially prioritizing replacement resources with expiring or declining tax credits from the All-Source RFP (predominantly wind projects), followed by additional RFPs to acquire resources to fill the remainder of the 2023 supply requirement.

Ms. Whitehead explained NIPSCO's implementation of its generation transition plan. She testified the 2018 IRP included a Short-Term Action Plan consisting of the actions NIPSCO will take for the period 2019-2021 and focuses on initiating the retirement process for all of the coal-fired units at Schahfer and selecting/acquiring replacement projects to fill the capacity gap. In March 2018, in conjunction with CRA, NIPSCO issued the All-Source RFP, the results of which led NIPSCO to negotiate with developers of four prioritized projects, which were wind energy projects subject to declining tax credits. She stated that after negotiations were complete, NIPSCO executed four wind agreements for a total purchase of approximately 1,100 MW of nameplate wind power, all of which approved by the Commission in Cause Nos. 45194 (Rosewater Joint Venture), 45195 (Jordan Creek PPA), 45196 (Roaming Bison PPA),[28] and 45310 (Indiana Crossroads Joint Venture). In October 2019, NIPSCO conducted three separate requests for proposals (the "Phase II RFPs") to acquire the remaining resources in the preferred portfolio. She stated NIPSCO currently has two projects that came out of the Phase II RFPs pending approval in Cause No. 45403 (1) the Greensboro Project (solar plus energy storage PPA), and (2) the Brickyard Project (solar project PPA),[29] as well as the Solar Projects presented for approval here. Ms. Whitehead testified that overall, as NIPSCO continues to execute its Short-Term Action Plan, it remains focused on implementing the plan in a way that (a) can be responsive to technological and economic changes; (b) allows for incremental decision-making that maintains flexibility, and (c)

RFP, NIPSCO appropriately recognized that for NIPSCO's future resource mix, maintaining maximum flexibility was a reasonable pursuit, based on the information available at the time."

27 Attachment 1-B, p. 6.

28 Following approval by the Commission, on February 25, 2020, NIPSCO filed a Notice with the Commission that, due to unresolved local zoning issues, Roaming Bison Wind, LLC was unable to meet its deadline associated with the acquisition of property. Thus, NIPSCO provided notice to Roaming Bison Wind, LLC that the Wind Energy Purchase Agreement dated January 18, 2019 was being terminated due to Roaming Bison's inability to perform its obligations under the agreement.

29 As discussed below, the Commission approved these projects in an order issued on January 27, 2021.

ultimately ensures NIPSCO achieves a diverse generation portfolio that will serve its customers well from the perspective of affordability, reliability, sustainability, and other important factors.[30]

Ms. Whitehead testified NIPSCO's implementation of its generation transition plan, and specifically the Short-Term Action Plan, has been a complex and multi-faceted undertaking involving numerous NIPSCO and NiSource business units, as well as other groups such as CRA (and others) as it works through the process strategically and intentionally. She stated NIPSCO is very pleased with the robust responses to its All-Source RFP and Phase II RFPs, and has continued to improve in negotiating with project developers. She stated these improvements have led to agreements that are presented in this proceeding that vary in some respects from the agreements NIPSCO has presented in prior proceedings.

Ms. Whitehead described NIPSCO's request for approval of the following four alternative practices, procedures and mechanisms in connection with the Joint Ventures:

(1) Since the Solar Projects arose out of the Phase II RFPs, 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 Solar Projects. Instead, NIPSCO will own an interest in Joint Ventures. NIPSCO seeks approval of the Joint Ventures and the joint venture structures. NIPSCO further seeks to record its interest in the Joint Ventures 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 Solar Projects. 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 Ventures.

(3) NIPSCO seeks to recover its payments made to each of the ProjectCos pursuant to the Solar Offtake Agreements, through the FAC, without regard to Ind. Code § 8-1-2-42(d)(1) through (4) and without regard to any benchmarks established by the Commission for PPAs.[31]

(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. These include corporate officer signatures and verifications, the elements in Ind. Code § 8-1-2-79(a)(1) through (6),

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[30] NIPSCO's path is consistent with the vision for IRPs recently expressed in the 2020 Report to the 21st Century Energy Policy Development Task Force by the Indiana Utility Regulatory Commission dated August 14, 2020 ("IURC Report") (Attachment 1-C), which states (pp. 22-23, fn 3) that the "overarching purpose of the IRP is to develop a long-term power system resource plan that will guide investments to provide safe and reliable electric power at the lowest delivered cost reasonably possible. Because of uncertainties and accompanying risks, these plans need to be flexible in order to respond to the unprecedented pace of change currently occurring in the production, delivery, and use of electricity."

[31] Bridge I ProjectCo, Bridge II ProjectCo, and Cavalry ProjectCo are collectively referred to herein as "ProjectCos" and are sometimes referred to individually as "ProjectCo."

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).

In addition, to the extent the Commission determines that each of the Joint Ventures is a "public utility," Joint Ventures elect to become subject to Ind. Code § 8-1-2.5-5.

Ms. Whitehead testified the Joint Ventures are in the public interest as determined by consideration of the four factors described in Indiana Code § 8-1-2.5-5(b) as required by Indiana Code § 8-1-2.5-6 (a)(1)(A). She testified the 2018 IRP, and the analysis performed subsequent to the submission of the 2018 IRP, shows that the most viable and prudent path for NIPSCO's customers in today's competitive market involves accelerating the retirement of a majority of NIPSCO's remaining coal-fired generation and acquiring renewable replacements in the near-term. She explained that to maximize the benefit of that lower-cost renewable energy for NIPSCO's customers, NIPSCO needed to find a path for monetizing the tax benefits, and must recognize the value for its customers from NIPSCO having operational control of its generation resources and minimizing the risk from relying too heavily on counterparties through purchased power agreements.

Ms. Whitehead further testified the Joint Ventures will enhance the value of NIPSCO's retail energy services or property, as referenced in Indiana Code § 8-1-2.5-6 (a)(1)(B), for the benefit of its customers. She said the creation of Joint Ventures allows NIPSCO to obtain less expensive energy for its customers by maximizing the benefit of the projects' Investment Tax Credits ("ITCs"), which will have a direct and substantial impact on the price of the energy NIPSCO provides to its customers and also ensure NIPSCO has procured sufficient and economic capacity over the next several years. She stated that without an alternative regulatory plan (i.e., if NIPSCO were not to employ the Joint Ventures and outright purchase the projects), the value of the tax benefits associated with the renewable projects would be greatly reduced. She said the Joint Ventures also allow NIPSCO's customers to receive the value of the tax benefits associated with the project as they are realized. She summarized that it is these joint venture structures that make the implementation of NIPSCO's 2018 IRP possible, thereby ensuring NIPSCO can provide reliable, affordable, renewable electricity to its customers over the coming decades.

Ms. Whitehead described the estimated value from monetizing the ITCs and described the no-tax ownership attributes of the Solar Projects retained by NIPSCO. She stated the Joint Ventures provide at least the following five benefits to NIPSCO's customers:

(1) NIPSCO will have full control of the projects, which will allow it to operate the project efficiently and will be responsible for the management of the Joint Ventures, each of which will own the respective ProjectCo (and hence the solar or solar plus storage project). This will allow NIPSCO greater flexibility in the operation of the assets in the MISO market. NIPSCO will be making the decisions on operating and maintenance expenditures. Further, NIPSCO will remain the managing member of the Joint Ventures, with control over the day-to-day operations. Any amendment of the LLC Agreements would require approval of both NIPSCO and the TEP.

(2) Based on current modeling assumptions, the levelized cost of the power from the Solar Projects over the projects' lifetimes will be less than if NIPSCO built the projects or

just signed PPAs with project developers. This is due to the monetization of the ITCs at their maximum value. Despite the TEP being a member of the Joint Ventures, it will not be responsible for project operations.

(3) NIPSCO's power portfolio will be more diversified because it will eventually include an owned, renewable asset. The 2018 IRP preferred plan called for a mix of technologies and duration commitments to provide resource diversity and mitigate risk. The Joint Ventures allow a path to ownership for NIPSCO and thus build a mix of PPA and owned assets, which have varied durations.

(4) NIPSCO will not have to bear the counterparty risk that exists in a traditional PPA. This would be the risk that is embedded within a PPA where a counterparty is in the transaction for the duration. This risk is present in all PPAs and is somewhat mitigated by the due diligence performed by NIPSCO and CRA during the RFP process.

(5) NIPSCO will have the option to repower the projects at the end of their life or to retire them, whichever provides its customers the best value.

Ms. Whitehead explained why it is in the public interest to relieve NIPSCO from or otherwise find that NIPSCO has satisfied the obligations to receipt of a CPCN established under Ind. Code § 8-1-8.5-5(e). With regard to the competitive procurement requirements set forth in Ind. Code § 8-1-8.5-5(e), she testified that since the cost estimates, indeed the Solar Projects, originated with the very competitive Phase II RFPs, NIPSCO seeks to be relieved of or otherwise found to have complied with those requirements. She stated that on the unique circumstances of this case, additional competitive procurement requirements would not only be unnecessary, but they would also jeopardize the implementation of the 2018 IRP.

Ms. Whitehead further explained why it is in the public interest that NIPSCO be permitted to include its investments in the Joint Ventures in NIPSCO's rate base for ratemaking purposes. She testified that without the ability to earn a return on its costs to invest in the Joint Ventures, there would be no incentive for NIPSCO to pursue the Joint Ventures. She stated that based on her understanding, traditional ratemaking would permit NIPSCO to include in rate base the value of its utility plant. She said that since NIPSCO must create the joint venture structures to capture the value of the tax benefits from the Solar Projects for the benefit of NIPSCO's customers, 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. She testified 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. She testified that the costs sought to be recovered and the actual cost recovery sought by NIPSCO is similar to the cost recovery NIPSCO would be afforded if it were the initial owner of the Solar Projects. She stated that providing NIPSCO similar cost recovery, even though it is using the Joint Venture structure, allows for NIPSCO's customers to receive the full benefit of the ITCs, while also allowing NIPSCO an opportunity to earn a full return on its investments.

Ms. Whitehead described why it is necessary to relieve NIPSCO from the technical requirements set forth in Ind. Code §§ 8-1-2-79 and 80, which relates to financing authority. She stated the request for financing is purely conditional. She testified NIPSCO is neither issuing new debt nor selling any securities, and that the provisions that NIPSCO seeks to be relieved of are provisions that are related to the issuance of securities, which are simply unnecessary in this context.

Ms. Whitehead sponsored Attachment 1-D, which were the Publishers' Affidavits associated with the publication of notice of its filing in this case in a newspaper of general circulation in each county in which NIPSCO provides retail electric service, in accordance with Indiana Code § 8-1-2.5-6(d).

Ms. Whitehead stated Indiana 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. She testified the Joint Ventures and each of the elements of NIPSCO's proposed ARP are in the public interest for the reasons she described. She stated that by implementing the Solar Projects through the joint venture structures, NIPSCO is reducing the overall cost of the Solar Projects to NIPSCO and to its customers, which enhances the value of NIPSCO's retail energy services and property. She stated two of the factors in Ind. Code § 8-1-2.5-5 are especially applicable here, because approval of the Joint Ventures and the proposed ARP will be beneficial to NIPSCO, its customers, and the State of Indiana. Further, she stated, by reducing overall cost, approval of the ARP promotes energy utility efficiency.

Ms. Whitehead testified that because the Joint Ventures will not be the title owner of the Solar Projects, Joint Ventures 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 Solar Projects at market based rates from the ProjectCos under the respective CFDs or BTA PPAs. As such, she testified none of the Joint Ventures is a "public utility." She stated each Joint Venture will own the related ProjectCo, which will own facilities that only provide service to NIPSCO on a wholesale basis, and Joint Ventures will not operate, manage, or control those electric generation facilities. She said that to the extent the Commission disagrees and determines that any of the Joint Ventures is a "public utility," Joint Ventures elect to become subject to Ind. Code § 8-1-2.5-5. She explained that 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 Ventures as a public utility unnecessary or wasteful. Further, she testified that declining to exercise jurisdiction will be beneficial to Joint Ventures, NIPSCO, its customers, and the State of Indiana, and will also promote energy utility efficiency. Additionally, she stated that the exercise of the Commission's jurisdiction over Joint Ventures as a public utility will inhibit the implementation of NIPSCO's generation transition plan as set forth in its 2018 IRP. She testified that for these reasons, to the extent necessary, the Commission should proceed to issue an order declining to exercise its jurisdiction over each of the Joint Ventures as a public utility. She testified that, identical to what was approved for Rosewater in Cause No. 45194 and Crossroads in Cause No. 45310, NIPSCO also requests that the Commission confirm that once the three ProjectCos become affiliated interests of NIPSCO, it will maintain the declination of jurisdiction, assuming such is granted, in the proceedings initiated by the ProjectCos seeking a declination of Commission jurisdiction.

Ms. Whitehead further testified NIPSCO seeks a CPCN pursuant to Ind. Code § 8-1-8.5-2 to purchase and acquire the Solar Projects through the Joint Ventures. She described the costs of the Solar Projects and described in detail why acquisition of the Solar Projects through Joint Ventures is in the public interest. She stated that for the same reasons, the public convenience and necessity require this acquisition. She stated the proposed ARP addresses competitive procurement and the Solar Projects are consistent with the 2018 IRP and Short-Term Action Plan. She explained NIPSCO has provided the best estimate for the cost of the Solar Projects as required in Ind. Code § 8-1-8.5-5(b)(1) noting that the cost estimate originated with the very competitive Phase II RFPs conducted at the direction of NIPSCO with the review of the responses performed by CRA, an experienced and independent third party. Ms. Whitehead testified the purchase and acquisition of the Solar Projects through Joint Ventures in this proceeding is consistent with Ind. Code § 8-1-8.5-5(2), noting NIPSCO's purchase and acquisition of the Solar Projects through Joint Ventures in this proceeding is consistent with its 2018 IRP wherein NIPSCO considered many different generation resources for modeling, including natural gas, coal, wind, solar, battery storage, and demand response.

Ms. Whitehead stated NIPSCO engaged and considered stakeholder input throughout its IRP process and utilized an array of best practices, including basing model inputs on the results of an RFP, 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. She testified the public convenience and necessity require or will require the construction, purchase and acquisition of the Solar Projects stating that the Solar Projects are the result of a thorough RFP process and a quantitative and qualitative evaluation of the RFP responses; the terms of the Solar Offtake Agreements were reached after arms-length negotiations; NIPSCO will only pay for the energy it receives at a set price established by the Solar Offtake Agreements; the energy provided through the Solar Projects 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. She stated NIPSCO reasonably modeled the agreements for purchasing the energy from renewable projects in its 2018 IRP, and, the Levelized Cost of Electricity ("LCOE") analysis and other RFP scoring factors show the Solar Projects selected for advancement to Definitive Agreement represented the best options for NIPSCO.

Ms. Whitehead testified approval of NIPSCO's request and issuance of a CPCN is consistent with the statutory purpose of Ind. Code ch. 8-1-8.8, which as expressed in Ind. Code § 8-1-8.8-1(a)(2) and (6) respectively, was enacted into law to encourage the "development of a robust and diverse portfolio of energy production or generating capacity" and to "encourage the construction of new energy production or generating facilities that increase the in-state capacity to provide for current and anticipated energy demand at a competitive price." She stated the Solar Projects will contribute to the development of NIPSCO's generation portfolio becoming more robust and diverse and will have the same effect on Indiana's overall generation mix and will also lead directly to the construction of the generating assets within the State of Indiana to ensure NIPSCO can serve its customers at a competitive price.

Ms. Whitehead described how the costs of the CFDs or BTA PPA will be recovered if all of the conditions precedent under the BTA are met. She explained that 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 Ind. Code § 8-1-2-42(a), which is anticipated to occur through NIPSCO's FAC filings. She stated NIPSCO is seeking approval of power purchases pursuant to the CFDs or BTA PPAs as reasonable throughout the entire term of the agreements and therefore confirmation that the costs thereof are recoverable through the FAC filing without regard to the Ind. Code § 8-1-42(d) tests or any other FAC benchmark. Ms. Whitehead described how the costs of the Back-Stop PPA will be recovered if all of the conditions precedent under the BTA are not met. She explained that NIPSCO is proposing to recover the costs through a rate adjustment mechanism approved pursuant to Ind. Code § 8-1-2-42(a), which is anticipated to occur through NIPSCO's FAC filings. She stated NIPSCO is seeking approval of power purchases pursuant to the Back-Stop PPAs 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 § 8-1-42(d) tests or any other FAC benchmark.

(b) Campbell Direct Testimony. Mr. Campbell provided a broad overview of the proposed transactions; discussed details of each of the Solar Projects that are reasonable and necessary components of NIPSCO's generation portfolio as it replaces certain legacy coal units; discussed how NIPSCO will integrate the solar and solar plus storage projects into NIPSCO's and MISO's operations; discussed the viability of solar and solar plus storage energy resources generally; and discussed the terms of the Solar Offtake Agreements outlining NIPSCO's rights to the Solar Projects' 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 PPAs will only come into play if the conditions precedent to the BTAs are not met.

Mr. Campbell provided background information for NIPSCO's 2018 IRP. He testified the 2018 IRP resulted in a preferred portfolio for NIPSCO generation that calls for (a) the retirement of 75% of NIPSCO's coal-fired generation by 2023 and 100% of the coal-fired generation by 2028, (b) the continued operation of NIPSCO's gas-fired Sugar Creek Generating Station ("Sugar Creek"), and (c) replacement of certain retired generation units largely with wind, solar, and energy storage. The Short-Term Action Plan contemplated the All-Source RFP, which NIPSCO undertook on May 14, 2018 and additional RFPs, which NIPSCO undertook in 2019. He stated that NIPSCO and CRA took the experience and knowledge gained from the All-Source RFP and leveraged it in the Phase II RFPs process, which also received robust responses. He explained that based on the outcome of the Roaming Bison Project which was ultimately cancelled due to local zoning restrictions,[32] NIPSCO increased the weight of the scoring related to "development risk" within the Phase II RFPs. He stated this scoring adjustment does not guarantee a selected project coming out of the Phase II RFPs will enter commercial operation, but it was an intentional decision by NIPSCO and CRA so that projects more advanced in development would receive credit in CRA's project scoring. He said that as it was negotiating with short-listed projects, NIPSCO's due diligence also included evaluating the likelihood of any county ordinances that could possibly increase development risk, such as the ordinance change that impacted the Roaming Bison Project.

Mr. Campbell described the projects that have been finalized coming out of the Phase II RFPs stating that NIPSCO had completed negotiations with several solar and solar plus energy

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[32] The Roaming Bison Project had a 300 MW ICAP and 45 MW UCAP, representing only a fraction of the capacity needed to replace the 2023 retirements.

storage projects as a result of the Phase II RFPs, including the 200 MW solar PPA ("Brickyard Project") and 100 MW solar and 30 MW energy storage PPA ("Greensboro Project") in Cause No. 45403, the Solar Projects in this filing, and is also in the midst of commercial negotiations with several additional projects. He stated that given the number of projects required to facilitate the retirement of and replacement of the capacity from Schahfer, and the dynamic nature of the renewable generation industry, while there is always a risk that a particular project may not achieve commercial operation, this risk also demonstrates part of the value associated with project diversification and entering into a portfolio of projects, rather than potentially putting emphasis on one or only a few projects, or even on a single technology. He noted that the failure of Roaming Bison also emphasizes one of the primary risks associated with entering into PPAs—the lack of control over the project's development, which can be mitigated by project ownership, such as through the joint venture structure proposed here for the Solar Projects, and it is one of the reasons NIPSCO believes it would be imprudent to rely exclusively (or too heavily) on PPAs to replace retiring generation. He stated that while a PPA may appear to be the "cheaper option" on paper, NIPSCO believes the Solar Projects are prudent and reasonable investments for NIPSCO and its customers, as they will help NIPSCO achieve an affordable, reliable, flexible, and diverse generation portfolio as part of its broader Short-Term Action Plan under the 2018 IRP – one reason why NIPSCO is continuing to pursue a diversified approach, with a mix of PPAs and project ownership through joint venture structures.

Mr. Campbell explained the process by which NIPSCO came to enter into the Solar Projects, NIPSCO's negotiations coming out of the Phase II RFPs, and his role in the Phase II RFPs process.

Mr. Campbell testified that solar energy is a renewable, indigenous, and clean energy source. He stated that solar 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 solar power is not impacted by the volatility of commodities. He stated that due to meteorological and resource diversity, the location of the Solar Projects influences the capacity accreditation and available solar energy. Mr. Campbell stated that the Solar Projects are all located in Indiana and are expected to have production levels consistent with their respective geographic location. He noted that while within the continental United States, solar production improves the further south and west a project is located with advances in solar technology in areas such as solar panel availability, capacity factor, efficiency, and design and size, solar energy has become a viable source of renewable energy resources on a per megawatt-hour ("MWh") basis in the Midwest.

Mr. Campbell testified the preferred portfolio under the 2018 IRP includes the following capacity replacements over time: 125 MWs of energy efficiency and demand side management peak load savings by 2023, growing to 370 MW by 2038; approximately 1,100 MW of installed capacity ("ICAP")[33] wind representing 157 MW of unforced capacity ("UCAP")[34] entering into

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

[34] Unforced capacity or UCAP represents the expected capacity available during the system peak. For renewable resources, MISO relies on historical operational data during peak hours or generic planning numbers based on a system-wide effective load carrying capability analysis. The 2018 IRP developed UCAP numbers based

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 stated the Solar Projects together account for 900 MW of ICAP solar (paired with 135 MW of ICAP storage), accounting for less than half of the 2023 solar needs under the Short-Term Action Plan. He said the Solar Projects, which will initially be owned by a joint venture but ultimately be owned by NIPSCO, are an important part of replacing the capacity from the retirement of Schahfer.

Mr. Campbell explained where NIPSCO would be in its implementation of the Short-Term Action Plan if the Solar Projects are approved. He testified that coming out of the All-Source RFP in 2018, NIPSCO filed and received approval for the following projects: (1) the 102 MW Rosewater Project, which is a wind BTA (Cause No. 45194); (2) the 302 MW Crossroads Project, which is also a wind BTA (Cause No. 45310); and the 400 MW Jordan Creek Project, which is a wind PPA (Cause No. 45195). He stated NIPSCO has also now completed negotiations with several solar and solar plus energy storage projects as a result of the Phase II RFPs, including the Brickyard Project, Greensboro Project, and the instant Solar Projects. He testified that even after inclusion of the Solar Projects, NIPSCO will have flexibility as it looks to fill the approximately 296 MW of wind, and 1,075 MW of solar and solar plus storage still needed to replace the generation at Schahfer by 2023. He noted there will also be additional opportunities for NIPSCO to adjust its ultimate generation portfolio to account for Michigan City's retirement in 2028. Additionally, he noted that between 2023 and 2028, NIPSCO will be able to rely on Michigan City, and it will continue to utilize Sugar Creek and its gas peaker units (Schahfer Units 16A and 16B) as part of its generation portfolio.

Mr. Campbell testified NIPSCO is confident that it will be able to reliably and affordably serve all customers during and upon completion of its generation transition. He stated that in accordance with the 2018 IRP preferred portfolio, NIPSCO intends to maintain fully dispatchable resources such as Sugar Creek and its gas peaker Units 16A and 16B at Schahfer. He indicated that with these levels of fully dispatchable resources, NIPSCO is confident it can respond to both the economic and reliability needs of the MISO Market and, therefore, its customers. Furthermore, he stated that wind, solar, and battery technology are complimentary resources and can now be seamlessly integrated into the bulk electric system. He said MISO has also transitioned these resources to Dispatchable Intermittent Resources ("DIR") to increase the operational flexibility of the assets and efficiently dispatch the resources in real-time and that developers are also requesting more robust interconnection positions with regard to the MISO Interconnection Queue, whereby they are requesting higher levels of network resource interconnection service ("NRIS") resulting in greater asset deliverability to the broader MISO market. He testified that NIPSCO has made, and continues to make, necessary upgrades to its transmission system to ensure generation deliverability and system reliability will not be impacted by its generation transition and that ultimately, NIPSCO is confident that through its own resource planning efforts and its participation in the MISO market it will be able to reliably and affordably serve all its customers during and upon completion of its generation transition.

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on bidder responses to the All-Source RFP (where available) and generic estimates of approximately 15% of ICAP for wind resources and 50% of ICAP for solar resources.

Mr. Campbell testified the Bridge I Project is being implemented through the Bridge I BTA using the Bridge I Solar Offtake Agreements to pay for the energy and capacity, the Bridge I MSA to support the O&M of the project, and the Bridge I EPC Agreement, as well as the ECCAs and LLC Agreements.[35] Bridge I Seller, through Bridge I ProjectCo, is developing a solar farm and associated electric transmission line in Jasper County, Indiana (utilizing MISO interconnect requests J643 and J847), having an aggregate nameplate solar capacity of approximately 265 MWs and is expected to achieve commercial operation by December 31, 2022 (the size of the project may change slightly as engineering and technical specifications are finalized). He stated the generation interconnection agreement ("GIA") for the Bridge I Project was executed with MISO on May 5, 2020.

Mr. Campbell testified the Bridge II Project is being implemented through the Bridge II BTA using the Bridge II Solar Offtake Agreements to pay for the energy and capacity, the Bridge II MSA to support the O&M of the project, and the Bridge II EPC Agreement, as well as the ECCA and LLC Agreement. Bridge II Seller, through Bridge II ProjectCo, is developing a solar plus storage farm and associated electric transmission line in Jasper County, Indiana (utilizing MISO interconnect requests J1336, J1339, and J1340), having an aggregate nameplate solar capacity of approximately 435 MWs and energy storage capacity of approximately 75 MW and is expected to achieve commercial operation by December 31, 2023 (the size of the project may change slightly as engineering and technical specifications are finalized). He stated the GIA for the Bridge II Project is anticipated to be entered into in late 2021 or early 2022.

Mr. Campbell testified the Cavalry Project is being implemented through the Cavalry BTA using the Cavalry Solar Offtake Agreements to pay for the energy and capacity, the Cavalry MSA to support the O&M of the project, and the Cavalry EPC Agreement, as well as the Cavalry ECCA and Cavalry LLC Agreement. Cavalry Seller, through Cavalry ProjectCo, is developing a solar plus storage farm and associated electric transmission line in White County, Indiana (utilizing MISO interconnect request J1067 and, if needed, J1810), having an aggregate nameplate solar capacity of approximately 200 MWs and energy storage capacity of approximately 60 MW and is expected to achieve commercial operation by December 31, 2023 (the size of the project may change slightly as engineering and technical specifications are finalized). He stated the GIA for the Cavalry Project is anticipated to be entered into in late 2021 or early 2022.

Mr. Campbell testified the ECCA and LLC Agreement both must be executed as a condition precedent to closing in the BTAs. He said NIPSCO anticipates that the ECCA will be entered into once a form of the LLC Agreement has been agreed to between the parties to the ECCA and the LLC Agreement will be executed in connection with the closing of the sale of the ProjectCos to the Joint Ventures. He explained that the ECCA will obligate NIPSCO and the TEP to contribute funds to the Joint Venture to fund the purchase of the ProjectCo, and the LLC Agreement will govern the operation and management of each respective Joint Venture after the purchase of the ProjectCos.

[35] The Bridge I ECCA, Bridge II ECCA, and Cavalry ECCA are collectively referred to herein as "ECCAs" and sometimes referred to individually as "ECCA." The Bridge I LLC Agreement, Bridge II LLC Agreement, and Cavalry LLC Agreement are collectively referred to herein as "LLC Agreements" and are sometimes referred to individually as "LLC Agreement."

Mr. Campbell briefly described NextEra Energy Resources, LLC ("NextEra"), the "Developer" and ultimate owner of Seller,[36] its experience in the solar and solar plus storage generation business, and its creditworthiness. He also described the extensive experience of NextEra as a renewable energy developer and provided Attachment 2-F outlining this experience in greater detail. He explained how NIPSCO reached its decision to contract for the MWs of electric energy made available through the Solar Projects. He explained that congestion risks of the Solar Projects were assessed using MISO's future year ProMod models which are capable of simulating hourly market operations for a given study year. He said the output was then used to determine the expected curtailments, total revenue and congestion and loss charges for each site under consideration. He indicated that sites with greater congestion risk have been appropriately discounted in NIPSCO's site analysis.

Mr. Campbell explained the main difference between the joint venture structures proposed in this proceeding and the joint venture structures approved for the Rosewater and Crossroads Projects are: (1) NIPSCO has incorporated several of the considerations requested by the OUCC that were agreed to by NIPSCO and approved by the Commission in those other two proceedings; (2) there will only be two members of the joint venture – NIPSCO (the Managing Member) and a TEP; (3) NIPSCO is seeking approval of Solar Offtake Agreements through which NIPSCO will pay for the energy generated by the Solar Projects; (4) use of an EPC Agreement; and (5) use of a MSA Term Sheet.

Mr. Campbell described the following structure of the each of the proposed transactions. Pursuant to the BTA, and as explained in the Example Term Sheet for LLC Agreement (<u>Confidential Attachment 2-D</u>), Joint Venture will purchase 100% of the equity interest in ProjectCo from Seller. As a pre-condition to the transaction, an LLC Agreement must be executed under which Joint Venture will be owned by two members (NIPSCO and TEP). 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 NIPSCO, which will manage the Project at the closing of the transaction under the BTA. NIPSCO is the managing member and will contribute cash to the Joint Venture of a specific percentage range of the purchase price of the Project. NIPSCO will remain the managing member of the Joint Venture at all times. The Seller will build the Project through ProjectCo, and ProjectCo will own the Project. Under the terms of the BTA, Seller will transfer 100% of ProjectCo to Joint Venture at the time the Project reaches project Mechanical Completion in exchange for cash from the Joint Venture. For its share, 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. TEP's interest in Joint Venture will enable it to receive 99% of the ITCs and tax losses generated by the Project along with distributions of up to a specific percent of cash available for distribution generated by the Project, with the remainder flowing to NIPSCO. NIPSCO will continue to pay ProjectCo for the output of the Project under the terms of the CFD (or BTA PPA), which continues until the TEP reaches the specified internal rate of return ("IRR") or the CFD or BTA PPA is terminated. Once TEP has attained an 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

[36] Bridge I Seller, Bridge II Seller, and Cavalry Seller are collectively referred to herein as "Sellers" and sometimes referred to individually as "Seller."

have the option to acquire the TEP interest for fair market value as defined in the LLC Agreement. Lastly, NIPSCO can consolidate the project and eliminate the need for the CFD or BTA PPA.

Mr. Campbell explained that NIPSCO's proposal of a different structure in this proceeding is a result of its experience in negotiating with TEPs in the previously-approved wind projects requiring there be three-party negotiations because NIPSCO, the developer, and the TEP were all to be parties to the Joint Venture, which necessitated all three parties to negotiate and sign-off on all relevant transactional documents, which is not as efficient as negotiations involving only two parties. For the Solar Projects, NextEra was amenable to selling the Solar Projects into the Joint Venture at the point of Project Mechanical Completion and allowing only NIPSCO and the TEP to be parties to the Joint Venture, because NextEra does not have a substantial interest in the details and terms of the financing arrangements between NIPSCO and the TEP.[37] He stated that based on NIPSCO's experience in negotiations coming out of the All-Source RFPs, including discussions with other project developers, having negotiations between the utility that will ultimately own a project and the TEP (with the developer not included) is also more in-line with industry practice. He said that NIPSCO believes this structure will provide some efficiencies with respect to the time and expense of negotiations, which is in the best interest of NIPSCO and, ultimately, its customers, and for these reasons, NIPSCO modified the joint venture structure for use in this proceeding and anticipates utilizing this modified joint venture structure in similar future filings.

Mr. Campbell stated 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 Solar Projects are unable to produce for an extended period of time, could result in a need for additional investment. He testified NIPSCO seeks authority in this case to include any such additional payments as an increase of its investment in the Joint Ventures. He noted that in response to concerns expressed by the OUCC in prior proceedings, NIPSCO is proposing that recovery of additional investments in the Joint Ventures be capped, so that any investments exceeding the cap will not be recovered from NIPSCO's customers.

Mr. Campbell described modifications to the BTAs to address potential uncertainties in the future and additional steps considered to mitigate against the potential that the Solar Projects may not qualify for the full 30% ITC. Although NIPSCO believes it has addressed the risk that the Solar Projects may not to qualify for the full 30% ITC through due diligence and is comfortable with safe harbor strategy utilized, Mr. Campbell explained that NIPSCO continues to assess and respond to potential project risks and has considered the potential of procuring an insurance product that would further protect NIPSCO and its customers by insuring against possible events that could impact the amount of ITC the Solar Projects qualify for.

Mr. Campbell described the Solar Offtake Agreements stating that NIPSCO currently anticipates using the CFD rather than the BTA PPA. He explained that at this time, if NIPSCO were to utilize a BTA PPA, and not receive certain guidance from the U.S. Internal Revenue Service ("IRS"), there is a potential that the Joint Ventures may not be able to fully utilize certain

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[37] NextEra does have an interest in ensuring that NIPSCO ultimately obtains TEP financing for the projects, because obtaining TEP financing is a key part of the structure of the transactions here, but NextEra does not have a desire to be involved in the negotiations of the specific terms.

tax-related benefits of the Solar Projects. He said that if this were to occur, it would increase the costs associated with the transactions, which would ultimately be borne by NIPSCO's customers. He testified that by utilizing the CFD (which is a "financial" rather than "physical" contract), NIPSCO is able to avoid the potential negative tax implications that would exist if the BTA PPA were used, thereby fully utilizing the tax benefits of the Solar Projects for the benefit of NIPSCO's customers. He explained that a CFD is a financial instrument that is often used in energy markets to establish a fixed price for energy when a party is not physically transacting in the underlying commodity (in this case, the energy from the Solar Projects). He explained that under the CFD, NIPSCO would pay to (or receive from) ProjectCo the difference between the specified contract price and the actual market price (Locational Marginal Pricing ("LMP")), at the ProjectCo's Commercial Pricing Node) for the expected energy production from the Solar Project – that is, NIPSCO would pay the ProjectCo the specified contract price; the ProjectCo would pay NIPSCO the market price; and there would be monthly settlements between the two parties, based on the differences between the two prices and the amount of power covered by the CFD. He testified that ultimately, utilizing the CFD instead of the BTA PPA will have no negative impact on NIPSCO's customers, as the price that will be paid will be the same under either the CFD or the BTA PPA.

Mr. Campbell demonstrated how a CFD would work and provided the pricing for the CFD for each of the Solar Projects. He stated that if the IRS guidance is provided, NIPSCO anticipates using the BTA PPAs, which would be NIPSCO's preference; however, it is possible that the guidance could be delayed to a point where commercial negotiations have advanced to a stage where the CFD approach needs to be used. This is why NIPSCO is requesting the necessary approvals to pay for the electrical energy output from the Solar Projects through any of the Solar Offtake Agreements. He indicated that to the extent NIPSCO gains additional clarity around this issue (i.e., if the IRS were to issue related party guidance), NIPSCO will update the Commission and all parties.

Mr. Campbell explained that which of the Solar Offtake Agreements would be used depends on whether the conditions precedent to the BTA are satisfied. He stated the Back-Stop PPA would be used if the conditions precedent to the BTA are not met. He explained that the Back-Stop PPA would be directly between NIPSCO and the ProjectCo, without transfer of ownership for the Solar Projects to the Joint Venture. He provided the pricing for the Back-Stop PPA for each of the Solar Projects and described how the pricing for the Solar Offtake Agreements were determined.

He testified that the negotiations were arms-length negotiations between two unaffiliated parties. The prices for each of the Joint Ventures are in line with other proposals received through the Phase II RFPs and are considered to be market-based prices at a level in which the transaction will attract a TEP's investment. He said the market price was based upon an open and competitive RFP and explained that attracting the TEP is a key component of the transaction whether the BTAs and CFDs (or BTA PPA) are in full effect or if the Back-Stop PPAs are employed. Mr. Campbell explained that although in prior regulatory proceedings NIPSCO has submitted Back-Stop PPAs, LLC Agreements, and similar documents that included the material terms for the agreement but not formally executed, in this case, NIPSCO is also submitting CFDs and BTA PPAs that been negotiated by NIPSCO and Seller but that have not be executed because there are certain regulatory compliance requirements that take effect at the time a CFD is executed since it is a financial, rather than physical, transaction. He stated that following execution of the BTAs, NIPSCO needed additional time to address those compliance requirements. Additionally, he stated that if the IRS issues the related party guidance, NIPSCO plans to utilize the BTA PPAs instead of the CFDs. He explained that because the BTA PPAs are physical transactions, the same compliance requirements that apply to CFDs do not apply, meaning NIPSCO may not need to address them at all. Thus, inclusion of the unexecuted CFDs and BTA PPAs provides the material terms for the agreements for the Commission and interested parties to review, while allowing NIPSCO time to address potential compliance requirements for use of the CFDs. He testified that at the time any of these CFDs or BTA PPAs are executed, NIPSCO will file the executed agreements with the Commission. He noted that the BTA PPAs and CFDs are exhibits to the executed BTAs and that the BTAs have an explicit requirement that the parties execute either the BTA PPA or the CFD once the determination of which of the two contracts is intended to be utilized.

Mr. Campbell described the terms of the CFDs stating they provide NIPSCO with 100% of benefit associated with the electrical energy output of the Solar Projects for 15 years. He noted that NIPSCO will not take delivery of the energy from ProjectCo under a CFD but will instead settle each month for the difference between the CFD price and the actual LMP at the ProjectCo's Commercial Pricing Node. He explained that MISO treats solar energy projects as dispatchable intermittent resources. He said other benefits (e.g., UCAP and environmental attributes (the RECs)) and costs (MISO Settlement Charges) addressed in the BTA PPA will be allocated to NIPSCO pursuant to the LLC Agreement, which will also address operating procedures / parameters for each Solar Project. He testified that the fixed price settlement of the CFD for energy and the allocation of other benefits / costs will ensure that the same economic position relative to the BTA PPA is maintained. He explained NIPSCO will settle each month for the difference between the CFD price and the actual LMP. He said that since MISO treats solar energy projects as dispatchable intermittent resources, the ProjectCos 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 ("MISO Tariff").

Mr. Campbell described the terms of the BTA PPAs stating they provide NIPSCO with 100% of the electrical energy output of the Solar Projects, the UCAP, which represents the percentage of ICAP available after a units forced outage rate is taken into account as shown in the BTA PPAs, and any environmental attributes (RECs) of the project for 15 years. He explained that if the BTA PPA is ultimately utilized, NIPSCO will take delivery of the energy from ProjectCos at a specified metering point, with NIPSCO being the Market Participant and making the energy available in the MISO energy market. He said NIPSCO will be paying the Joint Ventures (through the ProjectCos) the contract price per MWh and counting this energy as used in the NIPSCO system. He noted NIPSCO will settle the sale price for the energy sold into MISO against the price paid for the energy explaining 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 stated that since MISO treats solar energy projects as dispatchable intermittent resources, the ProjectCos will be subject to real-time Revenue Sufficiency Guarantee and Uninstructed Deviation charges assessed under the MISO Tariff.

Mr. Campbell explained that as used in the relevant contracts, the phrase "environmental or renewable characteristics or attributes" is contained within the definition of RECs, which are tradable credits corresponding to each megawatt-hour of electricity generated by a renewable-fueled or environmentally friendly source, and 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 contracts. He said NIPSCO anticipates the RECs it receives will be tracked through the Midwest Renewable Energy Tracking System ("M-RETS"), or similar system. 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.

Mr. Campbell testified NIPSCO will be able to designate each of the Solar Projects as network resources under the MISO Tariff. He explained that the GIA that each of the ProjectCos will be executing with MISO will have NRIS available for its full injection once any required transmission system upgrades are complete. He explained that having NRIS will allow NIPSCO to designate these generation facilities as network resources to receive Network Integration Transmission Service ("NITS") without further study.

Mr. Campbell testified that if all of the conditions precedent *are* met under the BTAs, the CFDs and BTA PPAs represent prudent, valuable and reasonably priced renewable energy resources for NIPSCO and will provide NIPSCO's customers with more affordable and cleaner energy resources, which is supported by the analysis performed in NIPSCO's 2018 IRP, as well as the additional analysis undertaken since the 2018 IRP. He testified that if all of the conditions precedent contained in the BTAs *are not* met, the Back-Stop PPAs represent prudent, valuable and reasonably priced renewable energy resources for NIPSCO and will provide NIPSCO's customers with more affordable and cleaner energy resources as well, which is also supported by the analysis performed in NIPSCO's 2018 IRP.

Mr. Campbell testified that NIPSCO secured the services of Sargent and Lundy ("S&L") to assist with negotiations of the key contractual documents related to the Solar Projects and to serve as "owner's engineer," a service offered by S&L, wherein they serve as an independent advocate for a project owner. He explained that as owner's engineer, S&L played a supporting but critical role by utilizing their expertise on solar and storage projects that NIPSCO does not currently possess "in-house." He stated that in this capacity, S&L reviewed template contracts and certain contract provisions and technical exhibits for the Solar Projects, and provided guidance on contract provisions and content of technical exhibits that NIPSCO should consider in commercial negotiations for these contracts, and also performed additional services, such as reviews of major equipment suppliers; engineering, procurement, and construction (EPC) contractors and subcontractors; and similar work. He stated that additionally, S&L, along with NIPSCO, will monitor the construction of the Solar Projects.

Mr. Campbell explained that to address concerns raised by the OUCC in previous proceedings, in rebuttal NIPSCO proposed that the Commission approve eight "conditions" as part of the approval of those transactions, which the Commission did ultimately approve. He described NIPSCO's proposal for five of the eight conditions (one of the eight conditions, relating to a cap on the amount paid to buy the developer out of the Joint Venture, is not applicable in these transactions, as the developer will not be a party to the Joint Ventures, and Witness Camp addressed the other two), as follows:

First, NIPSCO commits not to seek approval in this proceeding of any amounts related to its purchase of the TEP's share of any of the three Solar Projects. Rather, once a determination has been made by NIPSCO to purchase the TEP's share of any of the Solar Projects, NIPSCO will seek recovery of such costs in a separately docketed proceeding. NIPSCO commits not to seek recovery of more than the fair market value of the TEP's share of the Joint Venture in any such proceeding.

Second, NIPSCO commits that there will be a cap of cost recovery related to any additional cash payments across all three Solar Projects NIPSCO may make into the Joint Ventures. The cumulative amount recoverable from ratepayers shall be capped. During the 15 year term of the CFD (or BTA PPAs), to the extent sales revenue by the Joint Ventures to NIPSCO exceed operating costs, NIPSCO's cash allocation will be returned to NIPSCO's customers. To the extent revenues are less than operating costs, cash contributions by NIPSCO to the Joint Venture may be offset (netted against) by NIPSCO's cash allocations. At the time of the buyout of each TEP, any accrued balance of the additional portion of this regulatory asset to be recovered from NIPSCO's customers will be no more than a specific amount.

Third, NIPSCO has already begun and proposes to continue discussions with the OUCC about NIPSCO's strategy with regard to RECs from renewable resources within NIPSCO's quarterly FAC proceedings.

Fourth, except as described in the other agreed-upon conditions, for each of the Solar Projects, NIPSCO commits not to seek cost recovery from customers of any other costs related to the particular Solar Project incurred by NIPSCO related to (1) the buyout of the TEP(s), or (2) the operations of the Joint Venture while TEP(s) are still participants in the Joint Venture.

Fifth, NIPSCO commits to remain the managing member of each Joint Venture.

(c) <u>Augustine Direct Testimony.</u> Mr. Augustine discussed the preferred portfolio from NIPSCO's 2018 IRP, including additional portfolio analysis NIPSCO has subsequently performed to validate implementation of its IRP Short-Term Action Plan based on the results of its RFPs and updates to certain key assumptions, and how the assumptions associated with the new solar and solar plus storage resource options modeled in the 2018 IRP compared with the cost of NIPSCO's investment in the solar and solar plus storage generation Joint Ventures.

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 calls for the retirement of all four coal units at Schahfer by 2023 and the retirement of Michigan City in 2028. Mr. Augustine outlined the capacity replacements included in the preferred portfolio, which were also listed by Mr. Campbell. 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 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 testified that in the course of developing the preferred portfolio, NIPSCO concluded that across NIPSCO's scenario and stochastic-based retirement analysis, it was determined that the more coal-fired generation that was retained in the portfolio and the longer that it was retained, the more expensive the portfolio was for NIPSCO's customers – this was true across all of NIPSCO's scenarios, and the full stochastic distribution of uncertainties that was evaluated. He stated that although it was concluded that early retirement of existing coal-fired generation resources would result in lower customer costs, NIPSCO confirmed through its IRP scorecard approach that it is not reasonable to view the world in terms of choosing a simple "least cost option;" instead, it is necessary to think in terms of minimizing future environmental impacts and maximizing resource diversification, while ensuring reliable and affordable service to customers. He explained that as a result of these considerations, the preferred portfolio includes a staggered retirement plan for Schahfer in 2023 and Michigan City in 2028 so that all necessary reliability and transmission upgrades resulting from coal-fired generation retirements can be made and so that new resource additions can be acquired over a multi-year period and in a fashion that will allow for flexibility to respond to market and technology changes. He stated that in NIPSCO's scenario and stochastic-based replacement analysis, it was determined that the portfolios that included more renewable resources were more cost-effective and less risky than the alternatives; therefore NIPSCO's generation mix is projected to shift significantly from coal to renewables over time.

Mr. Augustine provided an overview of the 2018 IRP's Short-Term Action Plan and NIPSCO's implementation to date. He stated that in the Short-Term Action Plan detailed in Section 9.4 of the 2018 IRP, NIPSCO identified a phased approach to selecting and acquiring replacement resources needed to fill the capacity gap that develops as a result of the planned retirements in 2023 in the preferred portfolio. He said that the plan called for initially prioritizing replacement resources with expiring or declining tax credits, followed by additional RFPs to acquire resources to fill the remainder of the 2023 supply requirement. He stated the prioritized replacement resources were wind projects looking to qualify for the PTC, which is expiring over the next few years. Mr. Augustine testified that in 2019, NIPSCO requested approvals to either purchase and acquire or enter into PPAs with a total of approximately 1,100 MW of nameplate wind power in Cause Nos. 45194, 45195, 45196, and 45310. He stated that then NIPSCO conducted the Phase II RFPs (one for wind, one for solar, and one for thermal/other capacity resources) to target primarily renewables and storage and acquire the remaining resources in the preferred portfolio.

Mr. Augustine described how, in the 2018 IRP, NIPSCO used the All-Source RFP to determine the cost and operational performance assumptions of solar 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 cost 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 solar asset sale and PPA tranches, which were eligible to be selected in the portfolio analysis in part or as a whole block of capacity. He explained that NIPSCO's replacement portfolio analysis in the 2018 IRP was specifically designed to evaluate options with different commitment durations. He noted that PPAs tend to have shorter durations, while asset ownership options tend to lock in commitments for longer periods of time, generally thirty years. Thus, distinct tranches were developed to evaluate the costs and risks of different resource strategies. Mr. Augustine stated that the 2018 IRP concluded that a mix of shorter-term and long-term resources provided the best outcomes for the cost to customer and cost risk metrics. Specifically, the portfolios that were dominated by short-duration resources tended to have lower near-term customer cost impacts, but were exposed to significant long-term cost uncertainty. He explained that this long-term cost uncertainty was mitigated by the presence of asset acquisition tranches in the portfolios with a mix of short- and long-duration resources, including the preferred portfolio.

Mr. Augustine described the specific assumptions used for the solar tranches from the All-Source RFP that were selected in the preferred portfolio in the 2018 IRP. He said the preferred portfolio from NIPSCO's 2018 IRP included solar and solar plus storage resources from six different tranches, including three asset acquisition tranches and three PPA tranches. He said the three asset acquisition tranches totaled 1,104 MW of ICAP (552 MW of UCAP) and had a capacity-weighted acquisition price of $1,112/kilowatt ("kW") (in 2023 dollars) and a capacity factor of approximately 26%. Fixed operations and maintenance ("FOM") costs were assumed to be $16.89/kW-year (in 2017 dollars), with ongoing capital expenditures of $5.11/kW-year (in 2017 dollars). Property taxes were assumed to be 2.16% of the net book value of the plant over time. He stated the three PPA tranches totaled 1,176 MW of ICAP (593 MW of UCAP) with an average contract duration of approximately 21 years, a capacity-weighted fixed nominal PPA price of $30.24/MWh, and a capacity factor of approximately 25%.

Mr. Augustine explained that the Phase II RFPs solicited bids for energy and capacity for many types of resources, including solar, storage, wind, and thermal plants, and included a specific target for solar and solar plus storage resources based on the conclusions of the 2018 IRP and the Short-Term Action Plan. He stated that NIPSCO has already entered into two PPAs with solar and solar plus storage facilities, which were filed with the Commission on July 17, 2020 in Cause No. 45403 and has been negotiating with the developers of additional renewable and storage resources that were offered into the Phase II RFPs, including the Joint Ventures proposed here. He stated these solar and solar plus storage Joint Ventures make up a component of the remaining replacement resources necessary to complete the Short-Term Action Plan associated with NIPSCO's preferred portfolio in its 2018 IRP.

Mr. Augustine testified NIPSCO performed additional portfolio analysis after the Phase II RFPs were completed to evaluate the bids within the context of the expected performance of the 2018 IRP's preferred portfolio. He explained that one of the benefits of integrating RFP bids into NIPSCO's 2018 IRP was that the portfolio analysis was informed by real world assets and projects in the marketplace, which reduces the uncertainty around future resource replacement costs; however, because the marketplace is dynamic and evolving, as part of its ongoing and periodic review of its generation portfolio, NIPSCO performed a portfolio analysis in 2020 (the "2020 portfolio analysis"). He stated the 2020 portfolio analysis was not a full re-evaluation of the 2018 IRP but rather was intended to evaluate the direction of the preferred portfolio in light of the new information received in the Phase II RFPs and to reflect changes to NIPSCO's system and other market conditions.

With regard to changes to NIPSCO's system and other market conditions that were updated in the 2020 portfolio analysis relative to the 2018 IRP, Mr. Augustine explained that NIPSCO received approval to either enter into PPAs with or purchase and acquire three wind projects entering into service in the near term, so those portfolio updates were incorporated. In addition, he stated NIPSCO's load forecast was updated due to a rate structure change for industrial customers, which is referred to as "Rate 831." He stated that from the market perspective, the commodity price outlook was updated, and the expectation for a significant shift in MISO's generation mix towards intermittent renewables resulted in updates to the assumed capacity credit for solar resources over time and the introduction of stochastic renewable output variability to the risk analysis.

With regard to the changes in NIPSCO's electric load forecast that have occurred since the submission of the 2018 IRP, Mr. Augustine explained that a significant change in rate structure was approved by the Commission in Cause No. 45159, that resulted in a reduction of several hundred MWs of industrial load from NIPSCO's system, with several large industrial customers under Rate 831 no longer having their energy and peak demand needs served by NIPSCO. He stated that NIPSCO's current net supply-demand position after the implementation of Rate 831 is very similar to what it was before because even as peak load "requirements" have fallen, the "interruptible" capacity that many of the Rate 831 industrial customers previously offered is no longer available to NIPSCO, resulting in a similar net peak capacity position, even as NIPSCO's energy requirements have gone down. Mr. Augustine testified that given the presence of a large industrial load base in NIPSCO's service territory, the 2018 IRP contemplated this risk through the evaluation of a Challenged Economy Scenario, which was based on low economic growth and substantial industrial load leaving the system. He noted that the preferred portfolio provided savings for customers versus the alternatives not only under base case conditions, but also under the conditions in the Challenged Economy Scenario. He stated that in that scenario, NIPSCO's preferred Retirement Portfolio 6, which retired all four coal units at Schahfer in 2023 and Michigan City in 2028, provided significant savings relative to the portfolio that retained the existing coal fleet through 2035 (Retirement Portfolio 1). He indicated that part of the reason for this is that NIPSCO operates as a member of the MISO market, meaning that the performance and utilization of its generation resources, including resources NIPSCO will own pursuant to the solar and solar plus storage Joint Ventures, will be influenced by their expected cost structures and positions in the broader market and not solely against NIPSCO's internal load requirements. He stated that nevertheless, in the 2020 portfolio analysis, a revised load forecast, capturing the impacts of Rate 831, was incorporated.

Mr. Augustine testified the commodity price outlook was updated in the 2020 portfolio analysis. He explained that CRA updated the base case commodity price outlook for fuel prices and MISO power prices. He noted that the price of natural gas in the updated outlook was approximately \$0.50/MMBtu lower on average (in nominal dollars) than the forecast used in the 2018 IRP over the 2021 through 2038 time period. He stated the updated MISO power prices were approximately \$2/MWh lower during off-peak hours and \$4/MWh lower during on-peak hours on average (in nominal dollars) over the same time period; primarily due to the lower natural gas price forecast, but also a result of expectations for more renewables to enter the MISO market over time.

Mr. Augustine stated that given the potential for significant growth in solar generation in the MISO market over the next several years and given MISO's announced transition to an effective load carrying capability ("ELCC") methodology for capacity credit for solar, NIPSCO adjusted its capacity credit assumptions to decline from 50% in 2023 to 30% over a ten-year period.[38]

Mr. Augustine explained how NIPSCO developed portfolio concepts to analyze in the 2020 portfolio analysis. He explained that the Phase II RFPs' bid responses were organized into tranches in a similar fashion to what was done in the 2018 IRP in order to assess the performance of different portfolio options across a range of commitment durations and diversity measures.[39] He said that as was done in the 2018 IRP, the 2020 portfolio analysis evaluated portfolio concepts with shorter and longer commitment durations, as well as concepts with more fossil-fueled resources versus those with more renewable resources. He noted that although the 2018 IRP's diversity category was focused on CO_2 emissions and hence varied the amount of renewables and natural gas-fired resources across portfolio concepts, in response to the evolving expectations for more and more intermittent renewable resource additions in the broader MISO market and potential changes in market rules, the 2020 portfolio analysis explicitly evaluated operational flexibility or "dispatchability,"[40] testing portfolio concepts with different amounts of storage and natural gas capacity.

Mr. Augustine described the portfolio concepts that NIPSCO evaluated in the 2020 portfolio analysis. He stated that similar to the 2018 IRP's replacement analysis, the 2020 portfolio analysis developed six alternative concepts – three across the diversity/dispatchability category with two duration commitment ranges for each – based on the new input assumptions described above and the bids received in the Phase II RFPs. Across the diversity/dispatchability category, NIPSCO's portfolio concepts varied the amount of renewable, storage and natural gas capacity in each portfolio. Across the duration commitment category, NIPSCO evaluated portfolios with all PPA resources and portfolios with a split between PPA and owned resources. All portfolios included more storage capacity than the 2018 IRP's preferred portfolio as a result of Phase II RFP bid data and revised assumptions for solar capacity credit over time. The composition of each of the six portfolios that were evaluated included: (1) all renewable and storage PPAs; (2) mix of renewable and storage PPAs and owned resources; (3) all renewable and storage PPAs, with greater levels of storage capacity; (4) mix of renewable and storage PPAs and owned resources,

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38 MISO continues to study this issue as part of its Renewable Integration Impact Assessment ("RIIA") initiative. While future ELCC credit for solar remains uncertain and dependent on future load patterns, future siting of both solar and wind resources, and weather conditions, recent modeling by MISO suggests that solar capacity credit might fall from just under 60% now to approximately 30% when around 50,000 MW of solar is installed in the MISO region, a level that could plausibly be achieved in the next ten to twenty years. See MISO's RIIA presentation from June, 2020 at the following location: https://cdn.misoenergy.org/20200626%20RIIA%20Item%2003%20Resource%20Adequacy%20Siting%20and%20Expansion%20Sensitivity454963.pdf.

39 See Section 9.2.2 of Attachment 3-A (the 2018 IRP), including Figure 9-13 for a summary of the general concept from the 2018 IRP.

40 In addition to MISO's RIIA initiative noted above, MISO's Resource Availability and Need initiative is exploring seasonal resource adequacy requirements that could result in a shift away from a single summer peak planning structure. In light of these potential changes, operational flexibility or "dispatchability" was introduced as a planning concept and is broadly defined in this context as the ability of a resource to be controlled in response to a change in load or other market condition. Under this definition, thermal and storage resources are dispatchable, while intermittent renewable resources, like solar and wind, are not.

with greater levels of storage capacity; (5) all renewable and thermal PPAs; and (6) mix of renewable, storage, and thermal PPAs and owned resources.[41]

Mr. Augustine described the analysis NIPSCO performed on the revised portfolio concepts stating that NIPSCO performed detailed portfolio dispatch analysis and revenue requirement projections over a 30-year planning horizon, as it did in its 2018 IRP. He stated that while NIPSCO did not perform the full suite of scenario and stochastic analyses that would be done as part of its triennial IRP process, NIPSCO did evaluate the portfolios across a stochastic distribution of uncertainty around commodity prices and hourly solar generation output to assess risk.

In describing the takeaways from the 2020 portfolio analysis, Mr. Augustine stated that the exercise demonstrated that, when accounting for the latest expectations for NIPSCO's load requirements, commodity market prices, and expected market rule changes, the Phase II RFPs provided sufficient renewable capacity at a competitive cost to confirm the direction of the 2018 IRP's preferred portfolio. Furthermore, the analysis highlighted the opportunity to acquire more paired solar plus storage capacity to help mitigate risk associated with solar generation output, market energy price volatility, and capacity accreditation and to maintain flexibility in the portfolio. He stated that while the difference in costs between renewable and natural gas options has narrowed since the 2018 IRP, NIPSCO concluded that the thermal PPA option that made Portfolio 5 cost-competitive carried significant development risk and that portfolios with the most renewable capacity (particularly Portfolios 1 and 2) performed best across all of NIPSCO's scorecard metrics, including customer cost, risk, and environmental stewardship, as shown in the updated scorecard.[42] Finally, he said that Portfolio 2 performed better than Portfolio 1 on the cost risk metric and provides NIPSCO with additional risk mitigation and flexibility benefits than a portfolio relying solely on new PPAs, as described in more detail below. He testified that overall, the 2020 portfolio analysis confirmed the direction of NIPSCO's portfolio evolution, as laid out in the 2018 IRP and the Short-Term Action Plan.

Mr. Augustine testified he was able to compare the total cost of the Joint Ventures from the Phase II RFPs with the total costs of the tranche-level inputs used in the 2018 IRP modeling. He stated he made such a comparison through the development of a LCOE calculation for each of the 2018 IRP resource options and the Joint Ventures. Specifically, he evaluated (a) a 265 MW solar project (Bridge I Project), (b) a 435 MW solar and 75 MW storage project (Bridge II Project), and (c) a 200 MW solar and 60 MW storage project (Cavalry Project) and developed an LCOE for each. 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

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41 As explained above, NIPSCO's 2018 IRP indicated that portfolios that retained existing coal resources for longer were more costly and more risky than the alternatives. This was demonstrated across all scenarios and stochastic inputs and against different replacement alternatives, including a conservative MISO market energy plus cost of new entry construct. The 2020 portfolio analysis, therefore, focused on which assets are best suited for replacement of NIPSCO's retiring coal-fired capacity. Continued operation of Schahfer beyond 2023 and Michigan City beyond 2028 was not part of the 2020 portfolio analysis, as there have been no indications that the economics associated with coal-fired generation have changed since the 2018 IRP was performed.

42 The updated scorecard contains the same objectives and metrics used in NIPSCO's 2018 IRP, aside from the Employees metric, which tracked jobs at NIPSCO's existing coal plants, and the Local Economy metric, which NIPSCO is addressing on a project-by-project basis.

comparison of the costs of the different solar 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;[43] 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, inclusive of expected degradation, 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 or dollars per kW-month over the term of the contract; the expected generation output 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.[44] 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 to quantify the expected congestion risk over time.

With regard to other costs associated with a PPA resource that are not accounted for in his LCOE calculation, Mr. Augustine stated PPAs are long-term financial commitments for a utility, and certain credit rating agencies view such contracts as debt-like financial obligations that represent substitutes for debt-financed investments in generation capacity. He stated these obligations are considered when evaluating the utility's capital structure and overall creditworthiness. He stated that to the extent that these obligations negatively impact the credit worthiness and capital structure of a utility, they could result in increased borrowing costs and/or a shift of financing from debt to equity, increasing the overall cost of financing and negatively impacting costs to customers. He testified NIPSCO has estimated the additional costs associated with such imputed debt, and these tend to increase the LCOE of PPA resources by about \$3/MWh to \$4/MWh but that these potential costs associated with imputed debt, however, are not included in his LCOE calculations.

Mr. Augustine described the LCOE values calculated for the solar resource tranches incorporated in the 2018 IRP's preferred portfolio. He said the 30-year LCOE of the combined 2023 solar acquisition tranches was calculated to be \$52.62/MWh, based on the acquisition price, capacity factor, FOM costs, ongoing capital expenditures, and property taxes summarized in the section on NIPSCO's 2018 IRP and an assumed 30-year project life. He said the 30-year LCOE of the combined 2023 solar and solar plus storage PPA tranches was calculated to be \$39.50/MWh based on the 21-year PPA price summarized above plus an additional nine years of market-based energy and capacity costs over the full planning horizon.

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43 Owned resources from the 2018 IRP use the capital structure as of 2018.

44 Given the expectation that growth in solar capacity in the MISO market will reduce the ELCC of solar resources and the capacity credit of solar over time, post-PPA capacity replacement needs for solar capacity were assumed to be 30% of a PPA's solar ICAP rating, as explained above.

Mr. Augustine testified that the 30-year LCOE of the Solar Projects was calculated based on an acquisition cost, NIPSCO's expectations for future FOM and ongoing capital costs and property taxes based on estimates from the developer, NIPSCO's estimates for future congestion costs at the project's location, and a 30-year project life. He stated that while the storage components are not priced separately in the overall acquisition cost of the project, the capital costs for the storage capacity are included. He explained that the storage component of the projects also contributes to higher ongoing FOM costs and additional augmentation costs associated with maintaining the battery capacity over time and that although a storage component leads to these additional costs, it also helps provide additional capacity credit for the projects that can be achieved by shifting the solar resources' energy output to times that are more coincident with load peaks.

Mr. Augustine testified the preferred portfolio did incorporate one solar plus storage PPA tranche, although the total quantities were lower than the amounts of storage in the Solar Projects, and the ratio of storage to solar in the IRP tranche was lower than the 75 MW of storage associated with 435 MW of solar in the Bridge II Project and the 60 MW of storage associated with 200 MW of solar in the Cavalry Project; however, NIPSCO's 2018 IRP preferred portfolio and Short-Term Action Plan were designed to be flexible and incorporate adjustments in final resource selection based on evolving market conditions. He pointed out that in Section 9.3.4 of the 2018 IRP, NIPSCO noted that capacity credit rules may change and that a seasonal capacity construct may develop that would "expand resource adequacy from a single summer peak view to look at seasonal needs with greater emphasis on the ability of resources to provide energy all year around"[45] and that the 2018 IRP also emphasized that NIPSCO's preferred portfolio intentionally "leaves room to evaluate market and technology changes on a dynamic basis"[46] and to adjust accordingly. He noted that as MISO's Resource Availability and Need initiative moves towards some type of seasonal construct[47] and as the market anticipates more and more solar additions, which could impact future capacity credit, energy price volatility, and ancillary services prices, storage capacity will provide additional value to NIPSCO's portfolio. Thus, he stated that the inclusion of some paired solar and storage resources, such as through the Bridge II and Cavalry Projects, is one way NIPSCO is adjusting its preferred portfolio in response to market changes and the evolving technology options offered in the Phase II RFPs, which was confirmed in the 2020 portfolio analysis NIPSCO performed after the Phase II RFPs.

Mr. Augustine stated that it is possible to adjust the 2018 IRP tranches to include additional costs associated with the additional storage capacity value. He stated that since the addition of paired storage only shifts solar energy from certain hours to others, one major value associated with adding paired storage capacity is that it provides incremental UCAP, which was taken into account for both the Bridge II Project and Cavalry Project. Thus, adjusted IRP LCOEs can be calculated for comparison to each project by adding capacity costs that would result in an equivalent UCAP for a given amount of solar capacity. He testified that when accounting for additional capacity costs at the assumed market price of capacity from the 2018 IRP associated with the amount of storage in the Bridge II Project, the 30-year LCOE of the combined 2023 solar

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45 Attachment 3-A (the 2018 IRP), p. 177.

46 Attachment 3-A (the 2018 IRP), p. 178.

47 MISO's Resource Availability and Need initiative is ongoing and incorporates multiple aspects of resource adequacy and capacity planning, with a recent focus on seasonal capacity credit rules changes and the impacts of growing levels of renewable penetration. More information is available here: https://www.misoenergy.org/stakeholder-engagement/issue-tracking/resource-availability-and-need-ran/.

acquisition tranches was calculated to be $55.31/MWh, and the 30-year LCOE of the combined 2023 solar and solar plus storage PPA tranches was calculated to be $42.17/MWh. When accounting for additional capacity costs at the assumed market price of capacity from the 2018 IRP associated with the amount of storage in the Cavalry Project, the 30-year LCOE of the combined 2023 solar acquisition tranches was calculated to be $57.30/MWh, and the 30-year LCOE of the combined 2023 solar and solar plus storage PPA tranches was calculated to be $44.20/MWh.[48] Overall, he showed that the LCOE for solar acquisition and solar PPA tranches that were "adjusted for extra storage" were estimated to be in a range of approximately $2.70/MWh to $4.70/MWh higher than the LCOEs without storage.

Mr. Augustine provided a comparison of the LCOEs of the various tranches, with and without battery storage. He stated that this adjustment may be considered conservative, since the long-term price of available capacity could be higher than the values assumed in the 2018 IRP (reaching only approximately $2/kW-month in real 2017 dollars over the long-term forecast horizon), especially as market rules evolve. In fact, he stated that CRA's commodity price update used in the 2020 portfolio analysis projects capacity prices to be closer to $3/kW to $4/kW-month in real 2017 dollars over the 2030-2040 time period. He noted the adjustment also does not account for any potential ancillary services value nor the potential benefits associated with mitigation against energy price volatility that storage capacity may provide over the long-term. In summary, Mr. Augustine testified that the combined 30-year LCOE of the Solar Projects was calculated to be $56.28/MWh based on the project-specific details for each project, weighted by the expected MWh of output; the comparable, storage-adjusted LCOE for the 2023 solar acquisition tranches from the 2018 IRP was calculated to be $55.07/MWh.

Mr. Augustine testified NIPSCO has consistently identified an additional cost or "premium" associated with owning an asset versus entering into a PPA when reviewing bids from the All-Source RFP and the Phase II RFPs. However, there is also value in owning generation assets, some of which can be quantified in market risk analysis and some that is not always quantifiable. He stated that NIPSCO concluded in its 2018 IRP that a mix of short-duration and long-duration resources balances near-term cost considerations with long-term market risk exposure. He noted that NIPSCO's generation transition explicitly calls for a balanced mix of ownership and PPA arrangements to not rely too heavily on one structure and that since PPAs are typically for a term of 15-20 years, heavy reliance on PPAs could lead to a large capacity need developing at a future point in time with highly uncertain replacement costs and potentially high and/or volatile market prices. He said that because owned assets typically have a life of 30 years or more, this ensures a more staggered commitment duration, which provides NIPSCO a balance between long-term price certainty and portfolio flexibility. He testified that under the Joint Ventures, NIPSCO will have operational control of the solar and storage facilities, providing a level of operational flexibility not available in a PPA arrangement, which will allow NIPSCO the future option to change the operational strategy for the batteries, for instance to participate more actively in the ancillary services markets over time, or to increase the amount of battery capacity at a future date in response to potential market rules changes and storage technology advancements.[49] He stated this level of

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48 These calculations add capacity costs to the IRP tranches such that the resulting UCAP for each MW of solar ICAP is the same as either the Bridge II Project or the Cavalry Project.

49 As explained by Witness Whitehead, ownership of the Solar Projects will also allow NIPSCO to offer employment opportunities to current NIPSCO employees who will be impacted by the retirement of NIPSCO's coal-fired generation stations.

operational control and flexibility is simply not available under a PPA arrangement. Finally, he explained there is a financial risk that exists throughout the entire term of a PPA because there is always a potential that the project developer could experience financial difficulty but by owning an asset, NIPSCO eliminates this financial risk associated with a PPA.

Mr. Augustine explained what the bid responses to the Phase II RFPs revealed about the evolution of PPA prices and asset acquisition costs since the 2018 IRP. He stated that generally speaking, when comparing the LCOE estimates from the 2018 IRP, which were informed by the All-Source RFP, to the LCOEs for responses to the Phase II RFPs, the LCOEs for PPAs have increased and the LCOEs for asset sales (ownership) have been relatively flat or have increased to a lesser extent. As an example, he stated that the LCOEs for two PPAs that came out of the Phase II RFPs (in Cause No. 45403) came in higher than the IRP estimates. However, the LCOEs for the Solar Projects are much more in line with the IRP LCOE estimates for the respective tranches, which indicates that the "premium" between ownership and PPA arrangements has narrowed, and it further supports NIPSCO's decision to diversify the asset arrangements it is pursuing under its generation transition plan. He illustrated how the LCOE values for the solar resource tranches incorporated in the 2018 IRP's preferred portfolio compare to the LCOEs for each of the Joint Ventures.

Mr. Augustine testified the operational and cost characteristics of the Joint Ventures are generally with the assumptions for new solar resource asset sales used in the 2018 IRP, which developed a preferred portfolio with approximately 2,300 MW (ICAP) of solar additions in the 2023 time period, the direction of which was confirmed by NIPSCO's 2020 portfolio analysis. He compared the costs of the Solar Projects to the costs of the comparable IRP asset sale tranches, resulting in the weighted average cost of the three projects being approximately $1.20/MWh higher than the comparable asset sale tranche from the 2018 IRP, when including storage adjustments. He stated the Short-Term Action Plan called for acquiring such solar and solar plus storage projects by 2023 in order to produce substantial savings for NIPSCO's customers versus the alternatives and that the Joint Ventures provide NIPSCO with additional flexibility to manage operations and optimize the generation sites in the future as market rules change and battery storage technology evolves. Thus, Mr. Augustine testified, the addition of the Joint Ventures to NIPSCO's portfolio in 2023 is fully supportive of and consistent with the conclusions of the 2018 IRP and the recommended Short Term Action Plan.

(d) <u>Lee Direct Testimony.</u> Mr. Lee explained the analysis NIPSCO used to evaluate its various options for solar and solar plus storage energy and why NIPSCO's investment in the Joint Ventures 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 MW targets for each resource type (solar, wind, other) were derived from the preferred portfolio in NIPSCO's 2018 IRP. He stated the specific assets recommended for advancement were selected based on the scoring criteria for the Phase II RFPs, which were developed in advance of the RFP processes.

Mr. Lee sponsored <u>Confidential Attachment 4-D</u>, which includes the detailed scoring results for each project bid into the RFP. He stated that consistent with the Phase II RFPs process rules, each project was evaluated based on development risk, reliability, asset-specific risk, and the estimated LCOE per MWh.

Mr. Lee provided an overview of NIPSCO's 2018 IRP and All-Source RFP. He said in 2016, NIPSCO conducted an RFP 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 in 2018, NIPSCO conducted the All-Source RFP and, through that 2018 All-Source RFP, secured a portion of the capacity required to meet the needs of the resource requirement identified in the 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 Phase II RFPs were intended to secure the remainder of NIPSCO's capacity needs for 2023 and that his role was to help design and administer both the All-Source RFP and Phase II RFPs processes.

Mr. Lee discussed the IRP process conclusions and NIPSCO's preferred plan. He stated the 2018 IRP considered a range of options around the potential retirement of existing NIPSCO fossil generation facilities and also developed an optimal portfolio of assets based on detailed scenario and risk analysis and was informed by comprehensive market modeling. He stated the magnitude of the 2023 resource need was directly dependent on the conclusions derived from the 2018 IRP. He illustrated the NIPSCO supply stack versus the resource requirements for 2023 under a range of potential retirement scenarios for Schahfer and Michigan City based on that IRP analysis. He testified NIPSCO's 2018 IRP results indicated that the optimal path forward includes the retirement of Schahfer Units 14, 15, 17 and 18 by 2023 and the retirement of Michigan City Unit 12 by year-end 2028. He explained that given the retirement analysis conclusions included in the 2018 IRP, NIPSCO's resource requirements were greater than the approximately 600 MW of UCAP initially identified in the 2016 IRP and identified the composition of the optimal portfolio.

Mr. Lee said through the Phase II RFPs, NIPSCO sought to identify the discrete capacity resources best positioned to satisfy the anticipated capacity shortfall consistent with both the 2018 IRP analysis and each RFP's bid selection criteria. He said NIPSCO considered a wide range of asset types, including physical generating assets and PPAs. Mr. Lee stated that through the process, NIPSCO received bids supported by renewable facilities, fossil resources, and energy storage options and that bids for both standalone assets and integrated facilities 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 2018 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 Phase II RFPs were issued on October 1, 2019 as three separate but concurrent process: one for solar, one for wind, and one for other resources and CRA conducted a bidder conference on October 1, 2019. He said prospective bidders were required to provide a Notice of Intent, Bi-lateral Confidentiality Agreement and Pre-Qualification Application due on October 16, 2019, with final proposals due on November 20, 2019.

Mr. Lee provided an overview of the Phase II RFPs design and execution. He stated that prior to issuing the Phase II RFPs, 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, ensure the product requested was clearly defined, and ensure the evaluation criteria were clearly specified in the RFP documentation for each of the three RFPs.

Mr. Lee explained how CRA and NIPSCO informed interested parties about the Phase II RFPs. He stated that CRA managed the outreach to potential bidders interested in the processes and worked with NIPSCO to identify existing assets and projects in-development located within LRZ6. He said representatives from potential bidders were contacted via electronic mail notices and phone calls, informing them of the RFPs and relevant due dates and that both NIPSCO and CRA participated in a public information session to inform interested parties about the opportunity. In addition, he explained CRA ran trade press advertising in Megawatt Daily on September 24, 2019, NIPSCO published a press release related to the RFPs on its website on September 30, 2019, and other industry news sources carried stories on the processes and NIPSCO's capacity targets coincident with the announcement of the Phase II RFPs.

Mr. Lee testified that throughout the processes, CRA maintained a public Information Website that warehoused all key documents related to the RFPs. He explained that through that Information Website, interested parties could submit questions and comments related to the process, the documents or any 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 RFPs. 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 Phase II RFPs generated substantial interest from bidders. He said in 2018 NIPSCO received more bids in response to its All-Source RFP than any capacity RFP he had participated in to date and that NIPSCO received a level of interest across the Phase II RFPs consistent with the level realized in NIPSCO's 2018 All-Source RFP. Mr. Lee noted CRA received 96 proposals supported by 93 individual projects from more than 40 bidders across six states, characterizing all of the Phase II RFPs as highly competitive. He stated that many of the PPA proposals included fixed or variable pricing arrangements or had 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, over 18 gigawatts of ICAP was offered into the Phase II RFPs, 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 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) LCOE per MWh; (2) asset reliability and deliverability; (3) development risk; and (4) asset-specific benefits and risks. He explained that the evaluation categories were the same for all classes of bids (solar, wind, thermal, other); however, the Phase II RFPs were each separate RFPs, so solar projects were evaluated versus other solar, wind versus other wind, etc. He said the IRP process identified the preferred portfolio based on a range of market scenarios and stochastics and the IRP included aggregated tranches of technologies that captured representative project costs and market depth. He said the IRP analysis did not include a separate, detailed representation of each project bid into the RFP and that these aggregated tranches were used to identify the best portfolio of resources to meet NIPSCO's needs. He stated that because the preferred portfolio was identified in the 2018 IRP, the Phase II RFPs selected the individual projects consistent with that portfolio that best served the needs of NIPSCO's customers.

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 RFPs, the MWs 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 further testified the Phase II RFPs did not target the full required replacement capacity identified in the 2018 IRP since a portion of the resource needs were sourced through the All-Source RFP. He explained the adjustments made in the Phase II RFPs and project evaluations as a result of the Roaming Bison Project, which was a wind project that came out of the All-Source RFP but ultimately was cancelled. He explained that CRA and NIPSCO have continuously looked to improve the RFP process and that in the Phase II RFPs, the weightings for certain categories of evaluation were adjusted. He explained that the All-Source RFP awarded projects up to 200 points related to the Development Risk evaluation category with the points equally split across the specific milestones met towards the Commercial-in-Service date and the experience of the developer in MISO. For Phase II RFPs, CRA increased the points available for that evaluation category to 250 points, with all of the incremental 50 points assigned to the development milestones element of the scoring. He stated the effect of this change was to favor existing projects or projects further along the path towards their commercial operation date. Additionally, he stated a greater number of points were awarded in the Phase II RFPs for the Asset Specific Benefits and Risks evaluation category with the intent of increasing the awarded points from 100 to 150 was to provide greater flexibility in selecting projects based on any unique issues related to a given project.

Mr. Lee testified CRA recommended that NIPSCO advance a set of assets to the definitive agreement phase of the process. He testified all three RFPs were performed in a transparent, fair and nondiscriminatory manner and the processes 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 any of the Phase II RFPs, nor was any advantage or preference alleged by any participant in the RFPs.

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 solar power. He noted CRA identified a set of solar projects for advancement to the definitive agreement phase, which were selected consistent with the evaluation criteria that captured the project economics, project specific risks, and benefits associated with each option. He stated these projects offer NIPSCO customers low cost, renewable energy and the associated RECs and also provide capacity in support of NIPSCO's needs. He stated CRA was very comfortable in recommending solar plus storage projects to NIPSCO. He testified the Solar Projects (including specifically the two projects that include battery storage) resulted from the competitive Phase II RFPs, and as part of the Phase II RFPs, CRA performed extensive review and diligence on all submissions and scored each proposal based on development risk, reliability, asset-specific risk, and the estimated LCOE per MWh. He explained that with respect to the development risk and asset-specific risk, CRA evaluated projects related to their progress towards their commercial-in-service date, the experience the developer has in MISO, and any unique issues or benefits a given project may have had. He stated the development risk category was very clearly defined, with consideration of five milestones, and points were awarded to projects that achieved one or more of them. In addition, he stated that scoring recognized that some developers may have more experience with developing projects in MISO than others and that experience may mitigate some development risk even if all milestones have not yet been achieved. He said that as a result, scoring considered the MWs of developer experience in the region, which was an area where NextEra was particularly strong given their experience in the region and across the United States.

Mr. Lee explained that by design, the asset-specific risks and benefits category of scoring was less proscriptive since it was intended to provide flexibility on scoring. He stated that given the wide range of project and the various counterparty issues that can arise in a broad solicitation like NIPSCO's All-Source and Phase II RFPs, it is critical to include a mechanism to maintain flexibility; however, the RFP Appendix F identified certain issues that could be considered through the category, including minority business enterprise considerations or any material cost or regulatory uncertainty associated with a specific asset. He testified that for solar plus storage projects, CRA evaluated the projects versus standalone solar based on the project economics and the evaluation criteria outlined in Appendix F to the RFP. He said that project economics relied on an LCOE framework, and project risks were considered through each of the Evaluation Criteria categories. He stated that the RFP advanced projects to a final Definitive Agreement Phase, and during that phase a final determination was made on any optional project aspects like storage flexibility.

Mr. Lee testified all Indiana solar and solar plus storage projects were not considered equal priority. He explained that part of the value offered by solar resources relates to ITC that are a function of the date a facility begins construction and ultimately goes into service. He said solar resources that have incurred a certain level of construction expense by 2019 and can meet a 2023 in service date qualify for the maximum tax credits and prioritizing and supporting projects to help them meet the deadlines for maximum ITC qualification would be a consideration. Mr. Lee explained that in addition, certain assets were prioritized by NIPSCO due to resource constraints NIPSCO faces for finalizing commercial negotiations. He stated that assets with a common developer or counterparty were grouped together to facilitate an efficient Definitive Agreement process. He testified the Solar Projects have a common developer – NextEra. He stated that in total, NextEra is involved with six of the solar or solar plus storage projects prioritized by NIPSCO, accounting for approximately 1,400 MW (ICAP).

Mr. Lee explained how NIPSCO evaluated the bids 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 also explained why CRA valued the RECs qualitatively rather than quantitatively in some detail. 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.

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 levelized cost per MWh of each bid received and that the levelized cost was considered in two ways. First, he explained the levelized cost was considered over the duration of the bid. This means for a 15-year PPA, the 15-year LCOE was considered, while for a 20-year PPA, the 20-year year LCOE was considered. Next, he explained the LCOE was considered for all assets over 30 years. For shorter-term options, the balance of the 30 years was filled in with market purchases at market prices consistent with IRP modeling. He stated the two-phased LCOE analysis allowed CRA to compare all assets over a consistent time horizon without missing short-term opportunities that may offer a good value to customers.

Mr. Lee described how NIPSCO evaluated the difference in value offered through asset ownership BTA versus a PPA. He stated that for all assets, including those offered under a BTA, the explicit LCOE period was 30 years from the anticipated commercial operation date of the facility or the commencement of any PPA. The 30-year period facilitated the analysis of the value of owning an asset versus entering into a finite power purchase agreement. Assets offered under a BTA arrangement, however, would provide economic value to NIPSCO customer beyond the typical term of a PPA. As a result, the LCOE for BTAs captured the residual value beyond the normal term of a PPA.

Mr. Lee described how the LCOE was calculated over 30 years for shorter duration assets. He explained that for shorter-term assets, the balance of the 30-year period would require market purchases to create a package of assets with a comparable term for analysis. He stated the 30-year analysis period did not provide an advantage to longer-term assets. He explained that the LCOE was evaluated in two ways. First, a full 30-year LCOE was quantified. Next, an LCOE was calculated over the term of the offer provided. For example, if a 15-year PPA was offered, CRA calculated the 15-year LCOE for the asset, as well as the full 30-year LCOE. He stated points were awarded based on the 30-year LCOE and the asset life LCOE as well. He said the intent of performing the asset life LCOE was to identify any short-term assets that may provide value to customers.

Mr. Lee testified the proposed Solar Projects are economic options for meeting NIPSCO's retail electric load. He stated the 2018 IRP identified that based on the current market economics and outlook, solar power represents an excellent resource option for NIPSCO and its customers over the expected useful life of the new facilities. He testified that the Solar Projects were some of the highest scoring solar projects overall based on the evaluation criteria used for scoring the All-Source RFP bids.

Mr. Lee described the conclusions from the evaluation of the Solar Projects proposal. He stated NextEra offered the Bridge I and Bridge II Projects under several different configuration options that provided NIPSCO flexibility on the project scale, commercial operation date, and transaction structure. The facility received the maximum number of points for reliability as NextEra had performed extensive transmission reliability analysis. The Projects scored favorability on development risk as well. He explained that NextEra has significant development experience in MISO and more broadly and that NextEra has also achieved site control for both the Bridge I and Bridge II Projects. He stated no asset specific issues were identified for the Projects, so they received full credit for that category. He stated the Cavalry Project was one of the top scoring projects of all the solar options received under the Phase II RFPs. As was the case with most or all NextEra projects, the Cavalry Project received the maximum number of points possible for the reliability category due to the transmission analysis done by NextEra. He said the Project had achieved site control and completed certain zoning requirements and that combined with NextEra's development experience, the Project scored well on the development risk measure. He stated the Project showed strong economic results based on the LCOE analysis as well, and there were no asset specific issues identified.

Ms. Lee also described the bid score for a thermal PPA bid that resulted in a portfolio with gas capacity being cost-competitive with portfolios made up of only renewables and storage. He explained that the bid was a middle-of-the-pack thermal resource based on the RFP scoring. He said the proposal lost points on both the development risk and reliability evaluation criteria and that the development risk scoring category considered two aspects of project risk: progress towards meeting its in-service date and the experience of the developer with projects in MISO. He said the milestones were selected to measure broadly the project's progress towards meeting its in-service date. He explained that of the five, the thermal resource in question had only achieved a single milestone. In addition, the developer had fewer MWs in service than some other participating bidders. He stated the proposal also lost points for not having completed an (N-1-1) reliability study for the project.[50] Therefore, the bid associated with this thermal project may not be as attractive an option as other thermal resources or other non-thermal resources.

(e) Plewes Direct Testimony. Mr. Plewes discussed and sponsored Attachment 5-A, a report on the economic contributions of employment and spending related to the Solar Projects ("Economic Impact Report"), and explained the methodology used in his analysis. He testified the Economic Impact Report is focused on the benefits from the employment and expenditures related to the Solar Projects during their construction and during operations but does not assess the benefits that result from the electricity generated by the Solar Projects. He stated he evaluated benefits at the Indiana state level, although many of the benefits will accumulate at the county level.

Mr. Plewes testified the benefits of the Solar Projects derive from two main phases for each project: the construction phase and the operating phase. He stated that during both phases, sources of benefits can be categorized as direct (Indiana-sourced direct labor and on-site contractor labor), indirect (include spending on materials and services with Indiana-based supply chains), or induced benefits (include multiplier benefits throughout Indiana, as workers spend their income and as local and state governments spend tax revenues).

Mr. Plewes explained the economic contributions of the construction phase of the Solar Projects derive from total planned capital expenditures of over $1 Billion. He stated these benefits are larger in scale than operating phase benefits, although shorter in duration, occurring over approximately 15 months on average. He estimated cumulative impacts during 2022 and 2023, which are the primary construction years for the three Solar Projects, as one is anticipated to go into service in late 2022 and the other two in late 2023. He said that during construction, the Solar Projects will directly provide nearly 620 full-time equivalents ("FTEs") in employment to Indiana workers noting that the workers that provide these FTEs will earn $55 Million in income. He testified that after all indirect and induced benefits are considered, the Solar Projects will contribute 2,480 FTEs that will earn $160 Million in earnings, and the total impact on Indiana Gross State Product ("GSP") is expected to be $230 Million.

Mr. Plewes explained the economic contributions of the operating phase of the Solar Projects. He stated the annual operating phase benefits are smaller in scale than benefits during the construction phase, but they are highly impactful since they occur annually for the duration of the Solar Projects' asset lives and are highly concentrated in the counties where the projects are located. He said that during operations, the Solar Projects will directly provide approximately 23 FTEs in ongoing employment to Indiana workers, mostly related to O&M activities. He explained that the workers that account for these FTEs will earn $1.9 Million in income annually. He testified that after all indirect and induced benefits are considered, the Solar Projects will annually contribute 167 FTEs that will earn $9.9 Million in earnings, and the total impact on the Indiana GSP is expected to be $17 Million per year. He stated that in total, over the 30 years of operations of the

[50] An N-1-1 contingency analysis studies the impact of a sequence of events consisting of the initial loss of a single generator or transmission component followed by system adjustments, followed by another loss of a single generator or transmission component.

Solar Projects, the economic contributions are anticipated to total approximately $297 Million in earnings and more than $510 Million in impact to the Indiana GSP.[51]

Mr. Plewes explained that the difference between the ratio of direct impacts to total impact between the construction phase and operating phase is that the operating phase has a larger share of estimated impacts in the induced benefits category due to the significant property tax and land lease payments that drive induced benefits as local governments and landowners spend their additional revenues in the Indiana economy. He stated the Solar Projects will contribute over $85 Million in property taxes paid to local governments over their operating lives, including $59 Million to Jasper County and $25 Million to White County and that land lease payments are also significant and are expected to be in the millions of dollars each year.

Mr. Plewes noted that as plans for the Solar Projects evolve, such as making final decisions on the hiring of direct workers and the sources of materials, the expected economic impacts may change from his estimates; however, the estimates he provided in the Economic Impact Report are reasonable, as they are based on the best available information. He stated that although the estimates of benefits could increase or decrease over time, he does not expect that they would change drastically. He also noted that it is possible that the economic impacts will be higher if additional solar projects are approved beyond this proceeding, which could lead to creating sufficient regional scale for local Indiana businesses to develop manufacturing and service capabilities that would keep more of the economic benefits within Indiana.

(f) <u>Brummitt Direct Testimony.</u> Ms. Brummitt described the tax structure of the Joint Ventures that provide value to NIPSCO's customers and discussed certain tax considerations that impact the type of contract NIPSCO will utilize to pay for the energy generated by the Solar Projects. She testified that NIPSCO has requested and received approval of the joint venture structure similar to the structure requested here in both the Rosewater Order and Crossroads Order. She described the difference between the approved joint venture structures stating that the joint venture structure in this filing has been simplified with the elimination of the developer becoming a member of the joint venture with the Joint Venture here simply purchasing the project from the developer.

Ms. Brummitt testified each of the joint ventures is a limited liability company that will own and operate the solar (or solar plus storage) generation assets. She stated that 100% of the energy and capacity of each project will be paid for by NIPSCO through a CFD or a PPA. She testified there will be two (or more) members in each joint venture – NIPSCO and a TEP(s).

Ms. Brummitt explained why NIPSCO is seeking approval of a CFD, as well as the BTA PPA. She stated that if the Joint Venture sells electricity to NIPSCO under the BTA PPA, the PPA can make NIPSCO and the Joint Venture each a "related party" for IRS purposes explaining that the sale of electricity generates losses at the joint venture level as a result of accelerated depreciation. She testified that under the IRS rules, a related party relationship disallows the losses created by depreciation – depreciation that is a tax incentive to invest in renewables. She stated that NIPSCO has not yet received IRS guidance on the related party matter, which means using the BTA PPA could disallow losses and change the economics of the Solar Projects and negatively

51 See <u>Attachment 5-A</u> at Table 3.

impact NIPSCO and its customers. Therefore, until IRS guidance is issued, NIPSCO must appropriately structure the proposed transactions to remove the risk of not getting the full benefit of tax losses generated at the joint venture level. She stated that because a CFD is a "financial" instead of a "physical" contract, the related party issue does not come into play, which is why NIPSCO is seeking approval of a CFD, which would be utilized if related party guidance from the IRS is not received.

Ms. Brummitt testified that in Rosewater, NIPSCO indicated it would be requesting a private letter ruling ("PLR") from the IRS on two issues: normalization and related party. She stated NIPSCO received PLR 201946007 which ruled on normalization but declined to rule on related party. She explained that the IRS will not issue a letter ruling or a determination letter if the request presents an issue that cannot be readily resolved before a regulation or any other published guidance is issued. She testified the IRS is in the process of determining if it can issue general guidance to the utility industry relating to the related party and the use of tax equity partnerships to structure renewable transactions.[52] She testified NIPSCO submitted a PLR request on April 15, 2020 for its solar renewables but the ruling has not yet been issued by the IRS, and, as noted, NIPSCO is still awaiting related party guidance. She stated that in the event that related party guidance is not received, NIPSCO is seeking approval of a CFD to purchase the energy that will be produced by the Solar Projects and sold by the Joint Venture to NIPSCO. She explained that if this guidance were provided, NIPSCO anticipates utilizing the BTA PPA, rather than the CFD ensuring NIPSCO can fully utilize tax losses related to the projects.[53]

Ms. Brummitt testified two documents control each Joint Venture – the LLC Agreement and the ECCA. She noted that Mr. Campbell sponsors Confidential Attachment 2-D, which is an example Term Sheet of a joint venture agreement. She 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 projects such as those presented here. She stated the example Term Sheet outlines all the material items that would be in an LLC Agreement. She testified that when the LLC Agreement is finalized, a copy will be filed with the Commission and shared with all parties.

Ms. Brummitt noted the LLC Agreement sets forth the terms applicable to: (1) the operation and management of joint venture and 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) conditions precedent; (7) relationship to other related documents; (8) representations and warranties of parties; (9) purchase price option; and (10) governance.

Ms. Brummitt testified the ECCA is the document that binds the TEP to invest in the Joint Venture if all conditions precedent in the BTA are met. She stated the ECCA is the document that

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52 In the transaction for the Rosewater Project, the tax equity partner was funding more than 50% of the project cost, which meant NIPSCO had less than a 50% stake in the joint venture for IRS purposes. Because of this, the Rosewater Joint Venture and NIPSCO were not considered "related parties" and could enter into a BTA PPA without running into the "related party" issue.

53 It is possible that the timing of when guidance is received from the IRS could impact NIPSCO's ultimate decision, as NIPSCO may be too far along with negotiations or signed documents to change from the CFD to the BTA PPA.

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. She stated that on the financial closing date, which will coincide with Project Mechanical Completion, the Joint Venture will acquire all of the outstanding membership interests of the ProjectCo. She said the purchase will be paid in installments, with a portion being paid at Project Mechanical Completion (which will coincide with the closing date of acquisition of the ProjectCo) and the remainder being paid at Project Substantial Completion. She stated that when the ECCA is finalized, a copy will be filed with the Commission and shared with all parties. She testified NIPSCO will be the managing member of each Joint Venture and will remain the managing member of each Joint Venture.

Ms. Brummitt noted that the Joint Ventures were formed on August 20, 2020 with NIPSCO as the sole member. She stated the TEP(s) of a particular Joint Venture will be added when that Project reaches Project Mechanical Completion and is sold to Joint Venture. She testified the Bridge I Project is expected to be completed and in-service no later than December 31, 2022, with the Bridge II Project and Cavalry Project both expected to be completed and in-service no later than December 31, 2023. She explained that the significance of the dates of completion is that the Solar Projects are expected to qualify for Section 48 ITCs as provided under the Internal Revenue Code. She testified that if the project began construction in 2019 – which each of the Solar Projects did – and is completed and in-service by December 31, 2023, the project will qualify for the 30% ITC, a significant source of value to the project.

Ms. Brummitt explained the ITC and its declining value. She stated that federal tax incentives are currently in place for solar and paired solar plus storage resources. She said that resources are eligible for an ITC, which provides a dollar-for-dollar reduction in the federal income taxes that a company claiming the credit would otherwise pay. She explained that the ITC is based on the amount of investment in solar or paired storage property and to qualify for the ITC, projects need to "commence construction" by a certain date and be put into service by a certain date. Ms. Brummitt noted that the start of construction deadline can be met as long as certain equipment purchases and development costs have been "safe harbored" by federal tax authorities. She said the safe harbor for beginning of construction is investment of at least 5% of the total project cost on or before the specified date. She stated that safe harbored projects that commenced construction in 2019 are eligible for a 30% ITC, with a step-down over time. She testified that all three Solar Projects are expected to qualify for the 30% ITC and provided the dollar amount of ITCs each Solar Project will qualify for.

Ms. Brummitt stated the CFDs and PPAs NIPSCO will enter into to become the exclusive off-taker from the Solar Projects. She noted that under the terms of an anticipated LLC Agreement, a specific percent of the ITCs and tax losses of each Project will be allocated to the TEP until such time as the TEP has achieved the negotiated IRR. She stated that when this IRR is achieved, the allocation of profits to the TEP will increase to a specific percent and then flip down a specific percent, and the allocation of losses to the TEP will decrease to a specific percent. She testified that NIPSCO projects that 100% of the ITCs will have been generated and distributed prior to reaching this point.

Ms. Brummitt explained that cash investments will be made in installments. She explained the TEP will provide 20% of its overall committed investment when the projects reach Project Mechanical Completion, with the balance of its investment being paid at Project Substantial

Completion. She stated that at this time, the TEP is anticipated to provide cash equal to a specific percentage of the purchase price of each respective Project, and NIPSCO will provide the remaining cash required to make up the purchase price.

Ms. Brummitt testified that other than accounts payable and operating lines of credit, the Joint Ventures will not have any short- or long-term debt on their balance sheets. She testified that TEP brings financial efficiency to the projects by virtue of its ability to utilize the tax attributes on a more accelerated basis than NIPSCO. In essence, the tax equity partner is monetizing the tax attributes of the Solar Projects.

Ms. Brummitt explained why the TEP is able to utilize the tax attributes more efficiently than NIPSCO. She testified that NIPSCO is 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. She 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 accumulated by the project. She 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 customers) while still allowing NIPSCO to obtain 100% of the non-tax ownership attributes of the project.

Ms. Brummitt 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. She 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 projects for the remaining ownership interest.

(g) **Camp Direct Testimony.** Ms. Camp explained NIPSCO's proposed accounting treatment for its investment in Joint Venture. She testified NIPSCO proposes that its costs to invest in Joint Ventures 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 such costs, which are recorded as a regulatory asset, would be amortized over the life of the Solar Projects, which is currently estimated to be 30 years for each of the Solar Projects. She stated amortization of the regulatory asset associated with each Solar Project would begin once each Solar Project goes into service, which will be shortly after the closing on the BTA related to that project.

Ms. Camp described the authority NIPSCO is seeking with respect to the deferral of amortization expense and the accrual of PISCC. She explained that the regulatory asset will consist of NIPSCO's investment in the Joint Ventures. Over time, NIPSCO will make different capital contributions to the Joint Ventures. For instance, a significant contribution will be made at or about the closing on each BTA. 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 each of the Solar Projects. She said that, with respect to each capital contribution it makes to the Joint Ventures, 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 Solar 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 Ventures and deferred amortization, with such PISCC accrued at NIPSCO's 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 Solar Projects.

Ms. Camp testified NIPSCO is seeking to utilize the Joint Ventures for the benefit of customers and explained the accounting and ratemaking treatment NIPSCO is seeking for its investment in the Joint Ventures. She specifically discussed how the treatment NIPSCO is seeking for deferral of amortization and accrual of PISCC is similar to the regulatory treatment that would be afforded NIPSCO if it were the initial owner of the asset, as NIPSCO should ultimately be allowed to end up in a similar position with regard to costs related to investment in the Joint Ventures. She said the transaction is being pursued through three Joint Ventures to provide value to NIPSCO's customers by monetizing the ITCs, which can only be done by structuring the transactions in this fashion, but it will result in NIPSCO having an investment in the Joint Ventures rather than in utility plant. She explained NIPSCO needs the opportunity to earn a full return on its costs incurred to invest 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 ITCs would be significantly diminished. NIPSCO's investment in the Solar Projects under the traditional approach would be higher, reflecting the full purchase price under the BTA. She stated this is consistent with what NIPSCO requested and the Commission approved for Rosewater and Crossroads.

Ms. Camp testified that NIPSCO requests that the retail jurisdictional portion of the costs incurred pursuant to the Solar Offtake Agreements be recovered on a timely basis through retail rates over the term of the Solar Offtake Agreements. Witness Campbell describes that NIPSCO will receive payments as an owner of each 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 Solar Offtake Agreements, which is anticipated to be through the FAC. She said NIPSCO requests the Commission authorize NIPSCO to recover the costs of the Solar Offtake Agreements, as well as all associated MISO costs, from retail customers through the full term of the Solar Offtake Agreements 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 Solar Offtake Agreements 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 Solar Offtake Agreements 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 Solar Offtake Agreements as a separate line item for each type of project; that is, there will be line entry for wind energy purchases, wind joint venture purchases, solar energy purchases, and solar joint venture purchases. She explained that although NIPSCO is anticipating 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 Nos. 45194, 45195, 45196, and 45310. 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 Ventures' 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 Ventures. 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.

Ms. Camp testified NIPSCO's current proposal includes modifications to what NIPSCO initially proposed in Rosewater and Crossroads. She explained that to address concerns raised by the OUCC in those previous proceedings, in rebuttal NIPSCO proposed that the Commission approve eight "conditions" as part of the approval of those transactions, which the Commission ultimately approved. In addition to the five of conditions addressed by Mr. Campbell, Ms. Camp addressed two of those conditions as follows:

> First, NIPSCO will continue to treat its investment in the Joint Ventures as a regulatory asset with NIPSCO booking amortization instead of depreciation, even after such time as the TEP's portion of the project has been acquired by NIPSCO. The value to be included in rate base will be determined in a base rate case at the time of acquisition or in the next base rate proceeding following acquisition. Amortization of the regulatory asset will commence as of the in-service date of the Solar Projects. NIPSCO will 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.
>
> Second, NIPSCO will not record and accumulate on its books and records either the Solar Project revenues or the Joint Venture expenses. Instead, those revenues and expenses will be maintained by the Joint Venture, tracked and reviewed by NIPSCO and the OUCC, and subject to an independent audit. This is inclusive of any subsequent investments (cash contributions) NIPSCO makes into the Joint Venture.

10. **OUCC's Case-in-Chief.** The OUCC presented the testimony of Peter M. Boerger, Ph.D., Senior Utility Analyst; Lauren M. Aguilar, Utility Analyst; Anthony A. Alvarez, Utility Analyst; and Wes R. Blakley, Senior Utility Analyst, all in the Electric Division of the OUCC.

Dr. Boerger concluded Joint Petitioners have not provided sufficient evidence to allow the OUCC to reach a conclusion as to the reasonableness and necessity of the Solar Projects presented for approval. He stated that while he did not argue NIPSCO provided insufficient evidence for approval of the Brickyard and Greensboro Projects in Cause No. 45403, he did raise concerns about the economics of the proposal, but despite those concerns he did not oppose approval of the projects on economic grounds. He stated that the Solar Projects represent about three times the capacity of the Brickyard and Greensboro Projects and that this proceeding is for an ownership investment.

Dr. Boerger testified that while he appreciated the additional modeling NIPSCO performed and, to NIPSCO's credit, NIPSCO attempted to address the issue of reduced capacity accreditation for solar resources that he raised relating to the Brickyard and Greensboro Projects, there were other significant changes to the modeling assumptions, including a large drop in load related to Rate 831. He also stated that it appears that NIPSCO presents some changes to its modeling approach that were not previously presented or reviewed. More importantly, he stated that the totality of the changes cannot be properly reviewed under the constraints of the statute (Ind. Code ch. 8-1-8.8) allowing only 120 days for the Commission to issue its order.

Dr. Boerger testified that the OUCC is also concerned that other significant changes have arisen since 2018 that were not made to NIPSCO's modeling. For instance, while NIPSCO reported the effect of Rate 831 on its forecasted load, there have likely been other changes in expected load since 2018. Also, while NIPSCO modeled the effects of expected reductions in solar capacity accreditation, there are other lessons to be learned from ongoing MISO initiatives pertaining to the effects of increasing levels of intermittent resources that should be modeled, as well as information from sources other than MISO regarding the rapidly evolving energy sector. His conclusion was that based on his developing understanding of all these changes, NIPSCO's 2018 IRP is no longer a valid foundation for making decisions regarding implementation of the Short-Term Action Plan. As such, updates to the modeling that were performed by NIPSCO and reported in this filing, relying on a new invalid foundation, cannot reasonably form the basis for resource decisions at this time. He also stated that based on the scope changes made to the 2018 IRP in this proceeding, the absence of workpapers relevant to the updated assumptions and modeling[54] and the limited amount of time to evaluate such workpapers in this statutorily time-constrained proceeding, the OUCC is unable to properly evaluate the evidence NIPSCO presented regarding its updated modeling, nor judge its reasonableness and the necessity of the resources that the updated modeling supports.

Dr. Boerger stated that NIPSCO has not provided sufficient evidence to show its proposed investments are reasonable and necessary explaining that given three years have elapsed since the 2018 IRP, and given the major changes happening in the electric utility industry, NIPSCO must perform a comprehensive update of its IRP modeling and provide sufficient time for the OUCC

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[54] In his corrected testimony, Dr. Boerger acknowledged NIPSCO had provided access to Mr. Augustine's work papers for the 2020 portfolio analysis on December 3, 2020.

and other stakeholders to review the modeling and until that is done, there no not be sufficient evidence to judge the reasonableness of NIPSCO's resource expansion proposals.

Dr. Boerger also stated that NIPSCO "stepped out" in its 2018 IRP by proposing such a large shift from thermal to renewable resources that shifted people's perceptions of what was, and is, possible for a utility dominated by coal-fired generation. He testified that the OUCC has been supportive of NIPSCO's renewable additions, with the caveat of some concerns about some choices NIPSCO made pertaining to those resource additions. He stated the OUCC does not oppose NIPSCO continuing to shift toward renewable resources and recognizes, as a leader in this area, NIPSCO faces some risks and possible additional costs, with the end result being a more environmentally friendly utility. He said it would be a mistake to expect a bold plan of action can be implemented without some need for reevaluation and updating, and those changes should be especially considered prior to major capital investments, such as those requested in this proceeding. He also noted that Congress just recently reauthorized tax credits for solar facilities and NIPSCO is about to begin its 2021 IRP process.

Ms. Aguilar stated the OUCC wants to ensure Joint Petitioners are held to their representations if they implement the CFD instead of a BTA PPA. She said that although Joint Petitioners say the dollar flows under the CFD and BTA PPA result in the same ultimate charge credited to or recovered from NIPSCO's customers, this is only one of two instances of which she is aware of a joint venture arrangement seeking a CFD before the Commission. Therefore, in examining costs through NIPSCO's FAC, if it is determined the CFD produces a result different from what the BTA PPA would have produced that negatively impact customers, NIPSCO should not be allowed to collect the difference from its customers.

Ms. Aguilar discussed a term included in the BTA that was not included in the joint venture arrangements previously approved by the Commission (Rosewater and Crossroads), which affects the evaluation of the Solar Projects and, in her opinion, brings additional ratepayer risk. The OUCC also made a confidential recommendation related to the cap on cost recovery discussed on pages 56-57 of Mr. Campbell's direct testimony.

Ms. Aguilar testified that although the OUCC cannot properly evaluate the cap amount proposed by Mr. Campbell to determine if it is reasonable, the OUCC concludes that any cap should be applied at the per project level and not pooled under one cap amount. She explained that should one or more project(s) fail to reach commercial operation the pooled cap would be unbalanced and NIPSCO could obtain a windfall.

Ms. Aguilar discussed issues to be addressed in future filings. She stated that the OUCC has not had the opportunity to review evidence regarding whether NIPSCO will maintain declination of jurisdiction once the Joint Ventures purchase the Solar Projects (as none have been submitted) and is reserving the right to review and provide testimony addressing this issue in the separately-docketed procedure NIPSCO agreed to file upon its decision to purchase the TEP interest.

Ms. Aguilar supported Dr. Boerger's testimony that the OUCC cannot make a recommendation at this time; however, should the Commission grant Joint Petitioners' request, she identified additional risk to ratepayers in these joint venture arrangements that were not present in past joint venture arrangements. She concluded that ratepayers should not be held responsible for additional risk, or at least should be shielded from such risk. She reiterated that any unintended negative consequences produced by using CFD rather than a BTA PPA should not be recoverable from ratepayers through the FAC (or any other means of recovery) and made a recommendation about any potential modifications related to the confidential provisions contained in Section 5.14.16 of the BTAs.

Mr. Alvarez supported Dr. Boerger's testimony that the OUCC cannot make a recommendation at this time; however, should the Commission grant Joint Petitioners' request, he took issue with potential costs for the Solar Projects to interconnect to the MISO transmission grid.

Mr. Blakley summarized Joint Petitioners' requested accounting and ratemaking treatment and cost recovery. He stated it is important that NIPSCO's investment in the Joint Ventures remain as a regulatory asset. He explained that if NIPSCO's investment is transferred to plant accounts, it will be depreciated and the depreciation expenses would then be included as a deduction in NIPSCO's tax returns, which would not be appropriate.

Mr. Blakley supported Dr. Boerger's testimony that the OUCC cannot make a recommendation at this time; however, should the commission grant Joint Petitioners' request, he recommended the Commission require all Joint Venture assets be treated as a regulatory asset and allow NIPSCO to include only the amount of net original cost it has invested in the Solar Projects in any future rate case after NIPSCO purchases the TEP's interest in the Joint Ventures.

11. NIPSCO's Rebuttal Testimony. NIPSCO witnesses Whitehead, Campbell, and Augustine filed testimony in rebuttal to the testimony of the OUCC.

(a) Whitehead Rebuttal. Ms. Whitehead explained the appropriate framework under which the Commission should evaluate the Solar Projects; how NIPSCO's evidence submitted in its case-in-chief provides a sufficient evidentiary basis to approve the Solar Projects; and the implications if the Commission were to follow the OUCC's proposed path and require NIPSCO to perform new IRP analysis before seeking approval of any generation projects. She also discussed NIPSCO's proposed ratemaking and accounting treatment and clarified that there appears to be agreement with the OUCC on this matter.

Ms. Whitehead testified NIPSCO, in coordination with CRA, submitted a well-received IRP in 2018, completed in conjunction with the All-Source RFP, which allowed NIPSCO to incorporate real-world market data and conditions in the 2018 IRP. She stated the 2018 IRP demonstrated an opportunity to transition NIPSCO's resource portfolio in a manner that would create significant customer savings, in part by taking advantage of available tax incentives. She explained that under the Short-Term Action Plan, NIPSCO began negotiating with wind projects coming out of the All-Source RFP. She said that as explicitly contemplated by the Short-Term Action Plan, in late 2019, CRA issued and administered the Phase II RFPs for NIPSCO, which were completed in early 2020, at which time NIPSCO began negotiations with the preferred projects identified by CRA in the Phase II RFPs. Ms. Whitehead testified that those negotiations ultimately resulted in NIPSCO coming to terms with several solar and solar plus storage projects, including the Greensboro and Brickyard Projects recently approved in Cause No. 45403, the Solar Projects presented here, and two additional projects in Cause Nos. 45472 (Green River) and 45489

(Gibson). She explained that NIPSCO has submitted projects to the Commission shortly after the completion of commercial negotiations, generally within a couple months (beginning in mid-2020 and continuing through early 2021) in an attempt to allow the Commission and all interested stakeholders to complete their review as timely as possible. She testified that throughout this time, NIPSCO has continued to monitor industry trends and market developments, including at MISO, and in executing the Short-Term Action Plan, NIPSCO has been responsive to market changes. She stated that NIPSCO also took the additional step of performing updated IRP modeling in early 2020, informed by the results from the Phase II RFPs in the form of the 2020 portfolio analysis.

Ms. Whitehead stated that while she understands why the OUCC would have compared the Wind Transactions (Rosewater and Crossroads) to the Solar Transactions here, the Commission reviews proposed resources to determine if they are consistent with the utility's IRP and if the costs are the product of a competitive process. She stated that the Solar Projects are part of the Short-Term Action Plan that implements the 2018 IRP and leverages a highly-competitive RFP process. As a result, NIPSCO has provided substantial analysis and market evidence in this proceeding supporting the Solar Projects. She explained that, if a comparison is to be made to other resource alternatives, rather than referencing a different resource, such as wind projects, the more appropriate way for the Commission to evaluate the Solar Transactions is by comparing them to a scenario where NIPSCO was to build (or purchase) and then own and operate a solar resource on its own, and then to make an informed and evidence-based judgment as to whether the Solar Transactions are reasonable in comparison. She explained that in a more traditional setting, where NIPSCO was building a project or buying it outright, there would undoubtedly be some cost risk for NIPSCO, and by extension, its customers. She noted that under Ind. Code ch. 8-1-8.5, there are provisions allowing for ongoing reporting on generation station construction and the opportunity to return to the Commission for recovery of costs beyond the initially-approved cost estimate. She said that under the Ind. Code ch. 8-1-8.5, NIPSCO would be issued a CPCN if the Commission made the required findings in response to NIPSCO's initial application, including that NIPSCO had provided the "best estimate" and the project was consistent with NIPSCO's IRP. She explained that under Ind. Code §§ 8-1-8.5-5.5 and 5.6, there is a process for the Commission to monitor and review construction of a project that has been granted a CPCN, including a process for reviewing cost overruns. NIPSCO would not necessarily be held to the initial "best estimate" and would have an opportunity to recover increases in the project cost. Instead, if NIPSCO were to encounter cost overruns and they were found to be reasonable during the Commission's ongoing evaluation, NIPSCO would be able to recover such costs. This is not an automatic or guaranteed recovery, but it presents an opportunity for demonstration of the reasonableness of cost increases. The opportunity for ongoing cost review and recovery recognizes that such complex projects can result in cost increases for any number of reasons and that the utility should have the opportunity to demonstrate such increases are reasonable. It is not uncommon for utilities to recover cost increases, rather than being locked into the initial cost estimate and being completely at risk for future increases.

Ms. Whitehead also testified about certain confidential commercial provisions included in the BTAs, which were further explained and justified in Mr. Campbell's rebuttal testimony, as discussed below. She noted that NIPSCO has negotiated in good faith with NextEra and was able to secure terms and conditions that protections and/or mitigate risk for the benefit of NIPSCO's customers. She testified how the agreed-to cost of the Solar Projects are the result of market-based RFPs, which were run and evaluated by an independent third party, CRA and how the OUCC has not challenged the Phase II RFPs, the costs coming of these RFPs, or the overall economics of the Solar Projects proposed in this proceeding. Despite all of this, the OUCC is not satisfied. According to Ms. Whitehead, the OUCC now, in essence, asks that NIPSCO's shareholders be at risk for all, or at least most of, potential increases in the amount that may be owed to NextEra, which would not be the case if NIPSCO were to build the solar generation on its own. This would not be appropriate, especially considering that NIPSCO has voluntarily agreed to caps on certain costs in order to further insulate customers from risk.

Ms. Whitehead continued by discussing how NIPSCO's evidence was sufficient, and in fact was more robust that the evidence presented in prior renewable generation CPCN requests, which all had been approved by the Commission. This evidence falls into two general categories: analysis of the economic impact of the Solar Projects, provided by Ms. Whitehead and Mr. Plewes,[55] and updated IRP modeling, provided by Mr. Augustine. She explained that NIPSCO provided this additional evidence because the Solar Projects represent a significant, long-term investment by NIPSCO and they are some of the earliest utility-scale solar projects presented by a jurisdictional utility in Indiana; therefore, NIPSCO wanted to ensure awareness about the significant benefits to the local economies and Indiana economy from the Solar Projects, including in some of the areas where NIPSCO's retiring generation is located. While Mr. Augustine explains the reason NIPSCO provided the 2020 portfolio analysis and what all it entailed, Ms. Whitehead testified that NIPSCO's petition in this proceeding was filed under Ind. Code § 8-1-8.5-5(b)(2)(B), which requires a utility's proposal to be consistent with a utility specific proposal under Ind. Code § 8-1-8.5(3)(e)(1). Quoting Ind. Code § 8-1-8.5(3)(e)(1), she noted that a utility is allowed to "submit to the commission a current or updated integrated resource plan as part of a utility specific proposal as to the future needs for electricity to serve the people of the state or the area served by the utility." This is what NIPSCO has done through the 2020 portfolio analysis.

Ms. Whitehead also testified that NIPSCO's 2018 IRP is still a valid foundation upon which to base resource decisions for at least three reasons: (1) the 2018 IRP process, which occurred in concert with the All-Source RFP, was robust and well-developed, ultimately resulting in the Short-Term Action Plan and has been well-received, including in the Director's Report; (2) the Commission has repeatedly relied upon the 2018 IRP in approving multiple clean energy projects that resulted from one of the RFPs completed in conjunction with the IRP or contemplated by the Short-Term Action Plan, including as recently as January 27, 2021 in the Commission order in Cause No. 45403 approving a pair of PPAs; and (3) NIPSCO voluntarily undertook the additional effort and expense to perform the 2020 portfolio analysis and then presented its results in support of its Verified Petition in this proceeding, which was directly in response to criticisms from the OUCC in Cause No. 45403.

In response to the OUCC's complaint that the statutory 120-day procedural schedule in this proceeding does not provide sufficient time for the OUCC to form an opinion of the reasonableness of NIPSCO's request, Ms. Whitehead stated that NIPSCO has done its best to work with the OUCC to assist in its review of the evidence presented in NIPSCO's case-in-chief—such as providing thorough discovery responses, being available for informal discussions, and even not opposing the OUCC's request for an extension to file its testimony. She also noted that the OUCC did not submit

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[55] This includes testimonial evidence and the report titled "Economic Impacts of NIPSCO's Investments in Three Solar Projects with NextEra Energy Resources" included in Attachment 5-A.

a single discovery request seeking information about the 2020 portfolio analysis and Dr. Boerger did not participate in any informal discussion about it either, despite NIPSCO's offer to do so, as reflected in Attachment 1-R-A to her rebuttal testimony. She further noted that it was the Indiana Legislature, not NIPSCO or the Commission, who enacted Ind. Code ch. 8-1-8.8 and chose to include a 120-day procedural schedule in sub-section 11 to encourage the development of clean energy projects. Ms. Whitehead went on to explain the OUCC was part of the 2018 IRP stakeholder process and has repeatedly been provided the 2018 IRP analysis in prior proceedings but only now claims it is no longer a sufficient basis for project approval. Furthermore, NIPSCO's 2020 portfolio analysis was provided in response to a criticism by the OUCC in Cause No. 45403 which increased the evidence the OUCC was required to review, but directly responding to the OUCC's concerns has now somehow created too much work for them in this proceeding. In her words, "[t]he OUCC cannot have it both ways." She stated that it is reasonable to expect that the OUCC would perform a timely review of the evidence NIPSCO has submitted. All of this forms the basis for her testimony that NIPSCO has provided more evidence than in prior cases and has thus met its burden of proof and submitted sufficient evidence on which the Commission should determine that the Solar Projects are reasonable and necessary

Ms. Whitehead also testified about the implications of adopting the OUCC's proposal, which would require NIPSCO to perform completely updated IRP analysis and only then seek approval of generation resource additions. She explained NIPSCO has been very diligent in its efforts to capitalize on tax incentives through innovative ownership, develop a diverse portfolio, and negotiate risk-balanced projects with industry-leading developers and that denying approval of the Solar Projects and, in essence, requiring NIPSCO to "go back to the drawing board" for new IRP analysis would send the message that utilities can only act immediately after an IRP. This would have real-world implications for NIPSCO as it looks to replace Schahfer's retiring capacity, including eliminating three Indiana-based solar projects that will have significant economic benefits for the state and local economies, which could would harm NIPSCO, its customers, and the State of Indiana. It would also send the wrong message about whether utilities can rely on their IRPs for ongoing generation decisions—unless the decisions are concurrent with the issuance of an IRP—and whether project developers should worry about the regulatory climate in Indiana. She said this would not be appropriate, especially in light of the Commission's somewhat recent decision to require IRPs to be submitted on a 3-year cycle (instead of a 2-year cycle). NIPSCO's processes leading to these Solar Projects has been well-thought-out and appropriately timed as it transitions its resource portfolio to add diversity of resources, and to do so largely with resources located in Indiana.

She concluded by noting that there does not appear to be any disagreement between NIPSCO and the OUCC on ratemaking terms, as Ms. Camp originally proposed that NIPSCO would treat its investment in the Joint Ventures as a regulatory asset and amortize that asset over the life of the Solar Projects, which was the same proposal Mr. Blakley made.

(b) Campbell Rebuttal.

Mr. Campbell began his rebuttal testimony by noting that the OUCC is looking at the joint venture arrangements presented in this case in comparison to joint venture arrangements the Commission approved in Cause Nos. 45194 and 45310, which is not the appropriate way for the Commission to evaluate the Solar Transactions. According to him, the appropriate way for the

Commission to evaluate the Solar Transactions is by comparing them to a scenario where NIPSCO solely developed a solar resource. This is for several reasons, including that the Wind Transactions involved different generation technology and a different developer, and because the "world" is different than it was when the Wind Transactions were finalized in 2019.

In response to the OUCC's claims that the Solar Transactions include additional ratepayer risk, Mr. Campbell testified that when compared to NIPSCO self-building a solar generation asset, this is definitely not the case. Acknowledging this is not the comparison the OUCC undertook, he explained NIPSCO has worked diligently to ensure that the Solar Transactions are structured in a way to mitigate risks for NIPSCO and its customers. He concluded that the Solar Transactions are better for NIPSCO and its customers from a risk and cost perspective than if NIPSCO developed the Solar Projects on its own. He also explained that while there are indeed different terms that may have potentially *different* risks in the Solar Transactions, this does not necessarily mean there are *additional* risks for NIPSCO and its customers. NIPSCO's position is that the terms of the Solar Transactions should be evaluated by the Commission on their own merits and in comparison to a scenario where NIPSCO were to develop generation assets on its own.

Mr. Campbell also explained that partnering with a single developer for three BTAs allowed NIPSCO to streamline negotiations and resulted in NIPSCO being able to achieve risk protections spread across three transactions rather than wholly on one. He made the comparison to going to a dealership looking to buy three cars instead of one, which will lead the counter-party with whom you are negotiating to work with you in terms of price and terms and conditions.

Mr. Campbell testified in support of two provisions that addressed risk, a confidential term discussed on pages 36-37 [in Question / Answer 33] of his direct testimony challenged by Ms. Aguilar, and provisions related to the potential costs for the Solar Projects to interconnect to the MISO transmission grid challenged by Mr. Alvarez. He took issue with the implication that different terms in the Solar Transactions (as compared to the Wind Transactions) automatically means there are additional risks for NIPSCO and/or its customers. He explained how the joint venture structure more efficiently utilizes applicable tax incentives and how the Back-Stop PPA (in addition to the standard BTA PPA or CFD) helped mitigate risk. The Back-Stop PPA does what its name implies—it serves as a back-stop or safety net in case significant changes negatively impact the economics of the BTA transaction. In the event a BTA is terminated, NIPSCO is provided the opportunity to enter into a PPA (Back-Stop PPA) directly with the developer, rather than NIPSCO totally losing the opportunity to transact with the project upon termination. He noted the Back-Stop PPA's existence also serves as an incentive for the counter-party to ensure the project is designed and built according to industry standards because, in the event the Back-Stop PPA is triggered, they will end up being the long-term owner of the project.

Regarding the first of the provisions challenged by Ms. Aguilar, he explained the contents and justification for Section 5.14.6 of each BTA. He further testified and expressed disagreement with Ms. Aguilar's proposal regarding the cap on future recovery of additional investments in the Joint Ventures, as the cap NIPSCO proposed as part of its case-in-chief was intended to apply specifically to one type of investment—additional investments into the Solar Projects after the Joint Venture acquires the project, that are required to ensure ongoing viability of the projects, such as may be required if there were an extended outage or a force majeure event. He reiterated that the rationale for inclusion of Section 5.14.6 in each BTA and explained they were reasonable provisions that should be approved.

With respect to the provisions challenged by Mr. Alvarez, Mr. Campbell clarified what the provisions actually provided for and explained how NIPSCO would proceed under the BTA (and potentially the Back-Stop PPA) if these provisions were utilized. Mr. Campbell also stated that NIPSCO would be responsible for all interconnection costs if it were developing the Solar Projects on its own, with its only recourse for potentially unreasonable costs being to terminate the MISO Generator Interconnection Agreement and cancel the project. Thus, this provision is reasonable as it provides protection to NIPSCO and its customers and increases flexibility and project viability.

Mr. Campbell explained NIPSCO proposed a cap that would apply to additional investments in the Solar Projects that may become necessary (as outlined page 36 [in Question / Answer 32] of his direct testimony). He also explained the OUCC's criticism of this provision as potentially creating a "windfall" for NIPSCO.[56] He testified that NIPSCO did not agree with the OUCC's position. However, in the spirit of compromise, NIPSCO committed that, in the event that any of the Solar Projects do not reach commercial operation, it would reduce the proposed cap on a dollar-per-megawatt basis, based on the formula in footnote 38 of his direct testimony, which should address the OUCC's concern.

Mr. Campbell also testified about the proposed CFD, which the OUCC did not challenge but wanted to ensure would not negatively impact NIPSCO's customers. He provided a commitment from NIPSCO that it will ensure customers end up in no worse position if a CFD is ultimately utilized. Also, if the Commission believes it to be necessary, he said NIPSCO is willing to submit a work paper (or something similar) in each FAC proceeding (or equivalent proceeding) that demonstrates how customers are not impacted by a CFD as compared to a BTA PPA.

Mr. Campbell also directly rebutted Dr. Boerger's claim that NIPSCO's 2018 IRP is no longer a valid foundation for making decisions regarding implementation of the Short-Term Action Plan arising from that IRP, stating the 2018 IRP was well-developed and has continued to receive positive feedback from many sources, including in the Director's Report. He noted that Mr. Augustine discussed this topic more fully but that NIPSCO's timeline for implementing the Short-Term Action Plan has always been 3 years (2019-2021). He stated NIPSCO is currently on a reasonable and prudent path to implement the Short-Term Action Plan, and the Solar Projects proposed for approval in this proceeding are an integral part of that plan, which is intended to replace the capacity from Schahfer, which is set to fully retire no later than 2023. However, if the Commission were to adopt the OUCC's position, it would pose a significant disruption to NIPSCO's generation transition, thereby leading to reliability risk and exposing NIPSCO and its customers to substantial financial risk.

[56] Mr. Campbell also clarified that NIPSCO's proposal in its case-in-chief was that the proposed cap was intended to cover only one kind of cost—additional investments after the Solar Projects are purchased by the Joint Venture that would be necessary if the projects were not able to operate as expected, based on things like a force majeure event or a lengthy forced outage. It was not intended to serve as a cap for any-and-all types of costs. He testified that, for this reason, NIPSCO is not amenable to making the proposed cap applicable to "any additional investment, for whatever reason" as Ms. Aguilar advocates for, especially if NIPSCO's proposed cap amount was not to be raised significantly.

Mr. Campbell provided several implications of following the path the OUCC advocated for. First, the Solar Projects would not be approved, meaning NIPSCO and its customers would lose the benefits of the Solar Projects. He reiterated that the OUCC has not challenged the Solar Projects on the economic value they present for NIPSCO, which is not surprising, as the economics of the Solar Projects are generally consistent with the IRP tranche-level assumptions for owned resources from the 2018 IRP, indicating they are a prudent investment for NIPSCO and its customers. Second, NIPSCO would need to wait until its 2021 IRP cycle was completed in late fall of 2021. Mr. Campbell outlined what this timeline would look like if an RFP is run concurrent with the 2021 IRP: (1) RFP results would be expected in early 2022; (2) NIPSCO would then be required to identify preferred projects and negotiate deals all over again, which would likely take anywhere from 6-12 months; (3) then, in late 2022 through early 2023, NIPSCO would again need to file for Commission approval of any projects; (4) under a 120-day procedural schedule, this would lead to project approvals in early-to-mid 2023; (5) this would result in NIPSCO's projects coming out of a 2021 IRP not being approved until approximately 2 years after issuance of the IRP in fall 2023, which is not much different than the situation today, where NIPSCO submitted the Solar Projects for approval in November of 2020, approximately 2 years after issuance of the 2018 IRP in the fall of 2018. Furthermore, the projects coming out of this process would likely not enter into commercial operation until late 2024 and into 2025 and would not qualify for the full 30% ITC. Looking at all of this, NIPSCO would be in a position of significant risk related to Schahfer's retirement in 2023. He provided Figure 1 and explained that NIPSCO's "open" position without the 900 MWs from the Solar Projects or any additional projects would be 2,271 MWs (ICAP)—a significant gap that the Commission would likely not deem acceptable. He also noted the potential impact denial of the Solar Projects could have on the viability of projects NIPSCO continues to negotiate.

Ms. Campbell testified about the risks this would place on NIPSCO. NIPSCO and its customers would likely face reliability concerns by not having enough resources or capacity to meet its resource adequacy needs within MISO. Further, this could result in NIPSCO not having enough physical resources to adequately hedge customers' MISO market exposure. In turn, this could result in volatility in NIPSCO's cost to service its customers. While under this scenario NIPSCO could rely on procuring capacity and energy through the MISO market, because of the magnitude of this open position, there is no guarantee that NIPSCO would be able to procure its needs affordably. He concluded that, undoubtedly, NIPSCO and its customers would be exposed to significant market risk.

Mr. Campbell also testified that NIPSCO takes its obligation to provide safe, reliable service at a reasonable cost very seriously, including planning to meet both the short- and long-term needs of its customers. Through its 2018 IRP, companion All-Source RFP, and subsequent Phase II RFPs, he said NIPSCO is now well into implementation of the Short-Term Action Plan that will ensure it continues to meet this obligation when Schahfer is retired. This proceeding is one of the steps in that Plan—a very important step. He explained that, following completion of the Short-Term Action Plan, NIPSCO will have a flexible, diverse, cost-effective, and much cleaner generation portfolio. Also, through owned generation resources, contracted PPAs, and participation in the MISO market, NIPSCO is confident it will be able to reliably serve customers every hour of every day at a reasonable price. He stated NIPSCO will not be doing this work in its own, as both MISO (primarily through its market oversight and resource planning efforts)[57] and the Commission (primarily through its regulatory oversight) have important and complimentary roles in ensuring that NIPSCO's customers, and all customers in Indiana for that matter, will receive the electric service they deserve and expect.

Mr. Campbell contrasted NIPSCO's proposed implementation of the Short-Term Action Plan with the OUCC's proposed path, which is significantly more uncertain and risky and would lead to NIPSCO losing the opportunity to own the Solar Projects, which are cost-effective Indiana-based renewable resources. He cautioned that it could also have broader impacts by leading to cancellation of these and other projects NIPSCO has sought approval for, which would be bad for NIPSCO, its customers, and the State of Indiana more generally. He also warned that the OUCC's position would, at minimum, lead to NIPSCO and its customers losing the benefit of these significant, Indiana-based solar projects and could ultimately lead to their cancellation, meaning the State of Indiana would lose out on the projects altogether. This would inject significant uncertainty into Indiana's regulatory framework and very well could make developers hesitant to continue to work with NIPSCO and/or other Indiana utilities in the future. Given that NIPSCO is following the Commission's IRP process and timelines, and the costs of the Solar Projects are market-based and aligned with NIPSCO's 2018 IRP, if the Solar Projects are not approved, he believed it would be reasonable to expect developers may be hesitant to go through the time and expense to work with Indiana utilities. He concluded by testifying that it is important that the Commission not adopt the OUCC's position and thereby erect unreasonable regulatory hurdles for renewable projects, especially in situations like the one presented here where NIPSCO's proposed projects are supported by a solid IRP, as updated in early 2020, and market-based RFPs.

(c) Augustine Rebuttal.

Mr. Augustine first testified that the Solar Projects are unquestionably consistent with the 2018 IRP, noting the OUCC has not claimed that they are not, choosing rather to question the 2018 IRP itself. He explained that the 2018 IRP (including as updated in the 2020 portfolio analysis) continues to be a sufficient foundation on which to base the approval of the Solar Projects, despite the OUCC's claims to the contrary through Dr. Boerger's testimony. He agreed with Dr. Boerger's general observations that the MISO market is changing, but disagreed with his assertion that NIPSCO's 2018 IRP is no longer a valid foundation for three major reasons: (1) NIPSCO's 2018 IRP was favorably reviewed by the Director's Report, particularly with regard to the use of a RFP to validate resource assumptions, something NIPSCO has done again with the Phase II RFPs that selected the Solar Projects; (2) NIPSCO's 2018 IRP was specifically designed to be flexible in the face of evolving market conditions, and NIPSCO's Short-Term Action Plan explicitly called out changes that would be tracked in support of future resource decisions, meaning that the IRP conclusions were not reliant on a single set of assumptions that could later be invalidated by evolving market conditions; and (3) as a direct result of the flexibility built into NIPSCO's preferred portfolio strategy, NIPSCO performed updated analysis of its portfolio in 2020 to

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[57] As acknowledged in the Director's Report, at p. 49, which was included as Attachment 1-B to Witness Whitehead's direct testimony, "RTOs serve a critical role in the provision of reliable and economic electric service in real-time. It is the only entity with the authority and capability to monitor system conditions and take appropriate actions in response to changed system conditions." Page 47 of the same report states: "The focus of an RTO is to minimize the total cost of energy delivered to consumers while maintaining high levels of reliability. The total cost of electricity includes energy, generation capacity, and transmission."

incorporate market changes, validate the direction of the 2018 IRP's preferred portfolio, and pivot slightly in its resource selection.

Following a recitation of several of the compliments from the Director's Report, Mr. Augustine testified the 2018 IRP was effective in identifying that a significant number of cost-effective renewable projects were available in the market to replace retiring coal capacity, with an acknowledgement that optionality was preserved to allow NIPSCO to continue to assess the market throughout the implementation of its resource plan. Since the initial All-Source RFP, NIPSCO has subsequently conducted the Phase II RFPs to solicit additional projects, a step that was fully consistent with the overall framework established in the 2018 IRP. He further explained that in all the CPCN proceedings NIPSCO has initiated for renewable projects coming out of the 2018 IRP, the Commission has generally been complimentary of NIPSCO's IRP. For example, as recently as January 27, 2021 in Cause No. 45403, the Commission lauded NIPSCO's 2018 IRP and found that proposed solar and solar plus storage PPAs coming out of the Phase II RFPs were supported by a well-developed IRP. He stated that he was aware of nothing that would impact the conclusion recently reached by the Commission, including anything the OUCC said in its testimony in this proceeding.

Mr. Augustine also provided background about the Short-Term Action Plan, which has always been intended for implementation from 2019-2021. In the 2018 IRP, the Short-Term Action Plan specifically stated that select replacement projects would be identified as part of the 2018 All-Source RFP, but that NIPSCO would "[c]onduct a subsequent All-Source RFP to identify preferred resources to fill remainder of 2023 capacity need (likely renewables and storage)."[58] He recalled that the Commission explicitly acknowledged this element of NIPSCO's Short-Term Action Plan in the 2019 CPCN proceedings for wind, noting that it preserved optionality.[59] Thus, he believed the OUCC should not be surprised that NIPSCO is seeking approval of projects coming out of RFPs that began in 2019, as this was by design.

Mr. Augustine also emphasized that NIPSCO explicitly designed the Short-Term Action Plan to preserve flexibility to be able to respond to such developments. In the 2018 IRP, NIPSCO noted that the Short-Term Action Plan does not commit to immediately filling the entire 2023 capacity gap but leaves room to evaluate market and technology changes on a dynamic basis. It specifically noted that such changes might include MISO market changes regarding renewable resource availability, renewable capacity credit, and seasonal capacity constructs. He explained that, in fact, NIPSCO included a full section on "Capacity Resource Planning With Non Dispatchable Resources" in its 2018 IRP chapter on the preferred portfolio. Within this section, NIPSCO noted that MISO was likely to move to an ELCC (effective load carrying capability) capacity credit methodology for solar, that renewable capacity credit is likely to change over time, and that seasonal capacity accounting may be required in the future as part of MISO's Resource Availability and Need initiative. In anticipation of these market changes, NIPSCO's 2018 IRP emphasized that if capacity credit rules or methodologies change, NIPSCO's IRP path can be cost effectively scaled to adjust and by not committing to any single, large asset for the majority of UCAP needs, NIPSCO can flexibly adapt as rules and technologies change. This is precisely what

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[58] See p. 2, Table 1-1; p. 179, Figure 9-32 of Attachment 3-A (the 2018 IRP) to Augustine direct testimony.

[59] *See* Commission order in Cause No. 45195 (at p. 10), issued on June 5, 2019, which stated that "Consistent with this idea of optionality, we note that NIPSCO plans to issue another RFP in the near future to evaluate the economics and performance characteristics of a wide range of resources available in the market."

NIPSCO has done as it has implemented the Short-Term Action Plan. He noted as well that the 2020 portfolio analysis accounted for market changes and incorporated evolving technology options that were identified in the Phase II RFPs and how the inclusion of more paired solar plus storage capacity through the Bridge II and Cavalry Projects is an example of how NIPSCO has been slightly adjusting its preferred portfolio resource selection in response to market changes.

Mr. Augustine testified extensively about the reasons for and contents of the 2020 portfolio analysis, which was undertaken to evaluate the direction of NIPSCO's preferred portfolio in light of the new resource information received through the Phase II RFPs and in light of several changes to NIPSCO's system and the MISO market in which NIPSCO participates. He outlined what Dr. Boerger had said in Cause No. 45403, including suggesting that NIPSCO may need to revisit the Short-Term Action Plan from the 2018 IRP due to observed increases in solar costs and evolving MISO rules regarding solar capacity credit. According to Mr. Augustine, the 2020 portfolio analysis is exactly the kind of additional IRP modeling Dr. Boerger had requested in that proceeding, and this analysis addressed both changes in solar project prices and certain changes in the MISO market from the RIIA studies.

Mr. Augustine outlined the contents of the 2020 portfolio analysis in some detail and noted that NIPSCO supplied workpapers with all supporting input and output data including:[60]

- A comprehensive accounting of NIPSCO's existing portfolio of resources and associated operational characteristics, including plant capacities, heat rates, variable operations and maintenance costs, forced outage and maintenance rates, must run expectations for coal units, existing power purchase agreement and feed in tariff terms, short-term market capacity purchase expectations, and generation profiles for existing and recently approved intermittent resources.

- Monthly projections for NIPSCO's load on a total energy and peak load basis, along with hourly load shapes, demand side management (DSM) expectations, and a comparison with the load forecast used in the 2018 IRP.

- A documentation of all key commodity price inputs, including coal prices, natural gas prices, CO_2 prices, MISO power prices, MISO capacity prices, and a summary of the stochastic distribution used for power prices. A comparison of key variable inputs relative to what was used in the 2018 IRP was also provided.

- A detailed summary of the fourteen new resource tranches that were developed from the Phase II RFPs, including key operational parameters such as size, cost, capacity factor expectations, hourly generation profiles for renewable resources, and begin and end dates. A summary of the new resources that were included in each of the six portfolios that were evaluated was also provided, including the additional market capacity purchases assumed for each portfolio over time.

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60 Although there appears to have been some confusion about what was provided to the OUCC by NIPSCO, based on the corrected testimony from Dr. Boerger and Mr. Augustine's rebuttal testimony, NIPSCO seems to have provided the 2020 portfolio analysis in testimony in its case-in-chief on November 30, 2020 and provided the related work papers to the OUCC on December 3, 2020.

- Financial input assumptions related to NIPSCO's cost of capital and other related variables, as well as relevant capital and fixed operations and maintenance expenditures expected over time for the existing portfolio and recently approved renewable resources.

- A summary of major portfolio analysis outputs, including annual capacity accounting, annual CO_2 emissions accounting, and annual revenue requirement accounting by portfolio and by component, along with a net present value summary. The integrated scorecard of results across all of NIPSCO's key metrics for each portfolio was also provided.

- Detailed revenue requirement financial statements for each portfolio and each of the 200 stochastic iterations that were evaluated, including annual summaries of key variable portfolio cost components and comprehensive financial rate base accounting.

Mr. Augustine stated that Dr. Boerger did not provide a substantive review or critique of the 2020 portfolio analysis, but has summarily concluded that NIPSCO's updates to the modeling reported in this proceeding relying on a now invalid foundation (the 2018 IRP), cannot reasonably form the basis for resource decisions at this time. He said Dr. Boerger has effectively "moved the goalposts" by initially requesting in Cause No. 45403 that NIPSCO update its analysis and now, after NIPSCO did precisely what he requested, asserting that the fully responsive updated analysis provided in NIPSCO's case-in-chief in this proceeding cannot be relied upon because its foundation is invalid.

As Mr. Augustine had explained in his direct testimony, the 2020 portfolio analysis included an updated NIPSCO load forecast (including, but not limited to, load changes from NIPSCO's implementation of Rate 831), updated commodity price inputs (including power price forecasts reflective of recent views of the MISO market's generation mix evolution), changes to the assumed capacity credit for solar over time (based on ongoing developments at MISO), and the introduction of stochastic renewable output variability. The analysis also contained six new portfolio concepts that were developed based on the results of the Phase II RFPs and MISO's changing market rules. While this does constitute updates and changes to the 2018 IRP, he explained that NIPSCO did not make any wholesale changes to its modeling approach as part of the 2020 portfolio analysis. In fact, the modeling approach deployed in the 2020 portfolio analysis was quite similar to the approach used in NIPSCO's 2018 IRP, using the same methods and models that the stakeholders, including the OUCC and the Commission, reviewed during the 2018 IRP process. He explained these methods and models and concluded it would be reasonable for the OUCC to review the updated analysis as part of this case in the context of the 2018 IRP, which they are extremely familiar with from past regulatory proceedings.

Mr. Augustine noted that any changes in approach were made to account for recent power market developments, changes that Dr. Boerger himself identified in his direct testimony in Cause No. 45403. Mr. Augustine provided further testimony about how the 2020 portfolio analysis has largely addressed several changes in the MISO market, as discussed in the OUCC's responses to NIPSCO's discovery requests.

Mr. Augustine began his concluding testimony by stating NIPSCO's 2018 IRP developed a clear conclusion that retirement of existing coal-fired facilities and replacement with predominantly renewable resources provided cost savings to customers and mitigated risk, and NIPSCO is well on its way down the path to implementing this plan. He testified that the Solar

Projects are similar in cost to the renewable resource tranches evaluated in the 2018 IRP and are thus consistent with the Short-Term Action Plan that was established. Furthermore, NIPSCO's 2020 portfolio analysis concluded that the preferred portfolio's direction is still valid and that the addition of more battery storage capacity, such as what is included in two of the three Solar Projects, can help the portfolio adapt in the face of changing market conditions. Therefore, he offered confidence that NIPSCO has a solid evidentiary basis to continue implementing the Short-Term Action Plan and that the Solar Projects are reasonable and necessary generation additions for NIPSCO. He reiterated that since the filing of its 2018 IRP, NIPSCO has been consistently evaluating and reevaluating the markets and its resource options; conducted the Phase II RFPs in 2019-2020 to gain the latest market cost and technology information for resource decisions; and performed a thorough portfolio analysis in 2020 to confirm the direction of the preferred portfolio and the Short-Term Action Plan. Finally, he noted that NIPSCO's Short-Term Action Plan, including the Solar Projects, is largely focused on replacing the retiring Schahfer coal plant's capacity. NIPSCO thus expects to retain its coal-fired Michigan City plant, its natural gas-fired Sugar Creek combined cycle, and its natural gas-fired Schahfer gas peakers beyond 2023 and will continue to evaluate the best long-term course of action for the generation portfolio into the future. While the Solar Projects represent a significant component of NIPSCO's long-term resource portfolio, they are only one part of a modular, flexible resource acquisition strategy that will still allow for continued adjustment as the market continues to evolve and as NIPSCO performs its next IRPs in 2021 and beyond.

12. Commission Discussion and Findings.

A. Applicable Statutes and Sufficiency of NIPSCO's Evidence.

(i) NIPSCO's 2018 IRP. 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.[61] Similarly, in determining the reasonableness and necessity for the Solar Projects, we find it appropriate to include the application of principles reflected in the following Chapter 8.5 factors in our consideration: (1) the cost of the Solar Projects; (2) the consistency of the Solar Projects to NIPSCO's IRP; (3) the need for the Solar Projects; (4) and the reliability and the competitive solicitation of the Solar Projects.

The OUCC argues that Joint Petitioners failed to meet their burden of proof that the proposed Solar Projects are reasonable and necessary under Ind. Code § 8-1-8.8-11. Dr. Boerger stated the OUCC was unable to make a recommendation and concluded that Joint Petitioners "have not provided sufficient evidence to reach a conclusion as to the reasonableness and necessity of the Solar Projects presented for approval." In order to meet its burden of proof, the OUCC states NIPSCO should be required to perform a comprehensive update of its IRP modeling and provide

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[61] *See, Rosewater Order* at 50-54; *Crossroads Order* at 27-30; *N. Ind. Pub Serv. Co.*, Cause No. 45403, at 24-26 (IURC Jan. 27, 2021); *Ind. Mich. Power Co.*, Cause No. 44511, at 7-8 (IURC Feb. 4, 2015); and *N. Ind. Pub. Serv. Co.*, Cause No. 45195 (IURC Jun. 5, 2020) (Chapter 8.5 factors relevant for clean energy projects under Chapter 8.8); *see also, Ind. Mich. Power Co.*, Cause No. 44182, at 53-54 (IURC July 17, 2013) (Chapter 8.7 factors relevant for Life Cycle Management Project under Chapter 8.8).

sufficient time for review by all stakeholders, and only then would it be appropriate for the Commission to approve proposed generation projects.

To support its claim, the OUCC argues that NIPSCO's 2018 IRP is no longer a valid foundation for making decisions regarding implementation of the Short-Term Action Plan arising from the 2018 IRP. The OUCC's argument is based primarily on a claim that three years have elapsed since the 2018 IRP[62] and certain changes have occurred in the electric utility industry. Dr. Boerger explains that the OUCC did not oppose two very recent projects in Cause No. 45403 (e.g., the Greensboro and Brickyard Projects with which NIPSCO executed PPAs) on these grounds, but that these transactions are for NIPSCO to ultimately own three more expensive projects.

As highlighted in NIPSCO's rebuttal testimony, in all the CPCN proceedings NIPSCO has initiated for renewable projects coming out of the 2018 IRP,[63] we have consistently been complimentary of NIPSCO's IRP. For example, as recently as January 27, 2021, we reiterated our prior findings as to the sufficiency of NIPSCO's 2018 IRP and found that proposed solar and solar plus storage PPAs coming out of the Phase II RFPs were supported by a well-developed IRP.[64] The 2018 IRP has also received positive feedback from many sources, including the Director of Research, Policy and Planning for the Commission.[65]

There is no evidence in the record that would call into question our prior findings. The mere passage of time does not invalidate the 2018 IRP, nor does the fact that NIPSCO chose to submit three Solar Projects that represent its largest proposed investment to date. Inherently, integrated resource plans are performed at a point in time and use modeled scenarios to show how resources perform over a variety of alternative future conditions. This is not a case where NIPSCO performed the 2018 IRP analysis and has failed to respond to changes in the electric industry or the broader market, and now seeks approval of generation additions based on a questionable foundation.[66] As Mr. Augustine explained in his rebuttal testimony, Joint Petitioners Exh. No. 3-R, NIPSCO's 2018 IRP was specifically designed to be flexible in the face of evolving market conditions, and NIPSCO's Short-Term Action Plan explicitly called out changes that would be tracked in support of future resource decisions, meaning that the 2018 IRP's conclusions were not reliant on a single set of assumptions that could later be invalidated by evolving market

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[62] In fact, as explained in NIPSCO's rebuttal testimony, approximately two years passed between the issuance of the 2018 IRP in the fall of 2018 and NIPSCO's submission of its case-in-chief in this proceeding in November of 2020. Additionally, less than one year has passed between the issuance of the Director's Report related to NIPSCO's 2018 IRP and the filing of the OUCC's testimony in this proceeding.

[63] *See generally* the Commission's orders in Cause Nos. 45194, 45195, 45310, and 45403.

[64] Commission Order in Cause No. 45403 at pp. 27-29, issued on January 27, 2021.

[65] The Director's Report commended the development of NIPSCO's IRP and affirmed its credibility. The Director's Report further highlighted the extensive, objective, and transparent nature of the All-Source RFP competitive bidding process and noted that NIPSCO's IRP and RFP combination "enables NIPSCO to understand the uncertainties to help maintain a high degree of optionality and minimize adverse risks." Attachment 1-B at page 4. We note that the Director's Report was issued on February 10, 2020, less than a year before the Joint Petitioners submitted their case-in-chief in this proceeding.

[66] Ms. Whitehead outlined "NIPSCO's diligence in implementing the Short-Term Action Plan" on pages 2-4 of her rebuttal testimony, Joint Petitioners Exh. No. 1-R. In Joint Petitioners Exh. No. 3-R, at pages 7-10, Mr. Augustine likewise discussed how the 2018 was originally designed to be flexible and adaptable and how NIPSCO has implemented the Short-Term Action Plan to address several of the anticipated changes that have occurred since 2018.

conditions.[67] As Mr. Campbell noted on rebuttal in Joint Petitioners Exh. No. 1-R, since the 2018 IRP was issued, the timeline for implementation of the Short-Term Action Plan identified in the 2018 IRP has been 3 years (2019-2021) and NIPSCO's proposed projects are consistent with this implementation. NIPSCO has progressed in implementing this plan according to schedule, including seeking approval of renewable projects through 2020 and 2021. Therefore, we find NIPSCO's 2018 IRP process, which occurred in concert with the All-Source RFP, and has been supplemented by the Phase II RFPs, was robust and well-developed, ultimately resulting in the Short-Term Action Plan on which the proposed Solar Projects are based.

Although we have made the above finding that, even without any updated or supplemental analysis, NIPSCO's 2018 IRP serves as a sufficient evidentiary basis for NIPSCO's investments in the proposed Solar Projects, we also address the 2020 portfolio analysis that was offered by NIPSCO in this proceeding through Mr. Augustine.

(ii) The 2020 Portfolio Analysis. Although not required to do so, NIPSCO voluntarily undertook the additional effort and expense to perform the 2020 portfolio analysis and then presented its results in support of its request in this proceeding. NIPSCO conducted the 2020 portfolio analysis to consider changes that had occurred since its 2018 IRP and thereby determine whether its preferred portfolio and the Short-Term Action Plan remained a reasonable path for NIPSCO. The inclusion of this additional evidence undercuts the OUCC's criticisms of the sufficiency of NIPSCO's evidence, especially considering the OUCC's position about the 2018 IRP in Cause No. 45403. As explained by Mr. Augustine, the OUCC offered some critiques of the 2018 IRP in that case, and noted two things that NIPSCO should consider addressing in future CPCN requests: more recent market pricing for solar projects and recent, ongoing initiatives in the MISO market. The 2020 portfolio analysis offered in this proceeding directly and explicitly responded to the concerns the OUCC offered through Dr. Boerger in Cause No. 45403, including these two concerns.[68] The analysis also reflected load changes, including the impact of Rate 831.

Furthermore, the OUCC did not provide a substantive critique to refute NIPSCO's 2020 portfolio analysis. Instead, the OUCC summarily dismissed the 2020 portfolio analysis as relying on a now invalid foundation (the 2018 IRP). As we discussed above, the 2018 IRP is still a valid basis for NIPSCO's resource decisions. The OUCC did not offer any evidence to counter the 2020 portfolio analysis, or the 2018 IRP for that matter. In fact, the record indicates that the OUCC did not engage in any substantive analysis of NIPSCO's modeling. This is reflected in Joint Petitioners Exh. No. 8, OUCC Responses to NIPSCO Discovery Requests 2-1 and 2-2, wherein the OUCC admits that it "did not perform calculations or review detailed modeling inputs, outputs and modeling choices for the '2020 portfolio analysis,' as the OUCC determined from reading Mr. Augustine's testimony that an adequate review would not be feasible in the time frame of the statutorily time-constrained proceeding under which NIPSCO chose to file this case." While the OUCC may claim a substantive review of the 2020 portfolio analysis would have been a "waste

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67 Mr. Augustine also notes in his rebuttal testimony that the Short-Term Action Plan coming out of the 2018 IRP expected NIPSCO would conduct subsequent all-source RFPs to identify preferred resources to fill the remainder of NIPSCO's 2023 capacity need, which is precisely what NIPSCO accomplished with the Phase II RFPs.

68 The responsiveness of NIPSCO's 2020 portfolio analysis to the OUCC's criticisms in Cause No. 45403 is discussed in some detail in Mr. Augustine's rebuttal testimony, including how it addressed both recent solar pricing and MISO market changes.

[of] resources" and "futile under the time constraints under which NIPSCO chose to file this case,"[69] the OUCC's criticisms of the sufficiency of NIPSCO's evidence have no evidentiary basis. Having failed to present probative evidence that challenges the analysis actually conducted by NIPSCO to support the reasonableness of the proposed projects, the OUCC has no basis to make the claim that NIPSCO has failed to meet its burden of proof.

The 2020 portfolio analysis was undertaken by NIPSCO to incorporate the results of its Phase II RFPs, which revealed the latest market cost and technology information for resource decisions, and to determine whether NIPSCO's ongoing implementation of the Short-Term Action Plan continued to be the prudent path for NIPSCO and its customers. While we will not recite each update or modification Mr. Augustine explained in his rebuttal testimony, we note that the 2020 portfolio analysis, among other things, included (1) an update to NIPSCO load forecast (including changes from NIPSCO's implementation of Rate 831); (2) updated commodity price inputs (including power price forecasts reflective of recent views of the MISO market's generation mix evolution); (3) changes to the assumed capacity credit for solar over time (based on ongoing developments at MISO); and (4) the introduction of stochastic renewable output variability. Undisputed evidence in the record demonstrates that the 2020 portfolio analysis confirmed the direction of the preferred portfolio and the Short-Term Action Plan. Supported by that analysis, NIPSCO has taken steps to slightly adjust its preferred portfolio resource selection to respond to market conditions, such as by including more paired solar plus storage capacity through the Bridge II and Cavalry Projects. This analysis provides further support for our ultimate approval of the Solar Projects and demonstrates the reasonableness of NIPSCO's implementation of its Short-Term Action Plan. When this very recent analysis is viewed in combination with the rest of NIPSCO's evidence, the OUCC's contention that NIPSCO has not submitted sufficient evidence to support approval of the Solar Projects is without merit.

NIPSCO's implementation of the results of the 2018 IRP through its Short-Term Action Plan is intended to effectuate its transition from reliance on coal-fired generation as its primary resource. The 2018 IRP determined that this transition would save customers billions of dollars. Notably, there has never been any challenge made to that fundamental decision. Thus, this case, much like the prior cases where NIPSCO has proposed the addition to its portfolio of renewable resources, reflects the need to add new, replacement capacity in a timely manner in order to be able to replace the retiring coal resources no later than 2023. As further discussed below, the OUCC's challenge to these projects does not provide an alternative path to the ultimate requirement that within the next three years, NIPSCO will be positioned through its addition of resources to meet capacity requirements without those coal units and thereby realize the savings that the 2018 IRP identified. The fact that the proposed projects are supported by a sound RFP process provides unrefuted evidence that the Solar Projects represent another reasonable step in the transition that is economic and enables the planned unit retirements.

(iii) <u>Statutory Timeline for Review.</u> The OUCC states that the statutory 120-day procedural schedule in this proceeding has not provided them with sufficient time to form an opinion about the reasonableness of NIPSCO's request, especially since NIPSCO submitted the additional 2020 portfolio analysis for the first time in this proceeding. We first note that is was the Indiana General Assembly, not the Commission, who enacted Ind. Code ch. 8-1-8.8 and chose to

69 Joint Petitioners Exh. No. 8, OUCC Response to NIPSCO Discovery Request 2-1.

include a 120-day procedural schedule in sub-section 11 to encourage the development of clean energy projects. The Joint Petitioners chose to submit their request under this section of the Indiana Code, which is within their rights.

More importantly, and apart from the statute, Joint Petitioners filed their case-in-chief (including the 2020 portfolio analysis) in November of 2020. The Verified Joint Petition set forth a proposed procedural schedule at Paragraph 19. The OUCC filed no objection or other response to this proposed schedule. By Docket Entry issued December 16, 2020, the Presiding Officers approved the schedule proposed by the Joint Petitioners. Again, the OUCC did not request reconsideration of that Docket Entry or appeal the Docket Entry to the full Commission. If the OUCC was concerned that the procedural schedule did not allow sufficient time to respond to the Joint Petitioners' evidence, the time to bring those concerns to the Commission's attention was in December, 2020. Waiting until the filing of its case-in-chief is not the occasion to raise concerns over the schedule, especially through witness testimony rather than through motion practice.

In any event, we do not believe the OUCC's concerns present a valid basis to deny or even delay approval of the Solar Projects for at least two reasons. First, the OUCC was involved in the development of the 2018 IRP, and has also been provided data and analysis from NIPSCO related to it throughout the course of multiple proceedings spanning more than eighteen months. And much of the evidence NIPSCO submitted in this case is similar to what it has provided in past proceedings. Thus, the OUCC should be extremely familiar with much of NIPSCO's case-in-chief and, as noted above, NIPSCO's 2018 IRP alone is a sufficient evidentiary basis for the Solar Projects. Second, the evidence in the record indicates that NIPSCO did not make any wholesale changes to its modeling as part of the 2020 portfolio analysis; rather, the modeling approach deployed for the 2020 portfolio analysis was largely similar to that used in the 2018 IRP, using the same methods and models that the stakeholders, including the OUCC and the Commission, reviewed during the 2018 IRP process. Finally, NIPSCO was not required to submit the 2020 portfolio analysis to support the Solar Projects, which constitute the majority of the "new" evidence submitted by NIPSCO in this proceeding, but NIPSCO did so in direct response to criticisms offered by the OUCC in Cause No. 45403. It would be unfair to penalize NIPSCO by delaying or denying approval of these projects because NIPSCO provided the additional evidence the OUCC requested.[70]

(iv) Implications of Accepting the OUCC's Position. The evidence in this proceeding demonstrates that if we were to adopt the OUCC's position, there would potentially be several significant impacts from doing so.

If we were to deny approval and require NIPSCO to perform updated IRP analysis, NIPSCO and its customers would lose the benefit of the Solar Projects. As further discussed below, the pricing terms of the Solar Projects resulted from the competitive Phase II RFPs, and the LCOE for the projects, individually and in combination, are generally in line with the comparable tranches

[70] We also note there have been no allegations that NIPSCO engaged in delay tactics, withheld evidence, or something similar. In fact, as explained in Ms. Whitehead's rebuttal testimony, NIPSCO appears to have fully cooperated with the OUCC in the discovery process and also did not oppose a request for an extension of time for the OUCC to file its testimony, time that we granted assuming it be utilized to evaluate NIPSCO's case-in-chief.

from the 2018 IRP.[71] Additionally, as noted in NIPSCO's rebuttal, the Solar Projects are expected to qualify for the full 30% ITC, while, if not approved, the replacement projects NIPSCO would need to procure in their place would at best qualify for the 26% ITC. This difference alone is significant when looking at the combined purchase of the Solar Projects.[72]

Looking more broadly at NIPSCO's generation portfolio, if we were to deny approval of the Solar Projects and not approve any additional generation additions NIPSCO seeks if reliant on the 2018 IRP, as the OUCC has requested, NIPSCO's expected generation shortfall when the Schahfer Generation Station is fully retired in 2023 would be more than 2,200 MWs.[73] As Mr. Campbell discussed in some detail in his rebuttal testimony, a shortfall of this magnitude would pose a significant disruption to NIPSCO's generation transition and lead to reliability risks and substantial financial risks for NIPSCO and its customers, as well as broader reliability risks for Indiana's bulk electric system. When comparing NIPSCO's path (e.g., implementation of the Short-Term Action Plan) to the one offered by the OUCC, the OUCC's path would unquestionably result in additional market and reliability risk.

Additionally, as noted in Ms. Whitehead's rebuttal testimony, finding that NIPSCO's 2018 IRP no longer serves as a valid foundation for generation planning decisions, when we have repeatedly affirmed the sufficiency of the IRP and when NIPSCO's decisions are relatively close in time to issuance of the IRP,[74] would send the wrong message to other Indiana utilities. It was, in fact, the Commission who adjusted the requirements for IRP submissions to require triennial rather than biennial filings. The evidence reflects NIPSCO is currently on a reasonable and prudent path to implement the Short-Term Action Plan, and the Solar Projects proposed for approval in this proceeding are an integral part of that plan, which is intended to replace the capacity from Schahfer, which is set to fully retire no later than 2023.

Furthermore, delaying approval of new generation based upon where in the IRP timeline a request is filed runs the risk of delaying the construction of needed generation for Hoosiers. As noted, NIPSCO would be short by more than 2,200 MW under the OUCC's proposed path. NIPSCO would need to fill that gap with market purchases. But there is no guarantee that energy will be available for purchase. If we extend the OUCC's position across all of our Indiana energy utilities, we risk not having sufficient generation being constructed to meet the needs across the RTO footprint. That is not a risk we are willing to take so that more analysis can be done. Our

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71 The OUCC did not address the LCOEs for the Solar Projects in testimony but did admit NIPSCO's LCOE calculations presented by Mr. Augustine in Joint Petitioners Exh. No. 3, Confidential Figure 1, were calculated correctly and that they raised no concerns about the LCOEs. See Joint Petitioners Exh. No. 8, OUCC Response to NIPSCO Discovery Request 2-4.

72 The OUCC advocates for a path that would see NIPSCO's customers lose the benefits of these well-priced Solar Projects, with NIPSCO then being required to wait until an update to its IRP is completed in late 2021 to seek additional projects. Interestingly, in Joint Petitioners Exh. No. 8, OUCC Response to NIPSCO Discovery Request 2-3, the OUCC discussed "recent increases in the cost of solar PPA prices in NIPSCO RFPs" and cited to an article that stated solar generation prices were seen rising significantly in late 2020 and are expected to continue to do so in 2021. Yet the OUCC does not acknowledge, let alone attempt to quantify, the expected effect the increasing solar project prices would have on NIPSCO's customers.

73 As indicated in Figure 1, these numbers are in terms of ICAP.

74 This is especially the case when NIPSCO has undertaken the additional 2020 portfolio analysis, which was performed concurrent with the Phase II RFPs through which the Solar Projects were selected, less than 12 months before the Solar Projects were submitted for approval.

statutes already allow for necessary updating of integrated resource plans in connection with approval of new generation.[75]

Finally, we agree with Mr. Campbell that our denial of approval of the Solar Projects could have broader impacts by leading to cancellation of these and other projects NIPSCO has sought approval for or may be negotiating with, which would be bad for NIPSCO, its customers, and the State of Indiana more generally. Adoption of the OUCC's proposed path would inject unnecessary uncertainty into Indiana's regulatory environment and potentially erect unreasonable regulatory hurdles for the approval of generation resource additions, thereby discouraging investment in renewable generation in Indiana.

(v) NIPSCO's Evidence Is Sufficient. Joint Petitioners have provided evidence in this proceeding that goes beyond the evidence provided to the Commission in Cause Nos. 45194 and 45310, which we found in each instance was sufficient to demonstrate that the projects were reasonable and necessary. In addition to the testimony and other evidence it has typically provided in cases seeking approval for a renewable generation resource, NIPSCO also provided analysis of the economic impact of the Solar Projects, through Ms. Whitehead and Mr. Plewes,[76] and updated IRP modeling, through Mr. Augustine. The evidence before us in this Cause, therefore, is sufficient to allow us to make a decision on the Solar Projects, and, as further discussed below, this evidence also supports a finding that the energy to be obtained from the Joint Ventures and accompanying Solar Offtake Agreements is needed by NIPSCO, is reasonably priced compared to other alternatives, and provides other material benefits. The evidence demonstrates that the Joint Ventures will provide emission-free electric generation and allow for the development of additional renewable resources in Indiana that will further diversify NIPSCO's generation resources and provide substantial benefits to the Indiana economy. Notwithstanding the concerns made by the OUCC that Joint Petitioners have not provided sufficient evidence to reach a conclusion as to the reasonableness and necessity of the Solar Projects presented for approval, we find the Joint Ventures and accompanying Solar Offtake Agreements to be reasonable and necessary, and we approve and authorize NIPSCO to recover those costs from retail customers.

B. Clean Energy Project and Financial Incentives. 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). "Solar energy" is specifically listed as one of the clean energy resources in Ind. Code § 8-l-37-4(a)(l) through Ind. Code § 8-l-37-4(a)(l6), thus making it a "renewable energy

[75] *See* Indiana Code § 8-1-8.5-3(e), which allows for an IRP to be updated in connection with a utility specific proposal under Ind. Code §8-1-8.5-5(b)(2).

[76] While we do not discuss NIPSCO's economic analysis in detail, we acknowledge the effort and expense to provide this analysis and demonstrate the significant direct, indirect, and induced benefits associated with the Solar Projects. We have never required such information to be provided in a CPCN request, but the benefits to the State, including the counties where some of NIPSCO's retiring coal-fired generation is located, further support our decision to approve the Solar Projects.

resource" under Ind. Code § 8-1-8.8-10. Through the Joint Ventures and the associated Solar Offtake Agreements with ProjectCos, NIPSCO is undertaking projects to develop energy from solar and solar plus storage and so is eligible for the relief provided in Ind. Code § 8-1-8.8-11.

In addition to timely cost recovery, described below, NIPSCO seeks financial incentives including approval of the Joint Venture structures whereby NIPSCO will invest in the Joint Ventures, as described by Mr. Campbell, which will own the ProjectCos, which will build and own the Solar Projects. NIPSCO seeks approval of the BTA between the Joint Ventures and Sellers and of the Solar Offtake Agreements. The Back-Stop PPAs are effective if all conditions to the BTAs are not satisfied, and so approval of the Solar Offtake Agreements is sought and is necessary at this time. NIPSCO also seeks authority to record its costs incurred to invest in the Joint Ventures as a regulatory asset in Account No. 182.3 and to amortize its investment over the life of the Solar Projects (estimated to be 30 years for each of the Solar Projects). NIPSCO further seeks confirmation that the net balance of its costs 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 WACC until a return is recovered through NIPSCO's rates and charges. In short, NIPSCO seeks to reflect in rate base as a regulatory asset its costs to own an interest in the Joint Ventures like it would have reflected the costs to build and own the generating assets in Utility Plant in Service had NIPSCO instead been the direct owner of the Solar Projects.

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

- NIPSCO will not seek approval in this proceeding of any amounts related to its purchase of the TEP's share of the three Solar Projects. Rather, once a determination has been made by NIPSCO to purchase the TEP's share of any of the Solar Projects, NIPSCO shall seek recovery of such costs in a separately docketed proceeding. NIPSCO shall not seek recovery of more than the fair market value of the TEP's share of the Joint Venture in any such proceeding.

- NIPSCO will continue to treat its costs to invest in the Joint Ventures, even after such time as the TEP(s) 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. Amortization of the regulatory asset will commence as of the in-service date of the Solar Projects. NIPSCO will 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.

- NIPSCO shall not record and accumulate on its books and records either the Solar Project revenues or expenses, but rather those revenues and expenses shall be maintained by the respective ProjectCos, tracked and reviewed by NIPSCO, and the OUCC, and subject to an independent audit. This is inclusive of any subsequent investments (cash contributions) NIPSCO makes into the Joint Venture.

- There will be a cap of cost recovery related to any additional investments (cash contributions for force majeure, extended outages and circumstances described on Page 36 of Mr. Campbell's direct testimony) NIPSCO may make into the Joint Ventures that will be recoverable from ratepayers at a specific amount. This cap will be shared across all of the Solar Projects.[77] During the term of the CFDs (or BTA PPAs), to the extent sales revenue by the Joint Ventures 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 each TEP, any accrued balance of the additional portion of this regulatory asset to be recovered from ratepayers will be no more than a specific amount.

- NIPSCO has already begun and proposes to continue discussions with the OUCC about 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.

- Except as described in the other agreed conditions, NIPSCO shall not seek cost recovery from ratepayers of any other cash contributions to the Joint Ventures related to the specific Solar Project incurred by NIPSCO related to: (1) the buyout of the TEP(s); or (2) the operation of the Joint Ventures while TEP(s) are still participants in the Joint Venture.

- NIPSCO shall remain the managing member of each Joint Venture.

(i) <u>Need for the Solar Projects</u>.

NIPSCO relies on its 2018 IRP to support its request for approval of the capacity and energy that will be provided by the Solar Projects. We must determine whether to approve NIPSCO's chosen resource, the Solar Projects, and in doing so, consider whether those chosen resources are supported by a well-developed IRP. Above, we discussed the 2018 IRP, including our findings in prior orders. We also discussed how NIPSCO's 2020 portfolio analysis provided additional support for the necessity of the Solar Projects. We will not repeat that discussion here but reiterate our determination that NIPSCO's 2018 IRP was well-developed and that it demonstrates NIPSCO's need for the Solar Projects.

The evidence demonstrates that the Solar Projects are consistent with NIPSCO's 2018 IRP (including as updated in the 2020 portfolio analysis) and the Short-Term Action Plan, including being selected pursuant to a competitive RFP that was contemplated under the Short-Term Action Plan. The record reflects that NIPSCO conducted the Phase II RFPs and considered 96 proposals

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77 As further discussed below, in rebuttal testimony, NIPSCO committed to reduce the proposed cap on a dollar-per-megawatt basis in the event any of the Solar Projects does not reach commercial operation.

supported by 93 individual projects by more than 40 bidders across six states. The Phase II RFPs were conducted using best practices and utilizing the third-party expertise of CRA. In fact, as explained by Mr. Campbell and Mr. Lee, the Phase II RFPs were adjusted to give greater weight to project development risk, which was intended to further ensure projects further along in commercial development received the appropriate credit and thereby also further ensure NIPSCO selects projects that are more likely to reach commercial operation.

The evidence also demonstrates that NIPSCO has a need for capacity by 2023, which is supported by its 2018 IRP, as supplemented by the 2020 portfolio analysis. NIPSCO has prepared an IRP that demonstrates the acquisition of replacement resources over a period of time, with particular focus on solar and battery storage facilities in the near term to maximize the benefits of the ITC while it remains available. The Short-Term Action Plan was designed to allow for a phased transition towards renewables over a multi-year period, allowing for flexibility in resource procurement within the framework established by the 2018 IRP's preferred portfolio. Mr. Augustine explained how NIPSCO has adjusted its preferred portfolio to remain agile and flexible, including seeking additional energy storage resources, as reflected in the Bridge II and Cavalry Projects. The Solar Projects are consistent with that framework.

As we recently acknowledged in the IURC Report, "In an uncertain world, making several smaller resource decisions over time and maintaining decision optionality as long as practical can be beneficial, particularly compared to making fewer larger commitments that foreclose opportunities to adapt to changing industry circumstances."[78] We have also expressed the need for a utility's overall generation portfolio to be diverse, flexible, and adaptable.[79] NIPSCO's implementation of the Short-Term Action Plan, as illustrated by its evidence, reveals NIPSCO has been cognizant of these principles. NIPSCO has now sought approval from the Commission for ten different renewable projects to replace Schahfer's retiring capacity, which are a mix of wind, solar, and solar plus storage.[80] Only two of these projects are 400 MW or larger, with all others being 300 MW or smaller. NIPSCO has also utilized a mix of ownership/joint venture and PPA structures,[81] and the duration of renewable generation project commitments has been staggered at

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78 Attachment 1-C to Joint Petitioners Exhibit No. 1 at pp. 6-7.

79 *See, e.g.*, Commission order in Cause No. 45052 at p. 24 where we quoted the 2018 Statewide Analysis, which said, "A key consideration in long-term resource planning is the need to retain maximum flexibility in utility resource decisions to minimize risks." In that order, in denying Vectren South's CPCN request, we also stated that we were "hard pressed to see how reliance on one facility . . . *is consistent with maintaining flexibility to respond to changing market conditions and technological change*." *Id*. at p. 28 (emphasis added).

80 Coming out of the All-Source RFP in 2018, NIPSCO filed and received approval for the following projects: (1) the 102 MW Rosewater Project, which is a wind BTA (Cause No. 45194); (2) the 302 MW Crossroads Project, which is also a wind BTA (Cause No. 45310); and the 400 MW Jordan Creek Project, which is a wind PPA (Cause No. 45195). NIPSCO has also sought approval of several solar and solar plus energy storage projects as a result of the Phase II RFPs: (1) the 200 MW solar PPA Brickyard Project (approved in Cause No. 45403); (2) the 100 MW solar and 30 MW energy storage PPA Greensboro Project (approved in Cause No. 45403); (3) the 265 MW solar BTA Bridge I Project (approved herein); and (4) the 435 MW solar and 75 MW energy storage BTA Bridge II Project (approved herein); (5) the 200 MW solar and 60 MW energy storage BTA Cavalry Project (approved herein). Since submission of its case-in-chief in this proceeding, NIPSCO has also sought approval of: (1) the 200 MW solar PPA Green River Project (Cause No. 45472) and (2) the 280 MW solar PPA Gibson Project (Cause No. 45489).

81 Each of the Solar Projects approved herein will be controlled by NIPSCO, and ultimately will be owned by NIPSCO. Historically, Indiana utilities have owned the majority of their generation resources, which places the

various lengths between 20 and 30 years—both of which diversify NIPSCO's portfolio in metrics beyond fuel-source diversity. After all coal-fired units at Schahfer are retired by 2023, NIPSCO's overall portfolio would therefore be expected to include (1) the coal-fired Unit 12 at Michigan City, (2) the gas-fired units at the Sugar Creek Generating Station, (3) gas peaker units at Schahfer, (4) wind projects under both PPA and ownership arrangements, (5) solar and solar plus energy storage projects under both PPA and ownership arrangements, and (6) any additional projects NIPSCO may receive approval for in the near-term.[82] As it begins its 2021 IRP process, as further discussed below, we expect NIPSCO will continue to work with stakeholders, including the Commission and OUCC, as it determines how best to serve its customers reliably and affordably in the future, including as it plans for generation to replace Unit 12 at Michigan City. But we acknowledge that NIPSCO has heeded prior Commission direction and appears to be well-situated to continue to serve its customers with a diverse, flexible, and adaptable generation portfolio.

As established by the 2018 IRP, obtaining resources by 2023 in order to retire coal-fired units not only diversifies the resources relied upon, but results in significant economic savings for NIPSCO's customers compared to continued operation of its coal-fired units. And NIPSCO has also submitted evidence demonstrating the economic benefits associated with investment in the Solar Projects, which has not been disputed. Based upon the evidence presented, the Commission finds that NIPSCO has shown a need for the requested Solar Projects and are reasonable and in the public interest.

(ii) Reasonableness of the Terms of the Solar Projects.

The uncontroverted evidence in this Cause supports a finding that the energy to be obtained from the Joint Ventures and accompanying Solar Offtake Agreements is needed by NIPSCO, is reasonably priced compared to other alternatives, and provides material benefits. The evidence in the record also demonstrates that the pricing of the Solar Projects is similar to the renewable resource tranches evaluated in the 2018 IRP and are thus consistent with the Short-Term Action Plan. In fact, the OUCC did not offer any evidence questioning this fact. Additionally, record evidence establishes that the Solar Projects are the result of a thorough, highly-competitive RFP process, which reflect current market conditions. The Phase II RFPs also evaluated various technological options and different transactional structures, and NIPSCO relied upon a qualified third party to evaluate the RFP responses and recommend projects for commercial negotiations. The record further demonstrates that the terms of the Solar Projects, including pricing terms and provisions challenged by the OUCC and discussed below, were reached after arms-length negotiations and will also allow NIPSCO to efficiently use the ITC, thereby reducing the ultimate cost to NIPSCO's customers. The OUCC also does not allege that retention of legacy coal resources beyond 2023 would be more economic than the Solar Projects presented for approval in this proceeding.

Furthermore, NIPSCO's Phase II RFPs process incorporated extensive transmission and deliverability analysis to evaluate the reliability of energy generated by potential projects. This analysis included the potential for future congestion at the point of interconnection and any

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utilities (and, hence, the Commission) in greater control of how such assets are operated. This is one of the measures of portfolio diversity, and it is being addressed in NIPSCO's implementation of the Short-Term Action Plan.

[82] Mr. Campbell acknowledged that NIPSCO will have additional renewable generation projects for which it will be seeking approval in early 2021.

reliability constraints on the broader MISO system, which was performed with the most up-to-date MISO model and demonstrated average congestion costs on a MWh basis.

NIPSCO's request in this proceeding involves approximately 900 MW (ICAP) of solar resources, as well as additional energy storage, which represents a significant step in NIPSCO's implementation of the Short-Term Action Plan.[83] However, approval of these near-term resources still leaves open the type and timing of additional resources to be added to NIPSCO's resource portfolio. The Solar Projects will fit well into NIPSCO's overall generation portfolio, including further diversifying this portfolio. The record also shows that NIPSCO reasonably modeled the Solar Projects. Mr. Lee and Mr. Augustine demonstrated that the LCOE analysis showed that acquiring the solar energy from the Solar Projects was superior to other options available to NIPSCO, including not acquiring solar energy.

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). As we found in the Rosewater Order and Crossroads Order, NIPSCO's proposal in this Cause preserves optionality and flexibility and is also consistent with the Commission's findings in *S. Ind. Gas & 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.

We therefore find the Solar Projects are clean energy projects under Ind. Code § 8-1-8.8-11. We also find that the energy and capacity provided through the Solar Projects and Solar Offtake Agreements is a reasonable and necessary addition to NIPSCO's portfolio of generating resources 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 resources that provides flexibility. The record shows that the addition of the Solar Projects to NIPSCO's resource mix will provide needed energy and capacity. We note that NIPSCO has commenced work on its 2021 IRP, which will again assess the future of its coal-fired generating unit at Michigan City and consider all types of resources that would be available to replace that unit if it is determined that it should be retired. As a result, after the outcome of this case, and even after NIPSCO seeks additional resources related to Schahfer's retirement by 2023, there will continue to be opportunity to consider future resources in NIPSCO's portfolio that ensure the provision of reliable and economic service. We further find that NIPSCO's requested financial incentives, as limited in its case-in-chief and on rebuttal and set forth above, should be granted. We find the BTAs and Solar Offtake Agreements should be approved.

a. <u>BTA Terms Challenged by the OUCC.</u>

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[83] As shown in Figure 1 of Mr. Campbell's direct testimony (Joint Petitioners Exh. No. 2), the preferred portfolio under the 2018 IRP indicates a need for 3,375 (ICAP) of wind, solar, and solar plus storage projects. Pages 16-19 [Question / Answer 16-17] of Joint Petitioner's Exh. No. 2 outlines the preferred portfolio in more detail, including the ICAP and UCAP needs.

There are, however, two contractual provisions included in the BTAs for each respective Solar Project that were challenged by the OUCC and warrant some discussion. As discussed below, we ultimately accept both provisions as reasonable under the facts and circumstances of this proceeding. Before we evaluate these provisions, we first address an apparent disagreement between the OUCC and NIPSCO as to the appropriate way we should evaluate the terms of the proposed BTAs and Joint Ventures.

The OUCC argues that the joint venture structures presented in this case should be viewed "in comparison to the joint venture arrangements the Commission approved in [Cause] Nos. 45194 and 45310."[84] NIPSCO, on the other hand, argues that, if a comparison is to be made, rather than referencing a different resource, such as wind projects, the more appropriate way for the Commission to evaluate the Solar Transactions is by comparing them to a scenario where NIPSCO was to build (or purchase) and then own and operate a solar resource on its own, and then to make an informed and evidence-based judgment as to whether the Solar Transactions are reasonable in comparison.[85] NIPSCO provided several reasons justifying its position, including that (a) the projects approved in Cause Nos. 45194 and 45310 were wind projects, (b) the Solar Projects are for solar and energy storage projects, (c) a different project developer is involved, and (d) commercial provisions were added to the Solar Projects to address certain new realities that did not exist at the time the wind projects were executed. We agree with NIPSCO that, under the circumstances and facts presented, to the extent we are going to compare the Solar Projects to another commercial arrangement, the more appropriate comparison is with a scenario where NIPSCO solely developed solar generation resources. That is not to say that under different circumstances a comparison between and among other Commission-approved projects may not be appropriate. But, especially considering that the Solar Projects involve a different generation technology to be developed by a different project developer and the changes in the electric industry, it would not be appropriate to compare the commercial provisions for the Solar Projects to the provisions included and approved in Cause Nos. 45194 and 45310.

Regarding the first of these commercial provisions, the OUCC, through Mr. Alvarez, challenged provisions related to the potential costs for the Solar Projects to interconnect to the MISO transmission grid.[86] As Mr. Campbell pointed out, these provisions provide protection to NIPSCO and its customers and increase flexibility and project viability. As Mr. Campbell noted, while these provisions could bring additional costs, if NIPSCO were developing the Solar Projects on its own, NIPSCO would be responsible for all interconnection costs, and if NIPSCO believed the interconnection cost increases were too high and impacted the economic viability of a particular project, its recourse would be to terminate the MISO Generator Interconnection Agreement and cancel the project. We agree that the provisions mitigate potential risk and increase project viability and thus conclude they are reasonable.

Second, the OUCC, through Ms. Aguilar, challenged BTA provisions in Section 5.14.6 of each BTA, which were discussed in [Question / Answer 33] pages 36-37 of Mr. Campbell's direct

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84 Public's Exh. No. 2 at p.5.

85 Joint Petitioners Exh. No. 1-R-C at p. 6. Through Ms. Whitehead's rebuttal testimony, NIPSCO also spent significant time explaining the provisions of Ind. Code ch. 8-1-8.5 and comparing how project approval and ongoing cost evaluations occur under these provisions, and then compared this to the Solar Projects.

86 The details of these terms are confidential and are discussed at some length by Mr. Alvarez in Public's Exh. No. 3 and by Mr. Campbell in Joint Petitioners Exh. No. 2-R-C.

testimony, Joint Petitioners Exh. No. 2-C.[87] For the reasons discussed in Mr. Campbell's confidential rebuttal testimony, Joint Petitioners Exh. No. 2-R-C, we conclude that these are reasonable provisions that provide a level of protection to NIPSCO and its customers and also increase flexibility and project viability.

Therefore, we find the provisions of the BTAs challenged by the OUCC and the overall joint venture structures more generally are reasonable and should be approved. The evidence demonstrates NIPSCO actively and reasonably advocated on behalf of itself and its customers to secure favorable commercial terms, including by negotiating the three Solar Projects with NextEra and reaching terms that may not have been achievable if three separate projects were pursued. We commend NIPSCO for securing commercial provisions that provide greater protections for NIPSCO and its customers than would be available when compared to a scenario where NIPSCO were to solely develop a solar generation project on its own, including taking steps to address certain changes in the industry.[88]

(iii) Cost Recovery. NIPSCO proposes the timely recovery of costs incurred pursuant to the CFDs (or BTA PPAs) and, if necessary, the Back-Stop PPAs be administered through NIPSCO's FAC proceedings (or successor mechanism). Although this is the first instance of a Commission-jurisdictional public utility seeking recovery of costs associated with a CFD,[89] the OUCC did not oppose NIPSCO's request but noted that NIPSCO should be held to its representation that NIPSCO's customers will not be negatively impacted, as compared to if the BTA PPA were utilized. We find that the costs to be incurred pursuant to the Solar Projects are reasonable throughout the term of the Solar Offtake Agreements. 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 Solar Offtake Agreements should be approved. We further find that NIPSCO should recover the costs associated with the Solar Offtake Agreements 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 renewable PPA proceedings, we find that NIPSCO's recovery of its CFDs (or BTA PPAs) costs and, if necessary, Back-Stop PPAs costs should not be subject to the Section 42(d) tests or any other FAC benchmarks. In the event NIPSCO utilizes a CFD instead of a BTA PPA, we will ensure that NIPSCO's customers are not negatively impacted by this decision and will require NIPSCO to submit a work paper in each quarterly FAC filing to demonstrate it is upholding its commitment.[90]

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87 The details of these terms are also confidential and are discussed at some length by Ms. Aguilar in Public's Exh. No. 2 and by Mr. Campbell in Joint Petitioners Exh. No. 2-R-C.

88 Although we do not thoroughly discuss the inclusion of a Backstop PPA in each Joint Venture transaction, we do acknowledge NIPSCO's innovation in this respect, as the Backstop PPA is key in mitigating some of the risk associated with these transactions. *See* Joint Petitioners Exh. No. 2-R-C at pp. 8-10.

89 Based on evidence presented by NIPSCO, we acknowledge that utilizing the CFDs may be necessary to ensure the available tax benefits can be efficiently utilized if NIPSCO does not timely receive the guidance it has requested from the IRS.

90 This work paper would be provided only if a CFD is utilized for one or more of the Solar Projects, and NIPSCO would submit it beginning with the first quarter that transactions occurred under the CFD, which would be at the time of commercial operation of the project(s) that utilizes the CFD. NIPSCO must work with the interested FAC stakeholders in the development of the work paper.

C. Approval of CPCN for NIPSCO's Acquisition of the Solar Projects through the Joint Ventures. 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.[91] We will address each of these provisions below.

(i) Best Estimate of the Cost. Mr. Campbell testified to the cost of each of the Solar Projects represented by the total price for the purchase of the equity in each of the ProjectCos to the respective Joint Venture. This number is confidential and set forth on pages 22, 23, and 25 of Mr. Campbell's direct testimony. As noted above, NIPSCO committed not to seek approval in this proceeding of any amounts related to its purchase of the TEP's share of any of the three Solar Projects; rather, if NIPSCO decides to purchase the TEP's share of any of the Solar Projects, NIPSCO will seek recovery in a separately docketed proceeding. That investment will be no more than the fair market value of the TEP's share of the Joint Venture. In its case-in-chief, NIPSCO also agreed that there will be a cap of cost recovery related to any additional investments across all three Solar Projects. This number is confidential and set forth on page 56 of Mr. Campbell's direct testimony.

Ms. Aguilar took the position that (1) any cost cap should be applied at the "per project level" instead of being shared among the three Solar Projects, which could result in a windfall to NIPSCO, and (2) any additional investment, for whatever reason, required by NIPSCO beyond what is being modeled as the Solar Projects' costs, including the purchase costs, be subject to the future investment cap.

In rebuttal, NIPSCO Witness Campbell explained that NIPSCO's proposed cap was only intended to relate to additional investments after the Solar Projects are purchased by the Joint Venture that would be necessary if the projects were not able to operate as expected, based on things like a force majeure event or a lengthy forced outage. He also took issue with the claim that NIPSCO's initial proposal would result in a "windfall," because the cap would only be utilized to cover legitimate cost increases to one or more of the Solar Projects. However, in order to address the OUCC's concern, NIPSCO committed to reduce the proposed cap on a dollar-per-megawatt basis in the event that any of the Solar Projects do not reach commercial operation.[92] As reflected in Joint Petitioners Exh. No. 8, the OUCC expressed that NIPSCO's proposal addressed its concern about a potential "windfall."

In this case the cost estimate for the Solar Projects originated with a very competitive all-source Phase II RFPs conducted at the direction of NIPSCO with the review of the responses performed by an experienced third party. The efficacy of that RFP has never been challenged. Based upon the evidence, the Commission finds that NIPSCO has provided the best estimate for the cost of the project. We also approve NIPSCO's proposed cap on additional investments for the reasons enumerated by Mr. Campbell at page 36 of his testimony in the amount set forth on page

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91 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.

92 This reduction will be based on the formula in footnote 38 of Mr. Campbell's direct testimony.

56 of Mr. Campbell's direct testimony, which will be applied across all three Solar Projects. This cap will apply only to additional investments after the Solar Projects are purchased by the Joint Venture, not to all additional investments of any kind as requested by the OUCC. To the extent any of the Solar Projects do not reach commercial operation, NIPSCO's cap on additional investments will be reduced based on the formula outlined in footnote 38 of Mr. Campbell's direct testimony.

(ii) Consistency with the Statewide Analysis or NIPSCO's Utility Specific Proposal. Ind. Code § 8-1-8.5-5(b)(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 the Solar Projects would fill only a portion of the shortfall anticipated in 2023. The record reflects that NIPSCO considered 96 proposals supported by 93 individual projects from more than 40 bidders across six states with different generation resources for modeling, including wind, solar, and thermal/other capacity resources under the Phase II RFPs to target primarily renewables and storage and acquire the remaining resources in the preferred portfolio. As noted above, NIPSCO adjusted the scoring in the Phase II RFPs to give greater weight to project development risk. There is strong evidence in the record that NIPSCO utilized an array of best practices, including basing model input in the 2018 IRP on its All-Source RFP, which allowed for a more informed forecast of the costs 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. But NIPSCO did not stop there; it then undertook the Phase II RFPs and incorporated these results into the 2020 portfolio analysis to determine whether its continued path to implement the Short-Term Action Plan was reasonable or should be adjusted. Based upon the evidence presented, the Commission finds that NIPSCO has shown a need for the requested Solar Projects. 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 Solar Projects are consistent with NIPSCO's 2018 IRP (as updated in the 2020 portfolio analysis), which, to the extent it addresses the short-term need for capacity that would be addressed by the Solar Projects and to the extent it is necessary, we approve.

(iii) Public Convenience and Necessity. The record establishes that the Solar Projects are 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 Solar Offtake Agreements were reached after arms-length negotiations. NIPSCO will only pay for energy under the Solar Offtake Agreements at a set price established by the Solar Offtake Agreements.

We find that the energy provided through the Solar Projects 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 Solar Projects to the resource mix will provide needed energy and capacity. NIPSCO's evidence established that it reasonably modeled the Solar Projects in its 2018 IRP.

(iv) Conclusion. 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 Solar Projects through the Joint Ventures should be issued.

D. Consideration of NIPSCO's Proposed ARP. NIPSCO has proposed an ARP as follows: because the Solar Projects arose out of the Phase II RFPs, 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).[93] NIPSCO will not be the owner of the generating assets that make up the Solar Projects. Instead, NIPSCO will own an interest in Joint Ventures. NIPSCO seeks approval of the Joint Ventures and the joint venture structures. NIPSCO further seeks to record its interest in the Joint Ventures 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 Solar Projects. 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 Ventures. As noted, NIPSCO seeks to recover its payments made to ProjectCos pursuant to the Solar Offtake Agreements, 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 under 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.

(i) Relief from Ind. Code § 8-1-8.5-5(e). 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 projects – grew out of the Phase II RFPs. Moreover, with the cap on costs to which NIPSCO agreed, 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).

(ii) Investment Reflected in Net Original Cost Rate Base. NIPSCO's proposal in this proceeding is similar to the proposal which we approved in the Rosewater and Crossroads Orders. In this proceeding, NIPSCO similarly proposes to invest in Joint Ventures, which will own ProjectCos, which will own the "property . . . used and useful for the convenience

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

of the public." Ind. Code § 8-1-2-6. ProjectCos have entered into agreements related to the energy produced by the Solar Projects with NIPSCO in the form of CFDs and BTA PPAs. In this Cause, NIPSCO has provided evidence of the benefits of participation of a TEP and the Joint Ventures in the development of renewable projects, so as to more effectively monetize the ITCs. NIPSCO has also agreed not to seek in this proceeding approval of any amounts related to the purchase of TEP's share. 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 Ventures, which will be recorded in Account No. 182.3. NIPSCO witness Camp explained why this is needed. It is the Joint Ventures that monetizes the ITC for the benefit of customers, and it is NIPSCO's investment of capital that will make the Joint Ventures possible. If the requirements of Ind. Code § 8-1-2-6 would deny NIPSCO the opportunity to earn a return on its Joint Ventures investment, then NIPSCO would simply invest in the physical utility assets themselves, which would diminish the value of the ITCs. NIPSCO has sought approval of an ARP so that costs sought to be recovered and the actual cost recovery sought by NIPSCO can be similar to the cost recovery NIPSCO would be afforded if it were the initial owner of the Solar Projects and so that NIPSCO will also be able to monetize the ITCs for its customers. 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).

(iii) <u>Relief from FAC Purchased Power Benchmarks.</u> As already explained, NIPSCO is not seeking to recover the costs to be incurred through the Solar Offtake Agreements "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 anticipated to be 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 Solar Offtake Agreements (e.g., the CFDs, BTA PPAs, and Backstop PPAs) from these requirements. Such authority is not uncommon with PPAs that we approve in advance.[94] 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) – (3).

(iv) <u>Technical Financing Requirements.</u> As explained by NIPSCO witness Camp, it is possible that GAAP would require aspects of the Joint Venture structures 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

[94] *See, e.g.*, 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.

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).

(v) Notice of Publication. Before the Commission can approve an ARP, Ind. Code § 8-1-2.5-6(d) requires that the utility publish a notice of the filing of its petition for an ARP in a newspaper of general circulation in any county in which the utility provides retail energy service. On February 24, 2021, NIPSCO certified to the Commission that publications of notice of the filing of the Petition in this Cause were made as required by Ind. Code § 8-1-2.5-6(d). NIPSCO then attached a list of the newspapers and the counties in which the notices were published, along with the proofs of publication. As such, we find that NIPSCO has satisfied the notice requirement under Ind. Code § 8-1-2.5-6(d).

(vi) 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 energy services and property. We therefore find that NIPSCO's proposed ARP as outlined in this paragraph should be approved.

E. 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 Ventures as a regulatory asset in Account No. 182.3 and that the investment should be amortized over the life of each of the Solar Projects, 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 WACC 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 Solar Projects. We further find, subject to the limitation agreed to by NIPSCO, that NIPSCO's balance in Account 182.3 related to the Solar Projects should be included in net original cost rate base for ratemaking purposes. We find that NIPSCO should reflect in rate base as a regulatory asset its costs to own its interest in the Joint Ventures just as it would have reflected the costs to build and own the generating assets in Utility Plant in Service had NIPSCO instead been the direct owner of the Solar Projects. 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.

F. Jurisdiction over Joint Ventures. Because the Joint Ventures will not be the title owner of the Solar Projects, Joint Ventures will not own electric generation facilities that provide electricity that NIPSCO will use to serve the public. As such, Joint Ventures are not a "public utility." Joint Ventures will own the ProjectCos, which will own facilities that only provide service to NIPSCO on a wholesale basis, and Joint Ventures will not operate, manage or control those electric generation facilities. To the extent the Joint Ventures could be deemed a "public utility," Joint Ventures seek an order whereby we decline to exercise our jurisdiction and Joint Ventures have elected to become subject to Ind. Code § 8-1-2.5-5. 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 Ventures as a public utility unnecessary or wasteful. Further, declining to exercise jurisdiction will be beneficial to Joint Ventures, 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 Ventures as a public utility will inhibit the implementation of NIPSCO's generation transition plan as set forth in its 2018 IRP. Accordingly, as we found in the Rosewater and Crossroads Order and to the extent necessary here, the Commission finds that it should decline to exercise its jurisdiction over Joint Ventures as a public utility.

G. <u>Conclusion.</u> We find the evidence of record in this proceeding supports approval of the Solar Projects, the Solar Offtake Agreements, and the proposed method of cost recovery. The Solar Offtake Agreements 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 costs associated with the Solar Offtake Agreements should be recovered through a Section 42(a) tracking mechanism to be administered through NIPSCO's quarterly FAC filings and the power purchase benchmarks will not apply. We further find that: NIPSCO's proposed financial incentives as outlined above in Paragraph 12.B. should be granted; a CPCN should be issued for the acquisition of the Solar Projects; NIPSCO's proposed ARP should be approved; and the Accounting and Finance Authority set forth above in Paragraph 12.E. should be granted.

Through its 2018 IRP, companion All-Source RFP, and subsequent Phase II RFPs, NIPSCO is now well into implementation of the Short-Term Action Plan, which is a step in its long-term generation resource transition path. The evidence of record in this proceeding demonstrates that NIPSCO is acting prudently to ensure it can continue to reliably serve its customers when the Schahfer coal-fired station is retired. Following completion of the Short-Term Action Plan, NIPSCO will have a flexible, diverse, cost-effective, and much cleaner generation portfolio, as discussed above. Through owned generation resources (including the Solar Projects), contracted PPAs, and participation in the MISO market, NIPSCO appears well-positioned to reliably serve customers every hour of every day at a reasonable price. NIPSCO has kept an eye on industry trends and changes in the MISO market and is remaining agile and flexible in its implementation of the Short-Term Action Plan. In consultation with MISO, we will continue to monitor the impact of proposed generation resources on the overall reliability and resource adequacy of Indiana's bulk electric system. Similarly, while we note NIPSCO has made an effort to account for expected changes in the MISO market through the 2020 portfolio analysis, based on information available at the time it was performed, we expect NIPSCO's next IRP will likewise integrate the most up-to-date results of MISO's capacity resource accreditation and RIIA studies into its renewable resource cost modeling scenarios.

We would be remiss if we did not also acknowledge the significant challenges certain parts of the United States have faced during the summer of 2020 and winter of 2020-21, particularly in California and Texas. These challenges demonstrate the importance and seriousness of the Commission's oversight over the provision of utility services, as well as the trust and dependence Hoosiers place on utilities for the essentials services they render. Indiana customers are served primarily by vertically integrated utilities who have a statutory duty to produce (or procure) and deliver electricity to customers reliably and affordably every hour of every day, and we exercise our jurisdiction over their operations to ensure they do so. Each of these utilities and their electric transmission systems is also part a regional market—either MISO or the PJM Interconnection.

"[Regional transmission organizations] are keenly aware of the resource technology transition that is occurring in the electric industry," and "[t]hey practice continuous improvement by studying the implications of the resource transition on their capacity constructs, reliability, and market products."[95] These RTOs also work "to minimize the total cost of energy delivered to consumers while maintaining high levels of reliability."[96] And the Commission works with RTOs individually and through coalitions of state regulators—as applicable to NIPSCO, MISO and the Organization of MISO States—to set planning reserve margins, ensure resource adequacy, and make any necessary changes to market design or product offerings. We remain confident that as utilities, RTOs, the Commission, and all stakeholders work together, Hoosiers will continue to receive the reliable, affordable electric service they expect and deserve, even as the generation resources that produce this electricity may change.

Throughout this order we have discussed NIPSCO's generation transition plan and how the evidence presented supports approval of the Solar Projects as part of a balanced generation portfolio. Ultimately, we find the Solar Projects are consistent with NIPSCO's IRP, which was developed to meet the current reliability and resource adequacy constructs of MISO and the Commission. We further find that the Solar Projects are cost-effective resources that satisfy in part NIPSCO's obligation to reliably serve its customers with expected operational dates that precede the anticipated need arising from the retirement of Schahfer by 2023.

13. Confidential Information. On November 30, 2020, NIPSCO filed a motion seeking a determination that designated confidential information involved in this proceeding be exempt from public disclosure under Ind. Code § 8-1-2-29 and Ind. Code ch. 5-14-3. The request was supported by the affidavit of Andrew S. Campbell, showing documents offered into evidence at the evidentiary hearing were trade secret information within the scope of Ind. Code § 5-14-3-4(a)(4) and Ind. Code § 24-2-3-2. On December 15, 2020, the Presiding Officers issued a docket entry finding the information confidential on a preliminary basis. Petitioner submitted its designated confidential information on December 17, 2020 and February 4, 2021.

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 Solar Projects 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.

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[95] IURC Report at p. 44.
[96] *Id*. at p. 47.

2. The Build Transfer Agreements and the Solar Offtake Agreements are approved.

3. The financial incentives, as outlined in Paragraphs 12.B., 12.D., and 12.E. of this Order, are all approved.

4. NIPSCO's costs incurred pursuant to the Solar Offtake Agreements 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 Crossroads Project though the Joint Ventures is approved.

6. NIPSCO's ARP outlined in Paragraph 12.D. of this Order is approved.

7. NIPSCO shall record its costs to invest in the Joint Ventures as a regulatory asset in Account 182.3, and NIPSCO's investment therein shall be amortized over the life of the Solar Projects. 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. NIPSCO should include in the regulatory asset its costs to own its interest in the Joint Ventures just as it would have reflected the costs to build and own the generating assets in Utility Plant in Service had NIPSCO instead been the direct owner of the Solar Projects.

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. NIPSCO shall file a copy of the ECCAs and LLC Agreements with the Commission under this Cause upon finalization.

11. The Commission declines any jurisdiction over the Joint Ventures.

12. NIPSCO's request for confidential trade secret treatment is hereby 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.

HUSTON, FREEMAN, KREVDA, OBER, AND ZIEGNER CONCUR:
APPROVED:

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

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Dana Kosco
Secretary of the Commission