ORIGINAL

Commissioner	Yes	No	Not Participating
Huston	√		
Bennett	√		
Freeman	√		
Veleta	√		
Ziegner	√		

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC FOR (1) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY ("CPCN") PURSUANT TO IND. CODE CH. 8-1-8.5 TO CONSTRUCT AN APPROXIMATELY 400 MEGAWATT NATURAL GAS COMBUSTION TURBINE ("CT") PEAKING PLANT ("CT PROJECT"); (2) APPROVAL OF THE CT PROJECT AS A CLEAN ENERGY PROJECT AND AUTHORIZATION FOR FINANCIAL INCENTIVES INCLUDING TIMELY COST RECOVERY THROUGH CONSTRUCTION WORK IN PROGRESS RATEMAKING UNDER IND. CODE CH. 8-1-8.8; (3) AUTHORITY TO RECOVER COSTS INCURRED IN CONNECTION WITH THE CT PROJECT; (4) APPROVAL OF THE BEST ESTIMATE OF COSTS OF CONSTRUCTION ASSOCIATED WITH THE CT PROJECT; (5) AUTHORITY TO IMPLEMENT A GENERATION COST TRACKER MECHANISM ("GCT MECHANISM"); (6) APPROVAL OF CHANGES TO NIPSCO'S ELECTRIC SERVICE TARIFF RELATING TO THE PROPOSED GCT MECHANISM; (7) APPROVAL OF SPECIFIC RATEMAKING AND ACCOUNTING TREATMENT FOR THE CT PROJECT; AND (8) ONGOING REVIEW OF THE CT PROJECT, ALL PURSUANT TO IND. CODE CH. 8-1-8.5 AND 8-1-8.8, AND IND. CODE §§ 8-1-2-0.6 AND 8-1-2-23.	)	**CAUSE NO. 45947** **APPROVED: OCT 16 2024**

ORDER OF THE COMMISSION

Presiding Officers:
James F. Huston, Chairman
Kristin E. Kresge, Administrative Law Judge

On September 12, 2023, Northern Indiana Public Service Company LLC ("Petitioner" or "NIPSCO") filed its Verified Petition with the Indiana Utility Regulatory Commission ("Commission") seeking, among other relief, a certificate of public convenience and necessity ("CPCN") to construct an approximately 400 megawatt ("MW") natural gas combustion turbine ("CT") peaking plant ("CT Project") pursuant to Ind. Code ch. 8-1-8.5, and associated ratemaking and accounting treatment for the CT Project pursuant to Ind. Code ch. 8-1-8.8.[1]

[1] On August 11, 2023, NIPSCO provided its notice of intent to file an application for a CPCN in accordance with the Commission's General Administrative Order 2023-03.

Also on September 12, 2023, Petitioner filed the testimony and attachments of the following (all of whom are employees of Petitioner except as otherwise noted): Alison M. Becker, Manager of Regulatory Policy (Petitioner's Exhibit 1); David T. Walter, Vice President of Power Delivery (Petitioner's Exhibit 2); David Austin, Director of Transmission (Petitioner's Exhibit 3); Steven Warren, Senior Manager, Sargent & Lundy ("S&L") (Petitioner's Exhibit 4); Greg Baacke, Senior Director of Major Projects (Petitioner's Exhibit 5); Karl E. Stanley, Vice President of Supply & Optimization for NiSource Inc. (Petitioner's Exhibit 6);[2] Patrick N. Augustine, Vice President of Charles River Associates' Energy Practice, Charles River Associates ("CRA") (Petitioner's Exhibit 7); and Kevin J. Blissmer, Manager of Regulatory, NiSource Corporate Services Company ("NCSC") (Petitioner's Exhibit 8).

Petitions to intervene were filed by the Citizens Action Coalition of Indiana, Inc. ("CAC"); NIPSCO Industrial Group ("IG"); United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial and Service Workers International Union AFL-CIO/CLC and its Locals 12775 and 13796 ("USW"); and Primary Energy Recycling Holdings LLC ("Primary Energy"), all of which were granted.

On December 18, 2023, Petitioner filed an Agreed Modification to Procedural Schedule, which was granted by docket entry dated January 25, 2024.

On January 16, 2024, Petitioner filed the supplemental testimony and attachments of Ms. Becker (Petitioner's Exhibit 1-S), Mr. Walter (Petitioner's Exhibit 2-S), Mr. Baacke (Petitioner's Exhibit 5-S), Mr. Stanley (Petitioner's Exhibit 6-S), Mr. Augustine (Petitioners Exhibit 7-S), and Mr. Blissmer (Petitioner's Exhibit 8-S). The supplemental testimony reflected a one-year delay of the in-service date of the proposed CT Project.

On February 9, 2024, Petitioner filed an Agreed Modification to Procedural Schedule, which was granted by docket entry dated February 20, 2024.

A public field hearing was held in LaPorte, Indiana on March 14, 2024, during which members of the public presented testimony related to the relief sought in this Cause.

On April 16, 2024, the Indiana Office of Utility Consumer Counselor ("OUCC") filed the testimony and attachments of its witnesses, all of whom are employees of the OUCC's Electric Division: Cynthia M. Armstrong, Assistant Director (Public's Exhibit 1); John W. Hanks, Utility Analyst (Public's Exhibit 2); Roopali Sanka, Utility Analyst (Public's Exhibit 3); Gregory L. Krieger, Utility Analyst (Public's Exhibit 4); and Brittany L. Baker, Utility Analyst (Public's Exhibit 5). Also on that date, intervenors filed the testimony and attachments of their witnesses, including the following: Michael P. Gorman, Managing Principal, Brubaker and Associates, Inc. (IG Exhibit 1); Anna Sommer, Principal, Energy Futures Group (CAC's Exhibit 1); Robert G. James, Managing Director, Lumen Project Management Consultants (CAC's Exhibit 2); and Benjamin Inskeep, Program Director of CAC (CAC's Exhibit 3). USW did not file testimony. Primary Energy intervened after the deadline for intervenor testimony; therefore, Primary Energy

[2] Petitioner originally prefiled the Verified Direct Testimony of Andrew S. Campbell. NIPSCO filed a Notice of Substitution of Witness on January 16, 2024.

was precluded from filing testimony.

The OUCC also filed written consumer comments on April 19, 2024 (Public's Exhibit 6).

On May 21, 2024, NIPSCO filed the rebuttal testimony and attachments of Ms. Becker (Petitioner's Exhibit 1-R),[3] Mr. Warren (Petitioner's Exhibit 4-R), Mr. Baacke (Petitioner's Exhibit 5-R), Mr. Stanley (Petitioner's Exhibit 6-R), Mr. Augustine (Petitioner's Exhibit 7-R), Mr. Blissmer (Petitioner's Exhibit 8-R), and Stephen Holcomb, Director of Environmental Policy & Sustainability, NCSC, (Petitioner's Exhibit 9-R).

On June 17, 2024, NIPSCO filed revisions to reflect the marking of various confidential information in its case-in-chief, supplemental direct testimony, and rebuttal testimony from confidential to highly confidential.

On July 8, 2024, the Presiding Officers issued a docket entry question, to which NIPSCO responded on July 8, 2024.

The evidentiary hearing in this matter commenced on July 11, 2024, at 9:30 a.m. in Room 222 of the PNC Center, 101 W. Washington Street, Indianapolis, Indiana, at which time evidence was offered by NIPSCO, the OUCC, CAC, and IG without objection. Among the evidence offered at the hearing were certain stipulations between Petitioner and various intervenors with respect to certain facts and admissibility of specific exhibits, all of which were prefiled before the evidentiary hearing.

Based upon the applicable law and the evidence of record, the Commission finds:

1. Notice and Commission Jurisdiction. Due, legal, and timely notice of the public field hearing and evidentiary hearing in this Cause was given and published as required by law. NIPSCO is a "public utility" as defined in Ind. Code § 8-1-2-1(a) and Ind. Code § 8-1-8.5-1, an "energy utility" as defined in Ind. Code § 8-1-8.4-3, and an "eligible business" as defined in Ind. Code § 8-1-8.8-6. Pursuant to Ind. Code chs. 8-1-8.4 and 8-1-8.5, Petitioner may seek Commission approval of the CPCN requested in this Cause. Under applicable law, the Commission has jurisdiction over Petitioner and the relief sought by Petitioner in this Cause.

2. Petitioner's Characteristics. NIPSCO is a public utility with its principal office and place of business at 801 East 86th Avenue, Merrillville, Indiana. NIPSCO provides 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.

[3] Petitioner originally prefiled the Verified Rebuttal Testimony of Robert C. Sears. NIPSCO filed a Notice of Substitution of Witness on May 29, 2024.

3. **Relief Requested.** In this Cause, NIPSCO requests the Commission (1) issue a CPCN pursuant to Ind. Code ch. 8-1-8.5 to construct the CT Project; (2) approve the CT Project as a clean energy project and authorize financial incentives, including timely cost recovery through construction work in progress ("CWIP") ratemaking under Ind. Code Ch. 8-1-8.8; (3) authorize recovery of costs incurred in connection with the CT Project; (4) approve the best estimate of costs of construction associated with the CT Project; (5) authorize implementation of a Generation Cost Tracker ("GCT") Mechanism; (6) approve changes to NIPSCO's Electric Service Tariff relating to the proposed GCT Mechanism; (7) approve specific ratemaking and accounting treatment for the CT Project; and (8) approve ongoing review of the CT Project, all pursuant to Ind. Code ch. 8-1-8.5 and 8-1-8.8, and Ind. Code §§ 8-1-2-0.6 and 8-1-2-23.

4. **The Parties' Evidence.**[4]

A. **Petitioner's 2021 IRP and 2023 Portfolio Analysis.** Mr. Augustine provided an overview of NIPSCO's resource planning process and reviewed the conclusions from the last several years, particularly its most recent the Integrated Resource Plan ("IRP") submitted November 15, 2021 (the "2021 IRP"). He also reviewed major market developments since the 2021 IRP and summarized the portfolio analysis that CRA and NIPSCO performed in 2023 based on these major market developments (the "2023 portfolio analysis"). Mr. Augustine stated the CT Project is consistent with the Short-Term Action Plan identified in the 2021 IRP and supported by additional analyses NIPSCO has performed.

Mr. Augustine testified the operational and cost characteristics of the CT Project are fully consistent with the assumptions for new peaking thermal resources used in the 2023 portfolio analysis, which developed a preferred portfolio with between 400 MW and 442 MW of new nameplate thermal peaking capacity additions in the near-term. He stated NIPSCO's Flexible Resource Analysis concluded that increasing the amount of long-duration dispatchable capacity above the 300 MW identified in NIPSCO's 2021 IRP will contribute to risk mitigation for customers, and the 2023 portfolio analysis demonstrated NIPSCO can achieve cost savings for customers relative to the 2021 IRP's preferred portfolio by pivoting towards a larger-sized, cost-effective thermal resource as compared to expensive storage additions.

Mr. Augustine testified that overall, the addition of the CT Project to NIPSCO's portfolio is fully supported by and consistent with the conclusions of the Flexible Resource Analysis, the 2023 portfolio analysis, and the flexibility embedded in the short-term action plan from NIPSCO's 2021 IRP.

In his supplemental testimony, Mr. Augustine presented updated information from Midcontinent Independent System Operator ("MISO") related to planning reserve margin requirements ("PRMR"), capacity accreditation, and NIPSCO's supply and demand balance. He explained that while the 2021 IRP and the 2023 portfolio analysis both incorporated the assumption that new gas peaking capacity would be in service in 2026, NIPSCO's 2021 IRP explicitly called for the procurement of short-term capacity as needed from the MISO market, and

[4] Unless otherwise noted, the summary below reflects updated information included in NIPSCO's supplemental testimony and attachments of Ms. Becker (Petitioner's Exhibit 1-S), Mr. Walter (Petitioner's Exhibit 2-S), Mr. Baacke (Petitioner's Exhibit 5-S), Mr. Stanley (Petitioner's Exhibit 6-S), Mr. Augustine (Petitioners Exhibit 7-S), and Mr. Blissmer (Petitioner's Exhibit 8-S) filed January 16, 2024.

the 2023 portfolio analysis included an expectation that short-term capacity purchase opportunities would be pursued through 2027. Therefore, a 2027 in-service date for the CT Project, accommodated by capacity market purchases to meet reserve margin requirements, remains consistent with NIPSCO's most recent resource planning conclusions. Mr. Augustine testified the change in in-service date does not impact the operational and cost characteristics of the CT Project, which were shown to be fully consistent with the assumptions for new peaking thermal resources used in the 2023 portfolio analysis. He explained that based on the latest information from MISO regarding PRMR and capacity accreditation, the capacity purchase requirements through 2027 should be manageable and in line with historical levels, although NIPSCO will need to continue to actively monitor market conditions and evolving MISO rules as part of its ongoing capacity procurement plans. Mr. Augustine concluded the addition of the CT Project to NIPSCO's portfolio continues to be fully supported by and consistent with the conclusions of NIPSCO's Flexible Resource Analysis, the 2023 portfolio analysis, and the flexibility embedded in the short-term action plan from NIPSCO's 2021 IRP.

OUCC witness Mr. Hanks had concerns that NIPSCO's incorporation of misaligned results of an all-source request for proposal ("RFP") – together with an RFP that solicited bids for a particular technology configuration – inflates the cost of the thermal peaking resource incorporated into the 2023 portfolio analysis, which could potentially to distort the results of the resource selection process used within the IRP. Mr. Hanks argued the costs used for new generic peaking capacity in the 2023 portfolio analysis were artificially inflated, making NIPSCO's estimate for the CT Project appear more reasonable, and that NIPSCO inappropriately combined the results of an all-source RFP and a technology and configuration restricted RFP. Mr. Hanks also suggested that the $1,400/kW metric for capital costs for the CT Project used in NIPSCO's analysis understated the costs of the project by excluding $83.68 million in indirect costs. Mr. Hanks testified that the $/kW metric is more accurately reflected as $1,609/kW.

CAC witness Ms. Sommer noted the Flexible Resource Analysis did not quantify the cost of NIPSCO's potential market price risk exposure or compare the costs of resources that could reduce the net load exposure. Ms. Sommer argued there was no evaluation of an alternative approach to mitigate potential risks identified in the Flexible Resource Analysis, such as a portfolio with battery storage and more demand response. Ms. Sommer suggested that under the proposed direct loss of load ("DLOL") structure, battery resources will have stronger capacity accreditation than natural gas peaker resources. Ms. Sommer stated NIPSCO's capacity calculations overstate both summer and winter accreditation for the proposed natural gas peaker resource, while understating the value of battery storage resources. Ms. Sommer performed a levelized cost analysis to compare the costs of NIPSCO's proposed CT Project with potential battery storage capacity at the existing Schahfer site to suggest that new battery additions would be lower cost than NIPSCO's proposed CT Project.

IG witness Mr. Gorman stated that, instead of relying on a complete, or updated IRP, NIPSCO based the request for a 400 MW CT on a Flexible Resource Study. Mr. Gorman suggested NIPSCO failed to consider the introduction of MISO's seasonal resource construct and that NIPSCO has not fully evaluated its resource obligations at various times of the year. Mr. Gorman testified that NIPSCO failed to account for the expected changes in Rate 531 Tier 1 demand and has therefore failed to "right size" the CT Project.

In rebuttal, Mr. Augustine testified that while the OUCC and intervenors directly and implicitly challenge the size and technology composition of NIPSCO's proposed CT Project, no one testified NIPSCO does not need this type of new capacity, which was identified in its 2021 IRP and in the subsequent analyses. Mr. Augustine addressed the OUCC and intervenors' testimonies in relation to the 2023 portfolio analysis, the Flexible Resource Analysis, NIPSCO's future supply-demand balance, and additional analysis and considerations that were introduced.

Mr. Gorman testified that instead of relying on a complete, or updated IRP, NIPSCO based the request for a 400 MW CT on a Flexible Resource Study, Mr. Augustine responded that Mr. Gorman provided an incomplete characterization of the analysis NIPSCO performed in support of its requested CPCN. He stated that the Flexible Resource Analysis was only one component of the further diligence NIPSCO performed on the preferred portfolio from its 2021 IRP. He said that although the conclusions from the Flexible Resource Analysis supported and contributed to NIPSCO's sizing decision for the CT Project, NIPSCO also performed a 2023 portfolio analysis to assess the performance of alternative portfolio options against updated market conditions and the latest available information.

Mr. Gorman suggested NIPSCO failed to consider the introduction of MISO's seasonal resource construct and that NIPSCO has not fully evaluated its resource obligations at various times of the year. Mr. Augustine responded that although MISO's seasonal construct was implemented after the submission of NIPSCO's 2021 IRP, NIPSCO anticipated this change and evaluated seasonal peak load forecasts and seasonal capacity ratings for resource options in its 2021 IRP to develop portfolios based on capacity requirements for both the summer and winter seasons. He also stated NIPSCO's 2023 portfolio analysis incorporated updated seasonal reserve margin targets and seasonal accredited capacity levels that were published after the Federal Energy Regulatory Commission ("FERC") approved MISO's seasonal construct. He testified higher winter reserve margin targets contributed to higher requirements for dispatchable thermal or storage capacity additions in the 2023 portfolio analysis relative to the levels evaluated in NIPSCO's 2021 IRP, which was directly accounted for in the portfolio construction.

Ms. Sommer's testified she did not perform independent modeling in part due to concerns the portfolios that were examined included projects that NIPSCO has canceled. Mr. Augustine responded that while some of the portfolios did include projects that had been canceled, preferred Portfolio 3 was explicitly developed to incorporate the risk of project cancellations, specifically the potential loss of four out of ten or 700 MW of solar and 30 MW of storage of NIPSCO's current solar and solar plus storage projects. He stated that consistent with these assumptions, NIPSCO has since filed termination notices for these four projects and has used the 2023 portfolio analysis to support replacement of these projects with incremental wind and solar capacity,[5] as explicitly modeled in preferred Portfolio 3 and approved by the Commission.

Mr. Hanks argues the costs used for new peaking capacity in the 2023 portfolio analysis were artificially inflated and that NIPSCO inappropriately combined the results of an all-source RFP and a technology and configuration restricted RFP. Mr. Augustine responded that Mr. Hanks

[5] NIPSCO filed a CPCN for the 200 MW Appleseed solar project and the 200 MW Templeton wind project in Cause No. 45887 (approved September 13, 2023) and a CPCN for the 200 MW Carpenter wind project in Cause No. 45908 (approved October 18, 2023).

appeared to misunderstand what NIPSCO requested in the two RFPs that were issued in 2022, as well as the types of bids that were received. As a result, he argued the comparisons Mr. Hanks attempted to make are inappropriate. He stated that contrary to Mr. Hanks' claims, NIPSCO's Schahfer Development or Engineering, Procurement, and Construction ("EPC") RFP was not technology and configuration restricted. He explained while NIPSCO did require a dispatchable, blackstart-capable resource at the Schahfer site with several other performance criteria, no restrictions were placed on the technology and configurations that could be proposed by bidders, and bids into this RFP were used by NIPSCO and CRA to arrive at the $1,440/kW direct capital cost number presented in his direct testimony and in the 2023 portfolio analysis.

Mr. Augustine testified Mr. Hanks' criticism that the capital costs for the CT Project used in his analysis understate the costs of the project by excluding indirect costs is misplaced. He stated that for modeling purposes, to ensure an "apples-to-apples" comparison with other potential resource options, only the direct costs of the project were included in his analysis, which is both commonplace and appropriate. He explained that while NIPSCO includes indirect costs in the overall project cost estimate, these costs are generally ancillary to the core project components and incorporate overheads and other internal allocations. He testified that including these company-specific indirect costs in weighing resource options would serve only to skew the results and the purpose of the portfolio and revenue requirement modeling analysis he performed is primarily to compare costs of resource options; therefore, excluding indirect costs provides a direct cost comparison, which is a more meaningful and reasonable approach.

Ms. Sommer testified the Flexible Resource Analysis did not quantify the cost of NIPSCO's potential market price risk exposure or compare the costs of resources that could reduce the net load exposure. Mr. Augustine responded that the Flexible Resource Analysis was designed to assess the energy adequacy and flexibility characteristics of NIPSCO's preferred portfolio from the 2021 IRP and to analyze and characterize the potential for market exposure risk. He stated that as Ms. Sommer correctly points out, the Flexible Resource Analysis was not an economic assessment, but a means of assessing the magnitude, frequency, and duration of market exposure risk and the overall ability for NIPSCO's portfolio to be positioned to respond to evolving market conditions and bring its fair share of reliability attributes to the system in the face of uncertain MISO rules. Mr. Augustine testified although NIPSCO did not quantify the costs of market exposure risk in the Flexible Resource Analysis, the key outcomes are supportive of the fact that additions of long-duration dispatchable capacity like the CT Project will improve reliability and reduce market exposure cost risk for customers, which Ms. Sommer did not challenge.

Mr. Augustine testified Ms. Sommer's argument that there was no evaluation of an alternative approach to mitigate potential risks identified in the Flexible Resource Analysis is inaccurate. He stated that in addition to the resource attribute needs identified in the Flexible Resource Analysis, NIPSCO's 2023 portfolio analysis specifically evaluated a portfolio with additional battery storage resources and no new thermal peaking capacity to assess the economic tradeoffs relative to the portfolio that contained the new peaker, and that it concluded the portfolio with new peaking capacity was lower cost for customers. He noted NIPSCO's 2021 IRP did the same and concluded that the portfolio with new peaker capacity performed similarly or better on cost-based metrics than a portfolio relying only on storage and best on the reliability metrics. Mr. Augustine testified NIPSCO has performed multiple evaluations to assess alternative approaches and arrive at its preferred portfolio with the CT Project.

Mr. Gorman testified NIPSCO has failed to account for the expected changes in Rate 531 Tier 1 demand and has therefore failed to "right size" the CT Project. Mr. Augustine explained NIPSCO's 2021 IRP did evaluate a scenario with the exact reduction in Tier 1 demand commitments suggested by Mr. Gorman. Mr. Augustine noted NIPSCO incorporated the potential for additional industrial load migration to the new industrial rate service structure. The scenario incorporated a reduction of firm industrial load in Rate 831 down to 70 MW. He further explained that NIPSCO's 2021 IRP shows its preferred portfolio performed well under these assumptions.

Ms. Sommer proposes battery storage and demand response resources be deployed because these resources can be added quicker than the CT project can be built. Mr. Augustine testified while development and deployment timelines will vary by resource, NIPSCO's preferred portfolio from its 2021 IRP and 2023 portfolio analysis contemplated new battery storage and demand side management resource additions by 2028, and he expects additional capacity additions will be identified as NIPSCO continues its ongoing resource planning activities in 2024 and beyond. He explained the resource is expected to be in service by the end of 2027, in advance of the 2028/29 planning year when the MISO rules are due to change, and the resource offers a firm, dispatchable addition to NIPSCO's portfolio that will help fill the existing and emerging capacity gap.

Mr. Augustine disagreed with Ms. Sommer's suggestion that battery resources will have stronger capacity accreditation than natural gas peaker resources and her statement that NIPSCO's capacity calculations overstate summer and winter accreditation for the proposed natural gas peaker resource, while understating the value of battery storage resources. He testified future capacity accreditations under D-LOL remain too uncertain to definitively make such a claim, and the forward-looking information published by MISO is supportive of the assumptions used in NIPSCO's 2023 portfolio analysis, which included stable accreditation for gas resources and declining accreditations for four-hour battery storage resources over time.

In response to Ms. Sommer's levelized cost analysis, which compared the costs of NIPSCO's proposed CT Project with potential battery storage capacity at the existing Schahfer site and suggested that new battery additions would be lower cost than NIPSCO's proposed CT Project, Mr. Augustine opined that while levelized cost analysis can be a useful way of comparing resource options, Ms. Sommer's calculations were not performed correctly, nor do they replace the 2023 portfolio analysis performed by NIPSCO and CRA, which aimed to provide a more holistic comparison of NIPSCO's preferred portfolio concept versus one that relies primarily on new storage additions. Mr. Augustine described a significant calculation error and several limitations relative to the 2023 portfolio analysis in Ms. Sommer's analysis.

Mr. Hanks' and Ms. Sommer's oppose NIPSCO's application in part because of the cost of the aeroderivative turbine component, and Mr. Hanks' argues NIPSCO has not established that the benefits of aeroderivative units are worth the higher cost relative to industrial frame units. Mr. Augustine testified NIPSCO's 2021 IRP and Flexible Resource Analysis are supportive of resource additions with the attributes of the aeroderivative turbines. He explained in NIPSCO's 2021 IRP, the ancillary services valuation and the reliability assessment highlighted the need for certain attributes like fast ramping capability, particularly as the MISO markets evolve, and that NIPSCO's Flexible Resource Analysis identified growing 3-hour and 10-minute ramping requirements by 2030.

B. **<u>CT Project</u>.** In her direct testimony, Ms. Becker explained how NIPSCO supported, through sufficient evidence, the statutory requirements for the issuance of a CPCN, including financial incentives, under Ind. Code §§ 8-1-8.5-4, 8-1-8.5-5, and 8-1-8.8-11. She sponsored Attachment 1-A showing each element of Ind. Code §§ 8-1-8.5-4, 8-1-8.5-5, and ch. 8-1-8.8 and identified the NIPSCO witness with supporting testimony.

Ms. Becker explained how NIPSCO supported the requirements set out in Ind. Code § 8-1-2-0.6. She sponsored Attachment 1-C showing each of the Five Pillars, which includes reliability, affordability, resiliency, stability, and environmental sustainability. and identified the NIPSCO witness with supporting testimony. She also explained how NIPSCO has addressed the guidelines for additional evidence to be provided pursuant to IURC GAO 2022-01. She sponsored Attachment 1-D providing the required information as it pertains to NIPSCO's request for approval under Ind. Code chs. 8-1-8.5 and 8-1-8.8 in this Cause. She also sponsored Attachment 1-G, which is the Affidavit of Andy Witmeier, Director of Resource Utilization for MISO, providing a qualitative assessment regarding the new generation, including NIPSCO's request to MISO. In her supplemental testimony, Ms. Becker described NIPSCO's follow-up contact with MISO considering the shift in the in-service date.

Ms. Becker testified NIPSCO followed the guidelines applicable to applications for a CPCN established in the Commission's General Administrative Order 2023-03 ("GAO 2023-03"). She sponsored NIPSCO's notice of its intent to file an application for a CPCN as Attachment 1-E. She also testified NIPSCO met to discuss its filing with the Commission on May 8, 2023, the OUCC on May 24, 2023, and CAC on July 12, 2023. She sponsored an index of issues and identification of the witness(es) addressing each of the issues as Attachment 1-F.

As it relates to the statutory requirements set out in Ind. Code § 8-1-8.5-4, Ms. Becker addressed the requirement to consider conservation and load management. She testified that based on her experience with NIPSCO's energy efficiency ("EE") initiatives, NIPSCO could not derive sufficient energy savings from EE to replace Schahfer. She said NIPSCO is committed to the development of demand response programs for all customer groups but concluded that demand response would not eliminate the need for the CT Project, and, based on how such plants are constructed, would likely not reduce the size of the project.

Mr. Walter described NIPSCO's current generation fleet and explained the ultimate portfolio NIPSCO currently expects to have in place to serve its customers after its coal-fired generating units are retired over the next five years. He opined the CT Project is a clean energy project as that term is defined in Ind. Code § 8-1-8.8-2. He addressed how the proposed construction of the CT Project relates to the Five Pillars outlined in Ind. Code § 8-1-2-0.6.

Mr. Austin explained NIPSCO's gas distribution system as it relates to the CT Project, the quick-start, fast-ramping, and other important capabilities of the CT Project at the Schahfer site, and the CT Project's contribution to NIPSCO's system reliability.

Mr. Warren sponsored the Engineering Study prepared by S&L, which set forth the Class 3 cost estimate for NIPSCO's proposed simple cycle gas turbine project that was used by NIPSCO to develop its best estimate of the costs of the proposed CT Project. He presented information regarding the engineering work completed by S&L in support of NIPSCO's request for approval of a new peaker power plant to be located at the Schahfer site.

Mr. Baacke explained the CT Project, including key specifications and characteristics, the approach to configuration selection and the contracting strategy for the CT Project. He also provided the project schedule and the best estimate of costs of construction. He explained the CT Project is planned to be approximately 400 MW, consisting of one larger industrial frame unit with three smaller aeroderivative or similarly sized industrial frame units (dependent on the results of the CT original equipment manufacturer ("OEM") bid event). Finally, he discussed how the CT Project satisfies Ind. Code § 8-1-8.5-5(e).

Mr. Stanley discussed: (1) how the CT Project will interconnect into the MISO market through the replacement generation interconnection process, (2) NIPSCO's need for capacity from a peaking unit, and (3) how NIPSCO will procure gas supply for the Project at the lowest reasonable cost. Finally, he discussed how the CT Project is consistent with the resource alternatives that must be evaluated under Ind. Code § 8-1-8.4-4.

i. **Best Estimate.** In his direct testimony, Mr. Baacke stated NIPSCO employed S&L to help develop a scope of work to obtain preliminary quotes for major equipment during the engineering study phase to support the cost estimate shown in Appendix 20 of the Engineering Study (Highly Confidential Attachment 4-A). He stated S&L then supported NIPSCO by drafting technical specifications for the EPC RFP. He said the cost estimated by S&L was compared to the costs for gas-fired projects bid into the EPC RFP. He explained that after NIPSCO elected to move forward with the self-build option to capture cost savings and other advantages, S&L developed technical specifications to support a competitive bid event for the procurement of turbines for the CT Project that occurred in June 2023 (the "turbine equipment RFP") with bids received August 7, 2023. He indicated that similar competitive bid events are planned to be completed for other major equipment as well as major construction contracts.

Mr. Baacke testified the EPC RFP was issued in Fall 2022, seeking bids for projects between 370 MW to 450 MW. He stated technical specifications for the EPC RFP were drafted because of the work previously performed in collaboration with S&L during the engineering study phase. He testified bidders were requested to provide proposals with a combination of industrial frame and aeroderivative combustion turbines meeting specific performance criteria. He explained the performance criteria included desired machine sizing, cold start timing, ramp rates, minimum emission compliant loads, emission limits, remote start and operational capabilities, and other reliability capabilities.

Mr. Baacke described the results of the proposals were received from three bidders. One bid did not meet the performance criteria of the technical specifications and provided less than five pages of information and was not evaluated for further consideration. A second bid provided a proposal that consisted of ten refurbished aeroderivative turbines which did not align with the RFP criteria or the performance criteria of the technical specifications. A third bid aligned with the technical specifications however, the proposal price was $100 million more than the self-build option costs of construction. He testified NIPSCO ultimately chose the self-build option, which is in the best interest of NIPSCO and its customers.

Mr. Baacke described the procurement and bid process NIPSCO is using to purchase equipment for the CT Project. He stated NIPSCO plans to utilize a multi-prime contracting strategy for the CT Project, which is different from an engineering, procurement, and construction contracting strategy in which a single entity would be utilized to perform all engineering, procurement, construction, and start up and commissioning activities to complete the project. He stated NIPSCO plans to hold competitive bid events whenever practical for major equipment such as generator step-up transformers, unit auxiliary transformers, generator circuit breakers, switchgear, and other associated auxiliary equipment and to procure smaller equipment and materials through preferred suppliers that were identified through prior strategic sourcing events.

Mr. Baacke testified NIPSCO's multi-prime contracting strategy applies to construction on the CT Project as well. He stated NIPSCO plans to develop bid packages to competitively bid the three major scopes of construction in 2024: (1) site preparation/civil construction contract, (2) general works construction contract, and (3) an electrical installation contract. Mr. Baacke testified that under this planned construction and bid process, NIPSCO will have allowed third parties to submit firm and binding bids for the construction of the CT Project on NIPSCO's behalf that meet all the technical, commercial and other specifications so as to enable ownership of the CT Project to vest with NIPSCO not later than the date the facility becomes commercially available.

Mr. Baacke testified the best estimate of the total cost of construction for the CT Project is $641,223,000, which includes indirect costs but excludes allowance for funds used during construction ("AFUDC"). He explained NIPSCO will accrue AFUDC associated with the CT Project costs based upon the amounts at the time such costs or charges are incurred. He stated that based upon estimates of AFUDC at the time of this filing, the total estimated cost, including AFUDC of $2,468,449, is $643,691,449.[6] Mr. Baacke stated the cost estimate was developed with the support of S&L. Mr. Baacke sponsored the best estimate of cost summary in Attachment 5-A as well as a more detailed estimate of cost summary in Confidential Attachment 5-B.

In his supplemental direct testimony, Mr. Baacke discussed supply chain challenges that affected the project schedule and how NIPSCO's election to self-build utilizing a multi-prime contracting strategy has allowed NIPSCO to pivot in the face of these challenges without a presently anticipated impact to the best estimate. He sponsored an updated CT Project schedule and best estimate of costs of construction.

Mr. Baacke stated NIPSCO's originally estimated in-service date for end of year 2026 was with the understanding the CT Project must be in service no-later-than end of year 2027 due to planned retirements in 2028. He explained this timeline included some flexibility as is typical for significant construction projects, especially given supply chain challenges are more commonplace since COVID-19. He stated that based on the expectation that the combustion turbines and generation step-up transformers would be the longest lead time equipment, NIPSCO went out for bid on these components before filing its request for a CPCN and noted NIPSCO was still evaluating the information received from the bid events, including ongoing conversations with suppliers. Mr. Baacke testified NIPSCO's election to self-build with a multi-prime contracting

[6] NIPSCO Witness Mr. Blissmer testified that if NIPSCO's proposed CWIP ratemaking is approved, AFUDC is projected to be very limited, and would include only actual AFUDC accrued to date and through the effective date of the GCT Mechanism, expected to be in October 2024.

strategy was beneficial in the face of these supply chain challenges because it allowed NIPSCO to pivot without a presently anticipated impact to the best estimate. He noted other contracting structures, such as with an EPC contractor, would likely have required the execution of a change order to shift the in-service date to end of year 2027 and increased costs as a result. Additionally, he stated NIPSCO was able to secure a favorable procurement timeframe for generator step-up transformers due to its vendor relationship.

In his supplemental testimony, Mr. Baacke testified the best estimate of the total cost of construction for the CT Project remains at $641,223,000, which includes indirect costs but excludes AFUDC. He explained NIPSCO will accrue AFUDC associated with the CT Project costs based upon the amounts at the time such costs or charges are incurred. Based upon estimates of AFUDC at the time of this supplemental filing, Mr. Baacke testified the total estimated cost, including AFUDC of $1,531,039, is $642,754,039.

OUCC witness Ms. Armstrong recommended costs associated with certain pollution control technology be removed from the CT Project best estimate. Ms. Armstrong stated NIPSCO can seek approval of any future pollution control costs as federally mandated costs under the Federal Mandate Statute at Ind. Code ch. 8-1-8.4. Ms. Armstrong stated the OUCC does not consider NIPSCO's request for the CT Project, as currently proposed, to be affordable.

OUCC witness Mr. Hanks stated NIPSCO's best estimate potentially double counts indirect costs. Mr. Hanks stated NIPSCO did not justify a 5% escalation factor and recommended its proposed escalation be reduced to 3% to match its electric Transmission, Distribution, and Storage System Improvement Charge ("TDSIC") Plan. Mr. Hanks compared the cost of NIPSCO's proposed CT Project to average technology costs from the U.S. Energy Information Administration's ("EIA") Annual Energy Outlook of 2023 and to the cost of CEI South's CTs.

OUCC witness Mr. Krieger stated the OUCC is concerned with NIPSCO's estimated owner's costs. He believed NIPSCO's application of a simple nine percent is not supported or justified for a complex project. Mr. Krieger believed the owner's costs would be significantly less when an EPC contractor is hired.

IG witness Mr. Gorman stated NIPSCO's cost estimate should be rejected because it is not based on firm pricing because of competitive bids received from contractors, but rather on preliminary market analysis of the expected costs.

CAC witness Ms. Sommer argued for prejudgment of the prudency of certain actions and prospective disallowance of costs. Ms. Sommer argues for a cost cap on project costs. Ms. Sommer recommended denial of NIPSCO's request based on the cost of the aeroderivative turbines. Ms. Sommer recommended that costs to serve customers in order to accommodate a delay in the online date of the CT Project be disallowed including but not limited to capacity and energy costs.

Mr. Baacke disagreed with CAC witness Mr. James' assertion that a self-build approach is not in customers' best interests and adds significant risk to the Project cost. He testified NIPSCO has experience with both EPC and multi-prime contracts and provided some of NIPSCO's history of successfully executing on large and complex projects below.

In response to several witnesses claims that entering an EPC contract can mitigate cost risk and multi-prime contracting may translate into additional ratepayer costs, Mr. Baacke testified that while EPC contracts can provide some benefits, the parties fail to appreciate that, to create certainty, an EPC contractor is paid for risks that could potentially be avoided, mitigated, or not occur at all. Mr. Baacke testified that both contracting strategies have benefits and the potential for increased costs; however, for the CT Project, and after careful consideration, NIPSCO determined the multi-prime contracting strategy offers a greater potential for savings on the overall cost of the project, especially when managed effectively and scoped accurately.

OUCC witness Mr. Krieger and CAC witness Mr. James claim NIPSCO does not have experience building gas-fired generation projects of this scale and are concerned NIPSCO lacks large project management experience. Mr. Baacke explained NIPSCO is leveraging engineering firms including S&L, construction contractors, and suppliers, including the original equipment manufacturer ("OEM"), who have completed comparable projects. He testified NIPSCO's Major Projects team has completed a number of projects of varying complexity, including several projects that are first of their kind or one-of-a-kind projects and at the time of completion, within the industry.

Mr. Baacke testified Mr. Krieger's review of the accuracy as a percentage of budget for each project that he has served a major role is not a fair and complete picture of his project management experience. This review only shows the project variances in absolute dollars, which ignores the variances on these projects have been both higher and lower than the original budgets. He stated that in relative dollars, NIPSCO's original budgets versus actual costs for the referenced projects shows that, on an overall original budget of $1.41 billion, projects that have been completed under Mr. Baacke's direction and supervision reflect a negative variance of approximately -2.4%. This data reflects NIPSCO's commitment to manage the construction of the CT Project such that the Project is executed on time and on budget.

Mr. Baacke clarified S&L's scope of work in the CT Project. He stated S&L has also been contracted by NIPSCO to complete the detailed design for the CT Project. He testified NIPSCO plans to contract with S&L to provide onsite support during construction, start up and testing to provide quality assurance and quality control during installation. Mr. Baacke testified the costs associated with these additional services is included in NIPSCO's best estimate.

Mr. Baacke sponsored Attachment 5-R-A and Confidential Attachment 5-R-B showing the best estimate of the total cost of construction for the CT Project remains at $641,223,000, which includes indirect costs but excludes AFUDC. He explained NIPSCO will accrue AFUDC associated with the CT Project costs based upon the amounts at the time such costs or charges are incurred and that based upon estimates of AFUDC at the time of this rebuttal filing, the total estimated cost, including AFUDC of $2,680,234, is $643,903,234.

Mr. Baacke emphasized NIPSCO's best estimate although reasonable, is still an estimate; customers will pay the actual costs of the CT Project. He testified that prices for practically all products and materials in the U.S. are increasing, including the key equipment needed to construct the CT Project; this is an undeniable macroeconomic fact, which is beyond NIPSCO's control. He testified NIPSCO ran a competitive RFP, engaged S&L to assist with engineering and cost estimation, chose a multi-prime contracting approach which was $100 million lower in cost than any viable EPC option, and brought a reasonable, best estimate to the Commission to support a finding of best estimate of costs in this proceeding.

ii. <u>Configuration and Competitive Procurement</u>. Mr. Baacke testified the CT Project is expected to consist of one larger industrial frame unit with three smaller aeroderivative or similarly sized industrial frame units. He explained NIPSCO is targeting an F Class combustion turbine for the larger industrial frame turbine, which has been on the market for over 30 years and has a proven history of solid, reliable performance. General Electric's F Class combustion turbine has been upgraded to its 7FA.05 model with power output and heat rate values at ISO conditions of approximately 239 MWs and 8,871 btu/kWh (LHV) and shorter start times to as little as 11 minutes and ramp rates as high as 50 MWs per minute. Similar performance exists for Siemens Energy's SGT6-5000F combustion turbine. Larger industrial frame units typically have a lower capital cost per kilowatt to install, require fewer machines, and generally have longer intervals between maintenance when compared to aeroderivative turbines.

He explained NIPSCO is including three smaller aeroderivative or similarly sized industrial frame turbines in the CT Project. Aeroderivative turbines are typically more efficient, start faster and frequently, and fluctuate power generation faster to meet demand when compared to larger industrial frame turbines. These features, along with market import capabilities, allow a utility to install large volumes of renewable energy and still maintain the ability to reliably and efficiently serve a heavy industrial customer base, as well as commercial and residential load, when the intermittent renewable resources are not available for short or prolonged periods of time.

Mr. Baacke testified NIPSCO chose the preferred configuration to maximize benefits to NIPSCO and its customers. This preferred configuration was needed to conduct an RFP to seek proposals for the EPC RFP. NIPSCO and S&L developed a decision matrix to select the equipment configuration that would be used for purposes of the EPC RFP. This evaluation included performance criteria to align with the Flexible Resource Analysis, operational factors, costs, environmental factors, and schedule.

Mr. Baacke explained the benefits to constructing the CT Project on the Schahfer site. He stated NIPSCO already owns the property. He said constructing the CT Project on this site provides cost savings and advantages for NIPSCO, its customers, and the local economy.

As discussed by NIPSCO witness Mr. Stanley, NIPSCO holds interconnection rights at the Schahfer site related to Units 17 and 18 that will be retiring by the end of 2025. The MISO grid interconnection rights can be transferred from existing coal units to the CT for up to three years after retirement.

OUCC witness Mr. Hanks claims the EPC RFP prevented bidders from proposing less expensive all industrial frame configurations, Mr. Baacke testified EPC RFP bidders were not prevented from proposing all industrial frame configurations. He testified the technical specifications for the EPC RFP, which are over two hundred pages, were provided to the parties in discovery and shows that the EPC RFP asked bidders to select a combination of industrial frame and aeroderivative CTs and optionally, reciprocating internal combustion engines that could meet certain defined constraints, including (1) total net output between 370 MW and 450 MW; (2) maximum machine size of 275 MW; (3) at least one machine 150 MW or larger; (4) 10-minute cold start capability for 150 MW or more; (5) 50 MW/minute minimum ramp rate for at least 150 MW of the Facility's machines; and (6) at least one machine with a minimum emission compliant load less than or equal to approximately 25 MW. He testified the defined constraints were assembled to provide potential bidders with enough information to know the type of project that would fit the needs identified by NIPSCO and CRA through the Flexible Resource Analysis, but freely allowed potential bidders to provide bids that would include one larger industrial frame machine and multiple smaller aeroderivative or industrial frame units.

Mr. Baacke noted that while Mr. Hanks claims NIPSCO "self-selected" its preferred configuration and required bidders to offer aeroderivative units, CAC witness Mr. James claims the quality of NIPSCO's EPC RFP was wanting insofar as it relies upon a project that needs more definition and planning. Mr. Baacke testified that while the OUCC and CAC appear to disagree on the appropriate level of detail needed in the RFP, NIPSCO's balanced approach falls reasonably between the two.

Mr. Baacke testified NIPSCO's internal EPC RFP bid evaluation scorecard and related documentation were provided in discovery and show NIPSCO properly vetted the EPC RFP bids. He stated given the EPC RFP bid results and NIPSCO's history with successful project execution, NIPSCO made the prudent decision to pursue a multi-prime contracting strategy.

OUCC witness Ms. Sanka's claims NIPSCO failed to evaluate the configuration with one large industrial frame and smaller industrial frame, similarly sized to the aeroderivative turbines, in the decision matrix of S&L's Engineering Study. Mr. Baacke testified this criticism is misplaced. He explained smaller industrial frame machines provide similar performance when compared to smaller aeroderivative machines; therefore, it was not necessary to perform a separate analysis for a large industrial frame with smaller industrial frame machines.

NIPSCO witnesses Mr. Augustine and Mr. Holcomb explain in their rebuttal testimony that the U.S. Environmental Protection Agency released greenhouse gas emission rules for the power sector on April 24, 2024, which lay out the best system of emission reduction standards for new natural gas-fired facilities based on their capacity factor. Mr. Holcomb explained that based on the expected operational characteristics of NIPSCO's proposed units, the overall CT Project will be able to operate within the standards of the rule. Furthermore, given their higher efficiencies, the aeroderivative turbines will be able to more easily achieve the 1,170 lb. CO_2/MWh standard than the frame turbine, offering more flexibility and optionality for NIPSCO to operate the units at higher capacity factors should conditions within the MISO market make such operations beneficial for its customers.

OUCC witness Ms. Sanka claims that, base load plants come at a lower initial cost and have lower operations and maintenance costs compared to a peaker plant containing aeroderivative units, making them more financially viable. Therefore, in a 30-year lifespan, the cost-effectiveness of using a configurated base load plant outweighs the benefits of using a configuration containing aeroderivative technology for peaker plants. Mr. Augustine explained Ms. Sanka's framing of the cost-effectiveness evaluation is incomplete, particularly as resource planning questions become more complex.

5. <u>Commission Discussion and Findings</u>. Since the issuance of its 2021 IRP, NIPSCO has continued to evaluate and analyze its generation needs considering ongoing changes in market rules, supply chain, and other broader market changes. NIPSCO's most current analysis identifies a need for a gas-fired resource between 400 MW and 442 MW. Based on the needs associated with the retirement of most of NIPSCO's coal-fired generation by the end of 2025 and the addition of renewable resources, NIPSCO seeks to construct and operate the CT Project as a part of its overall, diverse portfolio of generation assets. Once operational, the facility will be a central part of NIPSCO's electric generating fleet, because it will provide key reliability attributes and additional capacity, particularly in the winter season.

NIPSCO's Flexible Resource Analysis concluded increasing the amount of long-duration dispatchable capacity above the 300 MW identified in NIPSCO's 2021 IRP will contribute to risk mitigation for customers, and the 2023 portfolio analysis demonstrated NIPSCO can achieve cost savings for customers relative to the 2021 IRP's preferred portfolio by pivoting towards a larger-sized thermal resource as compared to more expensive storage additions. The Flexible Resource Analysis identified potential reliability issues resulting from the relatively large share of planned renewable generation in NIPSCO's preferred portfolio and assessed flexibility needs on an inter-hour and intra-hour basis. The analysis also evaluated how NIPSCO's mix of resources is likely to perform in 2030 compared to 2021 and identified that the 10-minute ramp requirements are increasing by 150 MW. NIPSCO's EPC RFP specifications for the proposed CT Project included requirements of a 10-minute ramp cold start capability for 150 MW or more and a 50 MW/minute ramp rate for at least 150 MW. The OUCC agrees NIPSCO needs load-following generation. We conclude that the CT Project is an economical decision that will aid in reliability; therefore, the Commission grants the requested CPCN for the CT Project.

A. <u>CPCN for CT Project Under Ind. Code § 8-1-8.5-5</u>. Ind. Code § 8-1-8.5-2 states that a public utility must obtain a CPCN from the Commission prior to constructing, purchasing, or leasing a facility for the generation of electricity. Ind. Code § 8-1-8.5-5 sets forth the criteria for approving a utility-specific generation proposal. In granting a CPCN, the Commission must make findings on the best estimate of the project's cost based on the record, whether the proposal is consistent with our statewide analysis or a utility-specific proposal, and whether public convenience and necessity require the project. The Commission must also consider the items set forth in Ind. Code § 8-1-8.5-4. We address the required findings and review each factor in Ind. Code § 8-1-8.5-4 below.

i. <u>Best Estimate of Costs</u>. Under Ind. Code § 8-1-8.5-5(b)(1), a CPCN may be granted only if the Commission makes a finding "as to the best estimate of construction, purchase, or lease costs based on the evidence of record[.]"

Mr. Baacke explained the CT Project, including key specifications and characteristics, as well as NIPSCO's approach to configuration selection and contracting strategy. He provided the project schedule, the best estimate of costs of construction, and NIPSCO's request for ongoing review pursuant to Ind. Code § 8-1-8.5-6. He explained the CT Project is planned to be approximately 400 MW, consisting of one larger industrial frame unit with three smaller aeroderivative or similarly sized industrial frame units. Mr. Walter explained NIPSCO's cost estimate is the best estimate currently available and will be updated as the project proceeds, consistent with the Commission's requirements and NIPSCO's request for ongoing review.

Mr. Walter testified NIPSCO began with a competitive EPC RFP and engaged the assistance of Sargent and Lundy. Based on available information in the market and the bids received, NIPSCO determined the best path is to self-build the CT Project, leveraging the available interconnection rights from retiring generation at Schahfer. NIPSCO issued its turbine equipment RFP in June 2023 and executed an agreement with its turbine manufacturer on March 29, 2024 to reserve the selected equipment. Mr. Baacke's supplemental direct testimony described unexpected supply chain challenges impacting NIPSCO's ability to timely procure breakers and generator step-up transformers, and explained that this caused NIPSCO to shift the expected in-service date for the CT Project to year-end 2027. Despite this change, the best estimate of the total cost of construction did not change.

Mr. Blissmer testified NIPSCO is currently carrying significant preliminary, survey, and investigation costs on its books that it will record to the cost of owned generating resources, a portion of which will be applied to the new CT Project. These preliminary, survey, and investigation costs were not challenged by any party and are included in NIPSCO's best estimate of the cost of construction for the CT Project.

NIPSCO's best estimate of the total cost of construction (excluding AFUDC) for the CT Project is $641,223,000. NIPSCO confirmed its cost estimate in its supplemental testimony based on updated supply chain information. Mr. Blissmer explained NIPSCO removed escalation and reduced the amount of contingency associated with owner's costs and certain equipment. The total estimated cost of the CT Project, including estimated AFUDC of $2,680,234, is $643,903,234. This AFUDC estimate assumes NIPSCO's proposed forward looking GCT Mechanism is approved.

The following discussion details the challenges to NIPSCO's best estimate.

a. <u>Configuration of CT Project</u>. CAC witness Mr. James opined NIPSCO and S&L progressed through project initiation with less than adequate attention to current best practices for early project definition, namely a Front-End Engineering and Design ("FEED") study, and that NIPSCO's process to reach a final investment decision remains questionable. Based on the evidence presented, we find that NIPSCO and S&L's design and engineering process was thorough, consistent with industry standards, including the Association for the Advancement of Cost Engineering cost classification, and rigorous in evaluating three different configurations for the design of the CT Project. Mr. Warren explained FEED studies evaluate whether a project should move forward at each step or stage and is unnecessary because of the IRP process and S&L's Engineering Study. The process NIPSCO used to develop its CT Project is like processes we have seen used by other utilities for which we have approved CPCNs. While FEED studies have been used for other projects in Indiana, we have only seen them in connection with novel technologies, such as coal gasification or carbon capture. In designing and engineering the CT Project, NIPSCO leveraged S&L's extensive power industry expertise. S&L's Engineering Study provided NIPSCO with the level of information needed to determine the technology and configuration that best meet the simple cycle gas turbine requirements.

Based on the evidence of record, we find NIPSCO's CT Project was properly scoped, designed, and engineered and that NIPSCO and S&L's up-front design activities reasonably align with the intended purpose of CAC witness Mr. James' recommended design process. As such, NIPSCO is not required to complete any further front-end engineering and design diligence.

The OUCC and CAC took issue with NIPSCO's EPC RFP. The OUCC asserts that NIPSCO's EPC RFP was too narrow. CAC witness Mr. James alleges that a lack of detail contributed to the poor response rate to the RFP. The OUCC and CAC both challenge the aeroderivative turbines due to their cost. OUCC witnesses Ms. Sanka and Mr. Hanks assert that operational characteristics of the aeroderivative units do not justify the higher overall expenditure when compared to a configuration comprised of only industrial frame turbines. CAC witness Ms. Sommer recommended denial of the CT Project due to the three aeroderivative turbines and suggested reducing the cost of the CT Project by replacing the aeroderivative turbines with a second industrial frame machine.

Three of the Five Pillars we are charged with evaluating in the context of a CPCN for new generation are reliability, resiliency, and stability. We observe that before us is a request for new generation that is specifically designed with load-following characteristics to support NIPSCO's evolving generation fleet. NIPSCO's 2021 IRP Short-Term Action Plan identified a need for a thermal peaking option to mitigate the energy adequacy and flexibility characteristics of the IRP's largely renewable, and therefore intermittent, preferred portfolio. NIPSCO conducted further diligence through its Flexible Resource Analysis, which evaluated the risks associated with times of resource unavailability and market purchase exposure. Informed by these analyses, in its EPC RFP, NIPSCO sought bids for projects between 370 MW and 450 MW with certain performance criteria. This analysis further refined the need by noting that there is a significant growth in the need for faster ramping resources. The analysis shows that 150 MW with a ramp rate of 10 minutes is needed by 2030. As such, the EPC RFP specification included, among other things, 10-minute cold start capability for 150 MW or more and 50 MW/minute minimum ramp rate for at least 150 MW of the facility's machines. NIPSCO witness Mr. Baacke pointed out the Engineering Study recognized that smaller industrial frame machines provide similar performance when compared to smaller aeroderivative machines, rendering a separate evaluation of an all-industrial frame configuration unnecessary. The technical specifications for NIPSCO's turbine equipment were appropriately driven by the key performance criteria identified in the Flexible Resource Analysis. The cost of the CT Project here is below the $1,440/kW in direct capital cost that was assumed in the 2023 portfolio analysis, which was based on the responses to NIPSCO's 2022 RFP.

The OUCC seeks to reduce the best estimate to remove the aeroderivative configuration. Mr. Krieger provides the reduction in cost as a range of $30-40 million; he does not provide the methodology to arrive at this amount. Ms. Sanka compared the cost of three aeroderivative units to the cost of a single larger frame unit using data pulled from Public Exhibit No. 3 Confidential Attachment RS-3, and her comparison produces a difference of $37.6 million. The single larger frame unit, which Ms. Sanka used for comparison, does not possess the same 10-minute cold start and ramp rates that the smaller industrial units or aeroderivative units. Ms. Sanka stated her objection is that NIPSCO did not evaluate a configuration with three smaller industrial frame units sized to match the aeroderivative units. However, the OUCC's proposed reduction is based upon a peaker unit that would not possess the start time and ramping rates that NIPSCO requires.

The OUCC's and CAC's evidence fails to counter the fact that aeroderivative turbines provide several attributes that complement NIPSCO's largely renewable portfolio, including fast start capability, the ability to start and stop multiple times per day without impacting maintenance cycles, and high efficiency. The fast-ramping capability of the aeroderivative turbines provides functionality that will satisfy reliability needs within NIPSCO's service territory and the MISO footprint.

CAC witness Ms. Sommer testifies that, if certain MISO market reforms are implemented, NIPSCO will likely need more capacity starting in 2028, even if the proposed CT Project enters into service. It is this capacity potential that unlocks the unique customer benefit of the aeroderivative turbines. NIPSCO's rebuttal evidence establishes that the aeroderivative units provide NIPSCO with flexibility to qualify as an intermediate load unit and potentially operate at greater capacity factors than an industrial frame unit, while remaining compliant with the Rule's emissions limits. Absent adequate capacity, to manage resource adequacy, NIPSCO will have to purchase capacity on the market. It is this rationale that drives us to decline CAC's invitation to prejudge NIPSCO's proactive capacity purchases as described by NIPSCO witness Mr. Stanley.

OUCC witness Hanks' testimony raises general arguments about the cost of the CT Project, intimating that its cost per kilowatt should not exceed the cost of CEI South's CTs approved in Cause No. 45564 or the average cost per kilowatt located in the EIA 2023 Energy Outlook. We reject comparison between the CT Project and the average cost per kW figures in the EIA's 2023 Outlook, as EIA's own Administrator plainly stated that the Outlook is not intended to provide estimates or predictions. Mr. Hanks did not attempt to reconcile the many factors that could impact – positively or negatively – the installed cost per kW of various technologies. As to Cause No. 45564, we note that NIPSCO and CEI South operate under different generation constraints and customer composition. CEI South's project was designed three years ago within a different market. There is substantial record evidence describing the current high demand for critical equipment and contractors within the power industry. CEI South's CTs were designed before the escalation in demand for CTs occurred, which has created a more competitive construction market. The OUCC did not include the estimated $27.3 million in annual expense CEI South will incur to receive gas supply from a new 24-mile pipeline. The estimated cost of NIPSCO's gas interconnection (which is under $1.5 million) was discussed by NIPSCO witness Mr. Austin in his direct testimony and was included within the best estimate for the CT Project.

The technical specifications for the combustion turbine equipment were sufficiently defined, appropriately developed to address the needs of NIPSCO's renewable portfolio without limiting bidders to a specific kind of technology, and consistent with industry standards. We find NIPSCO's preferred configuration of one industrial frame turbine and three aeroderivative turbines is appropriately informed by the results of the bid event and will provide critical, stable, load-following generation. Finally, given the substantial evidence on the important, load-following attributes the aeroderivative turbines provide, we find the aeroderivative turbines are cost-justified and appropriately included in NIPSCO's preferred configuration for the CT Project.

b. <u>Contracting Strategy for CT Project</u>. The OUCC and the CAC challenged NIPSCO's decision to self-build the CT Project, as opposed to utilizing an EPC contractor. OUCC witness Mr. Krieger testified the OUCC is concerned with NIPSCO's self-build project management approach including its ability to properly manage construction, as well as its ability to manage and mitigate financial challenges. CAC witness Mr. James testified NIPSCO lacks experience constructing power plants and NIPSCO's contracting strategy is similar to one of the strategies Duke Energy Indiana attempted to employ during the construction of the

Edwardsport Integrated Gasification Combined Cycle project.

The record contains evidence regarding the results of NIPSCO's EPC RFP bid. Mr. Baacke's direct testimony stated NIPSCO received three EPC bids – one that was $100 million more than the self-build option, and two bids that were inconsistent with technical specifications. NIPSCO conducted extensive due diligence to evaluate each bid received to determine whether its technical specifications could be met at a reasonable cost, and ultimately chose to self-build the CT Project.

The OUCC and CAC express general concerns that, without an EPC contractor, the risk of ratepayer-borne cost overruns from the construction of the CT Project has increased. This criticism ignores the fact that NIPSCO solicited bids from the EPC market and received only one bid that would have met its technical requirements, which we found were appropriately defined and reasonably driven by system needs, at a price that is $100 million more than NIPSCO's best estimate of construction in this Cause. While an EPC contract is a valid way to execute a generation project, it is not a requirement to receive a CPCN in Indiana nor is it a guarantee against project cost overruns.

OUCC witness Mr. Krieger and CAC witnesses Ms. Sommer and Mr. James claimed NIPSCO does not have experience building gas-fired generation projects of this scale and are concerned NIPSCO lacks large project management experience. The evidence in this Cause establishes that NIPSCO conducted diligence in both resource planning decisions and project design, engineering, and contracting. The evidence in this proceeding demonstrates that NIPSCO's team has sufficient experience to handle this project.

This is NIPSCO's first time overseeing construction of a new gas-fired generation project. The CT Project has undergone extensive upfront design and engineering. It will be built on an existing NIPSCO-owned site. No land acquisition will be needed and there is only the need for a 1,500-foot lateral pipeline to access NIPSCO's natural gas system. NIPSCO has prudently extended its runway to complete the CT Project through year-end 2027 and given the substantial reservation payment to the turbine equipment manufacturer, the evidence supports NIPSCO has a project plan in place enabling the CT Project to be constructed on time and on budget within reasonable constraints. The multi-prime strategy selected by NIPSCO produces a best estimate of costs that is $100 million less than the cost that would be produced under the only responsive EPC bid NIPSCO received.

CAC and NIPSCO agree demand for EPC contractors in the power industry is high. NIPSCO witness Mr. Warren testified this high level of demand has shifted EPC contractors' interest to larger projects that maximize their potential profits. We do not believe it would be prudent to require NIPSCO to pursue an EPC contract that could exceed the cost of NIPSCO's multi-prime contracting strategy by $100 million.

S&L has experience executing gas-fired generation projects. Based upon the evidence of record, we conclude NIPSCO selected a competent partner in S&L, and that this collaboration will continue throughout construction and start-up/commissioning of the CTs.

NIPSCO has availed itself of ongoing review of the CT Project pursuant to Ind. Code § 8-1-8.5-6. In issuing a CPCN, we approve the best estimate of costs. To the extent the utility incurs costs more than the best estimate that we approve, the utility will have the burden of demonstrating that the additional cost is reasonable. If other parties believe that the increase should be rejected, they retain the right to take such a position. The CAC and OUCC's fears over risk and escalation are all appropriately mitigated through ongoing review, which can serve to protect ratepayers from unnecessary costs and project mismanagement.

NIPSCO contends choosing the self-build option will decrease costs by $100 million. Due to the expected cost savings, the Commission approves NIPSCO choosing this option. The Commission emphasizes the importance of the estimated $100 million savings being realized. These savings shall be reflected in the updated cost estimates in the semi-annual filings discussed later in this order.

c. **Best Estimate Cost Components.** OUCC witnesses Mr. Hanks and Mr. Krieger challenged NIPSCO's indirect costs, alleging they lacked support and were potentially double counted in S&L's cost estimate. However, Mr. Baacke's rebuttal testimony explained that the confidential version of the best estimate shows one line item for "Indirects," which represents NIPSCO's indirect costs while S&L's indirect costs are reflected as "Misc Inside the Fence," "Misc Electric Interconnect," "Misc Gas Interconnect," and "Misc Water Interconnect" in NIPSCO's best estimate. He stated NIPSCO explained each cost category and how they were estimated in response to CAC discovery and that the itemization of S&L's indirect costs in Section 10.2.3 of the Engineering Study confirms these costs do not duplicate NIPSCO's indirect costs. We agree. NIPSCO's internal indirect costs are capital overhead and stores, freight, and handling while S&L's indirect costs are associated with construction management and start-up and commissioning support. These line items are separate and distinct, and we find that NIPSCO's evidence supports concluding no indirect costs were double counted.

Mr. Hanks challenged NIPSCO's proposed 5% escalation factor and recommended it be reduced to 3%, as was approved in NIPSCO's electric TDSIC Plan. We are convinced by NIPSCO's evidence that a 5% escalation factor is appropriate. NIPSCO's supplemental testimony describes the global supply chain uncertainty, which prompted the shift in the CT Project's in-service date to end of year 2027. Mr. Baacke's rebuttal testimony provides specific detail on the 70% cost increase for 345kV breakers, which NIPSCO has witnessed in a few months in late 2023. Given that NIPSCO's electric TDSIC Plan was approved before the COVID-19 pandemic and its resulting supply chain issues, we conclude reducing NIPSCO's escalation factor to what was approved in that proceeding is not appropriate. Accordingly, we find NIPSCO's 5% escalation factor is reasonable and approved.

Mr. Krieger opposed NIPSCO's 9% estimate for owner's costs, arguing it is too simple for a high-cost capital project and that owner's costs would be lower under an EPC contract. Based on updated cost information from executed contracts with certain suppliers, NIPSCO updated the 9% owner's cost estimate to $41,210,000 in Mr. Baacke's rebuttal testimony. We addressed the parties' concern with NIPSCO's contracting strategy above and found NIPSCO's self-build, multi-prime approach will reduce the cost of the CT Project for the benefit of customers. Based on the evidence provided, we conclude NIPSCO's estimated owner's costs are informed by executed contracts and are approved.

d. <u>Pollution Control Technology</u>. OUCC Witness Armstrong testified the Selective Catalytic Reduction units are not needed for the CT Project to meet current environmental requirements and that if they are required in the future, NIPSCO could seek recovery of any future pollution control costs through the Federally Mandated Cost Management ("FMCA") statute. Mr. Holcomb's rebuttal testimony confirmed the CT Project will comply with the final Greenhouse Gas ("GHG") Rule; therefore, NIPSCO updated the best estimate to reflect removal of the Selective Catalytic Reduction units. We approve this revision to the scope of the CT Project and recognize that as federal environmental regulations may change, Indiana law offers options utilities may consider for recovering compliance costs, including the FMCA statute.

e. <u>Conclusion on Best Estimate</u>. We find NIPSCO has submitted sufficient evidence supporting its best estimate on the cost to construct the CT Project, which is driven by its preferred configuration and contracting strategy along with its projected $100 million savings due to utilizing the self-build option. NIPSCO's best estimate is based on a detailed engineering analysis, information from turbine manufacturers and contractor bid events from which capital costs, operating costs, performance characteristics, and construction schedules were determined. The best estimate reasonably reflects the current market, industry trends, and the potential cost impact of project risk and factors beyond NIPSCO's control. The CT Project is reasonably designed to manage industry and economic challenges while facilitating the capacity and energy resources required by NIPSCO to meet its customers' ongoing need for electricity. Based on the evidence, we find that $641,223,000 (excluding AFUDC) is the best estimate of the cost of construction of the CT Project.

ii. <u>Consistency with Petitioner's 2021 and 2023 Portfolio Analysis</u>. Ind. Code § 8-1-8.5-5(b)(2) provides that a CPCN shall be granted only if the Commission has made a finding that either:

> (A) the construction, purchase, or lease will be consistent with the commission's analysis (or such part of the analysis as may then be developed, if any) for expansion of electric generating capacity; or
>
> (B) the construction, purchase, or lease is consistent with a utility specific proposal submitted under [Ind. Code § 8-1-8.5-3(e)(1)] and approved under subsection (d).

Ind. Code § 8-1-8.5-3(e)(1) provides that a public utility may submit "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[.]" Mr. Augustine sponsored Petitioner's 2021 IRP as Petitioner's Highly Confidential Attachment 7-B and a summary of the key inputs and outputs associated with the 2023 portfolio analysis as Petitioner's Highly Confidential Attachment 7-C. Thus, we find NIPSCO has submitted a utility-specific proposal under Ind. Code § 8-1-8.5-3(e)(1).

The record demonstrates that the CT Project is consistent with the Short-Term Action Plan identified in Petitioner's 2021 IRP.

We note at the outset that we have recently expressed support of NIPSCO's 2021 IRP process, stating that "NIPSCO's 2021 IRP process, which occurred in concert with the 2022 RFP, was robust and well developed, ultimately resulting in the Short-Term Action Plan on which the proposed Appleseed and Templeton PPAs are based." *N. Ind. Pub. Serv. Co.*, Cause No. 45926 (IURC Nov. 22, 2023) at 20 citing *N. Ind. Pub. Serv. Co.*, Cause No. 45587 (IURC Sept. 13, 2023). IRPs are created at a point in time and use modeled scenarios to show how resources perform over a variety of alternative future conditions. NIPSCO performed the 2021 IRP analysis and has appropriately responded to changes in the electric industry and the broader market and now seeks approval of generation additions based on the same foundation we have repeatedly found was sufficient. NIPSCO's 2021 IRP did not rely on a single set of assumptions that could later be invalidated by evolving market conditions. Since the 2021 IRP was issued, the timeline for implementation of the Short-Term Action Plan identified in the 2021 IRP has been three years (2022–2024), and NIPSCO's proposed CT Project is consistent with this timeline.

NIPSCO's 2021 IRP performed a retirement analysis to assess different retirement dates for different elements of the existing fleet. The 2021 IRP continued to affirm earlier retirement of coal capacity resulted in lower costs for customers. The 2021 IRP concluded new additions should be predominantly renewable resources, supplemented by a diverse mix of other technologies, including an uprate to NIPSCO's existing Sugar Creek combined cycle, new thermal peaking capacity, new energy storage capacity, new distributed energy resources, and additional demand side management programs. These conclusions were informed by review of all metrics on NIPSCO's integrated scorecard, including cost to customer, scenario and stochastic-based cost risk, carbon emissions, resource optionality, impacts on the local economy, and a comprehensive quantitative reliability assessment, which included analysis of ancillary services, blackstart requirements, dispatchability, and other technical reliability parameters. Given evolving MISO market rules related to intermittent resource accreditation, seasonal reserve margin planning, and other reliability planning considerations, relative to NIPSCO's 2018 IRP, the 2021 IRP concluded that additional dispatchable resources like thermal peaking capacity and storage were necessary additions to the portfolio.

NIPSCO conducted an additional technical reliability assessment to ensure the non-economic implications of various portfolio options, particularly regarding compliance with MISO market rules and North American Electric Reliability Corporation ("NERC") standards, were accounted for. As part of the assessment, eight reliability criteria were identified, and different portfolio options were evaluated against each of them. The reliability criteria included blackstart capability, energy adequacy, dispatchability and automatic generation control, operational flexibility and frequency support, volt-ampere reactive ("VAR") support or reactive power, geographic location relative to load, predictability and firmness of supply, and short-circuit strength sufficiency. NIPSCO's analysis concluded portfolios that included new thermal resources (natural gas-fired peakers and combined cycles, including those with hydrogen enablement) scored better on the reliability criteria than portfolios reliant only on new renewables and storage and no new incremental thermal capacity.

The record demonstrates the 2023 portfolio analysis accounted for NIPSCO's ongoing resource planning and other market conditions and developments that have occurred since the 2021 IRP was completed, including, among other things, updated pricing from NIPSCO's 2022 RFP, changes to the MISO resource adequacy construct, commodity pricing updates, and changes to federal law.

We have previously concluded that, “[i]nherently, 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.” *Northern Indiana Public Service Co., LLC*, Cause No. 45462, at 62 (May 5, 2021). The Commission has previously found that utilities should utilize “an array of best practices, including basing model inputs on its 2022 RFP, which allow[s] for an informed forecast at that time.” *Southern Indiana Gas & Elec. Co.*, Cause No. 45501, at 29 (Oct. 27, 2021). The evidence demonstrates that NIPSCO has utilized best practices for an informed forecast.

IG witness Mr. Gorman recommended denial of NIPSCO’s requested CPCN based on his belief that NIPSCO had not updated its 2021 IRP and had not analyzed several material developments since the completion of the 2021 IRP including: (1) the introduction of MISO's seasonal resource adequacy construct; (2) the enactment of the Inflation Reduction Act; (3) the presence of supply chain constraints, tariff uncertainty and inflationary cost pressure; and (4) additional RFPs with Charles River Associates to assess the latest market data for new resources. His claims are contradicted by evidence in the record. Mr. Augustine explained Mr. Gorman’s testimony does not acknowledge or reference NIPSCO’s 2023 portfolio analysis. As discussed, this analysis used the preferred portfolio themes from NIPSCO’s 2021 IRP and updated their composition according to the latest market information, which resulted in additional wind capacity, less solar capacity, and more thermal peaking or storage capacity. Mr. Augustine’s direct testimony discussed how NIPSCO anticipated MISO’s seasonal construct in its 2021 IRP, which evaluated seasonal peak load forecasts and seasonal capacity ratings for resource options to develop portfolios based on capacity requirements for both the summer and winter seasons, and that its 2023 portfolio analysis incorporated updated seasonal reserve margin targets and seasonal accredited capacity levels that were published after FERC approved MISO’s seasonal construct. NIPSCO’s 2023 portfolio analysis has been relied upon to support approval of other generation projects.[7] As such, we find NIPSCO’s resource planning and selection process to select its Short Term Action Plan, including the CT Project, is consistent with its 2021 IRP, and is therefore consistent with NIPSCO’s utility-specific proposal under Ind. Code § 8-1-8.5-3(e)(1).

Mr. Gorman testified NIPSCO’s evaluation of the proposed CT Project was deficient because it failed to consider planned changes to its future Rate 531 Tier 1 load and instead relied on its future supply demand positions based on its 2021 IRP without modifying any assumptions associated with expected reductions in Rate 531 Tier 1 load. Mr. Augustine’s rebuttal testimony outlined three reasons why this criticism is invalid: (1) the Rate 831/531 Modification Agreement approved in Cause No. 45772 recognizes Tier 1 commitments may decline over time, but that no firm declarations of commitment reductions have been made by any Rate 531 customer, and it is not certain that all seven current Rate 531 customers would elect to reduce their demand to the tariff minimum as outlined by Mr. Gorman; (2) even if the proposed CT Project is approved and all seven Rate 531 customers reduce their commitments over a multi-year period through 2033 as outlined in the Rate 831/531 Modification Agreement, NIPSCO will likely still require additional capacity purchases or other capacity additions to meet current seasonal MISO planning requirements as well as potential future changes associated with resource accreditation rules at MISO to meet potential future demand growth; and (3) NIPSCO’s 2021 IRP did evaluate a

[7] Cause No. 45926 (Gibson Solar), Cause No. 45887 (Appleseed Solar and Templeton Wind), Cause No. 45908 (Carpenter Wind), and in NIPSCO requests for changes in cost and ownership structure for various solar and solar plus storage projects in Cause Nos. 45936, 46028, and 46032, the latter two of which are still pending.

scenario with the exact reduction in Tier 1 demand commitments suggested by Mr. Gorman, and NIPSCO's preferred portfolio was found to perform well under such assumptions. Mr. Augustine explained NIPSCO was not required to "hard code" into its demand forecast a reduction that may not come to fruition; instead, as it did, NIPSCO's 2021 IRP and 2023 portfolio analysis are based on probabilistic modeling which included numerous load scenarios, including the scenario Mr. Gorman advocated for.

The evidence of record demonstrates the CT Project is consistent with and supported by the 2021 IRP and 2023 portfolio analysis. The 2021 IRP concluded flexible thermal generation resources, additional solar capacity and a diverse mix of other resources including storage, emerging technologies, and market purchases/capacity were necessary additions to the portfolio for it to meet current and future load and reserve margin requirements. Moreover, as further discussed below, the CT Project is consistent with the Flexible Resource Analysis which found that flexible, dispatchable capacity resources are needed to complement NIPSCO's largely renewable portfolio – particularly resources that can meet specific ramp requirements.

We conclude NIPSCO's resource planning process is appropriate given the amount of uncertainty around timing and actual amounts of load reduction. Ms. Becker testified the Rate 531 customers may reduce their load, but they have not done so yet and NIPSCO cannot assume that they will. Furthermore, and as noted by CAC witness Ms. Sommer, NIPSCO likely will need an additional 400+ MW of capacity beginning in 2028, which could be partially addressed by further reductions of Rate 531 Tier 1 load. Based on the evidence, we find NIPSCO's 2021 IRP, as supplemented and supported by the 2023 portfolio analysis, is a valid basis for approval of the CT Project, and the CT Project is consistent with the 2021 IRP.

iii. Consistency with Commission's Energy Analysis. Ind. Code § 8-1-8.5-3(a) provides that "the commission shall develop, publicize, and keep current an analysis of the long-range needs for expansion facilities for generation of electricity." The Commission issued its 2018 Report on the Statewide Analysis of Future Resource Requirements for Electricity ("2018 Statewide Analysis") in October 2018.

The data and analysis underlying NIPSCO's proposal and the state of the overall electric industry have continued to develop since the 2018 Statewide Analysis. Mr. Walter's direct testimony noted that multiple IRPs have been completed since the most recent report. The record in this Cause demonstrates that MISO, MISO's Independent Market Monitor ("IMM"), and the NERC support the need for flexible, dispatchable resources to pair with increasing levels of renewable generation to ensure reliability.

Based on the evidence of record, we find NIPSCO's proposal to build the CT Project, which offers a flexible, dispatchable resource that will support NIPSCO's predominantly renewable generating portfolio and that of other Indiana electric utilities, is consistent with the Commission's energy analysis, including the 2018 Statewide Analysis and developments since that report was issued.

iv. Public Convenience and Necessity. Under Ind. Code § 8-1-8.5-5(b)(3), before granting a CPCN, the Commission must make "a finding that the public convenience and necessity require or will require the construction, purchase, or lease of the facility[.]" "The public convenience and necessity criterion is common in public utility matters and generally concerns whether the proposal is fitted or suited to the public need." Indiana Michigan Power Co., Cause No. 44871, at 30 (March 26, 2018). NIPSCO contends that its preferred configuration of one industrial frame unit and three aeroderivative units is reasonable and appropriate given NIPSCO's fast-ramping, load-following needs. Based on the evidence of record, we agree, as explained further below.

Our determination of public convenience and necessity under Ind. Code § 8-1-8.5-5(b)(3) is also guided by Ind. Code § 8-1-8.5-4(b), which provides the factors that the Commission must consider in acting on any petition for the construction, purchase, or lease of any facility for the generation of electricity.[8]

a. **Ind. Code § 8-1-8.5-4(b)(1).** Mr. Stanley described NIPSCO's involvement in MISO, an independent system operator, and testified this portion of the statutory language predates the formation of MISO. He stated the statutory concepts of "interchange of power" and "pooling of facilities" would seem to be addressed through use of an independent system operator. Mr. Stanley explained that while the current MISO market effectively utilizes the existing capacity resources to meet the overall energy requirements of the region, including NIPSCO, NIPSCO's membership in MISO does not eliminate its need to meet the capacity requirements of its customers, including adding new capacity resources to address potential load growth and reliable load-following generation. As to the remaining elements of Subsection (b)(1), Mr. Stanley testified NIPSCO has conducted several all-source RFPs, and joint ownership and power purchases were not excluded by those RFPs to the extent other electric utilities were interested. Mr. Augustine testified NIPSCO's all-source RFPs, its IRP, and the 2023 portfolio analysis allowed for and considered numerous resource options, including solar, solar plus storage, storage, thermal, wind, hydrogen, and a range of structures that may include both energy and capacity.

The evidence of record shows NIPSCO's participation in MISO was specifically considered in the development of its Short Term Action Plan, including the proposed CT Project, which supports the conclusion that Petitioner's current and potential options for entering arrangements with other utilities related to the interchange of power, pooling of facilities, purchase of power, and joint ownership of facilities have been evaluated, and Ind. Code § 8-1-8.5-4(b)(1) has been satisfied.

b. **Ind Code § 8-1-8.5-4(b)(2).** While some of the parties challenged the size and technology composition of NIPSCO's proposed CT Project, which we addressed above, no party proposed an alternative to the CT Project or stated NIPSCO does not have a need for the type of new capacity that was identified in its 2021 IRP and in the subsequent analyses undertaken after the submission of the IRP. The OUCC "agrees that load-following replacement generation capacity is necessary to reliably serve NIPSCO's customers" and "recognizes that NIPSCO's IRP and updated analysis shows additional replacement capacity for retiring generation is needed to preserve reliability, resiliency, and stability." Pub. Ex. 1 at 3. The

[8] No party identified an applicable federal phaseout mandate for purposes of Ind. Code § 8-1-8.5-4(b)(3). Ind. Code § 8-1-8.5-4(b)(4) is discussed later in the order.

CAC points out if recent proposed MISO market reforms are implemented, "NIPSCO likely needs more capacity starting in 2028" even when assuming the proposed CT Project enters into service. CAC Ex. 1 at 21, 24. These statements affirm NIPSCO's requirement for incremental capacity, and the evidence of record supports NIPSCO's CT Project as a required addition that will help fill this need.

Regarding maintaining essential reliability services, NERC, in its 2022 Long-Term Reliability Assessment, states: "[r]etiring conventional generation is being replaced with large amounts of wind and solar; … As replacement resources are interconnected, these new resources should have the capability to support voltage, frequency, and dispatchability." *Id*. at 18-19.

Regarding "refurbishment of existing facilities," NIPSCO witness Mr. Augustine testified NIPSCO evaluated the potential conversion of one or two units at its Schahfer plant in its 2018 IRP and found conversion cost more than the alternatives. Section 4.10.5 of NIPSCO's 2018 IRP noted the analysis "showed that converting one unit would cost at least $230 million more than retirement and replacement with economically optimized selections from the 2022 RFP results and replacing both units would cost customers at least $540 million more." Mr. Augustine explained a refueled Unit 17 or 18 would not be a viable alternative to the CT Project as it would not possess the fast-start/quick-ramping and reliability characteristics of a peaking facility that the 2021 IRP and the 2023 portfolio analysis called for. No party challenged this evidence.

As to cogeneration, NIPSCO witness Mr. Stanley testified renewable generation has been a significant component of NIPSCO's generation portfolio transition since its 2018 IRP, and the CT Project is intended to complement the substantial renewable fleet NIPSCO has added and continues to add. He explained cogeneration, if available, would have been responsive to the 2022 RFPs. NIPSCO witness Ms. Becker testified on conservation and load management by describing NIPSCO's three demand response programs and its robust portfolio of demand side management/energy efficiency programs targeted towards residential, commercial and industrial customers. She explained NIPSCO carried out a lengthy analysis of demand side management/energy efficiency resources included in its IRP process, including completing a market potential study to determine the achievable amount of savings. Ms. Becker explained NIPSCO's 2021 IRP modeling demonstrates energy efficiency will be an important part of NIPSCO's resource options in the future and will be particularly important to help mitigate against the need to build new generation to serve incremental load; however, NIPSCO's modeling indicates the most economical option for customers over the long term is to execute on its preferred portfolio, including, but not limited to, adding the proposed CT Project, adding solar and wind resources, and retiring coal generation. She concluded, based on her experience with NIPSCO's energy efficiency initiatives, NIPSCO could not derive sufficient energy savings to replace this generation.

NIPSCO engaged in the 2022 RFP process to inform its planning activities. Multiple RFPs were issued in 2022 to identify costs and availability of resource options to fulfill the 2021 IRP's short-term action plan.

c. Conclusion. NIPSCO conducted the 2022 RFP to meet its capacity needs, and the RFP responses enabled NIPSCO to consider a variety of alternatives. Given the foregoing evidence, the Commission finds Petitioner has satisfied the requirement under

Ind. Code § 8-1-8.5-4(b)(2); it considers alternative methods for providing reliable, efficient, and economical electric service, including the refurbishment of existing facilities, conservation, load management, cogeneration, and renewable energy sources. NIPSCO's 2021 IRP and subsequent 2023 portfolio analysis show that the proposed construction of the CT Project at the Schahfer site is a reasonable, least-cost resource to support NIPSCO's Short Term Action Plan and meet its customers' needs for electricity. The CT Project is designed to reliably cycle in response to the MISO market and will displace the retiring Schahfer coal units with more efficient and controllable load-following capacity.

Based on the evidence of record, the Commission finds Petitioner has shown a need for the proposed CT Project and that public convenience and necessity require or will require Petitioner's construction of the CT Project.

v. <u>Competitive Procurement</u>. Ind. Code § 8-1-8.5-5(b)(5) requires us to make certain findings under Ind. Code § 8-1-8.5-5(e) if the proposed facility has a generating capacity of more than 80 MW, as is the case here:

> Before granting a certificate to the applicant, the commission:
>
> (1) must, in addition to the findings required under subsection (b), find that:
>
> (A) the estimated costs of the proposed facility are, to the extent commercially practicable, the result of competitively bid engineering, procurement, or construction contracts, as applicable; and
>
> (B) if the applicant is an electricity supplier (as defined in IC 8-1-37-6), the applicant allowed or will allow third parties to submit firm and binding bids for the construction of the proposed facility on behalf of the applicant that met or meet all of the technical, commercial, and other specifications required by the applicant for the proposed facility so as to enable ownership of the proposed facility to vest with the applicant not later than the date on which the proposed facility becomes commercially available; and
>
> (2) shall also consider the following factors:
>
> (A) Reliability.
>
> (B) Solicitation by the applicant of competitive bids to obtain purchased power capacity and energy from alternative suppliers.
>
> The applicant, including an affiliate of the applicant, may participate in competitive bidding described in this subsection.

There are two different requirements for a CPCN. The first, Ind. Code § 8-1-8.5-5(e)(1)(A), is to confirm the reasonableness and reliability of the cost estimate. The second, Ind. Code § 8-1-8.5-5(e)(1)(B), is to assure actual costs incurred are, to the extent commercially practicable, based on competitive procurement.

NIPSCO conducted multiple RFPs in 2022 to identify the costs and availability of resource options to fulfill the 2021 IRP's short-term action plan and to respond to changing market conditions, including an RFP for a gas-fired generation resource. The RFPs provided actionable resource cost data that incorporated the latest policy, technology, and macroeconomic information. The RFPs provided information related to the latest costs of storage resources and the viability of alternative natural gas peaker options at the time they were solicited.

The statute requires the estimate to be the result, to the extent commercially practicable, of a competitively bid engineering, procurement or construction contract. Petitioner conducted the EPC RFP bid event and leveraged the information through that process to develop its best estimate for the cost to construct the CT Project through a multi-prime contracting strategy. NIPSCO's best estimate of construction reflects information received from equipment bid events for the CT original equipment manufacturer, generator step-up transformers, unit auxiliary transformers, and diesel generator. Accordingly, we find Ind. Code § 8-1-8.5-5(e)(1)(A) has been satisfied and that the cost estimates of the proposed facility are, to the extent commercially practicable, the result of competitively bid engineering, procurement, or construction contracts. Mr. Baacke described the construction and bid process NIPSCO will use through the multi-prime contracting strategy, whereby NIPSCO plans to develop competitive bids for all major scopes of construction. He testified that under the planned construction and bid process, NIPSCO will allow third parties to submit firm and binding bids for construction of the CT Project on NIPSCO's behalf that meet all of the technical, commercial, and other specifications so as to enable ownership of the CT Project to vest with NIPSCO no later than the date the facility becomes commercially available. This satisfies Ind. Code § 8-1-8.5-5(e)(1)(B).

Regarding Ind. Code § 8-1-8.5-5(e)(2), based on the evidence of record, we find the proposed CT Project is reliable. The record establishes Petitioner engaged in an All-Source RFP process to inform its overall generation transition plan. Thus, we find that the requirements of Ind. Code § 8-1-8.5-5(e) are satisfied.

vi. <u>Conclusion on CPCN for CT Project</u>. Based on the evidence of record, the Commission finds NIPSCO has met the requirements of Ind. Code ch. 8-1-8.5 and that the public convenience and necessity will be served construction of the CT Project. Therefore, we grant NIPSCO's request for a CPCN for its CT Project, subject to the findings and conditions of this order.

B. <u>Ongoing Review of CT Project Under Ind. Code § 8-1-8.5-6(a)</u>. Ind. Code § 8-1-8.5-6(a) addresses the Commission's review of facilities under construction as follows:

> In addition to the review of the continuing need for the facility under construction . . . the commission shall, at the request of the public utility, maintain an ongoing review of such construction as it proceeds. The applicant shall submit each year during construction, or at such other periods as the commission and the public utility mutually agree, a progress report and any revisions in the cost estimates for the construction.

NIPSCO requested ongoing review of the CT Project, including review of progress reports and any revisions to the best estimate, as the construction proceeds, and associated ratemaking treatment consistent with such review. OUCC witness Mr. Krieger recommends the Commission require NIPSCO to submit quarterly progress reports providing construction status, and accounting updates including project to date spending and remaining balances of contingency, escalation, owner's costs and indirects. Ms. Becker testified Mr. Krieger's recommended quarterly reporting requirements go beyond the yearly reporting required by the statute. She stated NIPSCO plans to file its GCT Mechanism semi-annually, which will provide the Commission and the parties an opportunity to review costs incurred to date and relevant project updates. She stated this cadence already exceeds the annual update requirement in the statute and that requiring quarterly reports from NIPSCO on top of this review is unnecessary and excessive. We find Ms. Becker's proposal reasonable given that it is more than contemplated by the statute.

We find NIPSCO shall report to the Commission a summary of the information related to the CT Project as contemplated under Ind. Code § 8-1-8.5-6(a), including any changes to scope, schedule, and the best estimate. In its initial report, NIPSCO is directed to include: (1) manufacturer, model number, and operational characteristics of the turbine generator and (2) anticipated total annual MW-hour ("MWh") output for the CT Project in each of its semi-annual GCT filing stylized as 45947 GCT XX. The initial report shall be filed on or before December 30, 2024 as a compliance filing in this Cause.

NIPSCO shall report semi-annually in this Cause to the Commission a summary of the information related to the CT Project, including safety, scope, schedule, and owner's cost contingency, as well as revisions to the cost estimate and update on the natural gas transportation and lateral pipeline. In addition, due to recent global supply chain issues that could potentially limit the availability of components necessary to build the CTs, Petitioner shall include in its semi-annual filings, an update on any supply-chain-related challenges and/or delays beginning on December 30, 2024.

The final project report shall contain the following information: (1) the actual total cost of construction; (2) the total MW output for the facility; and (3) the actual in-service (commercial operation) date for the facility. The final project report shall be filed in this Cause.

C. <u>Clean Energy Project and Financial Incentives Under Ind. Code § 8-1-8.8-11</u>. NIPSCO seeks approval of its CT Project as a clean energy project pursuant to Ind. Code § 8-1-8.8-11. 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 "proposes to construct or repower a facility described in IC 8-1-37-4(a)(21)." Ind. Code § 8-1-8.8-6(5). A "clean energy project" similarly includes "[p]rojects to construct or repower a facility as described in IC 8-1-37-4(a)(21)" Ind. Code § 8-1-8.8-2(5). We have already found that NIPSCO is an "energy utility." The only disputed issue of applicability is whether the CT Project qualifies as a project under Ind. Code § 8-1-37-4(a)(21). That subsection includes in the definition of "clean energy resource . . . [e]lectricity that is generated from natural gas at a facility constructed or repowered in Indiana after July 1, 2011, which displaces electricity generation from an existing coal fired generation facility." NIPSCO witness Mr. Walter testified the CT Project will displace electricity generated from the coal-fired generating plants at Schahfer Units 17 and 18 and Michigan City Unit 12.

CAC witness Mr. Inskeep asserted Schahfer Units 17 and 18 are retiring in 2025 "regardless of the fate of the CT Project." Mr. Inskeep stated NIPSCO did not demonstrate the CT Project is displacing electricity generated from the coal-fired Schahfer Units 17 and 18 and

Michigan City Unit 12. NIPSCO witness Mr. Stanley's stated NIPSCO will be using the injection rights from the retiring Schahfer units for purposes of MISO interconnection. NIPSCO's 2021 IRP's Short Term Action Plan plainly shows NIPSCO's overall plan to retire Schahfer Units 17 and 18 and Michigan City Unit 12 are related to and dependent on the addition of several resources, including a gas peaking resource. NIPSCO witness Mr. Holcomb explained that along with increasing levels of zero-emission renewable energy in the electric system, the CT Project will keep NIPSCO and NiSource on track to achieve their target of a 90% reduction in Scope 1 GHG emissions by 2030, compared to 2005 levels.

Partial displacement of retiring coal-fired energy generation with a gas peaking resource has been a component of NIPSCO's IRP modeling and related CPCN regulatory filings since 2021. As such, we find the CT Project is being constructed to displace energy from an existing coal-fired generation facility and is therefore eligible for the relief provided in Ind. Code § 8-1-8.8-11.

i. <u>The Clean Energy Project is Just and Reasonable</u>. 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 just and reasonable. While Chapter 8.8 does not set forth specific factors the Commission should consider in approving a clean energy project, the Commission has considered some of the factors outlined in Chapters 8.5 and 8.7 in other cases. Similarly, in determining the reasonableness and necessity for the CT Project, we find it appropriate to consider the principles reflected in the following Chapter 8.5 factors in our consideration: (1) the cost of the CT Project; (2) the consistency of the CT Project to NIPSCO's 2021 IRP; (3) the need for the CT Project; (4) and the competitive solicitation of the CT Project.

a. <u>The Cost of the CT Project</u>. The evidence in this Cause supports a finding that the energy to be generated by the CT Project is reasonably priced compared to other alternatives and provides material benefits. The best estimate of the costs is $100 million below the price for an EPC contract for a comparable facility and the cost is consistent with the costs assumed in the 2023 portfolio analysis.

b. <u>Consistency of the CT Project to NIPSCO's IRP</u>. The CT Project is consistent with NIPSCO's 2021 IRP (as updated in the 2023 portfolio analysis).

c. <u>The Need for the CT Project</u>. The CT Project fills the need for fast-start, quick-ramping generation that will complement NIPSCO's overall generation transition and follow the load. This evidence reflects that MISO, NIPSCO's grid operator, has indicated a system-wide need for controllable resources to ensure system reliability, particularly as more intermittent resources are added to the system. NIPSCO has demonstrated that the CT Project is necessary to assure reliability, resiliency, and stability of NIPSCO's supply of electricity.

d. <u>The Competitive Solicitation of the CT Project</u>. We have previously found and reiterate that NIPSCO's procurement of the CT Project has been and will continue to be through competitive solicitation.

Based on the evidence of record, we find the CT Project is a clean energy project under Ind. Code § 8-1-8.8-11 and is just reasonable. The record shows the addition of the CT Project to NIPSCO's resource mix will provide needed energy and capacity. We find the energy and capacity provided through the CT Project are reasonable and necessary additions 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.

ii. **<u>Cost Recovery</u>.** Having found the CT Project is a clean energy project and is eligible for the financial incentives pursuant to Ind. Code § 8-1-8.8-11 ("Section 11"), we turn now to NIPSCO's proposal to recover its costs during construction through the GCT Mechanism until such time as the project is included in base rates after being placed in service. Petitioner's witness Mr. Blissmer described the proposed GCT Mechanism and how it would work. NIPSCO anticipates these filings will be made by October 15 (reflecting the forward-looking period of March through August) and April 15 (reflecting the forward-looking period of September through February). NIPSCO anticipates a 120-day procedural schedule from filing to Commission order and rate implementation (on a bills rendered basis). Any variance between the forecasted tracker revenue requirement and the amounts collected will be compared to the actual revenue requirement based on the final books and records. The resulting variance would be captured in a reconciliation report within each tracker filing.

The revenue requirement for capital costs included in the GCT will be calculated by first computing the monthly average CWIP, or net plant in service when appropriate, over the forecasted six-month period. NIPSCO's direct testimony reflected NIPSCO would then multiply the weighted monthly average for the forecasted billing period by NIPSCO's monthly effective Weighted Average Cost of Capital ("WACC"). Up and until the CT Project is placed in service, there would be no depreciation expense. When and to the extent the CT Project is projected to be placed in service in a six-month forecast period, the GCT will commence the recovery of depreciation expense at NIPSCO's most recently approved depreciation rates (currently Cause No. 45772), which would be reconciled when actual depreciation expense is recognized in a future tracker. This avoids any deferral of depreciation expense. Similarly, forecasted property taxes will be included in the GCT and reconciled when actual property tax expense is recognized in a future tracker.

Mr. Blissmer testified NIPSCO proposes to allocate the costs associated with the CT Project based on NIPSCO's Commission approved demand allocators for the GCT Mechanism, whereby the demand allocators are based upon revenue attributable to each of NIPSCO's rate schedules used to establish NIPSCO's Commission approved electric base rates in Cause No. 45772. NIPSCO will adjust its allocation percentages to reflect the significant migration of customers amongst the various rates for each semi-annual tracker filing, as it does with other tracking mechanisms. This adjustment is appropriate to prevent any unintended consequences of the migration of customers between rates and to properly allocate their share of the revenue requirement. He described other changes to NIPSCO's electric service tariff relating to the proposed GCT Mechanism: (1) addition of Rider 595 – Generation Cost Tracker; (2) addition of Appendix L – Generation Cost Tracker Factors; (3) update to Appendix A to include Rider 595; and (4) update to the Table of Contents to add Rider 595 and Appendix L. NIPSCO anticipates its first GCT Mechanism filing would be October 15, 2024, or within 30 days of a final order in this Cause, whichever is later. As an additional financial incentive under Section 11, NIPSCO requests the operating income associated with the CT Project be included in the total electric Comparison of Electric Operating Income for purposes of the Ind. Code § 8-1-2-42(d) earnings test.

Mr. Blissmer explained how this proposed GCT Mechanism is authorized by new legislation. He testified House Enrolled Act 1421 ("HEA 1421"), among other things, amended the definition of "clean energy projects" in Ind. Code § 8-1-8.8-2 to include "[p]rojects to construct or repower a facility described in IC 8-1-37-4(a)(21)" and amended Section 11(a)(1) limiting when CWIP ratemaking can be authorized for a clean energy project as a financial incentive.

Mr. Blissmer testified NIPSCO's proposal satisfies the additional requirements relating to the authorization of CWIP ratemaking for a clean energy project as a financial incentive stating HEA 1421, among other things, amends Section 11(a) concerning financial incentives to provide:

> The commission may not approve a financial incentive under this subdivision unless the commission finds that the eligible business has demonstrated the timely recovery of costs and expenses incurred during the construction and operation of the project: (A) is just and reasonable; and (B) in the case of construction financing costs, will result in a gross financing savings over the life of the project.

Mr. Blissmer testified the construction financing costs will result in a gross financing savings over the life of the project. He explained the Summary tab includes the results from the data contained in the remaining tabs and presents two scenarios: (1) the top half presents the revenue requirement and financing costs portion of the revenue requirement under NIPSCO's proposed CWIP ratemaking treatment, and (2) the bottom half presents the same information under an alternative scenario where the asset is reflected in rates after being placed in service as part of a general rate case. He stated that under both scenarios, the CT is assumed to be placed in service in December 2027, the general rate case test year is assumed to be calendar year 2027, and the Step 2 rates in that general rate case are assumed to become effective on a bills rendered basis in March 2028. He explained that from that point forward, the sequence and timing of rate implementation under both scenarios is the same, as the CT Project under the GCT will have rolled into base rates and that the only difference from March 2028 over the remaining life of the project is the result of the higher accrued rate base (including regulatory asset) produced by the accrual of AFUDC and post-in service carrying costs ("PISCC") under the traditional model. He explained he has not included property taxes in the calculation because property taxes are not financing costs. He did include depreciation expense because the regulatory asset resulting from the deferral of depreciation expense would be reflected in rate base and thus depreciation does produce different financing costs under the two scenarios.

Mr. Blissmer concluded under NIPSCO's forward-looking GCT proposal, the total revenue from financing costs is $1,609,808,326, and under the traditional general rate case scenario, the total revenue from financing costs is $1,691,794,736, with the difference between these two amounts of $81,986,410 being the gross financing savings over the life of the CT Project. With a backward looking GCT Mechanism, the total gross financing savings over the life of the CT Project would be $48,019,573.

Mr. Blissmer testified NIPSCO's proposed financial incentive of CWIP ratemaking is just and reasonable. He stated the gross financing savings produces lower rates for customers. NIPSCO's proposal improves its cash flows and avoids rate shock to customers. He explained the primary benefit for a utility from CWIP ratemaking, from a financial health standpoint, is that it will provide NIPSCO cash flow during a potentially lengthy construction period. He testified CWIP ratemaking improves near term cash flow and mitigates the negative effects of the significant additional debt taken on to construct the project.

In addition to CWIP ratemaking resulting in savings and producing lower rates for customers, Mr. Blissmer testified that it has long been recognized that CWIP ratemaking is a benefit to customers because it prevents so-called “rate shock.” He explained that for large capital projects, waiting until the project enters service to include costs in rate base can lead to a significant one-time increase in the rate base and, in return, rates and that CWIP protects against that type of rate shock by phasing in the costs of the new facilities over the construction period.

Mr. Blissmer testified the exact estimated bill impact of the CT Project for an average residential customer will be dependent on several factors. However, assuming issuance of a CPCN for the CT Project and approval of the proposed GCT Mechanism as described above, NIPSCO currently estimates costs in the first GCT filing after approval would result in an incremental 2025 charge of approximately $0.56 to a 668 kWh per month residential bill, which is significantly lower than the $1.25/month impact based on a 2026 in-service date.

OUCC witness Ms. Baker objected to using the WACC in the calculation of CWIP ratemaking in the GCT. She contended NIPSCO should instead use project-specific financing costs or the cost of short-term debt.

IG witness Mr. Gorman testified the CWIP tracker is not just and reasonable simply because there are financial savings. Both IG witness Mr. Gorman and CAC witness Mr. Inskeep claimed the analysis of gross financing savings is inconsistent with Ind. Code § 8-1-8.8-11(a)(1)(B) in that it does not include net present value analysis. Mr. Inskeep also objected to the forward-looking version of the GCT Mechanism, alleging it was inconsistent with the verb tense of Ind. Code § 8-1-8.8-11(a)(1)and did not provide for “timely” recovery of costs.

In his rebuttal testimony, Mr. Blissmer testified NIPSCO is modifying its GCT proposal to remove WACC, and to apply its then current AFUDC rate. He stated he recalculated the gross financial savings from the use of CWIP ratemaking using both the forward-looking (NIPSCO’s proposal) and backward-looking (NIPSCO’s alternative proposal) using the estimated AFUDC rate instead of the WACC. He testified that (1) as shown in Petitioner’s Exhibit 8-R Attachment 8-R-A, with the forward-looking GCT, the gross financial savings are now estimated to be over $9 million greater utilizing the estimated AFUDC rate than the savings calculated in his supplemental direct testimony using the WACC, and (2) as shown in Attachment 8-R-B, with the backward looking GCT, the gross financial savings are now estimated to be over $6 million greater utilizing the estimated AFUDC rate. He testified both alternatives continue to produce gross financial savings when compared to traditional ratemaking consistent with Ind. Code § 8-1-8.8-11(a)(1)(B), with the forward-looking version producing greater gross financial savings. Mr. Blissmer in his rebuttal testimony also responded to the contentions of Messrs. Gorman and Inskeep in opposition to the proposed GCT Mechanism. Mr. Inskeep claimed the delay of in-service date of the CT Project has caused an increase in total financing costs, which Mr. Blissmer explained fails to acknowledge his supplemental direct testimony that the one-year delay produces $65 million in customer savings through 2028.

Having found the CT Project is "clean energy project" under Ind. Code § 8-1-8.8-2(5) and having found the CT Project is just and reasonable, we are now required by Ind. Code § 8-1-8.8-11(a) to create financial incentives for the CT Project. Specifically, NIPSCO has requested we approve its proposed GCT Mechanism, which would provide for construction work in progress ratemaking as allowed by Ind. Code § 8-1-8.8-11(a)(1). Subsection 11(a)(1) provides that we may authorize "[t]he timely recovery of costs and expenses incurred during construction and operation of the project," but we may not do so "unless the commission finds the eligible business has demonstrated that the timely recovery of costs and expenses during the construction and operation of the project: (A) is just and reasonable; and (B) in the case of construction financing costs, will result in a gross financing cost savings over the life of the project."

Mr. Blissmer presented the calculation of his gross financial savings in his direct and supplemental direct testimony. Using the forward-looking GCT, Mr. Blissmer calculated the gross financial savings in direct testimony at $81,986,410 over the life of the CT Project. Using the more traditional backward looking GCT Mechanism, there would be reduced savings of $48,019,573. In rebuttal, Mr. Blissmer changed the financing cost rate to the AFUDC rate rather than the WACC in response to OUCC witness Mr. Baker. This change increased the gross financing cost savings by $9 million (total savings of approximately $91 million) for the forward-looking version and by $6 million (total savings of approximately $54 million) for the backward-looking version.

IG witness Mr. Gorman and CAC witness Mr. Inskeep objected to Mr. Blissmer's calculations on the grounds that they were not done on a present value basis. The statute, by its terms, does not require the calculation to be done based upon net present value. Instead, the statute requires the demonstration of gross financing cost savings over the life of the project. The Commission is a creature of statute with delegated authority from the Indiana General Assembly. When a statute does not require interpretation, and is unambiguous as Section 11 is, the Commission shall follow the law as written. Had the General Assembly intended the calculation to be done on a net present value basis as argued by Messrs. Gorman and Inskeep, it would not have used the word "gross" and would have instead used "net present value." We find that, as calculated by NIPSCO witness Mr. Blissmer, both the forward-looking and backward-looking versions of the proposed GCT Mechanism will generate "gross financing cost savings" over the life of the CT Project.

We are unpersuaded by Messrs. Gorman and Inskeep's assertion NIPSCO did not demonstrate the proposed GCT Mechanism as just and reasonable, particularly because neither witness responded substantively to Mr. Blissmer's direct testimony describing how the GCT benefits customers through the avoidance of so-called "rate shock" when a large construction project is reflected in rates in a single step. By recovering costs through the GCT Mechanism during the construction period, the rate impact from the CT Project will be reflected in steps over six-month increments. The ultimate cost to customers once the CT Project is fully reflected in rates will be lower because of the greatly reduced AFUDC.

The General Assembly has specifically directed affordability as one of the attributes to be considered in the context of generation transition. One of the tools provided by the General Assembly in the case of transition to clean energy projects is a CWIP tracker, which, as explained by Mr. Blissmer, produces the benefits of lower rates and smaller rate increases. We cannot simply ignore the benefits a CWIP tracker will contribute to affordability by lowering rates and smoothing and mitigating rate increases during generation transition. NIPSCO's testimony on the overall benefits of CWIP ratemaking on credit quality, which ultimately informs the carrying charge applied to NIPSCO's investment and, therefore, customer rates, was effectively unrebutted. Mr. Inskeep asserted various other arguments against CWIP ratemaking generally, including that it creates generational inequities and erodes a utility's incentive to efficiently manage a project. These are not objections to whether this proposal meets the requirements of the statute, and they ignore the fact that the legislative decision has already been made to allow CWIP ratemaking. We find that, under Section 11, both the forward- and backward-looking versions of NIPSCO's proposed GCT Mechanism are just and reasonable.

We now move to the question of which method we should approve: the forward-looking or backward-looking GCT. As explained by Mr. Blissmer, NIPSCO has proposed the backward-looking GCT Mechanism in the alternative in the event we were not to approve the forward-looking version. With the forward-looking GCT, NIPSCO would reflect CWIP financing costs projected to occur over the next six-month billing period in each tracker filing. The projected CWIP financing costs would then be adjusted to the actual incurred costs and expenses by way of the reconciliation process. In this fashion, there would be no AFUDC reflected in the total cost of the CT Project except for the limited AFUDC that has already been accrued and expected to be accrued until rates take effect in March 2025 under the GCT Mechanism. In addition, there would be no depreciation to defer. The backward-looking GCT, in contrast, would reflect CWIP financing costs that had been incurred over the previous six-months. With the backward-looking GCT, there would be AFUDC accrued during each six-month period until the costs are reflected in the GCT. In addition, there would be depreciation deferred between the in-service date and reflection in rates. This AFUDC and deferred depreciation would increase the overall cost of the CT Project, which is why the backward-looking version of the GCT produces less gross financing cost savings.

Mr. Inskeep had two objections to the forward-looking version of the GCT. First, he claimed the statute uses past tense and that this precludes recovery of projected costs. Second, he claimed that because NIPSCO would be recovering financing costs before they have been incurred, the recovery would not be "timely" as the statute requires. We are unpersuaded by either argument. First, it is important to note that whether the tracker looks forward or backward will not change that NIPSCO will recover only its actual costs. With the reconciliation process inherent in the proposed tracker, NIPSCO's recovery will always be based upon its actual costs incurred. The statute requires that the mechanism provide for timely recovery of costs and expenses incurred during construction. With the forward-looking mechanism coupled with its reconciliation process, NIPSCO's proposal provides for recovery of the costs and expense that are actually "incurred," and this recovery begins during the same six-month period during which those costs are being incurred. The forward-looking GCT Mechanism would result in timely recovery consistent with the statute. In addition, given that the forward-looking GCT Mechanism produces approximately $37 million in gross financing cost savings ($91 million less $54 million) when compared to the backward-looking mechanism, it is the method that creates a more affordable result for customers. Further, Ind. Code § 8-1-8.8-11(a)(4) authorizes us to approve other financial measures we consider appropriate, and we consider the forward-looking GCT to be appropriate. The General Assembly has established an infrastructure policy "to use all practicable means and measures, including financial and technical assistance, in a manner calculated to create and maintain conditions under which utilities plan for and invest in infrastructure necessary for operation and maintenance while protecting the affordability of utility services for present and future generations of Indiana citizens." Ind. Code § 8-1-2-0.5. Denying a utility the use of a forward-looking tracker that would produce an additional $37 million in gross financial savings for customers based upon verb tense would be inconsistent with this overall infrastructure policy and the pillar of affordability. Accordingly, we find NIPSCO's proposed forward-looking GCT Mechanism using the AFUDC rate as reflected on rebuttal should be approved.

We further approve Petitioner's request that the operating income associated with the CT Project recovered through the GCT Mechanism be included in the total electric Comparison of Electric Operating Income for purposes of the Ind. Code § 8-1-2-42(d) earnings test. This is an appropriate additional financial incentive under Section 11, and it is therefore approved.

D. <u>The Five Pillars</u>. In HEA 1007, the Indiana General Assembly declared it is the continuing policy of the State that decisions concerning Indiana's electric generation resource mix, energy infrastructure, and electric service ratemaking constructs must consider each of the five pillars of electric utility service. See also Ind. Code § 8-1-8.5-4(b)(4). Ind. Code § 8-1-2-0.6 codifies the five pillars of electric utility service: as reliability, affordability, resiliency, stability, and environmental sustainability. NIPSCO witness Ms. Becker's Petitioner's Exhibit No. 1 Attachment 1-C identifies the seven different NIPSCO witnesses who sponsored testimony supporting each of the Pillars.

We address the Five Pillars in the order in which they are listed in Ind. Code § 8-1-2-0.6, acknowledging that no one pillar takes precedence over the others and that each must be balanced against the others.

Based on the evidence of record and having considered the Five Pillars enumerated in Ind. Code § 8-1-2-0.6, the Commission finds NIPSCO's proposed CT Project and related proposals are consistent with and appropriately balance the legislative directive in this state policy statement.

i. <u>Reliability</u>. Reliability is ensuring customers have the power they need when they need it. We have recognized that in a dramatically shifting generation landscape the need for fast start/quick ramping resources is magnified. Southern Ind. Gas & Elec. Co., Cause No. 45564 (IURC 6/28/2022). NIPSCO witness Mr. Austin's testimony informs us this need is increasing. Evidence of record supports findings that the proposed CT Project addresses needs identified by key stakeholders, including MISO, NERC, the MISO IMM, and others, and addresses needed attributes to directly support NIPSCO's overall generation portfolio.

Both the NERC and MISO have warned stakeholders that, as the penetration of solar generation increases, the challenge of steeper ramping needs for the non-solar fleet magnifies. Mr. Austin cited numerous publications from NERC, MISO, and MISO's IMM discussing the need to install fast-starting, quick ramping generation to support the growing portfolio of renewable resources and maintain reliable service. NERC specifically recognizes the important role regulatory policy plays in ensuring a reliable grid. Mr. Austin explained that 2023 marked the first year, "energy policy" has been added as a risk profile to Electric Reliability Organization ("ERO") Priorities Report. Mr. Austin, quoted the ERO Priorities report stating: "[t]raditional resource adequacy approaches that assume the system is adequately planned if there is enough generation capacity during peak load hours have become insufficient given the accelerated changes in resource mix, extreme weather events, and fuel dependencies." Petitioner's Exhibit No. 3. The 2022 Long-Term Reliability Assessment issued December 2022 states as follows:

> As more solar and wind generation is added, additional flexible resources are needed to offset these resources' variability, such as supporting solar down ramps when the sun goes down and complementing wind pattern changes. This can be accomplished by adding more flexible resources within committed portfolios or by removing system constraints to flexibility.

Further, NIPSCO witness Mr. Austin explained the proposed CT Project will help meet MISO's Resource Adequacy Requirements. The 2023 Organization of MISO States- MISO Survey Results (published July 14, 2023) reflect delayed retirements and capacity additions have resulted in a capacity surplus of 1,500 MW for the 2024/25 planning year. Id. Demand growth is projected to continue for five years across all four seasons at 0.8 GW or 0.68% per year on average across the MISO footprint and the results show a deterioration of MISO's current capacity surplus above the required capacity level, to a sizeable projected shortfall of 2,100 MW in summer 2025/26. This demonstrates a growing need for dispatchable resources to support system reliability within the MISO region, including Indiana.

NIPSCO witness Mr. Austin explained why batteries, inverter-based resources ("IBRs"), and energy storage resources ("ESR") do not meet system reliability needs. NERC and MISO's IMM reach similar conclusions, as the NERC highlights in its 2022 Long-Term Reliability Assessment and notes:

> … IBRs produce low amounts of fault currents based on control functions. Changing fault current magnitudes and characteristics in parts of the system with high penetrations of IBRs has the potential to invalidate current protection system designs, potentially leading to more protection system misoperation.

The IMM, in its 2022 State of the Market Report for the MISO Electricity Markets, concurs, stating that:

> Although ESRs can provide tremendous value in managing the fluctuations in intermittent output and maintaining reliability, ESRs are not fully substitutable for conventional generation. This is particularly true as the quantities of ESRs rise, which causes the marginal value of ESRs to fall.

NIPSCO witness Mr. Stanley explained MISO's interest in the significant transition of electric generation in the MISO region:

> MISO is focused on reliability, and that means it is focused on ensuring the resource portfolio has the necessary capability and attributes. Yet, due to decarbonization goals, economics and customer preferences, key existing resources will retire. Some plans to build new resources with the needed attributes are delayed or abandoned, and other technologies are not ready for broad deployment. Proposed replacement capacity has shown to be lacking key traits given current technologies. The gap between retirement capabilities and attributes is a growing reliability

concern.

Petitioner’s Exhibit No. 6. The Executive Summary in the 2022 State of the Market Report goes on to outline different attributes or characteristics provided by different generation resource types and reflects that gas resources have a significant relative advantage over renewable resources in providing: (1) long duration energy at high output; (2) voltage stability; (3) ramp up capability; (4) rapid start-up; and (5) blackstart capability. It is these attributes that the CT Project will offer to NIPSCO’s generation portfolio, for the benefit of all of its customers and the broader MISO region. In addition, while still in development and under review, NIPSCO witness Mr. Augustine cited from MISO’s Resource Adequacy Subcommittee October 2022 presentation that noted the importance of key technical attributes like blackstart and detection of short circuit strength and prioritized a set of attributes associated with capacity, energy adequacy, flexibility, and essential reliability services. These priority attributes are consistent with the reliability criteria NIPSCO evaluated within the economic and non-economic assessments that were conducted during the 2021 IRP.

NIPSCO conducted extensive diligence on the reliability of the potential resource portfolios in its 2021 IRP. The Non-Economic Reliability Assessment evaluated each potential portfolio based on the following reliability criteria and metrics: (1) blackstart capability, (2) energy adequacy, (3) dispatchability, (4) operational flexibility and frequency support, (5) VAR support, (6) location, (7) predictability and firmness, and (8) short circuit strength. In 2023, NIPSCO conducted the Flexible Resource Analysis to assess the preferred portfolio’s flexibility needs on an inter-hour and intra-hour basis, given the variability and intermittency of renewable resources and performed a sub-hourly analysis to provide insights into the type of market exposure NIPSCO could face as its portfolio evolves. The Flexible Resource Analysis showed the preferred portfolio of approximately 1,200 MW of flexible capacity by 2030 would be insufficient to meet net load and three-hour ramp requirements in extreme conditions without reliance on the market and revealed a 150 MW growth in NIPSCO’s need for capacity with a 10-minute ramp rate by 2030. NIPSCO’s CT Project in its preferred configuration is designed to fill this capacity gap ensuring service on NIPSCO’s entire system is reliable.

Our review of the evidence of record regarding the attributes of the aeroderivative turbines leads us to conclude that their operational characteristics are a vital part of the CT Project’s expected reliability. NIPSCO witness Mr. Baacke explained aeroderivative turbines are typically more efficient, start faster and more frequently, and fluctuate power generation faster to meet demand when compared to larger industrial frame turbines. We conclude it is these features that will allow NIPSCO to continue to install large volumes of renewable energy (which serves the environmental sustainability pillar discussed below) while still maintaining the ability to reliably and efficiently serve a heavy industrial customer base, as well as commercial and residential load, when intermittent renewable resources are not available for short or prolonged periods of time.

Finally, we note the CT Project’s gas usage will be supported through NIPSCO’s gas system, which already contains transportation rates, riders, and pooling options. NIPSCO’s gas system is robust, with multiple interconnection points with seven interstate pipelines, which offer an uncommon level of supply diversity as natural gas generators are typically captive to only one interstate pipeline connection. This is an advantage for the CT Project, especially as compared to intermittent resources, and further bolsters its reliability and resiliency.

ii. Affordability. The addition of a large generation resource such as the CT Project will necessarily impact the cost of electric service NIPSCO provides to its customers. This illustrates the tension between the Five Pillars that naturally occurs as a utility invests to ensure the availability and delivery of reliable energy to its customers. The OUCC, IG, and CAC testimony each raised affordability concerns with NIPSCO's proposed CT Project and related cost recovery through the GCT Mechanism. The thrust of their varied concerns is the pillars of reliability, resiliency, and stability should not supplant meaningful consideration of the customer affordability of NIPSCO's request.

Although we are not approving rates as part of this proceeding, we are authorizing NIPSCO to construct a generation facility that will operate for many years and approving a recovery mechanism for costs associated with construction of the facility. Because a utility has limited control over nearly all the external factors that could impact its customers' ability to pay for utility service, the challenge for public utilities in the face of a highly consequential generation transition is to meet its customers' need for electric generation cost effectively. NIPSCO's evidence supports that its proposal for the CT Project does that.

The proposed CT Project originated from NIPSCO's 2021 IRP from which a preferred portfolio was selected as a lower cost option than alternatives. NIPSCO utilized a competitively bid EPC contract event and determined a multi-prime contracting strategy could save $100 million over the viable EPC bid it received. When NIPSCO determined supply chain constraints caused the originally contemplated in-service date to no longer be reasonably achievable, it reevaluated its approach and submitted supplemental direct testimony to shift the in-service date of the CT Project by one year to end of year 2027. This shift in in-service date produced an immediate savings for customers of $65 million over the course of the next five years through delayed rate implementation. In addition to these savings, NIPSCO's proposed GCT Mechanism will further produce gross financial cost savings of approximately $90 million over the life of the CT Project as compared to traditional ratemaking. Finally, the CT Project will not require additional pollution control technology to comply with GHG Rule and offers the flexibility to run as an intermediate load unit, which could serve to reduce NIPSCO's need to procure additional market capacity, which reduces exposure to price volatility to the benefit of NIPSCO's customers. Each of these facts demonstrate the steps NIPSCO took to address affordability as part of its overall project proposal.

While we acknowledge that a project of this size will inevitably lead to an increase in customers rates, we conclude that, when considered in totality, NIPSCO's CT Project supports the goal of utility service costs that are affordable and competitive across the customer classes.

iii. Resiliency. Resiliency is similar to reliability, and much of our discussion above regarding reliability is applicable here. Resiliency represents the distinct concept concerned with ensuring availability of electricity under changing or extraordinary system conditions. The fast start capabilities of the CT Project, especially given the configuration with aeroderivative units are a key component of resiliency. NIPSCO witness Mr. Walter testified NIPSCO has a need for additional winter capacity, and the CT Project will be a key part of ensuring the resiliency of NIPSCO's electric operations. Mr. Austin offered extensive confidential testimony that directly addressed how the CT Project will support resiliency.

In addition to the system's ability to respond to an acute system emergency or unexpected outage, longer-term resiliency can be considered based on evolving market rules, changing weather patterns, or climate-related phenomena. As outlined by NIPSCO witness Mr. Augustine, the 2023 portfolio analysis incorporated market shifts and changes that have occurred since the 2021 IRP, including the MISO seasonal resource adequacy construct. These changes point to an increased need for capacity-advantaged resources in NIPSCO's generation portfolio, a need which the CT Project directly fulfills.

iv. **Stability.** Stability is defined in the statute as the ability of the electric system to: (a) maintain a state of equilibrium during normal and abnormal conditions or disturbances and (b) deliver a stable source of electricity, in which frequency and voltage are maintained within defined parameters, consistent with industry standards. Stable sources of power provide a critical backbone to the grid, which is particularly vital during this dynamic time of significant generation transition. With renewable generation being a significant component of NIPSCO's generation portfolio transition since its 2018 IRP, NIPSCO conducted a Reliability Analysis as part of its 2021 IRP, which identified the need for longer-duration, flexible resources additions within its service territory. As gas turbines can operate continuously for extended durations, the CT Project clearly supports system stability. NIPSCO witness Mr. Stanley testified that gas resources have a significant advantage relative to inverter-based (e.g., renewable) resources, as gas resources can provide (1) long duration energy at high output; (2) voltage stability; (3) ramp up capability; (4) rapid start-up; and (5) blackstart capability. These characteristics, which were also discussed above in the Reliability discussion, are essential to a stable generation transition, and a stable generation transition drives value for utility customers. Evidence of record supports a finding that the CT Project offers these types of needed attributes and supports system stability for NIPSCO, Indiana, and the broader MISO region.

v. **Environmental Stability.** Environmental sustainability considers both the impact of regulations and the demand from customers for power from environmentally sustainable resources. The CT Project fits as part of NIPSCO's overall plan to retire all its coal-fired generation by 2028 and to reduce its carbon emissions from its electric operations by 90% measuring from a 2005 baseline. The CT Project will have the flexibility to run beyond its currently anticipated capacity factors and still maintain compliance with the newly adopted EPA GHG rule. The CT Project fits within an overall portfolio whereby NIPSCO has successfully transitioned away from a portfolio heavily reliant on coal to one that relies on a fleet of wind, solar, and battery energy storage resources. The intermittent capabilities of those renewable resources must be supported by the quick start/fast ramp capabilities of the CT Project.

OUCC witness Mr. Armstrong states that the determination of whether natural gas generation is environmentally sustainable is subjective. The CT Project supports increasing levels of renewable energy in the electric system and replaces capacity from NIPSCO's coal units that are planned to retire by 2025 and 2028. The retirement of coal generation and replacement with zero-emission generation and low/intermediate-load gas generation—such as the CT Project—keeps NIPSCO and NiSource on-track to achieve their target of a 90% reduction in Scope 1 GHG emissions by 2030, compared to 2005 levels. The efficiency of the aeroderivative turbines serves the environmental sustainability pillar. NIPSCO witness Mr. Holcomb explained that, at full load, the aeroderivative units are expected to meet the intermediate load emission standard in the EPA greenhouse gas rule and be allowed to operate at capacity factors up to 40%, as needed. The frame unit is not expected to meet the intermediate load emission standard and would, therefore, be limited to a 20% capacity factor. This demonstrates how the proposed CT Project's configuration balances environmental sustainability while also supporting reliability, resiliency, and stability.

6. Confidentiality. NIPSCO filed a motion for protection and nondisclosure of confidential and proprietary information on September 12, 2023, January 16, 2024, and April 25, 2024. These motions related to information NIPSCO claimed to be trade secrets and protected from disclosure under Ind. Code §§ 8-1-2-29 and 5-14-3-4. Docket entries were issued on September 28, 2023, February 8, 2024, and March 13, 2024, finding such information to be preliminarily confidential and protected from disclosure under Ind. Code §§ 8-1-2-29 and 5-14-3-4. The confidential information was subsequently submitted under seal. The Commission finds the information that is the subject of these motions is confidential pursuant to Ind. Code § 8-1-2-29 and Ind. Code ch. 5-14-3, is exempt from public access and disclosure by Indiana law, and shall continue to be held by the Commission as confidential and protected from public access and disclosure.

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

1. NIPSCO is issued a certificate of public convenience and necessity under Ind. Code ch. 8-1-8.5 to construct an approximately 400 MW natural gas combustion turbine peaking plant to be located at NIPSCO's existing R.M. Schahfer site. This Order constitutes the certificate.

2. NIPSCO's estimated total cost of the CT Project in the amount of $641.2 million (excluding AFUDC) is approved as set forth herein.

3. NIPSCO's request for ongoing review of the CT Project is approved. NIPSCO shall file reports as described herein for the purpose of ongoing review in accordance with Ind. Code § 8-1-8.5-6.

4. The CT Project is approved as a clean energy project and NIPSCO's request for financial incentives, including timely cost recovery through construction work in progress ratemaking under Ind. Code Ch. 8-1-8.8 is approved.

5. NIPSCO is granted authority to recover costs incurred in connection with the CT Project through its Generation Cost Tracker Mechanism, as proposed, including approval of the specific ratemaking and accounting treatment approved herein. NIPSCO's proposed changes to its Electric Service Tariff relating to the GCT Mechanism are approved.

6. The Confidential Information submitted under seal in this Cause pursuant to the parties' requests for confidential treatment is determined to be confidential trade secret information as defined in Ind. Code § 24-2-3-2 and shall continue to be held as confidential and exempt from public access and disclosure under Ind. Code §§ 8-1-2-29 and 5-14-3-4.

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

HUSTON, BENNETT, FREEMAN, VELETA, AND ZIEGNER CONCUR:

APPROVED: OCT 16 2024

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

Dana Kosco Digitally signed by Dana Kosco
Date: 2024.10.16 10:11:29
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Dana Kosco
Secretary of the Commission