**STATE OF INDIANA**

**INDIANA UTILITY REGULATORY COMMISSION**

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| **PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY d/b/a CENTERPOINT ENERGY INDIANA SOUTH ("CEI SOUTH") FOR (1) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY PURSUANT TO IND. CODE CH. 8-1-8.5 FOR THE CONSTRUCTION OF TWO NATURAL GAS COMBUSTION TURBINES ("CTs") PROVIDING APPROXIMATELY 460 MW OF BASELOAD CAPACITY ("CT PROJECT"); (2) APPROVAL OF ASSOCIATED RATEMAKING AND ACCOUNTING TREATMENT FOR THE CT PROJECT; (3) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY PURSUANT TO IND. CODE CH. 8-1-8.4 FOR COMPLIANCE PROJECTS TO MEET FEDERALLY MANDATED REQUIREMENTS ("COMPLIANCE PROJECTS"); (4) AUTHORITY TO TIMELY RECOVER 80% OF THE FEDERALLY MANDATED COSTS OF THE COMPLIANCE PROJECTS THROUGH CEI SOUTH'S ENVIRONMENTAL COST ADJUSTMENT MECHANISM ("ECA"); (5) AUTHORITY TO CREATE REGULATORY ASSETS TO RECORD (A) 20% OF THE FEDERALLY MANDATED COSTS OF THE COMPLIANCE PROJECTS AND (B) POST-INSERVICE CARRYING CHARGES, BOTH DEBT AND EQUITY, AND DEFERRED DEPRECIATION ASSOCIATED WITH THE CT PROJECT AND COMPLIANCE PROJECTS UNTIL SUCH COSTS ARE REFLECTED IN RETAIL ELECTRIC RATES; (6) IN THE EVENT THE CPCN IS NOT GRANTED OR THE CTS OTHERWISE ARE NOT PLACED IN SERVICE, AUTHORITY TO DEFER, AS A REGULATORY ASSET, COSTS INCURRED IN PLANNING PETITIONER'S 2019/2020 IRP AND PRESENTING THIS CASE FOR CONSIDERATION FOR FUTURE RECOVERY THROUGH RETAIL ELECTRIC RATES; (7) ONGOING REVIEW OF THE CT PROJECT; AND (8) AUTHORITY TO ESTABLISH DEPRECIATION RATES FOR THE CT PROJECT AND COMPLIANCE PROJECTS ALL UNDER IND. CODE §§ 8-1-2-6.7, 8-1-2-23, 8-1-8.4-1 ET SEQ., AND 8-1-8.5-1 ET SEQ.** | ) | **CAUSE NO. 45564** |

**INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR**

**PUBLIC'S EXHIBIT NO. 2**

**TESTIMONY OF OUCC WITNESS ANTHONY A. ALVAREZ**

**NOVEMBER 19, 2021**

Respectfully submitted,

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**TESTIMONY OF OUCC WITNESS ANTHONY A. ALVAREZ**
**CAUSE NO. 45564**
**INDIANA SOUTH GAS AND ELECTRIC COMPANY**
**d/b/a CENTERPOINT ENERGY INDIANA SOUTH**

## I. INTRODUCTION

**Q: Please state your name and business address.**

A: My name is Anthony A. Alvarez, and my business address is 115 West Washington Street, Suite 1500 South, Indianapolis, Indiana 46204.

**Q: By whom are you employed and in what capacity?**

A: I am employed as a Utility Analyst in the Indiana Office of Utility Consumer Counselor's ("OUCC") Electric Division. I describe my educational background in Appendix A to my testimony.

**Q: Have you previously testified before the Indiana Utility Regulatory Commission ("Commission")?**

A: Yes. I have testified in a number of cases before the Commission, including electric utility base rate cases; environmental and renewable energy Purchase Power Agreement and tracker cases; Transmission, Distribution, and Storage System Improvement Charge cases; and applications for Certificates of Public Convenience and Necessity ("CPCN").

**Q: What is the purpose of your testimony?**

A: My testimony addresses CenterPoint Energy Indiana South's ("CEIS" or "Petitioner") request for approval to construct two natural gas simple cycle combustion turbines in this Cause.[1] In particular, my testimony: 1) describes CEIS'

[1] *See* Petitioner's Verified Petition dated July 17, 2021, p. 8.

proposed 460 MW simple cycle combustion turbines ("CT Project");[2] 2) evaluates CEIS' cost estimate for its proposed CT Project; 3) addresses the functional and operational characteristics of CEIS' proposed CT project and existing simple cycle turbine assets; 4) discusses why CEIS' proposed CT Project is not a good choice for ratepayers; 5) describes refueling the coal-fired A.B. Brown units to gas-fired as a viable and cost-effective alternative for CEIS and its ratepayers; 6) analyzes the gas conversion technology as a less-expensive alternative option available to enhance and extend the life of the A.B. Brown legacy generating units; and 7) recommends the Commission deny CEIS' proposed CT Project and encourage CEIS to adopt the more reasonable alternative of refurbishing and refueling the A.B. Brown generating units to gas.[3] I support the testimonies of OUCC witnesses Cynthia M. Armstrong, Dr. Peter M. Boerger, and Kaleb G. Lantrip.

**Q: Please summarize your testimony.**

A: The following summarizes my testimony:

1) Despite CEIS' flexibility claims, the simple cycle gas combustion turbine technology employed in CEIS' proposed CT Project is the most restrictive in terms of utility-scale electricity generation because of its relatively low efficiency and operational functionality. Simple cycle turbines perform in a narrow role as peaker generators because the technology and design of these machines do not allow them to run or operate long durations throughout the year.

2) CEIS claims that the proposed CT Project will support intermittent renewable resources being developed across Midcontinent Independent System Operator ("MISO") Zone 6 and will allow other Indiana utilities to meet their peak loads when energy from renewables is insufficient. However, MISO, not CEIS, has the authority to decide which generators to

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[2] Public's Attachment AAA-1, CEIS response to OUCC DR Set 5-2 (b) states "[s]imple Cycle Gas Turbines (SCGT) are Combustion Turbines (CT) and used interchangeably throughout testimony."

[3] *In re Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc*., Cause No. 45052, Final Order, p. 2 (Ind. Util. Regul. Comm'n April 24, 2019) ("*Cause No. 45052*").

dispatch and serve the demand and load within its footprint. As peaker class generators, simple cycle turbines are projected by CEIS to have inherently low Capacity Factors ("CF"). Because they are very expensive to run with relatively low efficiency characteristics, they are the last generators MISO dispatches.

3) CEIS' system peak demand has been declining since 2013, showing a compound annual growth rate of -2.7% (2013-2020). Despite a contracting system demand, CEIS' long-term plan remains misaligned and focused on expanding rate base, which is and will be detrimental to its relatively small customer base.

4) CEIS has had the overall highest residential rates among the five Indiana investor-owned utilities ("IOU") from 2017 to 2021 in the Commission's annual residential bill survey (based on Total Rate of customers consuming 1,000 kWh). Instead of selecting a plan to extend the life of its existing generation assets and mitigate rate base increases, CEIS seeks to retire and replace high performance generators with expensive simple cycle turbines, thereby expanding its rate base.

5) CEIS has two existing simple cycle turbine generating units at the A.B. Brown station. Both A.B. Brown Units 3 & 4 are 80 MW simple cycle turbines that in the last seven years (2014 through 2020) generated and injected electricity to the grid only a few hundred hours per year. CEIS expects the same disappointing performance from its proposed CT Project.[4]

6) The proposed CT Project is not the appropriate available alternative option to replace the coal-fired 490 MW A.B. Brown units. CEIS did not consider comparing, evaluating and assessing the performance of the gas conversion alternative option with similar existing generating units in Indiana. CEIS handicapped and eliminated a viable alternative option by assigning it a shorter useful life in its analysis.

7) The gas-fired conversion and refueling technology is an adoptable, viable and cost-effective alternative to refurbish the coal-fired A.B. Brown legacy units and provide CEIS and its customers with capacity.

8) The Commission should deny CEIS' proposed CT Project and require CEIS to pursue the viable and cost-effective alternative of refurbishing, converting, and refueling the A.B. Brown legacy units to gas.

[4] Petitioner's witness Steven C. Greenley, Direct Testimony at page 14, ll. 33 to p. 15, ll.1, states "[t]he CT units will not be a base loaded and are projected to have a low-capacity factor only operating when economical for the customer."

**Q: What did you do to prepare your testimony?**

A: I reviewed CEIS' petition, direct testimony, and exhibits filed in this Cause. I prepared discovery questions and reviewed CEIS' discovery responses issued in this Cause. I also reviewed the Commission's Cause No. 45052 Order dated April 24, 2019, ("Cause No. 45052 Order").

**Q: To the extent you do not address a specific item in your testimony, should it be construed to mean you agree with CEIS's proposal?**

A: No. My silence regarding any topics, issues, or items CEIS proposes does not indicate my approval of those topics, issues, or items. Rather, the scope of my testimony is limited to the specific items addressed herein.

## II. CAUSE NO. 45052 ORDER LESSONS LEARNED

**Q: Briefly discuss the Cause No. 45052 Order, CEIS' last request for new generation.**

A: The Cause No. 45052 Order found Petitioner failed to "fully consider options to extend the life, or refurbish, existing units" and such "failure began during Vectren South's IRP [Integrated Resource Planning] process," when Vectren "screened out, without further sturdy, viable refurbishment options."[5] Additionally, from a perspective of "minimizing risk and providing future flexibility," the Commission found "the refurbishment option would seem to provide a potential bridge to the future, providing system capacity value that was not sufficiently evaluated" by the Petitioner.[6] Ultimately, the Cause No. 45052 Order denied CEIS' (at that time "Vectren South" or "Vectren") request for a CPCN to install an 850 MW combined cycle gas turbine ("CCGT").

[5] *Cause No. 45052*, p. 22.
[6] *Cause No. 45052*, p. 22.

**Q: Briefly discuss the relevance and lessons learned from the Cause No. 45052 Order.**

A: In the current case, Cause No. 45564, Petitioner's witness Steven G. Greenley refers to the Cause No. 45052 Order stating "[t]he Commission made findings regarding deficiencies in the Company's [Vectren's] planning which led to the overall denial" of Petitioner's request for a CCGT.[7] Mr. Greenley further describes the Commission's Cause No. 45052 findings of deficiencies in Petitioner's request as "lessons learned."[8] Among the "lessons learned" was removing restrictions from CEIS' request for proposal ("RFP"), which the Commission stated "was unduly restrictive" and too narrowly focused and limited on large dispatchable resource options.[9] Mr. Greenley's direct testimony at page 9, lines 4 – 5, acknowledges the need for CEIS to "consider refueling [A.B.] Brown"[10] and "incorporate flexibility in the modeling" by not screening out multiple less expensive alternatives.[11] Mr. Greenley states these "lessons learned" guided CEIS in preparing its request in this case.[12]

**Q: Did CEIS incorporate all "lessons learned" from Cause No. 45052 in this case?**

A: No. Although CEIS did not "screen-out" less expensive alternatives in this case , it imposed an unreasonable burden on the alternative option of refueling the A.B. Brown units with higher cost estimates than its own previous refueling estimates in

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[7] Greenley, Direct Testimony, p. 9, ll. 2 – 3, states "[t]he Commission made several findings regarding deficiencies in the Company's planning which led to the overall denial."
[8] Greenley Direct Testimony, p. 9, ll. 3, states "I would describe these deficiencies as 'lessons learned.'"
[9] *Id.*, p. 9, ll. 18 – 22, referring to *Cause No. 45052*, pp. 20 – 21.
[10] Greenley Direct, p. 9, ll. 27.
[11] *Id.*, p. 9, ll. 4 – 6.
[12] Greenley Direct, p. 9, ll. 4 – 5, and p. 11, ll. 17 – 18.

Cause No. 45052[13] or actual costs of similar completed refueling projects in Indiana.[14] Further, CEIS imposed additional operational restrictions so that the capabilities of the alternative option appear unviable for CEIS' purposes.

**Q: Briefly explain the comparison between the generators CEIS proposed in Cause No. 45052 and CEIS' proposal in this Cause.**

A: The proposed generating facility in Cause No. 45052 consisted of two GE F-Class simple cycle combustion turbines combined with one heat recovery steam generator ("HRSG") to form a CCGT in a 2x1 configuration.[15] By comparison, CEIS' proposal in this Cause is simply a "stripped down" version of its previous CCGT proposal, which takes away the HRSG and retains the two simple cycle turbines.

**Q: In your review of CEIS' request in this Cause, did you consider the Commission's findings in Cause No. 45052 related to the issue of refurbishing existing facilities?**

A: Yes. Indiana Code § 8-1-8.5-4(b)(2) requires the Commission to consider other methods of providing reliable, efficient, economical electric service including "the refurbishment of existing facilities[.]"[16] This statutory requirement was central to the Commission's discussion and findings in its Cause No. 45052 Order.[17] I considered the Commission's findings in its 45052 Order as I reviewed and evaluated CEIS' proposed CT Project and assessed Mr. Greenley's claims of using

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[13] *Cause No. 45052*, p. 22, paragraph 2, states "[r]efueling is viable, proven technology that could be accomplished at a fraction of the price of the CCGT - approximately $45 million for both A.B. Brown units."
[14] *In re Indianapolis Power & Light Company*, Cause No. 44540, Final Order, p. 34 (Ind. Util. Regul. Comm'n July 29, 2015) states "[f]rom an economic perspective, the long position would appear to be the least cost market position, relative to the low capital cost for the HS-7 refuel (less than $200/kW) and the ongoing projected market peaking capacity value provided."
[15] Cause No. 45052, Petitioner's witness Wayne D. Games, p. 11, ll. 9 – 13.
[16] I.C. § 8-1-8.5-4(b)(2) states "(b) In acting upon any petition for the construction, purchase, or lease of any facility for the generation of electricity, the commission shall take into account the following: (2) Other methods for providing reliable, efficient, and economical electric service, including the refurbishment of existing facilities, conservation, load management, cogeneration and renewable energy sources."
[17] *Cause No. 45052*, p. 19.

the lessons learned from the 45052 Order as guidance in this Cause. I researched and evaluated the performance of other existing refurbished and refueled coal-fired to gas-fired converted units with nominal capacity ranges similar to the A.B. Brown units.

## III. CT PROJECT OVERVIEW

**Q: Please provide a brief overview of CEIS' proposed CT Project.**

A: CEIS proposes to construct and install two natural gas simple cycle combustion turbine generators with a combined capacity output of 460 MW[18] to replace a portion of the 490 MW coal-fired A.B. Brown Units 1 & 2.[19] Mr. Greenley states CEIS proposes to diversify its generation asset portfolio by adding two F-Class natural gas CTs (the CT Project) at the A.B. Brown site "with an in-service date of fourth quarter 2024."[20] The simple cycle turbines are not base load generators and are projected to have a low-capacity factor, but are designed to provide fast start and fast ramping capability.[21] CEIS' CT Project cost estimate is $323 million consisting of an Engineering Procurement and Construction ("EPC") Estimate, Owner's Costs (including project management, owner's engineer, and regulatory or permitting costs), Escalation Costs, and Planning and Development Costs,

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[18] *See* CEIS Witness Jason A. Zoller, Attachment JAZ-2 (Public), p. 4, for the nominal rating and technical description of CEIS' proposed combustion turbines.

[19] Greenley Direct, p. 14, ll. 31 – 33.

[20] Greenley Direct, p. 15, ll. 29 – 31, states "[a]s discussed in greater detail by Petitioner's Witness Games, the Company proposes to construct the two F-Class CTs at the A.B. Brown site (the "Brown Site"), with an in-service date of fourth quarter 2024."

[21] *Id.*, p. 14, ll. 33 to p. 15, ll. 6, states: "[t]he CT units will not be base loaded and are projected to have a low-capacity factor only operating when economical for the customer. Further, the CTs are designed to provide fast start and fast ramping capability, providing dispatchable energy which is necessary to complement the Company's renewable energy resources and ensure sufficient dispatchable capacity to reliably and efficiently serve the Company's load when the intermittent renewable resources are not available for short or prolonged periods of time."

among other costs.[22] However, the CT Project cost estimate does not include the costs of the required pipeline and emission control equipment.[23] CEIS negotiated a 20-year service contract with Texas Gas Transmission LLC. to construct 24 miles of 20-inch pipeline lateral and place the pipeline lateral in-service by 2024 to serve the CT Project.[24]

## IV. CT PROJECT COST ESTIMATE

**Q: Please briefly discuss your evaluation of CEIS' cost estimate for its proposed CT Project.**

A: I evaluated the $323 million proposed CT Project cost estimate Petitioner's witness Wayne Games presented.[25] Based on the cost information Mr. Games provided, the CT Project yielded a capital cost of $702 per kilowatt ("kW").[26] Table 1 below summarizes the total cost estimate information found in Mr. Games' direct testimony, Table WDG-4: Estimated CT Project Costs, page 35, line 10.

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[22] *Id.*, p. 16, ll. 7 – 11.
[23] Zoller, Attachment JAZ-2 (Public), p. 3, states "[e]mission control for this cost estimate is based upon combustion controls only and does not include selective catalytic reduction (SCR) or oxidation catalyst."
[24] Greenley Direct, p. 16, ll. 11 – 15.
[25] *Id.*, p. 34, ll. 18.
[26] To calculate the capital cost in $/kW, divide $323 million by 460 MW and multiply by 1,000 to convert MW to kW.

**Table 1: CEIS CT Project Current Cost Estimate**

| Description | Cost, $ million | Remarks |
|---|---|---|
| EPC Estimate | $188 | EPC; 2x0 Simple Cycle GE 7F.05 gas turbines; direct and indirect costs; EPC overhead and profit, escalation, bonding, warranty, and builder's risk insurance. |
| Owner's Total Cost | $135 | Owner's cost and contingency; internal labor and loadings; administrative and general overheads ("A&G"), allowance for funds used during construction ("AFUDC"), spare parts, and study/pre-work costs. |
| Total Cost Estimate | $323 | Estimated costs including projected escalation. New pipeline cost *not* included. |

I also evaluated the EPC cost estimate provided in Petitioner's Exhibit No. 7, Petitioner's witness Jason A. Zoller, (Confidential) Attachments JAZ-2 and JAZ-4,[27] and the technical specifications of the simple cycle GE 7F.05 gas turbines Mr. Zoller provided. Using the EPC cost estimate and combining it with the turbine ratings Mr. Zoller provided, I calculated a higher capital cost of $720 per kW (compared to Mr. Games' $702 estimate) for the CT Project.[28] Further, I compared Messrs. Games' and Zoller's estimates to the range of overnight capital cost estimates[29] for gas peakers using Lazard's Levelized Cost of Energy Analysis, Version 14.0 (2020) ("Lazard LCOE V.14.0").[30] The results show Messrs. Games'

[27] Zoller, Attachment JAZ-2 (Confidential): EPC Basis of Estimate for the F-Class Configuration and Attachment JAZ-4 (Confidential): Petitioner's OEM F Class 2x0 Simple Cycle Preliminary Bid Evaluation Combustion Turbine-Generators Report.
[28] Zoller, Attachment JAZ-2 (Confidential), p. 4 and Attachment A, p. 2.
[29] Overnight costs exclude interest accrued during plant construction and development. *See* U.S. EIA, Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2021, February 2021. Weblink: https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf. Accessed: 10/21/2021.
[30] Lazard. Website: https://www.lazard.com/media/451419/lazards-levelized-cost-of-energy-version-140.pdf. Accessed: 10/21/2021.

and Zoller's capital cost estimates were at the lowest end of Lazard capital cost range for a gas peaker. Table 2 below shows the capital cost comparisons benchmarked against Lazard capital cost ranges for a gas peaker.

**Table 2: Lazard Capital Cost Comparison, $/kW**

| | **Capital Cost, $/kW** |
|---|---|
| Lazard Capital Cost Gas Peaker | Range: $700 - $925 |
| CT Project Cost Estimate (Games) | $702 |
| CT Project Cost Estimate with EPC Cost and Technical Update (Zoller) | $720 |

Taking into consideration the Lazard capital cost range for gas peakers does not include any interest, financing, or escalation costs, it appears anomalous for CEIS' estimate to be at the lower end of the range.

I also compared Messrs. Games' and Zoller's estimates to the range of overnight capital cost estimates for gas peakers[31] using the U.S. Energy Information Administration ("EIA") base and regional overnight capital cost for new electricity generating technologies.[32] The EIA data included gas peaker overnight capital costs by region for MISO's west, central, east, and south regions.

[31] EIA's combustion turbine – industrial frame technology. *See* U.S. EIA Annual Energy Outlook 2021.
[32] U.S. EIA Annual Energy Outlook 2021.

**Table 3: EIA Base and Regional Overnight Capital Cost Comparison, $/kW**

| | Base | MISW* | MISC* | MISE* | MISS* |
|---|---|---|---|---|---|
| EIA Overnight Capital Cost, Combustion Turbine | $709 | $742 | $746 | $768 | $653 |
| CT Project Cost Estimate (Games) | $702 | | | | |
| CT Project Cost Estimate with EPC Cost Update (Zoller) | $720 | | | | |

*Source:* U.S. EIA, Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2021, February 2021.
* Denotes: MISW (MISO West), MISC (MISO Central), MISE (MISO East), and MISS (MISO South).

Considering CEIS' cost estimates (Messrs. Games and Zoller) already include financing costs in the "Owner's Total Cost" (shown in Table 1 above), while the EIA's base and regional overnight capital costs do not include any interest, financing, or escalation costs, it appears CEIS presented an unrealistically low estimate for the CT Project in this Cause. If this is the case, by providing an unrealistically low-cost estimate and not disclosing the high degree of risk for cost escalation the CT Project is carrying, CEIS is artificially bolstering the CT Project's chances of receiving the Commission's approval. However, it is simultaneously exposing its ratepayers to the risk of subsequent cost increases.

**Q: CEIS states emission control equipment is not included in its estimate.[33] Would the addition of this equipment explain the relatively low CT Project cost estimate CEIS provided in this Cause? Please explain.**

A: No, the lack of emission control equipment in the CEIS' CT Project cost estimate does not explain the discrepancy against benchmarked capital costs; rather, such

[33] Zoller, Attachment JAZ-2 (Public), Executive Summary, p. 3, states "[e]mission control for this cost estimate is based upon combustion controls only and does not include selective catalytic reduction (SCR) or oxidation catalyst."

deficiency earmarks the unreliability of CEIS' cost estimate. CEIS' ratepayers are sensitive to large scale, rate base-expanding capital projects due to the outsized rate impact it will cause on CEIS' small customer base (approximately 140,000), who are already experiencing high residential electricity rates. Table 4 below summarizes and ranks (1 being highest to 5 being lowest) the five Indiana IOUs based on simple tariff rates paid by residential customers who use 1,000 kWh per month for the period 2017 to 2021.

**Table 4: Indiana IOU Residential Rates Ranking Per 1,000 kWh Consumption, 2017 through 2021**

| | | Rank, Residential Rates ($) per 1,000 kWh Consumption | | | | |
|---|---|---|---|---|---|---|
| **IOU** | **Indiana Customers** | **2017** | **2018** | **2019** | **2020** | **2021** |
| DEI | 858,000[34] | 3<br>($120.46) | 4<br>($122.84) | 4<br>($121.76) | 4<br>($119.61) | 4<br>($119.61) |
| I&M | 470,000[35] | 4<br>($116.47) | 3<br>($132.14) | 3<br>($132.53) | 2<br>($153.34) | 2<br>($153.34) |
| AESI | 500,000[36] | 5<br>($110.72) | 5<br>($117.07) | 5<br>($114.30) | 5<br>($111.55) | 5<br>($111.55) |
| NIPSCO | 470,000[37] | 2<br>($138.57) | 2<br>($132.43) | 2<br>($136.37) | 3<br>($152.40) | 3<br>($152.40) |
| CEIS | 140,000[38] | **1**<br>($153.06) | **1**<br>($153.54) | **1**<br>($152.27) | **1**<br>($156.75) | **1**<br>($156.75) |

*Note: Rates Ranking: 1 – Highest and 5 - Lowest*

CEIS has consistently topped the Commission's annual residential bill survey in the last five years 2017 to 2021 with the overall highest residential rates

[34] *See* Duke Energy Indiana, LLC ("DEI"), Verified Petition dated March 1, 2021, in Cause No. 45508.
[35] *See* Indiana Michigan Power Company ("I&M"), Verified Petition dated July 1, 2021, in Cause No. 45576.
[36] *See* Indianapolis Power & Light Company dba AES Indiana ("AESI"), Verified Petition dated March 1, 2021, in Cause No. 45504.
[37] *See* Northern Indiana Public Service Company LLC ("NIPSCO"), Verified Petition dated June 1, 2021, in Cause No. 45557.
[38] *See* Southern Indiana Gas and Electric Company dba CenterPoint Energy Indiana South ("CEIS"), Verified Petition dated June 17, 2021, in this Cause.

among the five Indiana IOUs based on "Total Rate at 1,000 kWh consumption."[39] CEIS also has the distinction of having the smallest size customer base of only 140,000 ratepayers, less than a third of the size of the next IOU. As a smaller-sized electric utility with ratepayers already paying high electric rates, CEIS should consider its ratepayers' diminished capacity to carry the additional burden of paying for big ticket items such as the acquisition of new generation. However, CEIS chose a proposal that expanded its rate base considerably (by 20%),[40] rather than other more cost-effective alternatives such as the option of refueling existing generators and thereby extending the lives of these assets.

## V. CT PROJECT TECHNOLOGY AND DESIGN

**Q: Please briefly discuss the technical characteristics of CEIS' proposed CT Project.**

A: Mr. Games' direct testimony at page 38, lines 13 – 15, identified the simple cycle turbines as "two General Electric (GE) F Class CT units."[41] Meanwhile, Mr. Zoller's direct testimony identified the make and model as "GE 7F.05" combustion turbine generators.[42] I researched and evaluated the characteristics and attributes of the GE 7F.05 gas turbine in a simple cycle configuration.[43] I also reviewed the

[39] *See* IURC Electricity Bill Survey. Website: https://www.in.gov/iurc/energy-division/electricity-industry/electricity-residential-bill-survey/. Accessed: 10/25/2021.

[40] Petitioner's witness Kara R. Gostenhofer, p. 6, ll. 2 – 4, states "[t]he CT Project capital costs are approximately 20 percent of CenterPoint Indiana South's December 31, 2020 authorized electric rate base." The rate base impact issue is discussed by OUCC witness Kaleb G. Lantrip.

[41] Games, Direct, p. 38, ll. 13 – 15, states "Kiewit Power was chosen as the EPC to install two General Electric (GE) F Class CT units under a full turnkey agreement. All three RFP responses using GE F class equipment were more competitive than with Siemen's equipment."

[42] Petitioner's witness Jason A. Zoller, Direct Testimony, p. 13, ll. 15 – 17, states "[r]esponses were received from GE and Siemens for the GE 7F.05 and the Siemens 5000F CTs, respectively."

[43] *See* GE Gas Power. Website: https://www.ge.com/gas-power. Accessed: 10/12/2021.

operational capabilities of the GE "simple cycle 7F.05 gas turbine"[44] in a utility-scale power generation application compared to other bulk electrical and industrial systems applications.[45] GE identified the general characteristics and attributes of its gas turbines in a simple cycle configuration shown in Table 5 below.[46]

**Table 5: GE Simple Cycle Gas Turbines**

| | Simple Cycle |
|---|---|
| **Applications** | • Peaking Power<br>• Emergent power demands (can later be converted to combined cycle)<br>• Mechanical drive |
| **Advantages** | • Lowest CAPEX<br>• Shortest construction cycle<br>• Easily scalable for growth |
| **Disadvantages** | • Lower efficiency compared to combined cycle<br>• Higher specific emissions |

From a utility-scale power generation perspective, CEIS' proposed CT Project would operate in a simple cycle configuration and primarily as a peaker because of the disadvantages inherent to this type of generators, such as lower efficiency and higher specific emissions, which limit its operations or run time to short durations only. GE expects its simple cycle 7F.05 gas turbines to perform with a net efficiency lower than 40%.[47]

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[44] *See* GE Gas Power, 7F Gas Turbine features. Webpage: https://www.ge.com/gas-power/products/gas-turbines/7f. Accessed: 10/12/2021.
[45] *See* GE Gas Power, utility power generation. Webpage: https://www.ge.com/gas-power/applications/utility-power-generation. Accessed: 2021/10/12.
[46] *See* GE Gas Power 2021-2022 catalog. Webpage: https://www.ge.com/gas-power/resources/catalog. Accessed: 10/12/2021.
[47] *See* GE Gas Power, 7F Series gas turbine. Webpage: https://www.ge.com/gas-power/products/gas-turbines/7f. Accessed: 10/12/2021.

**Q: Please discuss your evaluation of the fast start and ramp rate characteristics of CEIS' proposed CT Project.**

A: The GE simple cycle 7F.05 gas turbine has fast start and ramp rate capabilities.[48] There is nothing special about these capabilities; such capabilities are expected or typical of peaker generation units because these generators compete and operate against similar peaker units in a narrow role characterized by a relatively low position in the dispatch stack (last in the dispatch merit order). However, even with its capabilities, the inherent disadvantages of a simple cycle gas turbine (i.e., relative lower efficiency and higher emissions) make it too expensive to dispatch and operate and puts it at the tail-end position of the dispatch merit order of generators. Therefore, when compared to other types of utility-scale generator technologies used as base load, intermediate load, and peaker units, the simple cycle gas turbines, such as CEIS' proposed CT Project, are not expected to operate long durations on an annual basis.

## VI. CT PROJECT CAPACITY AND RENEWABLE ENERGY SUPPORT

**Q: Please discuss your evaluation of CEIS' capability "to install large volumes of renewable energy" contingent upon the features of its proposed CT Project.[49]**

A: Mr. Games' claims the features of the simple cycle 7F.05 gas turbines, among others, will allow CEIS "to install large volumes of renewable energy[.]"[50] However, CEIS' ability to deploy more renewable energy is not dependent at all on

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[48] *See* GE Gas Power, 7F Gas Turbine features. Webpage: https://www.ge.com/gas-power/products/gas-turbines/7f. Accessed: 10/12/2021. *See also* Games Direct, p. 28, ll. 3 – 5.

[49] Games Direct, p. 28, ll. 16 - 20, states "[t]hese features along with market import capabilities allow CenterPoint Indiana South to install large volumes of renewable energy and still maintain the ability to reliably and efficiently serve our 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."

[50] *Id.*

the features of the simple cycle 7F.05 gas turbines. Rather, as a load serving entity ("LSE") and member of MISO,[51] CEIS is expected to have sufficient generation capacity to serve its load and reserve margin requirements.[52] Therefore, it is these needs and requirements that drive the demand for any additional or new generation capacity, renewable or otherwise, and not the features of a simple cycle turbine.

**Q: Is CEIS' demand and load increasing to drive the need for additional or new capacity?**

A: No. On the contrary, CEIS' demand has continued to decline. Table 6 below shows CEIS' system peak demand (MW) from 2013 through 2020.

**Table 6: Historical Peak Load, MW**[53]

| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|
| System Peak Demand, MW | 1,191 | 1,186 | 1,155 | 1,136 | 1,074 | 1,042 | 1,055 | 984 |
| Compound Annual Growth Rate (CAGR) 2013-2020, % | | | | | | | -2.7% | |

Based on its historical peak load for the period 2013 through 2020, CEIS' system did not experience any appreciable load growth, instead experiencing continued decline with a negative growth rate (-2.7%) during the period.

**Q: Did CEIS incorporate its continued negative growth rate into its long-term plan?**

A: No. While its system demand is experiencing a negative growth rate, CEIS' long-term plan is based on the unfounded premise of expanding demand. Despite the continued decline in system demand since 2013, in Cause No. 45052 and in its 2016

[51] *See* MISO Business Practice Manuals, BPM 001 – Market Participation. Webpage: https://www.misoenergy.org/legal/business-practice-manuals/. Accessed: 10/12/2021.
[52] *Id*. MISO BPM 011 – Resource Adequacy. Webpage: https://www.misoenergy.org/legal/business-practice-manuals/. Accessed: 10/12/2021.
[53] *See* IURC Summer Capacity Surveys and Presentations. Website: https://www.in.gov/iurc/2390.htm. Accessed: 10/12/2021. *See also* Public's Exhibit No. 2, Direct Testimony of Anthony A. Alvarez, in Cause No. 45052, p. 5. *See also* Att. AAA-1 - CEIS response to OUCC DR Set 5-1 (b).

IRP, CEIS forecasted energy and demand growth of 0.5% beyond 2019. Even after the continued downward trend of its system demand in 2019 and 2020, CEIS forecasted an even higher energy and demand growth rate of 0.6% per year in its 2019/2020 IRP.[54] By doing so, CEIS failed to acknowledge the reality and actual needs and requirements of its system on a path of continued negative demand growth rate. On this basis, I support Mr. Lantrip's recommendation the Commission deny CEIS' request to defer any costs related to its misaligned 2019/2020 IRP for future recovery through retail electric rates.

**Q: How does a utility's negative system demand growth rate coupled with a mismatched long-term plan adversely affect its ratepayers?**

A: The utility's proposed system investment costs in its misaligned long-term plan unfairly fall on its ratepayers. A smaller-scale utility facing these adverse downward-trending conditions should explore cost effective alternatives that do not require intensive capitalization and would not only extend the use of its existing assets, but still provide benefits to ratepayers. However, in this case, CEIS opted to grow its rate base by investing in new assets instead of taking a more sensible approach of refurbishing and extending the life of its existing assets. In the pretext of obtaining ratepayer savings, CEIS justified the construction and installation of two new simple cycle 7F.05 gas turbines by subjecting and imposing unnecessary constraints on the alternative option, thereby rendering its pre-disposed choice appear economically viable. Dr. Boerger discusses the CT Project's economic issues in his testimony.

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[54] Petitioner's Exhibit No. 5 (Public), Direct Testimony of Matthew A. Rice, Attachment MAR-1, Vectren [CEIS] 2019/2020 Integrated Resource Plan, p. 42.

**Q: What is your opinion of CEIS' statement that "[t]he CT units will not be base loaded and are projected to have a low-capacity factor, only operating when economical for the customer," while also claiming that the CT units will provide "low cost dispatchable capacity"?[55]**

A: CEIS is using the term "capacity" loosely. This statement compared a typical "low-capacity factor" peaker unit to a "low cost dispatchable capacity" generating unit and qualified it by stating the CT will "only operate when economical for the customer."[56] First, a "low-capacity factor" peaker unit means the CT will not be called upon or dispatched often or expected to operate long durations on an annual basis. As such, the expected amount of electricity (in MWh) the CT would generate and inject into the grid on an annual basis is very low compared to the theoretical amount of electricity it could generate based on its nameplate rating.[57] The reason for this is peaker units are the most expensive generating unit to dispatch, thus, they are typically held off to a position of being the very last generators to be called upon to meet demand.

Second, the term "capacity" in the statement related to the CT being a "low cost dispatchable capacity" pertains to generator capacity (in MW) that CEIS must hold to satisfy the MISO Planning Reserve Margin ("PRM") requirements.[58] Contrary to CEIS' statement, the CT Project is *not* "low cost dispatchable

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[55] Games Direct, p. 30, ll. 17 – 21, states "[t]he CT units will not be base loaded and are projected to have a low-capacity factor, only operating when economical for the customer. This provides low cost dispatchable capacity to regularly meet customer demand while minimizing carbon and other air emissions allowing CenterPoint Energy to meet the carbon reduction goals described by Witness Retherford."
[56] *Id*.
[57] U.S. Energy Information Agency ("EIA") defines "capacity factor" as '[t] The ratio of the electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous full power operation during the same period." Webpage: https://www.eia.gov/tools/glossary/index.php?id=Capacity_factor. Accessed: 10/18/2021.
[58] Games Direct, p. 28, ll. 32 – p. 29, l. 2.

capacity," considering the CT Project requires a minimum projected investment of $323 million for just 460 MW, while the refueling alternative for the 490 MW A.B. Brown units would require far less capital.[59]

Third, CEIS' statement that the CT will "only operate when economical for the customer," means there are very limited dispatch windows for peakers. During days and hours when the demand and temperatures are at an extreme, and the price of electricity is high enough to render the peaker units economical to dispatch, then these generators will be called upon and brought online to meet that demand.

Finally, once peaker units are dispatched, other generators (with higher priority position in the dispatch merit order) that were dispatched ahead of the peaker units will receive the same payment rates set by the peakers. After demand in the system subsides and generators are switched offline in the reversed dispatch order of merit, the peaker units are the first ones switched off, while the other generators remaining online continue to receive payments for their service. This means a repowered A.B. Brown unit (with a relatively higher CF) would be dispatched ahead, kept running longer to serve the demand and, therefore, earn more money in the MISO market than the simple cycle turbines (with relatively lower CF) of the proposed CT Project.

[59] Zoller, Attachment JAZ-3 (Public), Section 6.0 – Estimated Costs, Table 6-1 – Estimated Project Costs, p. 41, showed the "Total Project Costs" for the gas conversion of the 490 MW A.B. Brown Units 1 and 2 as $55.8 million and $61.8 million, respectively. Zoller Direct, p. 10, ll. 3 – 4, states "[t]his estimate excludes the Petitioner's cost which must be added to determine the Total Project Cost." *See* Cause No. 44339 for the estimated cost of repowering Harding Street Units 5 and 6, and Cause No. 44540 for the estimated cost of repowering Harding Street Unit 7.

**Q: CEIS' claims "[i]f hydrogen becomes affordable, the F Class [gas turbine] technology is currently able to burn 5%-10% hydrogen and with modifications can currently burn up to 30% hydrogen, further reducing carbon emissions."[60] Did you evaluate this claim? Please explain.**

A: Yes. To evaluate CEIS' claim, I turned to GE Gas Power hydrogen calculator available at GE's website.[61] Table 7 below shows the GE Hydrogen and $CO_2$ emission calculator results for a single GE 7F.05 turbine configured as a simple cycle plant operating as a peaker unit with an estimated 2,667 annual operating hours (out of a possible 8,760 hours) burning 30% hydrogen.[62]

**Table 7: <u>Hydrogen Production and Infrastructure Requirements</u>[63]**

| Gas Turbine | GE 7F.05 | Simple Cycle Configuration, 1x0 |
|---|---|---|
| Estimated Operating Hours Per Year | 2,667 Hours | Peaker unit |
| Fuel Requirement | 30% Hydrogen | Green hydrogen required to be created or produced with renewable energy input. |
| Process | Electrolysis | Hydrogen infrastructure production process. |
| Electricity Required Per Year | 131.5 MW or 1,150,625 MWh | Equivalent to the estimated annual output of 176 – 1.5 MW wind turbines. |
| Water Flow Required Per Day | 37,696 Gallons | Hydrogen infrastructure daily water flow requirement. |
| Hydrogen Flow Required Per Day | 6.6 million cu. ft. | Hydrogen infrastructure daily production. |

*Source*: GE Gas Power Hydrogen Calculator

[60] Games Direct, p. 30, ll. 26 – 28."
[61] *See* GE Gas Power Hydrogen Calculator. Weblink: https://www.ge.com/gas-power/future-of-energy/hydrogen-fueled-gas-turbines?utm_campaign=h2&utm_medium=cpc&utm_source=google&utm_content=rsa&utm_term=Ge%20hydrogen%20turbines&gclid=CjwKCAjw_L6LBhBbEiwA4c46urlq01cmqK93ub56cDn3l7FDv79Y0-IdWrslbAQCfn4CBrIji4lu9hoCbJgQAvD_BwE#. Accessed: 10/20/2021.
[62] Public's Attachment AAA-2 – GE Gas Turbine Hydrogen Calculator.
[63] GE Gas Power Hydrogen Calculator.

Table 7 above shows the hydrogen infrastructure requirement for a single GE 7H.05 gas turbine. However, in the context of CEIS' proposed 460 MW CT Project with two simple cycle GE 7F.05 gas turbines running on 30% hydrogen, it would require multiplying the GE estimated energy and water requirements by at least a factor of 2, thus doubling the size of the hydrogen infrastructure required.

**Q: What is your opinion of Mr. Games' testimony asserting the possibility to produce green hydrogen from the nearby 300 MW solar project proposed in Cause No. 45501?[64]**

A: Mr. Games' statement does not recognize the magnitude of the infrastructure needed to produce the green hydrogen required to fire the turbines. The electrolysis process' power requirement needed to produce the required amount of green hydrogen would far exceed what a 300 MW solar facility could provide when the sun is shining high and bright, much more on a 24/7, around-the-clock basis. The cost to run the simple cycle turbines as peakers at a 30% hydrogen level on very limited hours per year would be exorbitant and would be unreasonable to pass on to ratepayers.

**Q: From a technical perspective, how do you see the future development and production of clean hydrogen in utility-scale power generation?**

A: The U.S. Department of Energy ("DOE") launched its first Energy Earthshots Initiative ("Hydrogen Shot") on June 7, 2021, which aims to accelerate breakthroughs of more abundant, affordable, and reliable clean energy solutions within the decade.[65] The Hydrogen Shot seeks to reduce the cost of clean hydrogen

[64] Games Direct, p. 30, lines 30 – 31, states "[t]here is also the possibility to produce green hydrogen from the nearby 300 MW solar project CenterPoint Indiana South is proposing in Cause No. 45501."
[65] U.S. DOE Energy Earthshots Initiative. Website: https://www.energy.gov/eere/fuelcells/hydrogen-shot. Accessed: 10/25/2021.

by 80% to $1 per kilogram ("kg.") in a decade, or "Hydrogen Shot 111."[66] Currently, the DOE estimates, "hydrogen from renewable energy costs about $5 per kilogram," and "achieving the Hydrogen Shot's 80% cost reduction goal can unlock new markets for hydrogen, including steel manufacturing, clean ammonia, energy storage, and heavy-duty trucks."[67] Although no carbon dioxide ("$CO_2$") is produced when hydrogen is burned to produce power, hydrogen has handling and safety issues such as embrittlement of metals and deterioration of plastic and rubber seals that methane (natural gas) does not.[68] However, one drawback of hydrogen as fuel for electric power generation is that it has about 30% of the energy content of methane. It takes about 3.3 cubic feet ("cu. ft.") of hydrogen to deliver the same energy as 1 cu. ft. of natural gas.[69] If the DOE is successful in achieving the goal of $1/kg. for clean (or green) hydrogen in a decade, it may still be some time before industry can produce clean hydrogen fuel at the level required for power generation. Regardless, it will likely take more than a decade and continuous government effort and support to bring clean hydrogen into the mainstream of viable utility-scale power generation fuels.

**Q: What is CEIS' position regarding the dispatch of renewable resources?**

A: CEIS claims the dispatch of renewable resources has changed the generation stack within MISO and the intermittency of wind and solar has left fossil-fuel based resources to balance the system when the output of the renewable resources

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[66] *Id.*
[67] *Id.*
[68] *See* Seeking Alpha, *Hydrogen Vs. Natural Gas for Electric Power Generation*, Online Article, Dec. 2, 2020. Weblink: https://seekingalpha.com/article/4392471-hydrogen-vs-natural-gas-for-electric-power-generation. Accessed: 11/02/2021.
[69] *Id.*

changes.[70] CEIS also claims this impacts the dispatch of its coal-fired generation units causing them to cycle up and down throughout the day, increasing the frequency of stop and start cycles throughout the year.[71]

**Q: What is your response to this?**

A: Since MISO has the authority to dispatch generators, it is difficult to determine the direct relationship between MISO's dispatch of renewable resources and the cycling of CEIS' coal-fired generation units. However, if CEIS' coal-fired generation units (such as the A.B. Brown Units 1 and 2) "cycle up and down throughout the day and increase the frequency of stop and start cycles throughout the year,"[72] that operation signals a departure from dispatch as base load generators and rather as load-following generators. It is possible to determine whether the dispatch of CEIS' coal-fired generation units changed by evaluating their CF.

**Q: Have you performed this analysis?**

A: Yes. I researched the unit monthly operations and evaluated the CFs of the A.B. Brown Units 1 & 2. I reviewed monthly and annual data and information in EIA Form 913 filings collected by S&P Capital IQ Pro®,[73] and analyzed information on the U.S. coal fleet from the EIA Electric Power Monthly, Capacity Factors for Utility Scale Generators Primarily Using Fossil Fuels report released September

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[70] Games Direct, p. 7, line 17 and ll. 26 – 30.
[71] *Id*.
[72] *Id*., p. 7, ll. 29 – 30.
[73] S&P Capital IG Pro, A.B. Brown Unit Monthly Operations. Website: https://www.capitaliq.spglobal.com/web/client?auth=inherit#powerplant/UnitMonthlyOperations?ID=1273 Accessed: 10/20/2021. Games Direct, p. 11, ll. 28, identifies "S&P Global Market Intelligence" as among the data sources of CEIS' analysis.

24, 2021.[74] Table 8 below summarizes the monthly CFs of A.B. Brown Units 1 and 2 in 2021.

**Table 8: <u>A.B. Brown Units 1 and 2 Monthly Capacity Factor (%), 2021</u>**

| Generating Unit | Jan | Feb | Mar | Apr | May | June | July |
|---|---|---|---|---|---|---|---|
| ABB Unit 1 | 58.64 | 74.01 | 56.59 | 67.26 | 51.65 | 77.12 | 82.73 |
| ABB Unit 2 | 61.22 | 66.01 | 63.11 | 72.60 | 70.22 | 65.95 | 72.38 |
| U.S. Coal Fleet[75] | 51.50 | 60.70 | 39.40 | 35.40 | 40.80 | 58.00 | 65.40 |

*Sources: - S&P Capital IQ Pro®*
*- EIA, Electric Power Monthly, Capacity Factors for Utility Scale Generators Primarily Using Fossil Fuels*

Table 8 above shows that on a month-to-month basis in 2021, both A.B. Brown Units 1 and 2 operated as typical coal-fired power plants, showing no deviation from operating characteristics of base load generating units. Energy Information Administration ("EIA") data shows both A.B. Brown Units 1 and 2 outperformed the U.S. coal fleet during the winter months of 2021 and continued to remain operationally strong in succeeding months. In particular, the A.B. Brown Units 1 and 2 performed very well during the 2021 Polar Vortex period despite the chemical inventory challenges CEIS stated it experienced during that event.[76] Such seasonal operational issues could easily be addressed and resolved with advance planning and having proper and adequate winterization plan in place.[77] Further,

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[74] EIA, Electric Power Monthly, Capacity Factors for Utility Scale Generators Primarily Using Fossil Fuels. Webpage: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_a. Accessed: 10/26/2021.
[75] *Id*. EIA, Electric Monthly Power.
[76] Games Direct, p. 17, ll. 6 – 8.
[77] Forbes, *Winterization And The Texas Blackout: Fail To Prepare? Prepare To Fail*, Article, Feb. 19, 2021. Weblink: https://www.forbes.com/sites/thebakersinstitute/2021/02/19/winterization-and-the-texas-blackout-fail-to-prepare-prepare-to-fail/?sh=7bcbe3ee7c83. Accessed: 10/26/2021.

contrary to CEIS' claims,[78] there was no evidence showing these coal-fired units were cycling outside their typical operating parameters or experiencing any increase in the start and stop cycle frequency that would cause dramatic changes in their monthly CFs.[79]

**Q: Do you agree with CEIS' conclusion that the A.B. Brown Units 1 & 2 are "among the smaller, least efficient coal units remaining in the state" as compared to other Indiana coal units?[80]**

A: No, I do not agree with CEIS' characterization of the A.B. Brown Units 1's & 2's performance. As shown in Table 8 above, these units surpassed the performance of the U.S. coal fleet on a month-to-month basis this year and performed very well for CEIS ratepayers during the critical Polar Event month of February. Such performance is good evidence that those boilers are operating well. The A.B. Brown Units 1 & 2 may be smaller in size, but they fit the needs of the customer base and system demand of smaller-sized-utility such as CEIS.

**Q: Mr. Greenley identified two other generating units at the A.B. Brown generating facility. Please describe and discuss the current performance of these units.**

A: Mr. Greenley's testimony includes his Table 1: Generating Units, which contains a list of CEIS' existing generation resources, including A.B. Brown Units 3[4] and 4[5].[81] Both A.B. Brown Units 3 and 4 are simple cycle combustion turbines, GE

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[78] Games Direct, pp. 9 – 11, discusses "the impacts of frequent cycling of coal units off/on and ramping up/down."

[79] A coal-fired unit cycling up and down throughout the day and increasing its stop and start cycle frequency throughout the year beyond its typical operating parameters would directly affect its monthly and overall capacity factor performance because of the relative slow ramp rates and prolonged start and shutdown characteristics typical of coal-fired units.

[80] Games Direct, p.14, ll. 22 – 25.

[81] The numbers enclosed in brackets denote the actual "Generator ID(s)" of A.B. Brown Units 3 and 4 respectively, as established in EIA Form 860. To avoid confusion, this testimony will maintain the use of the colloquial reference of the units as A.B. Brown Units 3 and 4. *See* Public's Attachment AAA-3 – CEIS Response to OUCC DR Set 5-4.

Model series MS7001EA (or GE 7EA), with a net summer rated capacity of 80 MW each.[82] Neither unit has quick ramp capabilities. While Unit 3 is dual-fuel (capable of burning natural gas or fuel oil) giving it black-start capability, Unit 4 is single-fuel and only burns natural gas.[83] Table 9 below summarizes the A.B. Brown Units 3 and 4 service hours and CFs for the seven-year period 2014 through 2020.[84]

**Table 9: A.B. Units 3 and 4 Annual Capacity Factors and Service Hours, 2014-2020**

| A.B. Brown | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|
| **Unit 3** | | | | | | | |
| Capacity Factor, % | 0.7 | 0.9 | 1.4 | 1.2 | 1.5 | 1.0 | 1.3 |
| Service Hours | 92 | 139 | 263 | 185 | 255 | 168 | 220 |
| **Unit 4** | | | | | | | |
| Capacity Factor, % | 1.7 | 3.5 | 1.6 | 2.0 | 3.2 | 2.0 | 1.9 |
| Service Hours | 222 | 464 | 226 | 404 | 445 | 265 | 244 |

*Data Source: CEIS Response to OUCC DR Set No. 5-3(b).*

From 2014 through 2020, A.B. Brown Units 3 and 4 performed as expected of typical peaker units with relatively low CFs and service hours on an annual basis.[85] Further evaluation of these units revealed that in the winter months of January and February 2021, including the 2021 Polar Vortex event period

[82] Contrary to the Installed Capacity (ICAP) ratings of 80 MW each for A.B. Brown Units 3 and 4, as found in Greenley Direct, Table 1, p. 7, the nameplate capacity of these units is 88.2 MW each. *See* Public's Attachment AAA-4 – A.B. Brown CT Power Plant Profile.
[83] Public's Attachment AAA-5 – CEIS Response to OUCC DR Set 5-3.
[84] Public's Attachment AAA-6 – CEIS Response to OUCC DR Set No. 5-3(b).
[85] Service hours is the amount of operating time (in hours) the generating unit was in operation and load was connected to the grid. *See* Attach. AAA-6 – CEIS Response to OUCC DR Set No. 5-3 (b).

highlighted by CEIS,[86] both units only operated minimally for 3 hours in January 2021; Unit 3 operated for 6 hours and Unit 4 for 16 hours in February 2021. Despite the limited-service hours, both Units 3 and 4 operated reliably during the 2021 winter months and critical Polar Vortex event and demonstrated performance that was expected of simple cycle gas turbine peaker units. Comparable, if not slightly better, performance should also be expected during critical periods from the simple cycle turbines in CEIS' proposed CT Project. The same reliability could be depended upon and expected from A.B. Brown Units 1 and 2 after converting the boilers to burn natural gas at a much lower price than the $323 million proposed for new CTs.

## VII. ALTERNATIVE OPTION: REFUELING COAL-FIRED A.B. BROWN UNITS 1 AND 2

**Q: Does Ind. Code ch. 8-1-8.5, the Utility Powerplant Construction of the Indiana Code governing this proceeding, include considering other methods of providing reliable, efficient, and economical electric service?**

A: Yes. When a utility proposes adding new generating capacity, Ind. Code § 8-1-8.5-4(b)(2) requires the Commission to consider other methods of providing reliable, efficient, and economical electric service, including the refurbishment of existing facilities.[87] In Cause No. 45052, the Commission found CEIS failed to consider options to extend the life of the existing units as a potential bridge to the future and had screened out viable refurbishment options.[88] As noted above, Mr. Greenley

[86] Games Direct, p. 17, ll. 6 – 8.
[87] *See* fn 13. I.C. § 8-1-8.5-4(b)(2) states: "(b) In acting upon any petition for the construction, purchase, or lease of any facility for the generation of electricity, the commission shall take into account the following: (2) Other methods for providing reliable, efficient, and economical electric service, including the refurbishment of existing facilities, conservation, load management, cogeneration and renewable energy sources."
[88] *Cause No. 45052*, p. 22.

acknowledged the Commission's findings in Cause No. 45052 as "lessons learned."[89] While CEIS cites economic reasons for pursuing simple cycle combustion turbines in its 2019/2020 IRP as support for its proposed CT Project,[90] it presented a flawed analysis suppressing the viability of the refueling of the A.B. Brown coal-fired boilers.

**Q: Please provide an overview of the A.B. Brown generating units.**

A: Both A.B. Brown Units 1 and 2 are rated at 245 MW net capacity. A.B. Brown Unit 1 was placed in service in March 1979, and A.B. Brown Unit 2 was placed in service in February 1986.[91] These coal-fired units have a full complement of coal-handling and emission controls equipment such as selective catalytic reduction, low nitrogen oxide burners, and flue gas desulphurization, which represents a significant amount of "parasitic load."[92] Once converted to gas-fired, the units would shed parasitic load from the coal-based equipment and regain power to maintain the same rated capacity with the added bonus of lowering emissions during startups.[93]

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[89] Greenley Direct, p. 9, ll. 4 – 5 and 27.
[90] *Id*., p. 14, ll. 24 – 26, and Games direct, p. 27, ll. 24 – 27.
[91] S&P Capital IQ Pro, A.B. Brown Power Plant Profile.
[92] Parasitic load means the amount of electricity consumed by auxiliary equipment that supports the electricity generation or cogeneration process. It includes, but is not limited to, the power required to operate the equipment used for fuel delivery systems, air pollution control systems, wastewater treatment systems, ash handling and disposal systems, and other controls (i.e., pumps, fans, compressors, motors, instrumentation, and other ancillary equipment required to operate the affected facility). Law Insider. Website: https://www.lawinsider.com/dictionary/parasitic-load. Accessed: 10/27/2021. *See also* PJM System Planning Modeling and Support, *PJM Planning Center: Gen Model User Guide*, p. 35, Effective Date: April 1, 2021. Weblink: https://www.pjm.com/~/media/etools/planning-center/gen-model-user-guide.ashx. Accessed: 10/28/2021.
[93] Zoller, Attachment JAZ-3 (Public), Executive Summary, p. 6.

**Q: Please discuss the technical aspects of converting coal-fired boilers to gas, such as the alternative option of refueling A.B. Brown Units 1 and 2.**

A: The last decade saw the advancement and establishment of gas conversion technology for power boilers and is considered tested and proven technology today. Converted power plants retain their original capacity ratings, start, ramp, cycle, and are dispatched accordingly (sometimes even faster and with better performance); and are reliable, efficient and viable alternative options to maintain system reliability and extend the useful life of the generating asset after gas conversion. The technology is commercially available with leading industry vendors and suppliers having the capability to assure and provide power plant owners and operators the adaptability of the technology. These offerings are backed with full-scope installations, project management and worry-free offerings from initial engineering and feasibility studies up to start-up and commissioning stages, including operator and instrumentation training and regulatory compliance requirements, regardless of the coal-fired boiler's original manufacturer.[94] Indiana has the distinct advantage of having not just one but three power plants with the new and advanced gas conversion technology installed converting coal-fired boilers of different vintages and capacity ratings.[95] The performance records of

[94] Public's Attachment AAA-7 – B&W Natural Gas Conversions for Power Boilers. *See* Babcock & Wilcox, Upgrades & Retrofits. Website: https://www.babcock.com/home/about/services/upgrades-and-retrofits/. Accessed: 10/28/2021.

[95] *In re Indianapolis Power & Light Company*, Cause No. 44339. Final Order (Ind. Util. Regul. Comm'n May 14, 2014), gas conversions of AES Indiana's 2-100 MW Harding Street Units 5 and 6 in Cause No. 44339, and 410 MW Harding Street Unit 7 in Cause No. 44540. IURC Portal website: https://iurc.portal.in.gov/advanced-search/. Accessed: 10/28/2021.

these Indiana-based gas-fired converted power plants show the operational viability and cost-effectiveness of this technology in the energy and capacity markets.[96]

**Q: Please briefly discuss the capacity ratings, vintages and gas conversion costs of the Indiana-based legacy power plants you refer to above.**

A: One of the goals achieved by the advancement of the gas conversion technology for power boilers in the last decade was the ability to maintain 100% of the boiler's maximum continuous rating once converted to gas. The technology developments of plug-in gas burners and igniters achieved superior combustion results and overcame any typical boiler de-rating capacity loss characteristic of previous burner and component technologies. In addition, the vintage of the legacy power plants did not affect the ability of the power plants to achieve full capacity upon conversion. Overall, the Indiana-based legacy power plants realized the operational benefits offered by these technical advancements and extended their useful lives. Table 10 below summarizes relevant information of the Indiana-based AES Indiana ("AESI") Harding Street Units 5, 6 and 7 before and after gas conversion.

[96] "From an economic perspective, the long position would appear to be the least cost market position, relative to the low capital cost for the HS-7 refuel (less than $200/kW) and the ongoing projected market peaking capacity value provided." *Cause No. 44540*, p. 34.

**Table 10: AESI Gas-Converted Legacy Power Plants**

| Power Plant | **Harding Street** | | |
|---|---|---|---|
| Generating Unit | 5 | 6 | 7 |
| Online Date (Vintage) | 1956 | 1961 | 1973 |
| Conversion Year | 2015 | 2015 | 2016 |
| Gas Conversion Costs, $M[97] | **$42.10 M** | | **$64.3 M** |
| Capacity Rating, MW | | | |
| Nameplate Rating | 100 | 100 | 463 |
| Before Conversion | 101 | 99 | 418 |
| After Conversion | **101** | **99** | **418** |
| Conversion Cost, 2021 $/kW* | $244/kW | | $178/kW |

*Data Source: S&P Capital IQ Pro*
** U.S. Bureau of Labor and Statistics, CPI Inflation Calculator*

**Q: Please discuss CEIS' cost estimate for the A.B. Brown Units 1 and 2 gas conversion and how it compares to AESI's Harding Street gas conversion costs.**

A: Mr. Zoller stated the A.B. Brown Units 1 & 2 conversion cost estimates were $56 million and $62 million, respectively, without owner's cost.[98] However, the conversion cost estimates included the costs of optional emission control equipment,[99] which the Black & Veatch report (Zoller Direct, Attachment JAZ-3 (Public), p. 6) stated should be removed. Nonetheless, considering the A.B. Brown

[97] *See* IPL Submission of Semi-Annual Progress Report (May 2017). IURC Portal weblink: https://iurc.portal.in.gov/_entity/sharepointdocumentlocation/5de9a937-fe45-e711-8104-1458d04e2f50/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=44339_IPL_Submission%20of%20Semi-Annual%20Progress%20Report%20May%202017_053017.pdf. Accessed: 10/29/2021.
[98] Zoller Direct, p.10, ll. 1 – 4, states "[t]he capital cost estimate for the Gas Conversion Project is estimated at approximately $56,000,000 for A.B. Brown Unit 1 and $62,000,000 for A.B. Brown Unit 2. This estimate excludes the Petitioner's cost which must be added to determine the Total Project Cost."
[99] Zoller Direct, Attachment JAZ-3 (Public), Table 6-1 – Estimated Project Costs, Section 6.0 – Estimated Costs, p. 41.

Units 1 and 2 total capacity rating of 490 MW, CEIS' $241/kW conversion cost estimate is quite comparable to the actual $244/kW conversion cost of the combined smaller 200 MW (net) Harding Street Units 5 and 6. However, CEIS' estimate is much higher than the 465 MW (418 MW net) Harding Street Unit 7 $178/kW conversion cost, calculated in 2021 dollars after inflation.[100] Table 11 below summarizes the conversion cost comparison of CEIS's A.B. units and AESI's Harding Street units.

**Table 11: <u>Gas Conversion Cost Estimate Comparison</u>**

| Power Plant | A.B. Brown Units 1 & 2 | Harding Street Units 5, 6, & 7 |
|---|---|---|
| Combined Capacity, MW | 490 MW | 618 MW |
| Conversion Estimate/Actual, $ million | $119 million | $106 million[101] |
| Conversion Cost, $/kW (*2021) | $241/kW | $193/kW* |

** U.S. Bureau of Labor and Statistics, CPI Inflation Calculator*

Although CEIS admitted converting the A.B. Brown units to gas requires less capital "when compared to other dispatchable options explored,"[102] its estimates were still at a premium and more than tripled compared to the original estimate for the same conversion it presented to the Commission in Cause No. 45052.[103]

[100] U.S. Bureau of Labor and Statistics, CPI Inflation Calculator. Weblink: https://data.bls.gov/cgi-bin/cpicalc.pl. Accessed: 10/30/2021.
[101] IPL SAPR (May 2017).
[102] Games Direct, p. 25, ll. 6 – 10.
[103] *Cause No. 45052*, para. 2, p. 22, the Commission states "[r]efueling is viable, proven technology that could be accomplished at a fraction of the price of the CCGT - approximately $45 million for both A.B. Brown units."

**Q: Does AESI's Harding Street units' refueling and conversion prove there are alternative cost-effective options for meeting a utility's capacity needs?**

A: Yes. The refueling and conversion of the smaller Harding Street Units 5 and 6 was the first refueling project undertaken by an Indiana utility. With the addition of the larger Harding Street Unit 7 refueling project, the three units' refueling and conversion work was done consecutively in a short time schedule with a high degree of coordination and work consolidation for efficiency to minimize conflicts and congestion at the work site.[104] Although the conversion cost of the Harding Street Units 5 and 6 was $241/kW, the Harding Street Unit 7 was completed at $178/kW, below the $70.88 million cost estimate the Commission approved in Cause No. 44540.[105] The utility completed refueling the three units at an overall conversion cost of less than $200/kW. While the engineering and design assumptions initially predicted the need to derate the units by as much as 20% - 30% of their original capacity, once in commercial operation, there were no derates or outages associated with the conversions. Below is an excerpt from the May 2018 Semi-Annual Progress Report submitted to the Commission:

> Harding Street Station Units 5 & 6 have been released for commercial operation since December of 2015 and there have not been derates or outages associated with the conversions to date. The Induced Fan (ID) motor change was completed in October 2016. This concludes all major construction on this project. Punch list items are completed for Units 5 & 6.

(Indianapolis Power & Light Company ("IPL"), Semi-Annual Update, May 2018, Cause No. 44339, p. 3).

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[104] IPL SAPR (March 21, 2016) in Cause No. 44339.

[105] *In re Indianapolis Power & Light Company*, Cause No. 44540. Final Order (Ind. Util. Regul. Comm'n July 29, 2015).

**Q: Is refueling and conversion of CEIS' A.B. Brown units a viable, cost-effective option?**

A: Yes. Despite the magnitude of CEIS' estimates for the conversion of the A.B. Brown units ($118 million) and simple cycle turbines ($323 million), the cost of conversion and refueling still represents a very low capital cost for a viable option with a proven track record and extension of the A.B. Brown units' useful life. Preserving and extending the life of existing assets at a very low capital cost using proven technology provides greater service to ratepayers.

**Q: Will the age of A.B. Brown Units 1 and 2 affect CEIS' ability to successfully adopt gas conversion and refuel these units?**

A: No. CEIS states the "A.B. Brown unit 1 will be 45 years old and A.B. Brown unit 2 will be 38 years old in 2023 when the units are planned to be retired."[106] The age of these legacy units will not affect their boilers' ability to successfully adopt the technology. The results of CEIS' own gas conversion assessment and evaluation shows that for a low capital cost of $118 million,[107] the A.B. Brown units could successfully be converted "from firing coal to 100 percent natural gas."[108] Although the A.B. Brown Unit 1 is the older of the two units, it is younger in age than the youngest AESI Harding Street gas-converted unit. Table 12 below compares the ages of the A.B. Brown and Harding Street generating units.

[106] Games Direct, p. 17, ll. 32 – 33.
[107] Zoller Direct, p. 10, ll. 2 – 3.
[108] *Id*., p. 8, ll. 17 – 18.

**Table 12: <u>Age Comparison Between A.B. Brown and Harding Street Legacy Generating Units</u>**

| Power Plant | **A.B. Brown** | | **Harding Street** | | |
|---|---|---|---|---|---|
| Generating Unit | **1** | **2** | **5** | **6** | **7** |
| Online Date (Vintage) | 1979 | 1986 | 1956 | 1961 | 1973 |
| Unit Age (2021) | 42 | 35 | 65 | 60 | 48 |
| Conversion Year | - | - | 2015 | 2015 | 2016 |
| Age at Conversion | - | - | 59 | 54 | 43 |

If converted to gas by 2023, the older A.B. Brown Unit 1 will be at a similar age as Harding Street Unit 7 was at conversion.[109] Another important aspect of this is gas conversion will definitely extend the life of the A.B. Brown units beyond the 10 years life assumption CEIS assigned and used for these units in its analysis.[110] In response to discovery, CEIS indicated during its December 13, 2019, IRP stakeholder meeting, it picked a 10-year life assumption for the converted A.B. Brown units because no stakeholders suggested otherwise.[111] CEIS stated in a discovery response "[t]here were no studies that estimated the life of a Brown unit coal-to-gas conversion[.]" However, documents regarding the gas conversions of the Harding Street units (Cause No. 44339 and 44540) were publicly available at the Commission's Portal free of any charges and readily accessible for CEIS' research.[112] IPL's "[r]efueling studies evaluated an additional ten, fifteen, and

[109] A.B. Brown unit 1 will be 44 years old and A.B. Brown unit 2 will be 37 years old in 2023 contrary to Games Direct, p. 17, ll. 32 – 33.
[110] Public's Attachment AAA-8 – CEIS Response to OUCC DR Set 1-18.
[111] *Id*. Attach. AAA-8 - CEIS Response to OUCC DR Set 1-18(a).
[112] IURC Online Services Portal. Website: https://iurc.portal.in.gov/advanced-search/. Accessed: 11/02/2021.

twenty year useful life for Harding Street 5 & 6."[113] Assigning a 10-year life assumption for the A.B. Brown conversion flaws CEIS' analysis. Dr. Boerger further analyzes economic issues in his testimony.

**Q: What is your response to CEIS' claims there are other major expenses to continue operating the A.B. Brown units?**

A: CEIS claims "[t]he A.B. Brown units are due for major turbine and generator overhauls in 2021 (unit 1) and 2022 (unit 2) at an estimated expense of $4 million - $5 million each."[114] However, CEIS' (then Vectren) response to question number 2, in the Commission's February 9, 2012, Docket Entry in Cause No. 44067, states "[t]he AB Brown turbines were last overhauled in 2004. These turbines are normally overhauled on a 5- to 7-year cycle."[115] Turbine and generator overhaul cycles are expected and typical of good power plant management practices by protecting and preserving ratepayers' investment whether the turbines are coal-fired, gas-fired or simple cycle. If the A.B. Brown turbines and generators are due for overhaul soon, it would make sense to efficiently coordinate and consolidate the boiler conversion and refueling with the turbine and generator overhauling. AESI gained efficiency by consolidating and coordinating the refueling and conversion work of the three units consecutively with a short time schedule.[116]

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[113] Cause No. 44339, Petitioner's Exhibit HNS-1, Direct Testimony of Herman N. Schkabla, p. 17, ll. 2 – 3, states, [t]he S&L [Sargent & Landy] Refueling studies evaluated an additional ten, fifteen, and twenty year useful life for Harding Street 5&6."

[114] Games Direct, p. 23, ll. 13 – 14.

[115] Cause No. 44067, Southern Indiana Gas & Electric Company's Response to The Indiana Utility Regulatory Commission's February 9, 2012 Docket Entry, dated February 13, 2012. *See* IURC Online Services Portal.

[116] IPL SAPR (March 21, 2016) in Cause No. 44339.

CEIS burdened the viable option of gas conversion with expenses in order to eliminate this option and then elevate its predetermined choice for selection by assuming a flat $1.9 million maintenance expense for the simple cycle turbines in its analysis. Assuming a flat maintenance rate instead of reflecting the actual cyclic maintenance outage costs is another flaw in CEIS' analysis. Dr. Boerger discusses the CT Project's economic issues in his testimony.

**Q: What about CEIS' claims regarding Solid Particle Erosion ("SPE") damage to its turbine by-pass valve due to the effects of cycling?[117]**

A: In Cause No. 45052, CEIS testified about converted units having incomplete combustion. In this Cause, CEIS is critical about converted units having SPE damage.[118] As I stated in my Cause No. 45052 testimony, these issues are solvable engineering problems.[119] CEIS should bring this issue up with its boiler or turbine manufacturer prior to the next scheduled turbine and generator overhaul outage to address these issues and seek permanent solutions. Nevertheless, the preventions and solutions to these issues will become a part of the power plant's good management, operation, and maintenance practices.

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[117] Games Direct, p. 11, ll. 10 – 16, states "A.B. Brown unit 1 has experienced the effects of cycling firsthand as SPE damaged a turbine by-pass valve, allowing foreign particles to enter the turbine and causing a three-month outage and a $3.8 million repair during the summer of 2016. The issue appears to have occurred in the main steam outlet header where scale appears to have flaked off the internal header due to multiple thermal transitions related to unit cycling."

[118] CEIS states SPE was due to cycling of coal fired A.B. Brown units. However, once CEIS refuel the A.B. Brown units to gas, these units take on the role of peaker generators and operate at significantly less hours per year characterized by a decreased capacity factor. Less hours of operation brings less cycling and consequently, less probability of SPE occurring. Otherwise, CEIS should have its boiler or turbine manufacturer check the main steam outlet header for solutions to this issue because AESI did not report this issue occurring with its Harding Street gas converted units.

[119] Cause No. 45052, Public's Exhibit No. 2 (Redacted), Direct Testimony of Anthony A. Alvarez, p. 22, ll. 7 – 10.

## VIII. CONCLUSIONS

**Q: What do you conclude?**

A: The following summarizes my analysis and evaluation:

1. The proposed CT Project is an inappropriate choice to replace the 490 MW capacity of A.B. Brown Units 1 and 2.

2. CEIS' analyses burdened the refueling option with unreasonable operating expenses and used a short expected-life assumption to screen out and render the refueling option undesirable in its analysis. On the other hand, CEIS bolstered the proposed CT Project with unfair flat-rate operating expenses and enhanced operating characteristics to elevate its choice for selection.

3. Refueling coal-fired boilers to gas-fired is a viable and cost-effective option to extend the life of the A.B. Brown legacy units.

4. Gas conversion technology advancements in the last decade achieve the capability of maintaining 100% of the power plants' rated capacity after conversion.

5. Refueling the A.B. Brown Units 1 and 2 could be achieved at a reasonable range of around $200/kW.

6. Refueling the A.B. Brown Units 1 and 2 requires low capital outlay that protects and preserves ratepayer's interests in these existing assets.

7. Refueling the A.B. Brown Units 1 and 2 fit the requirements of a small customer base and the system demand of a small-sized utility like CEIS.

## IX. RECOMMENDATIONS

**Q: What do you recommend?**

A: Based on my conclusions above, I recommend the Commission:

1. Deny CEIS' request for a CPCN for its proposed CT Project.

2. Require CEIS to fully evaluate the refueling of the coal-fired A.B. Brown Units 1 and 2 to extend the life of these legacy units.

**Q: Does this conclude your testimony?**

A: Yes.

## APPENDIX A

**Q: Please describe your educational background and experience.**

A: I hold a Master of Business Administration degree from the University of the Philippines ("UP"), in Diliman, Quezon City, Philippines. I also hold a Bachelor of Science degree in Electrical Engineering from the University of Santo Tomas ("UST"), in Manila, Philippines.

I joined the OUCC in July 2009 and have completed the regulatory studies program at Michigan State University sponsored by the National Association of Regulatory Utility Commissioners ("NARUC"). I have also participated in other utility and renewable energy resources-related seminars, forums, and conferences.

Prior to joining the OUCC, I worked for the Manila Electric Company ("MERALCO") in the Philippines as a Senior Project Engineer responsible for overall project and account management for large and medium industrial and commercial customers. I evaluated electrical plans, designed overhead and underground primary and secondary distribution lines and facilities, primary and secondary line revamps, extensions and upgrades with voltages up to 34.5 kV. I successfully completed the MERALCO Power Engineering Program, a two-year program designed for engineers in the power and electrical utility industry.

## Data Requests - Set 5

5-1 Petitioner's Exhibit No. 1, Direct Testimony of Steven C. Greenley, p. 18, lines 25 – 26, states "[r]enewables cannot, by themselves, satisfy utilities' hourly peak demands."

a) Please explain why renewables cannot satisfy the utility's hourly demand and provide support for the response.
b) Please state CenterPoint Energy Indiana South's ("CEIS") (highest) summer and winter (hourly) peak demands, in megawatt-hours ("MWh"), for each year 2016 through 2020.
c) Please explain how CEIS' (highest) summer and winter (hourly) peak demands for each year 2016 through 2020 were met.
d) Did CEIS experience any power outages, load curtailments, rolling blackouts, etc., specifically due to unmet or unserved summer and winter (hourly) peak demands for each year 2016 through 2020? Please explain and provide support for the response.
e) Please state CEIS' (highest hourly) peak demand during the "2020 Polar Vortex" event (Petitioner's Exhibit No. 2 (Public), Direct Testimony of Wayne D. Games, p. 17, line 6).
f) Did CEIS lose power and experience any power outages, load curtailments, rolling blackouts, etc., specifically due to unmet or unserved (hourly) peak demand during the "2020 Polar Vortex" event? Please explain and provide support for the response.

**Objection:**

Petitioner objects to Request 5-1(c) on the grounds and to the extent it seeks a calculation, compilation or analysis Petitioner has not performed and Petitioner objects to performing.

**Response:**

Subject to and without waiver of the foregoing objection, Petitioner responds as follows:

a) The question mischaracterizes Mr Greenley's testimony. He testified that "Renewables cannot, **by themselves**, satisfy utilities' hourly peak demands." (emphasis added) Numerous witnesses have discussed and provided support for this.

b) Peak demand is measured in MWs. Please see summer and winter peak demand between 2016 and 2020 below.

| | |
|---|---|
| 2016 Summer 1096 MWs 6/22/16 | 2016 Winter 866.5 MWs 1/13/16 |
| 2017 Summer 1041.5 MWs 7/21/17 | 2017 Winter 780.8 MWs 1/7/17 |
| 2018 Summer 1041.7 MWs 7/5/18 | 2018 Winter 823.6 MWs 1/16/18 |
| 2019 Summer 1055.2 MWs 9/12/19 | 2019 Winter 757.2 MWs 1/30/19 |
| 2020 Summer 984.3 MWs 8/10/20 | 2020 Winter 715.5 MWs 2/14/20 |

c) Unless a unit is designated Must Run, MISO commits and dispatches CEI South generation resources economically based on the associated costs of each unit. If CEI South generation is less than CEI South's demand need, CEI South purchases the remaining energy need from the MISO Market.

d) CEI South did not perform rolling blackouts in 2016 through 2020. CEI South was asked by MISO to curtail LMR load in January 2019 in near monthly peak conditions due to conditions in the MISO footprint. There were no local CEI South issues during that time. Any power outages during summer and winter peaks were coincidental and not due to load and were considered typical/normal causes. In addition, in June 2021, CEI South was asked by MISO to curtail LMR load in near peak conditions due to conditions in the MISO footprint, including forced generation outages, above normal temperatures in the north region and higher than forecasted load.

e) Clarification as this was to be the "2021 Polar Vortex." Peak demand of 742.1MWh.

f) No. CEI South did not lose power or experience power outages, load curtailments or rolling blackouts during the 2021 Polar Vortex.

5-2 Greenley Direct, p. 18, lines 26 – 27, states "[r]enewables must be supported by dispatchable generation in order that customer demands are fulfilled."

a) Please state whether CEIS' proposed two natural gas combustion turbines ("CTs") are examples of "dispatchable generation."
b) Are the two CTs simple cycle gas turbines ("SCGT")? Please explain.
c) Will CEIS dispatch by itself or designate the two CTs as "must run" to support renewables and fulfill its customers' demand? If yes, please explain and provide support for the response.
d) Does CEIS have the authority to dispatch by itself or designate its own generators as "must run" to support renewables and fulfill its customers demand? If yes, please explain and provide support for the response.
e) Will CEIS dispatch the two CTs out of (order from) the Midcontinent Independent System Operator ("MISO") Security Constrained Economic Dispatch ("SCED") order to support renewables and fulfill its customers' demand?
f) Will CEIS dispatch its generators out of (order from) the MISO SCED order to support renewables and fulfill its customers' demand? If yes, please explain and provide support for the response.
g) Would CEIS also consider coal-fired A.B. Brown units converted to gas-fired units as "dispatchable generation"? If no, please explain and provide support for the response.
h) Would CEIS dispatch the gas-converted A.B. Brown units out of (order from) the MISO SCED order? If yes, please explain and provide support for the response.
i) Would CEIS designate the gas-converted A.B. Brown units as "must run"? If yes, please explain and provide support for the response.

**Response:**

a) Yes. The proposed CTs are dispatchable generation.

b) Yes. Simple Cycle Gas Turbines (SCGT) are Combustion Turbines (CT) and used interchangeably throughout testimony.

c) As stated in Mr. Games' testimony (Petitioner Exhibit No. 2, Page 7), the purpose of MISO is to enable the reliable delivery of low-cost energy. Thus, CEI South relies on MISO to dispatch resources to ensure system reliability in the most economical way. Consequently, MISO will dispatch renewable resources. When there is not enough renewable generation to satisfy load, MISO will call upon dispatchable resources already on-line to ramp up and/or request dispatchable resources with fast start times and a high ramp rate to come online, to economically support grid reliability. Generation, such as coal units or converted gas units are not capable of starting or ramping quickly to support the expected renewables build out on our system and throughout MISO.

   Please note that occasionally, CEI South will declare a unit must run for local reliability concerns, contractual obligations or testing for safety, environmental or performance reasons.

d) See response 5-2c.

e) See response 5-2c.

f) See response 5-2c.

g) See response 5-2c.

h) See response 5-2c.

i) See response 5-2c.

HYDROGEN AND $CO_2$ EMISSIONS CALCULATOR

# YOUR HYDROGEN AND $CO_2$ EMISSIONS RESULTS

These results are based on your estimate of **2,667 annual operating hours** at **30% hydrogen** on a **7F.05 turbine** **configured as a simple cycle** plant and a current $CO_2$ tax of **$8.69 per ton**.

RECALCULATE

**Infrastructure Requirements** | **$CO_2$ Savings** | **Summary**

## HYDROGEN PRODUCTION AND INFRASTRUCTURE REQUIREMENTS

**Choose your process:** **Electrolysis** **Steam methane reforming**

| ELECTRICITY REQUIRED | | WATER FLOW REQUIRED | | HYDROGEN FLOW REQUIRED |
|---|---|---|---|---|
| Energy per year | + | Gallons of water per day required | → | Cubic feet per day |
| **131.5** MW | | **37,696** | | **6.6** million |
| You will need the equivalent of **176 - 1.5 MW** wind turbines to create the required energy for your hydrogen infrastructure. | | You will consume the equivalent of **0.06 Olympic-sized pools** of water every day as part of your hydrogen infrastructure plan. | | Amount of hydrogen created |

Assumption: Wind turbines running at 50% capacity factor.



# Hydrogen fueled gas turbines

While the effort to reduce carbon emissions from traditional power generation assets is driving an increase in renewable power production from renewables, hydrogen-ready gas turbines could also play a role. See how we're leading the charge.

Explore our H2 FAQ >
Try our hydrogen calculator >

## GE technology behind Australia's first gas and hydrogen blend power plant

EnergyAustralia is relying on GE's combustion technology experience to build a dual-fuel, natural gas + hydrogen plant—the country's first.

→

## HYDROGEN AND $CO_2$ EMISSIONS CALCULATOR

These results are based on your estimate of **2,667 annual operating hours** at **30% hydrogen** on a **7F.05 turbine configured as a simple cycle** plant and a current $CO_2$ tax of **$8.69 per ton**.

RECALCULATE →

Infrastructure Requirements | $CO_2$ Savings | **Summary**

# INFRASTRUCTURE AND SAVINGS SUMMARY

### YOUR INFRASTRUCTURE REQUIREMENTS

ELECTROLYSIS

WATER
37,696
GALLONS/DAY

ENERGY
131.5 MW

STEAM METHANE REFORMING

WATER
18,848
GALLONS/DAY

METHANE REQUIRED

### ESTIMATED HYDROGEN FLOW RATE

View by: Day Hour

6,564,597
Cubic feet per day

185,883
Cubic meters per day

15,854
Kilograms per day

### POTENTIAL $CO_2$ TAX SAVINGS*

ESTIMATED SAVINGS IN USD
$357.9 k

(Based on $8.69/ton $CO_2$ tariff paid)

$CO_2$ EMISSIONS REDUCTION

11.6%

Based on your inputs your emissions will be 445 g/kWh.

GE Gas Power PRODUCTS SERVICES RESOURCES Sign In Regions CONTACT US

GE Gas Power

Search GE Gas Power
Type your search and hit enter

Products
Gas turbines
Power plant solutions
Explore our portfolio
Services
Equipment services and upgrades
Lifecycle services
Resources
All resources
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# Hydrogen fueled gas turbines

Globally the effort to reduce carbon emissions from traditional power generation assets is driving an increase in renewable power production from renewables, hydrogen-ready gas turbines could also play a role. See how we're leading the charge.

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Try our hydrogen calculator >

## GE technology behind Australia's first gas and hydrogen blend power plant

EnergyAustralia is relying on GE's combustion technology experience to build a dual-fuel, natural gas + hydrogen plant—the country's first.

→

5-4 Refer to Greenley Direct, p. 7, Table 1: Generating Units.

a) Please state the "Generator ID" of the A.B. Brown Unit 3 in the U.S. Energy Information Administration ("EIA") Form EIA-860.
b) If the Form EIA-860 "Generator ID" unit number for the A.B. Brown Unit 3 is different, please explain why.
c) Please state the "Generator ID" of the A.B. Brown Unit 4 in the U.S. Energy Information Administration ("EIA") Form EIA-860.
d) If the Form EIA-860 "Generator ID" unit number for the A.B. Brown Unit 4 is different, please explain why.

**Response:**

a) A.B. Brown unit 3 has a Generator ID of 4 in the EIA 860 system.

b) This generator ID was established when the unit was placed in service in 1991.

c) A.B. Brown unit 4 has a Generator ID of 5 in the EIA 860 system.

d) This generator ID was established when the unit was placed in service in 2002.

# A.B. Brown CT | Power Plant Profile

| OWNER | ULTIMATE PARENT | OPERATING CAPACITY OWNERSHIP (%) | PLANNED CAPACITY OWNERSHIP (%) |
|---|---|---|---|
| Sthrn IN Gas & Electric Co. | CenterPoint Energy Inc. | 100.000 | 100.000 |

## Operator

Sthrn IN Gas & Electric Co.

## Site Information

| | |
|---|---|
| City or County | Posey County |
| State, Province, or Admin Region | Indiana |
| Country | USA |
| NERC Region and Subregion | RFC/R-MISO (100.00%) |
| ISO or TSO | MISO (100.00%) |
| Planning Area | Midcontinent Independent System Operator, Inc. (100.00%) |
| Balancing Authority | Midcontinent Independent System Operator, Inc. (100.00%) |
| Interconnected Utility | Sthrn IN Gas & Electric Co. |
| Water Source | Ohio River |
| Other Plants at Site | A.B. Brown<br>AB Brown CCGT |

## Recent News & Notes

**EXTRA The Daily Dose: FERC's transmission task force; FERC chair defends added review for gas projects** 6/18/2021

**CenterPoint looking to build 460 MW of gas turbines to replace Ind. coal plant** 6/17/2021

## Summary Operating Data - 2020

| | |
|---|---|
| Operating Capacity (MW) | 174.0 |
| Net Generation (MWh) | 24,432 |
| Heat Rate (Btu/kWh) | 13,531 |
| Capacity Factor (%) | 1.60 |
| Total Operating & Maintenance Expense per MWh ($/MWh) | 99.70 |

## Plant Description

| | |
|---|---|
| Operating Status | Operating & Planned |
| Current Operating Capacity (MW) | 174.0 |
| Planned Capacity (MW) | 460.0 |
| Prime Mover | Gas Turbine |
| Primary Fuel | Gas |
| Secondary Fuel | Natural Gas |
| Additional Fuel Type(s) | Distillate Fuel Oil |
| Fuel Group(s) | Gas, Oil |
| Co-Fired Units? | No |
| Fuel Switching Units? | Yes |
| Year First Unit in Service | 1991 |
| Cogenerator? | No |
| Offshore? | No |
| Regulatory Status | Regulated |

## Total Plant Investment - 2020

| | |
|---|---|
| Cost of Land & Land Rights ($) | 40,443 |
| Cost of Structures & Improvements ($) | 1,692,936 |
| Cost of Equipment ($) | 59,866,029 |
| Gross Capital Expenditures ($) | 61,599,408 |
| Construction Cost/ Capacity ($/kW) | 349.20 |

## Unit Details

| | | | | CAPACITY (MW) | | | | |
|---|---|---|---|---|---|---|---|---|
| UNIT NAME | GENERATION TECHNOLOGY | TECHNOLOGY DETAIL | UNIT NAMEPLATE CAPACITY (MW) | SUMMER NET CAPACITY (MW) | WINTER NET CAPACITY (MW) | PRIMARY FUEL | OPERATING STATUS | ONLINE DATE |
| 4 | Gas Turbine (GT) | NA | 88.2 | 80.0 | 87.0 | Natural Gas | Operating | Jun - 1991 |
| 5 | Gas Turbine (GT) | NA | 88.2 | 80.0 | 87.0 | Natural Gas | Operating | May - 2002 |
| 7 | Gas Turbine (GT) | NA | 230.0 | 230.0 | 230.0 | Gas | Early Development | 2024 |
| 8 | Gas Turbine (GT) | NA | 230.0 | 230.0 | 230.0 | Gas | Early Development | 2024 |

## Project Summary

| PHASE | PROJECT TYPE | GENERATION TECHNOLOGY | TECHNOLOGY BREAKOUT | CURRENT DEVELOPMENT STATUS | NEW CAPACITY (MW) | PRIMARY FUEL | ESTIMATED COMPLETION DATE | ESTIMATED PROJECT COSTS ($000) | ESTIMATED PROJECT COST ($/KW) |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Generation | Gas Turbine (GT) | 2 CT | Early Development | 460.0 | Gas | 2024 | 437,000 * | 950 |

*Cost estimated by S&P Global Market Intelligence.

S&P Global Market Intelligence guarantees coverage of operational power plant units that file data with the EIA or are larger than 1 MW in North America, and 5 MW outside of North America. S&P Global Market Intelligence does not comprehensively cover operational plants below this threshold. S&P Global Market Intelligence comprehensively covers power projects (generation or environmental) with units over 1 MW within North America, and over 5 MW outside of North America, which supply more than 50% of power generated to the grid.

Due to the variability of sources reporting values on in-development projects, S&P Global Market Intelligence accuracy on the following fields is guaranteed to be within 10%: unit capacity (nameplate, summer and winter) and project costs (minimum and maximum). Online date is guaranteed within 6 months for operational plants.

S&P Global Market Intelligence guarantees coverage on Power Purchase Agreements for plants first tracked after Jan - 2011 and with a unit greater than 100 MW.

5-3 Greenley Direct, p. 7, provided Table 1 showing CEIS' generating units.

a. Please identify the manufacturer and turbine type(s) of A.B. Brown Units 3 and 4 gas turbines. Please explain and provide support for the response.

Please respond to and provide support for the following:

b. Please state the amount of time or number of hours A.B. Brown Units 3 and 4 gas turbines were in operation, and load was connected to the grid, for previous seven years 2014 through 2020.

c. Please state the annual "Capacity Factors" of A.B. Brown Units 3 and 4 gas turbines for previous seven years 2014 through 2020.

d. Please state whether the A.B. Brown Units 3 and 4 are simple cycle gas turbines. If not, please explain why.

**Response:**

a) AB Brown Units 3 and 4 gas turbines are both General Electric gas turbines, Model series MS7001EA, most commonly referred to in the industry as 7EAs. Neither unit has the capability to ramp quickly. In addition, the difference between A.B. Brown Units 3 and 4 is that AB Brown 3 gas turbine is a dual fuel unit capable of using natural gas or fuel oil, whereas AB Brown 4 gas turbine is a single fuel machine burning natural gas only. The dual fuel capability also gives CEI South the ability to black start the proposed CTs at the Brown site providing additional reliability and support to the grid.

b) See attached 45564_OUCC DR05.3_B3&B4 Service Hours and Capacity Factor.xlsx.

c) See response 5-3b.

d) Yes. Brown units 3 and 4 are simple cycle gas turbines although Brown unit 3 can operate on fuel oil as well as natural gas.

5-4 Refer to Greenley Direct, p. 7, Table 1: Generating Units.

a) Please state the "Generator ID" of the A.B. Brown Unit 3 in the U.S. Energy Information Administration ("EIA") Form EIA-860.
b) If the Form EIA-860 "Generator ID" unit number for the A.B. Brown Unit 3 is different, please explain why.
c) Please state the "Generator ID" of the A.B. Brown Unit 4 in the U.S. Energy Information Administration ("EIA") Form EIA-860.
d) If the Form EIA-860 "Generator ID" unit number for the A.B. Brown Unit 4 is different, please explain why.

**Response:**

a) A.B. Brown unit 3 has a Generator ID of 4 in the EIA 860 system.

b) This generator ID was established when the unit was placed in service in 1991.

c) A.B. Brown unit 4 has a Generator ID of 5 in the EIA 860 system.

d) This generator ID was established when the unit was placed in service in 2002.

| Year | Plant | Unit | Service Hours | Net Capacity Factor |
|---|---|---|---|---|
| 2014 | Brown CT's | BCT3 | 92 | 0.7 |
| 2014 | Brown CT's | BCT4 | 222 | 1.7 |
| 2015 | Brown CT's | BCT3 | 139 | 0.9 |
| 2015 | Brown CT's | BCT4 | 464 | 3.5 |
| 2016 | Brown CT's | BCT3 | 263 | 1.4 |
| 2016 | Brown CT's | BCT4 | 226 | 1.6 |
| 2017 | Brown CT's | BCT3 | 185 | 1.2 |
| 2017 | Brown CT's | BCT4 | 404 | 2.0 |
| 2018 | Brown CT's | BCT3 | 255 | 1.5 |
| 2018 | Brown CT's | BCT4 | 445 | 3.2 |
| 2019 | Brown CT's | BCT3 | 168 | 1.0 |
| 2019 | Brown CT's | BCT4 | 265 | 2.0 |
| 2020 | Brown CT's | BCT3 | 220 | 1.3 |
| 2020 | Brown CT's | BCT4 | 244 | 1.9 |

# Natural Gas Conversions for Power Boilers

*A fuel cost savings opportunity for power boiler owners and operators*

The decreasing cost and positive outlook for supply of natural gas makes fuel switching an increasingly attractive option for power boiler owners and operators.

As a leading worldwide supplier of power boilers and combustion systems for a wide variety of fuels, Babcock & Wilcox (B&W) has the expertise and experience to convert your power boiler to natural gas firing, regardless of the manufacturer.

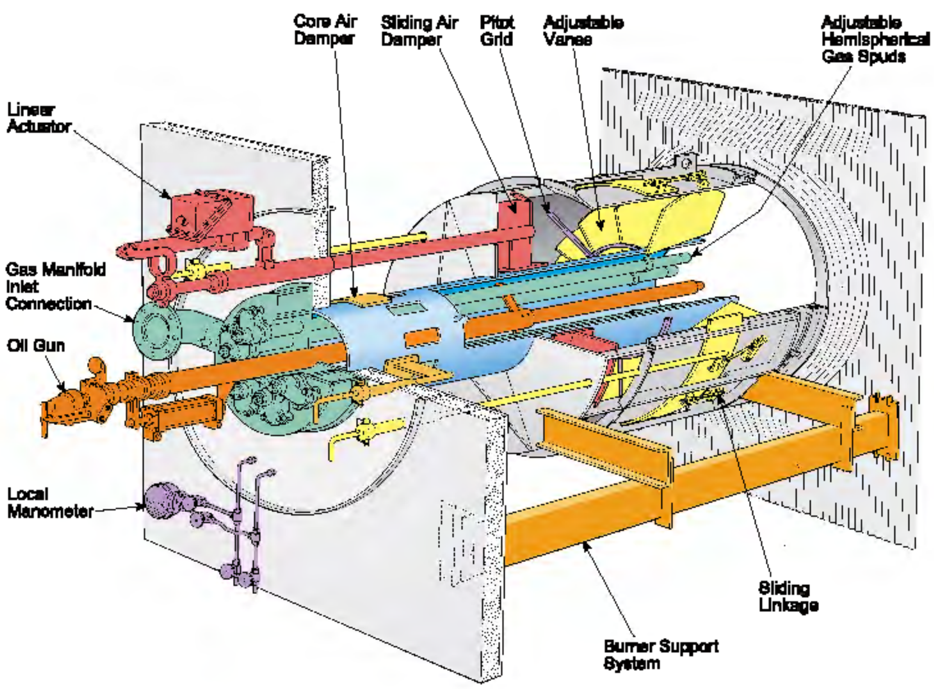
## *Fuel switching considerations*

Currently, a significant advantage of natural gas conversions is the low cost of fuel when compared with oil, a common alternative power boiler start-up and operational fuel.

B&W's natural gas conversion experience is proven: many power boiler owners and operators have successfully converted their existing units to 100 percent natural gas firing systems, significantly reducing annual fuel and plant operating costs.

In some instances, capital investment payback periods are less than one year. In addition, power boiler owners and operators who are already considering equipment improvements can capitalize on the major benefit of reduced fuel costs by incorporating a gas conversion into their upgrade plans.

*Power boiler natural gas conversions are currently an attractive and economical option.*




*B&W's plug-in type low $NO_X$ XCL-S® burner for superior combustion.*

## *Natural gas conversion technology*

Through our integrated systems approach, B&W can deliver the results you need with increased reliability and reduced maintenance.

We integrate your fuel train, burner and burner management system for optimal operation.

Conversion modifications include:

- B&W's plug-in type, low $NO_X$ XCL-S® natural gas or dual fuel burner
- State-of-the-art FPS™ class 1 gas igniter with integral flame detection
- Easily accessible local igniter, burner controls and valve trains
- Pre-assembled main gas header valve assembly for igniter and burner supply
- Complete burner management system and operator interface graphics

Because our conversion system components are fully shop assembled and wired, we perform factory acceptance testing prior to installation. We encourage customer participation in this testing, enabling us to optimize the operator interface to suit your specific needs, improve the reliability of your overall system and reduce commissioning time.

*Duplex cooling air blower assembly.*

*Wall-fired natural gas igniter.*


*Shop-assembled main gas header valve train.*

## *Full-scope capabilities*

In addition to equipment supply, we provide a complete range of services including design engineering, manufacturing, project management, start-up and commissioning, and training.

Conversion project capabilities include:

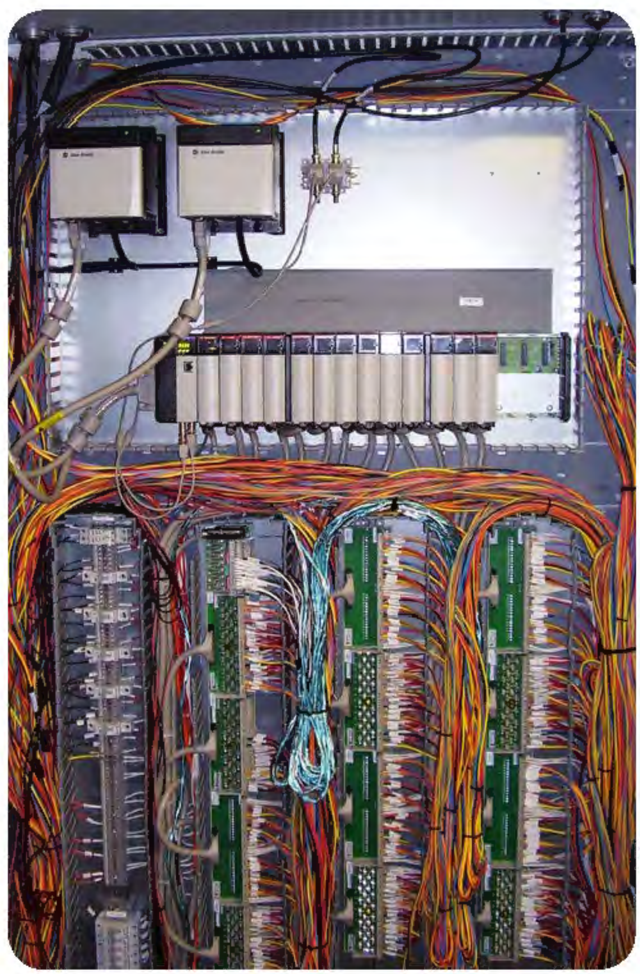
- Engineering and feasibility studies
- Complete natural gas conversion systems and components
- Shop assembly modularization and factory acceptance testing
- Project management
- Aftermarket on-site support
- Start-up and commissioning
- Operator, electrical and instrumentation group training
- National Fire Protection Association, FM Global and NEC Electrical Code compliant


*Cooling air blower and igniter burner controls.*

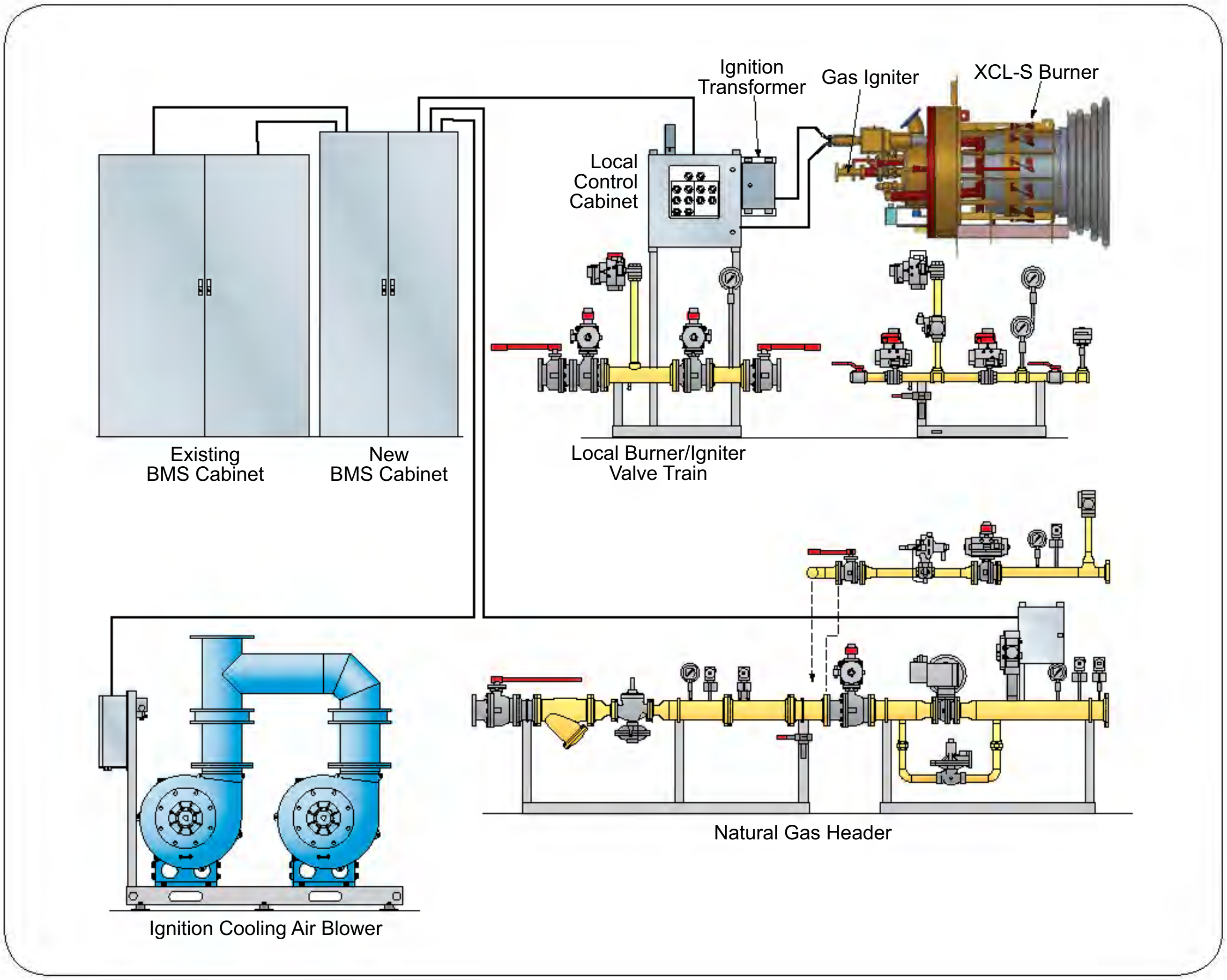
Our full-scope project approach allows us to fully integrate your power boiler with its new natural gas combustion system.

We minimize project cost, schedule and unit downtime through pre-assembled modular components, plug-in type burners, staged equipment delivery for pre-outage installation and overall streamlined project management execution.

*Burner/igniter valve train with local control panel.*



*Burner management system control cabinet wiring.*




*Offering integrated, quality technology and services, B&W can be your single-source supplier for power boiler natural gas combustion systems and fuel conversion projects.*



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**PS-467** 250PSF4

Established in 1867, Babcock & Wilcox is a global leader in advanced energy and environmental technologies and services for the power and industrial markets, with operations, subsidiaries and joint ventures worldwide.

For more information, or a complete listing of our sales and service offices, send an e-mail to info@babcock.com, or access our website at www.babcock.com.

1-18. Each of the three sections pertaining to the gas conversion options (Sections 8.1.3.4.1, 8.1.3.4.2 and 8.1.3.4.3) in CenterPoint's 2019/20 Integrated Resource Plan ("IRP") report (provided in Attachment MAR-1) indicate that the A.B. Brown ("ABB") units would be "expected to operate for 10 years before retirement."

a) Please provide support for the 10-year operational life assumption presented in these sections.
b) Please provide studies performed by CenterPoint or on behalf of CenterPoint investigating an appropriate operational life for ABB units after conversion to run on gas.
c) Please provide studies possessed by CenterPoint, or firms working for CenterPoint on its 2019/20 IRP, examining reasonable assumptions to use for remaining useful life for coal fired units after conversion to run on gas.
d) Please identify the useful life assumed for the combustion turbine units for which a CPCN is requested by CenterPoint in this proceeding ("CTs") and provide support for their assumed useful life.
e) Please identify the expected remaining undepreciated value for the CTs after 10 years of operation.

**Objection:**

Petitioner objects to the subpart (e) of the Request on the grounds and to the extent it seeks a calculation, analysis or compilation which has not already been performed and which Petitioner objects to performing.

Petitioner further objects to the Request on the separate and independent grounds and to the extent the Request seeks information which is trade secret or other proprietary, confidential, and competitively sensitive business information of Petitioner, its customers, or its vendors. Petitioner has made reasonable efforts to maintain the confidentiality of this information. Such information has independent economic value and disclosure of the requested information would cause an identifiable harm to Petitioner, its customers, or its vendors. The responses are "trade secret" under law (Ind. Code § 24-2-3-2) and entitled to protection against disclosure. See also Indiana Trial Rule 26(C)(7). All responses containing designated confidential information are being provided pursuant to non-disclosure agreements between Petitioner and the receiving parties.

Subject to and without waiver of the foregoing objections, Petitioner responds as follows:

**Response:**

a) The bridge portfolio strategy and accompanying development assumptions were discussed with IRP stakeholders on December 13, 2019. At that time, CenterPoint presented the 10 year life assumption prior to developing two conversion portfolios (ABB1 conversion and ABB1 & ABB2 conversion), consistent with the strategy to consider long-term off ramps, utilizing existing resources. No stakeholders suggested that a different life assumption would be more appropriate. It should be noted that these conversion options were available for selection during the full IRP planning period on a least cost basis, and neither conversion of ABB1 nor ABB1 & ABB2 conversion were selected.
b) There are no studies that estimated the life of a Brown unit coal-to-gas conversion. This was not practical without performing a full assessment of all equipment and the uncertainty regarding frequency of unit starts and run times. Frequent cycling would result in faster unit degradation. The Coal-to-Gas Conversion studies are included in the filing as Petitioner's Exhibit No. 5, Attachment MAR-2 (Confidential) 6.5 Coal to Gas Conversion Study.
c) See Petitioner's response to 45564 OUCC DR 1-18(a) and 1-18(b).
d) Petitioner has assumed the book life to be 30 years. Support can be found in Petitioner's Exhibit No. 5, Attachment MAR-2 on page 27.
e) This analysis has not been performed, but the IURC approved depreciation rate for the combustion turbines at the A.B. Brown site is 3.44%.

**AFFIRMATION**

I affirm, under the penalties for perjury, that the foregoing representations are true.

Anthony A. Alvarez
Utility Analyst
Indiana Office of Utility Consumer Counselor
Cause No. 45564
CenterPoint Energy Indiana South

November 19, 2021
Date

# CERTIFICATE OF SERVICE

This is to certify that a copy of the Indiana OUCC's Testimony Filing of Anthony A. Alvarez has been served upon the following parties of record in the captioned proceeding by electronic service on November 19, 2021.

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