STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

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. 1

TESTIMONY OF OUCC WITNESS PETER M. BOERGER PH.D

NOVEMBER 19, 2021

Respectfully submitted,

Lorraine Hitz

Lorraine Hitz
Attorney No. 18006-29
Deputy Consumer Counselor

TESTIMONY OF OUCC WITNESS PETER M. BOERGER, PH.D.
CAUSE NO. 45564
SOUTHERN INDIANA 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 Peter M. Boerger, and my business address is 115 West Washington St., Suite 1500 South, Indianapolis, Indiana, 46204.

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

A: I am employed by the Indiana Office of Utility Consumer Counselor ("OUCC") as a senior economist, with the official job title of Senior Utility Analyst, in the Electric Division. A summary of my educational and professional background, as well as my duties and responsibilities at the OUCC, can be found in Appendix A.

Q: What is the purpose of your testimony?

A: I address the economic justification for Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South's ("CEIS" or "Petitioner") request for a Certificate of Public Convenience and Necessity ("CPCN") to construct two new combustion turbine ("CT") generation facilities on the site of its A.B. Brown generation station. I recommend denial of CEIS' request for a CPCN to construct the proposed CTs.

Q: Why is the selection of generation resources important to consumers of Indiana's electric utilities?

A: The cost of generation resources represents a significant share of the Indiana electric utilities' revenue requirements and thus a significant share of the rates paid by Indiana's electric consumers. While it is important to ensure utilities have adequate resources to maintain reliability, rates that are higher than needed can unnecessarily affect the affordability of those rates for Indiana consumers and the competitiveness of the state's businesses. When a utility obtains a CPCN,[1] the risk of making unaffordable decisions is shifted from the utility's shareholders to its customers. Thus, it is vital that generation proposals from utilities be scrutinized closely.

Q: Is the inclusion of a proposed generation resource in a utility's Preferred Resource Portfolio ("PRP") sufficient for the grant of a CPCN?

A: No. Section 5 of Ind. Code ch. 8-1-8.5 requires the Commission to only grant a CPCN if the Commission finds "that the public convenience and necessity require or will require the construction, purchase, or lease of the facility." This requirement goes beyond a simple verification that the utility has included the proposed project in its PRP from its Integrated Resource Plan ("IRP") to making a judgment independent of that plan as to the reasonableness of the proposed resource. Thus, inclusion of a project in a utility's PRP is a necessary but not sufficient condition for approval, and my testimony addresses the reasonableness of CEIS' proposal.

Q: How is your testimony organized?

A: I first present some thoughts on the current state of the electric utility industry and implications for decisions like the one CEIS faces. I next discuss CEIS' stated need

---

[1] I.C. ch. 8-1-8.5.

for dispatchable resources in the context of its obligations to the Midcontinent Independent System Operator ("MISO") and its recent reliability initiatives in light of growing levels of intermittent resources. Accepting CEIS' need to maintain a reasonable level of dispatchable resources, CEIS' choice of dispatchable resource is evaluated in the context of other options available to the utility. Given the relatively low cost of converting CEIS' A.B. Brown units to burn natural gas, I focus on Petitioner's choice to invest in a new CT with higher initial costs and evaluate the economics of that choice. I evaluate additional aspects of this selection beyond economics and reference the testimony of OUCC witnesses Anthony Alvarez and Cynthia Armstrong to the extent their testimony is relevant to the economics of the CTs. Finally, I present my conclusions and recommendations.

Q: To the extent you do not address a specific item in your testimony, should it be construed to mean you agree with CEIS' 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. THE STATE OF THE ELECTRIC UTILITY INDUSTRY AND IMPLICATIONS FOR CEIS' INVESTMENT DECISION IN THIS CAUSE

Q: How would you characterize the current state of the electric utility industry?

A: The electric utility industry is in a state of massive change. Concerns about climate change effects and declining costs for renewable resources have changed utilities' approaches to resource choices, which have historically been focused largely on fossil-fueled technologies.

Q: What are the implications of the changed utility approach to resource choices?

A: Those changes will be good for the environment, but many of the most economic renewable resources rely on sources that are intermittent in nature, making the maintenance of system reliability a subject of rising importance. MISO, in its RIIA report,[2] recently examined the challenges involved as levels of intermittent resources increase.

From an electric generation perspective, the challenge of maintaining reliability is one of ensuring sufficient resources can be dispatched in every moment of every day to meet customer demand. That challenge has historically been one of ensuring customer load can be followed. However, the introduction of intermittent resources adds another complexity—that of also having resources available to "fill in" for intermittent resources when they are unavailable (e.g., when the sun is not shining, or the wind is not blowing). I will refer to this more complex task as "following net load" in place of the historical phrase "following load." Resources capable of following net load will need to be resources that can be reliably dispatched irrespective of the availability of such intermittent sources, often referred to as "dispatchable" resources.

---

[2] MISO'S Renewable Integration Impact Assessment (RIIA): Summary Report, February 2021. Mid-Continent Independent System Operator. Available at https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf .

Q: Are there dispatchable resources that do not create direct climate-altering effects, such as creating carbon dioxide or using natural gas (which is comprised of methane and might partially escape into the atmosphere in transport or use)?

A: Yes. Some such sources would include hydropower and batteries or other forms of storage (which could be charged or refilled from renewable resources). Nuclear power is another zero-carbon resource, but these units historically have not been used to follow load in the United States.[3] Efforts using hydrogen-powered resources (such as CTs or fuel cells) have increased in recent years, which I will address later in my testimony.

Q: Are all of these zero-carbon resources technically and economically viable?

A: All[4] of these methods are technically feasible to one extent or another, though they all are currently expensive compared to traditional natural gas-fired generation and are not all ready to be implemented at utility scale. Batteries have received some federal incentives if they are part of and charged from solar facilities. This has lowered their cost and, thus, some Indiana utilities have selected batteries as part of solar projects. However, none of these net-load-following resources would likely be selected without some expectation of future climate-related requirements or taxes. Also, even after economic feasibility is attained, there will still be technical challenges for incorporating these resources into the grid and maintaining the level of reliability and resilience appropriate for such an essential service.

---

[3] For background information see https://www.powermag.com/flexible-operation-of-nuclear-power-plants-ramps-up/, which highlights recent efforts to make nuclear better able to follow load.

[4] Hydropower is feasible in some locations around the country, but Indiana is not well-situated for this resource.

III. CEIS' STATED NEED FOR DISPATCHABLE RESOURCES

Q: What does CEIS say about its need for dispatchable resources?

A: CEIS' current coal-fired generation at the A.B Brown Station can adjust its output and is able to follow load and thus also able to follow net load. However, CEIS witness Wayne D. Games presents[5] issues making the continued use of coal at the facility problematic, leading to his conclusion that new dispatchable generation is needed. CEIS proposes fulfilling this generation need by adding the two new CTs presented for approval in this Cause:

> This [the two proposed CTs] will provide a reliable, cost-effective portfolio with renewable resources being dispatched as available and the two CTs, F.B. Culley Unit 3, batteries and the two natural gas peaking units providing enough dispatchable energy to serve CenterPoint Indiana South's current customer load 98% of the time.[6]

Q: Would replacing the burning of coal at A.B. Brown station with burning natural gas at that facility fulfill CEIS' stated need for dispatchable capacity?

A: Yes. As further discussed in Mr. Alvarez's testimony, there would be no technical impediment to burning natural gas in the A.B. Brown plant after conversion, which would result in that facility being able to provide dispatchable capacity as it does

---

[5] Petitioner's Exhibit No. 2, Direct Testimony of Wayne Games, p.16, l.1 through p. 23, l. 26.
[6] Games Direct, p. 13, ll.19-22.

now. Further, Ms. Armstrong's analysis shows there would be no impediment to gas conversion from an environmental permitting standpoint.

Q: Does CEIS specifically address the potential to convert the A.B. Brown plant to run on natural gas?

A: Yes. Mr. Games addresses[7] CEIS' analysis of a gas conversion for the A.B. Brown plant.

Q: Does CEIS' analysis identify gas conversion as an attractive option?

A: No. CEIS does not include gas conversion in its preferred portfolio, and Mr. Games identifies[8] a number of reasons why CEIS rejected this option.

Q: Was CEIS incorrect to reject gas conversion?

A: Yes. In the next section I address the economic basis for CEIS' gas conversion rejection. Mr. Alvarez also addresses CEIS' technical objections to conversion, and Ms. Armstrong explains gas conversion will qualify for the same air permits and emissions netting benefits as the new gas CTs. In total, the OUCC's testimony identifies gas conversion as the most reasonable option for CEIS to meet its service obligations at the lowest cost reasonably possible.

IV. <u>THE ECONOMIC ARGUMENT FOR REJECTING CEIS' CT PROPOSAL IN FAVOR OF CONVERTING ITS A.B. BROWN UNITS TO GAS</u>

Q: Why did CEIS reject converting its coal units to gas in favor of building new CTs?

A: In its 2019/2020 Integrated Resource Plan ("IRP"), CEIS used resource planning software trade-named "Aurora," which is modeling software intended to allow

[7] Games Direct, p. 25, l.1 through p. 26, l. 33.
[8] Games Direct, p. 25, l.1 through p. 26, l. 33.

evaluation of generation resource options and development of optimized, least-cost portfolios. CEIS attached its 2019/2020 IRP to the testimony of CEIS witness Matthew A. Rice, presenting the results of its Aurora modeling with the economics summarized as a Net Present Value of Revenue Requirement ("NPVRR") for each candidate portfolio. Table PMB-1 pulls stochastic mean and 95th percentile NPVRR values[9] from the 2019/2020 IRP for two portfolios including A.B. Brown gas conversion[10] and for the selected portfolio, named the "High Technology" portfolio, wherein the CTs proposed in this Cause are included.

Table PMB-1 – NPVRR Values for Selected Portfolios from CEIS' 2019/2020 IRP (corrected) (millions of $)

Portfolio Name	Stochastic Mean 20-Year NPVRR	95th Percentile
Bridge A.B. Brown Unit 1 ("ABB1") Conversion	$2,632	$3,001
Bridge ABB1+A.B. Brown Unit 2 ("ABB2") Conversions	$2,784	$3,161
High Technology	$2,590	$2,978

Q: What do the values in Table PMB-1 mean?

A: After filing corrections on September 29, 2021, CEIS' modeling found its chosen "High Technology" portfolio had a stochastic mean NPVRR $42 million less than for the "Bridge ABB1 Conversion" portfolio, in which only ABB1 would be converted to gas with ABB2 retired, and $194 million less than the "Bridge ABB1+ABB2 Conversions" portfolio, in which both units would be converted to gas. These differences are somewhat smaller using 95th percentile values from the

[9] See NPVRR values presented in Figure 8-8 on Page 253 of 341 in Attachment MAR-1.
[10] I do not address the "ABB1 Conversion + CCGT" portfolio for efficiency of presentation. Issues regarding modeling of the ABB1 Conversion exist in that portfolio as well.

stochastic analysis ($23 million for the ABB1 conversion and $183 million for the ABB1+ABB2 conversion).

Q: Does it make sense that the ABB1+ABB2 conversion would have a much higher NPVRR than for the ABB1-only conversion?

A: No, it does not. These gas conversions can be completed at a very low capital cost compared to the cost of a new CT, and CEIS shows it would have a capacity need after converting only ABB1. On its face, it makes sense there would be economies in converting and operating both units rather than only one. However, CEIS' analysis shows a significant additional disadvantage to converting both units compared to converting only one.

Q: Have you identified a possible explanation for why such a counterintuitive result may have arisen in CEIS' analysis?

A: Yes. The OUCC asked for detail supporting the costs CEIS input into the Aurora model.[11] That detail shows essentially no economies assumed from converting both units compared to converting only one unit—not in capital cost, O&M expenses or in fixed gas supply costs.[12] In contrast, CEIS did reflect significant economies for a second CT when constructed with the first CT.[13] For instance, CEIS modeled a significant reduction in fixed gas costs for the second CT unit ($[redacted]

---

[11] The costs input to the model are found in 45564_CEIS_Workpaper MAR-2 CONFIDENTIAL - Aurora Input Model Files_061721.xlsb and support for those values were provided in a number of discovery responses to OUCC DR 6.1, with a final summary document containing cost support being provided to the OUCC as Confidential -45564_OUCC-DR 06.1(a) Summary.xlsx, which I am attaching to my testimony as CONFIDENTIAL Attachment PMB-1.

[12] See tabs "ABB1_Corrected_For_ABB1_Only" and "ABB2_2033" in CONFIDENTIAL Attachment PMB-1.

[13] See SCGT_F in CONFIDENTIAL Attachment PMB-1.

annually for the first CT vs. $[redacted] annually for the second CT).[14] The lack of similar modeling of economies likely contributed to the counterintuitive result for adding a second gas conversion unit.

Q: How will the inappropriate analysis of the second gas conversion unit affect the remainder of the economic review you conduct in your testimony?

A: Because CEIS' analysis does not reasonably reflect economies from adding a second gas conversion unit, my analysis is going to focus on the ABB1+ABB2 portfolio and how its costs and benefits compare to the proposed CT's., I believe the ABB1+ABB2 portfolio, despite CEIS' NPVRR calculations, to be the most economic option if any gas conversion is performed.

Q: Did you identify any errors and omissions in CEIS' analysis causing the gas conversion options to appear less attractive than appropriate?

A: Yes. I discuss this further in my testimony below.

Q: Based upon your analysis, do the NPVRR values for the gas conversion portfolios reasonably reflect the relative costs of those portfolios vs. the "High Technology" portfolio (which includes the proposed CTs)?

A: No. NPVRR values for the gas conversion portfolios incorporate a significant overestimation of O&M costs, based on the reduction in O&M costs AES Indiana ("AESI") experienced after converting its Harding Street Station units to burn gas. In addition, CEIS modeled the cost of removing the Brown units as part of the gas conversion costs but did not do so with its CT cost evaluation. CEIS also limited the life of the gas conversion units to 10 years, and CEIS included cost of removal for flue gas desulfurization ("FGD") units as part of the capital cost of the gas

[14] Cells D21 and D54 of SCGT_F tab of CONFIDENTIAL Attachment PMB-1.

conversion despite the fact that CEIS has already recovered some removal costs in rates. I will further discuss below an apparent error which inappropriately improves the relative attractiveness of the CT option related to the capital recovery factor modeled. I will also address an omission in CEIS' analysis of the benefit from using securitization for recovering remaining Brown plant balances.

Q: Please present your analysis of CEIS-modeled O&M costs for gas-converted units compared to cost reductions experienced by AESI for its gas-converted units.

A: I evaluated the reasonableness of CEIS' forecast of O&M expenses at its A.B. Brown units following gas conversion by reviewing the experience of AESI before and after its conversion of three units[15] from coal to natural gas, which occurred in 2017. Based on that analysis,[16] AESI saw a 44% average reduction in O&M expenses (in 2018$) after converting to gas. In contrast, CEIS projects a small overall increase in O&M after conversion compared to its historical average (again in 2018$). Modeling the same 44% O&M reduction AESI experienced would have led CEIS to an average annual reduction in O&M expenses of $[redacted] in 2018$, which when discounted would lead to a reduction in NPVRR of $[redacted] using CEIS' discount rate and discounting to 2019.

Q: Are there unusual expenditures CEIS forecasted to occur over the 10-year life of the gas-converted units?

A: Yes. CEIS shows unusually high O&M expenditures in years 2027-2029, which Petitioner indicates are related to overcoming issues with what are described in Mr.

---

[15] Harding Street units 5, 6 and 7.
[16] See Confidential Workpaper PMB-1.

Games' testimony as solid particle erosion ("SPE").[17] These expenditures are a material part of why CEIS' forecast of O&M expenditures are as high as they are. Mr. Alvarez questions the reasonableness of CEIS' forecasted expenditure for SPE, which implies the analysis I just presented (which includes CEIS' forecasted SPE expenditures--resulting in a $[redacted] reduction in NPVRR for the gas conversion case) is correct. For completeness, I also performed an alternative calculation[18] removing the years 2027-2029 from CEIS' calculation of forecasted O&M expenses (the years in which the SPE expenditures were forecasted), which would change the reduction to NPVRR to approximately $[redacted]. Again, the higher reduction to NPVRR grounded in Mr. Alvarez's stated concern is appropriate, but I include the lower number to show that even setting aside Mr. Alvarez's concern about SPE expenditures, CEIS' forecasted O&M expenditures are still far above AESI's experience with its gas conversion.

Q: Please discuss the issue regarding recognition of removal costs in CEIS' modeling of the cost of gas conversion compared to how it is treated in CEIS' evaluation of its proposed CT project.

A: My review of CEIS' modeling of costs found CEIS assigned costs[19] for removal of the A.B. Brown facility at the end of the 10-year projected life following conversion to gas. My review of CEIS' modeling of costs[20] for the CT units does not show

[17] Games Direct p.11, ll.10-12, and details of CEIS' modeled expenditures related to this matter was provided in tab "ABB Unit Coal-Gas" in spreadsheet titled "45564_CONFIDENTIAL OUCC DR07.1 - Gas Conversion O&M and Capex in 2018$.xlsx."

[18] See Confidential Workpaper PMB-1.

[19] In tabs titled "ABB1_corrected_for_ABB1_Only," "ABB1_corrected_For_ABB1ABB2," and "ABB2_2033" of CONFIDENTIAL Attachment PMB-1 for removal costs modeled in years 2034 and 2035 for A.B. Brown units.

[20] In tab "SCGT_F" of CONFIDENTIAL Attachment PMB-1.

analogous removal costs for A.B. Brown units, which would presumably occur shortly after the CT units were constructed. By assigning removal costs to the gas conversion portfolios but not to the CT portfolio,[21] CEIS inappropriately advantages the CT option because the A.B. Brown units will need to be removed and incur removal costs under either scenario. The total removal cost included in CEIS' modeling for both units in 2018$ at time of removal is approximately $[redacted] which has an NPVRR value of $[redacted] million if considered to be inappropriately included in the gas-conversion models or $[redacted] million if considered to be inappropriately absent from the CT model—the difference being the time value of money related to when the retirement occurs. These costs should have been considered in both portfolios or in neither.

Q: Is there an observation you would like to make about the discount rate CEIS used in its IRP modeling?

A: Yes. CEIS' modeling was performed using costs expressed in 2018$, but it is using a discount rate which does not remove expected inflation. Assuming the utility's cost of capital is the correct discount rate to use for evaluating IRP options, this mismatch has the effect of overvaluing costs (and benefits) in the near term while undervaluing costs (and benefits) further in the future. This effect shows up in the large difference in NPVRR effects of matters such as removal costs, depending on how far in the future costs (or benefits) are assumed to occur. These effects would have had potentially significant effects on CEIS' IRP modeling across all portfolios

[21] The "High Technology" portfolio.

and scenarios, but the effect of this mismatch cannot be identified without rerunning the model. However, it must be considered when interpreting the model results.

Q: Please discuss the life span CEIS assumed in its modeling for the gas-converted units.

A: CEIS assumed a 10-year life[22] for the gas-converted units. When asked in discovery for any studies performed by, or on behalf of, CEIS investigating an appropriate operational life for the A.B. Brown units after conversion to run on gas, CEIS indicated no such studies were performed.[23] The limited life assumed for the gas-converted units could significantly affect their economic attractiveness as, unlike the CT investment, there will be no offsetting benefits in the years beyond the 10th year to justify the initial cost. This issue is discussed further in Mr. Alvarez's testimony. I do not quantify an effect for this limitation, but it should be considered when evaluating the economics of CEIS' proposal.

Q: Please discuss the removal cost of FGD facilities assumed in CEIS' modeling of the gas-conversion option.

A: The Black and Veatch estimate for the cost of converting the A.B. Brown units to burn natural gas includes a cost for FGD demolition.[24] The cost of this demolition, along with the related cost of the installation of a bypass duct for the FGD left from the demolition, is shown to be $13,398,000 for both units. Because the bypass duct cost is not broken out from the total cost of this line item, I do not calculate an

---

[22] Page 238 of Attachment MAR-1.
[23] See Attachment PMB-3.
[24] Referred to in a project cost item identified as "FGD Demo and Bypass Duct" on page 41 of Attachment JAZ-3 (Public).

NPVRR effect for this item. But it is important to recognize that demolition costs have been recovered from customers as part of the depreciation expense for the A.B. Brown units over the years. Thus, it is not appropriate to include the entire cost of such demolition in evaluating the attractiveness of the gas conversion option. When such demolition occurs, standard accounting should be used to recognize the amounts already booked and those amounts will not again be collected from customers. It is inappropriate to use such costs as part of the resource option comparison, even though those amounts will be spent as part of the project.

Q: You earlier identified an issue with an apparent error that inappropriately improved the relative attractiveness of the CT option related to the capital recovery factor modeled. Please discuss that issue.

A: In reviewing CEIS' implementation of capital cost values in its Aurora modeling for the proposed CTs, I noticed that unlike how CEIS models the gas-conversion options, CEIS does not model a CT option's full capital costs in the year it goes into service. Rather, CEIS models[25] a levelized cost for the CT units, with those costs modeled to occur in every year of the planning horizon. This levelization occurs via a "capital recovery factor." Since the full capital cost is not modeled in the year placed in service, it is important that this capital recovery factor include a recognition of that initial capital cost—typically referred to as depreciation.

When I reviewed the capital recovery factor CEIS used, I noted that it was less than one percentage point greater than the discount rate for the model (which

[25] In tab "SCGT_F" of CONFIDENTIAL Attachment PMB-1.

is CEIS' cost of capital). A depreciation rate of less than 1% implies an expected life of over 100 years for the CT units.[26] When I incorporate a depreciation rate reflecting a more reasonable 30-year life for the CTs, I find the annualized capital cost used in modeling the CTs underestimates their cost by $[redacted] per year for both units. The net present value of that stream of underestimates over 30 years at CEIS' assumed discount rate is $[redacted], which when discounted back to 2019 represents $[redacted] present value of revenue requirement, making the High Technology portfolio appear better than it should compared to the gas conversion options.

Q: Please discuss the omission in CEIS' analysis of the benefit from using securitization for recovery of remaining Brown plant balances.

A: CEIS witness Matthew A. Rice presents[27] tables showing low and high estimates of the revenue requirement impact of CEIS' overall proposals in this proceeding, along with other aspects of implementing CEIS' preferred portfolio. In both of those tables he shows the benefit from securitization to be $[redacted]. Upon review of the calculations supporting this benefit, I initiated a review as to whether the Internal Revenue Service ("IRS") would view transfer of the undepreciated balance to the special purpose entity created to implement the securitization as a taxable event. This led to an investigation regarding IRS rules on this matter, and I

[26] Easily calculated as one divided by the amount included in the capital recovery factor to represent depreciation. For example, 1/0.01=100. In CEIS's model, the capital recovery factor is shown as [redacted]%. With a cost of capital of 7.71%, the amount included to represent depreciation is calculated to be [redacted]% or [redacted], which implies an expected life of [redacted] years.

[27] Tables 6 and 7 shown on pages 42 and 43 of Mr. Rice's direct testimony (Petitioner's Exhibit No. 5 Updated).

learned d that while the transfer of the undepreciated balance itself does not appear to be a taxable event, the non-bypassable charges[28] imposed as part of the securitization implementation must be recognized by the utility as gross income.[29] I do not find a reflection of this tax effect in CEIS' calculation of this benefit. I calculated[30] the value of this offset to be $5.9 million annually, which lowers the benefit estimates in Mr. Rice's testimony by that amount.

V. DISCUSSION, CONCLUSIONS, AND RECOMMENDATION

Q: Please summarize the effects of the errors and omissions you discussed in your testimony.

A: The three issues for which I calculated NPVRR effects total between $[redacted] and $[redacted].[31] These calculated NPVRR effects reduce the differential between the gas conversion option ABB1+ABB2 by over half, and the effects of other issues discussed above, in my estimation, make the two options (the CT and the gas conversion options) very close on the basis of NPVRR.

Q: Given those narrow NPVRRs, how do you recommend the Commission assess the choice between the CTs proposed in this proceeding and the option to convert A.B. Brown units to natural gas?

A: It is most prudent to view this decision using the lens of the significant change going on in the utility industry I discussed earlier. We do not know what our nation's position regarding natural gas will be ten years from now. Using the economic analysis under which CEIS evaluated the gas-conversion options, the

[28] Charges that customers are not able to bypass, per the provisions of I.C. ch. 8-1-40.5.
[29] See Attachment PMB-2—the IRS Revenue Procedure 2005-62.
[30] See Confidential Workpaper PMB-1.
[31] A lower range calculated as [redacted] and a higher range of [redacted].

gas-converted A.B. Brown facilities will be fully paid through depreciation at that time. Under CEIS' proposal, ten years from now there will still be an undepreciated balance of over $200 million on the new CTs, which could very well lead to the need for another round of securitization at that time, depending on the country's position toward natural gas. While the OUCC does not dispute CEIS should be able to seek an investment allowing it to maintain a reasonable level of dispatchable capacity during this time of uncertainty, now is not the time to make major investments in natural gas infrastructure that will require 30 years to be fully recovered.

Q: What about the need for fast ramp and fast starts and other technical benefits of the CTs, as Mr. Games proposed in testimony?

A: Mr. Alvarez addresses these purported CT benefits. It is the OUCC's position these technical capabilities are not significantly relevant to the Commission's decision in this proceeding. Mr. Alvarez also indicates the technology for using green hydrogen will only get better in the next ten years, making Mr. Games' proposed option to later make investments enabling these CTs to use a hydrogen blend an option that will likely be made irrelevant when overtaken by other technologies.

Q: What about the time involved for CEIS to go back and re-present a natural gas conversion for the A.B. Brown Units?

A: As Mr. Alvarez analyzed and discussed, CEIS already had the studies performed that are needed to move forward quickly with gas conversion. Further, Ms.

Armstrong explains gas conversion will qualify for the same air permits and emissions netting benefits as new gas CTs.

Q: Why shouldn't CEIS take advantage of the recently enacted Indiana law allowing it to securitize the undepreciated plant balance for the A.B. Brown facility?

A: While securitization does provide a benefit and appears to be a useful tool, it is the OUCC's conclusion that consumers are better off by continuing to utilize the A.B Brown units by converting them to burn gas and consequently not using securitization at this time. Retiring the A.B. Brown units would lock CEIS' customers into a long-term relationship with a fuel and a generation technology that may be usurped in the near future. The benefits afforded by securitization do not overcome the risk of investing in a high capital cost facility at this time.

Q: What do you conclude and what is the OUCC's recommendation in this case?

A: Based on my analysis, the most prudent course of action and the OUCC's recommendation is to deny CEIS' request for a CPCN to construct the proposed CTs in this Cause. While I understand the Commission cannot order CEIS to come back with a proposal to convert its A.B. Brown facility to use natural gas, it would be useful for the Commission to point CEIS in that direction. Gas conversion will minimize capital outlays for CEIS customers, provide the dispatchable capacity CEIS indicates it needs, and provide the flexibility needed by a small utility that minimizing immediate capital outlays can provide.

Q: Does this conclude your testimony?

A: Yes.

APPENDIX A - QUALIFICATIONS OF PETER M. BOERGER, PH.D.

Q: Please summarize your professional background and experience.

A: My undergraduate education consisted of a Bachelor of Science degree in Mechanical Engineering from the University of Wisconsin-Madison and a Bachelor of Arts degree in Physics from Carthage College, through its 3-2 engineering program. The extra year of liberal arts study during my undergraduate career allowed me to take significant coursework in business and economics, including courses in microeconomics, macroeconomics and accounting. After working as an engineer at a manufacturing company, my graduate training began at Purdue University (West Layette campus) in a program of Technology and Public Policy, resulting in a Master of Science in Public Policy and Public Administration. My training there included courses in microeconomic theory, cost-benefit analysis, operations research (cost minimization algorithms as might be used in utility economic optimization programs), and policy analysis. I came to Indianapolis and worked doing research and analysis at Legislative Services Agency and later at the Indiana Economic Development Council. Following those stints, I began working on my Ph.D. at Purdue University (West Lafayette campus) in Engineering Economics through Purdue's School of Industrial Engineering. That program required taking Ph.D.-level microeconomics classes, as well as additional work in operations research. During my time there I taught a 300-level engineering economy class for three semesters. While finishing my doctoral thesis I worked in policy research for the Indiana Environmental Institute in Indianapolis and then, after obtaining my doctorate, went to work at the Indiana Office of Utility Consumer Counselor, starting as an economist in the Economics and Finance Division. During my 8 years there, I rose to Assistant Director of the Electric Division and then Director of that Division. In 2005 I left the Agency to pursue other interests, largely outside of utility regulation, and then returned in November of 2015 to work in my current position as a senior economist in the Electric Division, with the formal title of Senior Utility Analyst.

Q: Please describe your duties and responsibilities at the OUCC.

A: I review petitions submitted to the Commission for their economic justification and perform other duties as assigned by the Agency.

Q: Have you previously testified before the Commission?

A: Yes, I have testified before the Commission in several significant cases during the 1997 to 2005 timeframe. I also recently submitted testimony in several proceedings since my return to the agency.

Cause No. 45564
OUCC
CONFIDENTIAL Attachment PMB-1

CASE MIS No.: RP-115797-05

Part III

Administrative, Procedural, and Miscellaneous

26 CFR 601.105: Examination of returns and claims for refund, credit, or abatement; determination of correct tax liability.
(Also: Part 1, §§61, 451, 1001)

Rev. Proc. 2005-62

SECTION 1. PURPOSE

This revenue procedure sets forth the manner in which a public utility company may treat the issuance of a financing order by a State agency authorizing the recovery of certain specified costs incurred by the utility and the securitization of the rights created by that financing order.

SECTION 2. BACKGROUND

Revenue Procedure 2002-49, 2002-2 C.B. 172, provides a safe-harbor regarding the treatment of legislatively authorized transactions entered into by investor-owned electric utilities to recover transition costs resulting from the restructuring of the electric utility industry and the institution of a competitive marketplace. Some States enacted legislation to allow the recovery of these transition costs through a non-bypassable surcharge to customers within a utility's historic service area.

Utilities continue to operate in wholly or partially regulated environments and maintain exclusive distribution networks for customers in their historic service areas. Rates charged for these operations are determined by local authorities to allow for the recovery of costs and an appropriate return on capital. Some States have enacted legislation that allows utilities to recover certain specified costs through a surcharge based on consumption by customers within the utilities' historic service areas and also authorizes securitization of the surcharge. These statutes are unique to regulated utilities. Accordingly, the tax treatment allowed by this revenue procedure for these transactions is peculiar to this situation. See Revenue Procedure 2005-61, page **[INSERT PAGE NUMBER]**, this Bulletin, which adds certain related issues to areas in which rulings or determination letters will not be issued.

SECTION 3. CHANGES

The scope of Revenue Procedure 2002-49 was limited to transition costs that resulted from the deregulation of the generation operations of electric utility companies.

This revenue procedure expands the scope of Revenue Procedure 2002-49 to all public utility companies, and costs that are recoverable through a securitization mechanism are not limited to transition costs. Additionally, this revenue procedure eliminates certain requirements in section 4.04(3) of Revenue Procedure 2002-49 relating to level payments and now requires that payments be made on a quarterly or semiannual basis.

SECTION 4. SCOPE

This revenue procedure applies to investor owned public utility companies that, pursuant to specified cost recovery legislation, receive an irrevocable financing order from an appropriate State agency that determines the amount of certain specified costs the utility will be permitted to recover through qualifying securitization of an intangible property right created by the special legislation.

SECTION 5. DEFINITIONS

.01 PUBLIC UTILITY

For purposes of this revenue procedure, the terms "public utility" or "utility" refer to any investor owned utility company (electric or non-electric) that is subject to the regulatory authority of a State public utility commission or other appropriate State agency.

.02 SPECIFIED COST RECOVERY LEGISLATION

For purposes of this revenue procedure, specified cost recovery legislation is legislation that—

(1) Is enacted by a State to facilitate the recovery of certain specified costs incurred by a public utility company;

(2) Authorizes the utility to apply for, and authorizes the public utility commission or other appropriate State agency to issue, a financing order determining the amount of specified costs the utility will be allowed to recover;

(3) Provides that pursuant to the financing order, the utility acquires an intangible property right to charge, collect, and receive amounts necessary to provide for the full recovery of the specified costs determined to be recoverable, and assures that the charges are non-bypassable and will be paid by customers within the utility's historic service territory who receive utility goods or services through the utility's transmission and distribution system, even if those customers elect to purchase these goods or services from a third party;

(4) Guarantees that neither the State nor any of its agencies has the authority to rescind or amend the financing order, to revise the amount of specified costs, or in any way to reduce or impair the value of the intangible property right, except as may be contemplated by periodic adjustments authorized by the specified cost recovery legislation;

(5) Provides procedures assuring that the sale, assignment, or other transfer of the intangible property right from the utility to a financing entity that is wholly owned, directly or indirectly, by the utility will be perfected under State law as an absolute transfer of the utility's right, title, and interest in the property; and

(6) Authorizes the securitization of the intangible property right to recover the fixed amount of specified costs through the issuance of bonds, notes, other evidences of indebtedness, or certificates of participation or beneficial interest that are

issued pursuant to an indenture, contract, or other agreement of a utility or a financing entity that is wholly owned, directly or indirectly, by the utility.

.03 SPECIFIED COSTS

For purposes of this revenue procedure, specified costs are those costs identified by the State legislature as appropriate for recovery through the securitization mechanism of the specified cost recovery legislation.

.04 QUALIFYING SECURITIZATION

For purposes of this revenue procedure, a qualifying securitization is an issuance of any bonds, notes, other evidences of indebtedness, or certificates of participation or beneficial interests that—

(1) Is secured by the intangible property right to collect charges for the recovery of specified costs and such other assets, if any, of the financing entity that is wholly owned, directly or indirectly, by the utility;

(2) Is issued by a financing entity that is wholly owned, directly or indirectly, by the utility that is initially capitalized by the utility in such a way that equity interests in the financing entity are at least 0.5 percent of the aggregate principal amount of the non-equity instruments issued; and

(3) Provides for payments on a quarterly or semiannual basis.

SECTION 6. APPLICATION

.01 The utility will be treated as not recognizing gross income upon—

(1) The receipt of a financing order that creates an intangible property right in the amount of the specified costs that may be recovered through securitization;

(2) The receipt of cash or other valuable consideration in exchange for the transfer of that property right to a financing entity that is wholly owned, directly or indirectly, by the utility; or

(3) The receipt of cash or other valuable consideration in exchange for securitized instruments issued by the financing entity that is wholly owned, directly or indirectly, by the utility.

.02 The securitized instruments described in Section 5.04 will be treated as obligations of the utility.

.03 The non-bypassable charges are gross income to the utility recognized under the utility's usual method of accounting.

SECTION 7. EFFECT ON OTHER DOCUMENTS

This document modifies, amplifies, and supersedes Rev. Proc. 2002-49.

SECTION 8. EFFECTIVE DATE

This revenue procedure is effective **[INSERT DATE THIS DOCUMENT IS PUBLISHED IN THE INTERNAL REVENUE BULLETIN.]**

SECTION 9. DRAFTING INFORMATION

The principal author of this revenue procedure is Thomas M. Preston of the Office of Associate Chief Counsel (Financial Institutions & Products). For further information regarding this revenue procedure contact Mr. Preston at (202) 622-3970 (not a toll free call).

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.

Peter M. Boerger, Ph.D
Senior Utility Analyst
Indiana Office of Utility Consumer Counselor
Cause No. 45564
CenterPoint Energy Indiana South

November 19, 2021

CERTIFICATE OF SERVICE

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

P. Jason Stephenson
Heather Watts
Matthew A. Rice
Michelle D. Quinn
CENTERPOINT ENERGY SOUTH
Jason.Stephenson@centerpointenergy.com
Heather.Watts@centerpointenergy.com
Matt.Rice@centerpointenergy.com
Michelle.Quinn@centerpointenergy.com

CAC
Jennifer A. Washburn
Reagan Kurtz
Citizens Action Coalition
jwashburn@citact.org
rkurtz@citact.org

Sierra Club
Tony Mendoza
Megan Wachspress
SIERRA CLUB
tony.mendoza@sierraclub.org
megan.wachspress@sierraclub.org
Kathryn A. Watson
KATZ, KORIN, CUNNINGHAM
kwatson@kcclegal.com

Nicholas Kile
Hillary Close
Lauren Box
BARNES & THORNBURG LLP
nicholas.kile@btlaw.com
hillary.close@btlaw.com
lauren.box@btlaw.com

Sunrise Coal
Robert L. Hartley
Darren A. Craig
Carly J. Tebelman
FROST BROWN TODD LLC
rhartley@fbtlaw.com
dcraig@fbtlaw.com
ctebelman@fbtlaw.com

Industrial Group
Todd A. Richardson
Tabitha L. Balzer
LEWIS & KAPPES, P.C.
TRichardson@Lewis-Kappes.com
TBalzer@Lewis-Kappes.com

Lorraine Hitz

Lorraine Hitz, Attorney No. 18006-29
Deputy Consumer Counselor

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
115 West Washington Street, Suite 1500 South
Indianapolis, IN 46204
infomgt@oucc.in.gov
Lhitz@oucc.in.gov
317.232.2494 – Main
317.232.2775 – Hitz Direct
317.232.5923 – Facsimile