SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
d/b/a CENTERPOINT ENERGY INDIANA SOUTH
(CENTERPOINT INDIANA SOUTH)

IURC CAUSE NO. 45564

DIRECT TESTIMONY
OF
WAYNE D. GAMES
VICE PRESIDENT POWER GENERATION OPERATIONS

ON

DESCRIPTION AND SUPPORT FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY, AND REPLACEMENT OF EXISTING INEFFICIENT UNITS

SPONSORING PETITIONER'S EXHIBIT NO. 2 (PUBLIC)

ATTACHMENTS WDG-1 THROUGH WDG-3

DIRECT TESTIMONY OF WAYNE D. GAMES

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Wayne D. Games. My business address is 211 NW Riverside Drive, Evansville, Indiana 47708.

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting testimony on behalf of Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South ("Petitioner", "CenterPoint Indiana South", "CEI South", "CEIS", or "Company"), which is an indirect subsidiary of CenterPoint Energy, Inc.

Q. What is your role with respect to Petitioner?

A. I am Vice President Power Generation Operations.

Q. Please describe your educational background.

A. I received a Bachelor of Arts in Industrial Technology from Ohio Northern University in 1980 and a Master of Arts in Management from Antioch University in 2002.

Q. Please describe your professional experience.

A. I have thirty years of varied experience in the utility industry. I started my career with The Dayton Power & Light Co. in 1991 where I held supervisory, manager, and regional manager titles on the energy delivery side of the business. Upon joining the Company in 2000, I served as Director of Construction and Service and Regional Manager in the Ohio service area. In 2003, I moved to Evansville, Indiana, and accepted responsibility as Director of Petitioner's A.B. Brown Generating Station. I was promoted to Vice President of Power Supply in April of 2011. I was named to my present position in February 2019.

Q. What are your present duties and responsibilities as Petitioner's Vice President Power Generation Operations?

A. I am responsible for the overall budgeting, operation, maintenance, and personnel decisions for Petitioner's electric generation fleet. In addition, I have responsibility for ensuring demand of our customers is met at a reasonable cost through the production and purchase of electric energy (including fuel purchases) necessary to meet the needs of our jurisdictional customers. I am responsible for completing these functions while ensuring compliance with the environmental requirements of all applicable regulatory or governmental agencies. As part of overseeing CenterPoint Indiana South's generation assets, I supervise personnel providing cost inputs to the modeling associated with the Integrated Resource Plan ("IRP") process and have reviewed the modeling results and the risk evaluation set forth therein.

Q. Have you previously testified before the Indiana Utility Regulatory Commission ("IURC" or "Commission")?

A. Yes. I regularly testify in the Company's fuel adjustment clause ("FAC") proceedings and in the related sub-dockets in Cause No. 38708. I have also provided testimony before the Commission in support of Petitioner's Mercury and Air Toxics Standards ("MATS") compliance filing in Cause 44446; Petitioner's Certificate of Public Convenience and Necessity ("CPCN") for a Combined Cycle Gas Turbine ("CCGT") and F.B. Culley Federal Mandate Compliance Project filing in Cause No. 45052; and Petitioner's A.B. Brown Federal Mandate Compliance Project filing in Cause No. 45280. I have also provided testimony in support of the Company's proposal to construct solar facilities in Causes No. 44909 and 45086. And most recently I testified in Cause No. 45501 in support of Petitioner's request: (i) for a CPCN to purchase and acquire, indirectly through a Build Transfer Agreement ("BTA"), a solar facility in Posey County, Indiana; and (ii) to enter into a Power Purchase Agreement ("PPA") to purchase energy and capacity from a 100 megawatts alternating current ("MWac") solar project in Warrick County, Indiana.

Q. Are you sponsoring any attachments in this proceeding?

A. Yes. I am sponsoring the following attachments in this proceeding:

- Petitioner's Exhibit No. 2, **Attachment WDG-1**: CT Project Schedule
- Petitioner's Exhibit No. 2, **Attachment WDG-2:** Dry Fly Ash Project Schedule
- Petitioner's Exhibit No. 2, **Attachment WDG-3:** F.B. Culley and A.B. Brown CCR-Compliant Pond Schedules

Q. Were the attachments identified above prepared or assembled by you or under your direction or supervision?

A. Yes. It is important to recognize, however, that other CenterPoint Indiana South employees and consultants with specific areas of expertise engaged by the Company were involved in the process of these studies. I served the role of overseeing the project's planning process.

Q. What is the purpose of your testimony in this proceeding?

A. I describe and provide support for Petitioner's request for a CPCN to construct two natural gas combustion turbines ("CTs") on available property at its A.B. Brown Generating Station. My testimony describes CenterPoint Indiana South's current generation fleet, including challenges facing that fleet; and explains the options explored by the Company to address generation needs. My testimony explains the impact the addition of two CTs will have on the Company's current generation fleet and the basis for cost estimates for the CTs. I describe the Company's construction of new dry fly ash handling facilities to allow compliance with federal regulations and enable completion of the Brown ponded ash closure project approved in Cause No. 45280. My testimony also describes the installation of two new ponds to comply with the Coal Combustion Residuals Rule ("CCR") Part A Rule: one at Brown and one at Culley ("CCR-compliant Ponds"). Finally, I describe why the proposed projects are in the public interest and support the Company's request for ongoing Commission review.

II. <u>CENTERPOINT INDIANA SOUTH'S CURRENT GENERATION RESOURCES</u>

Q. Please describe the generation portfolio that CenterPoint Indiana South currently operates.

A. CenterPoint Indiana South's current generation mix, shown in Table WDG-1 below, has a heavy reliance on coal generation. Of its total 1,329 MWs of installed capacity, over 78%, or 1,032 MWs of CenterPoint Indiana South's generation portfolio consists of coal-fired generation, which includes 32 MWs associated with a 1.5% ownership in the Ohio Valley Electric Cooperative ("OVEC") and 150 MWs associated with 50% ownership in Warrick Unit #4 operated by Alcoa Power Generating, Inc. ("Alcoa"). The portfolio also contains

160 MWs of natural gas peaking generation, 54 MWs of solar, 3 MWs of landfill gas, 1 MW of battery storage and two wind Purchase Power Agreements ("PPA") totaling 80 MWs. Because renewables receive a much smaller capacity credit from Midcontinent Independent System Operator ("MISO"), coal makes up 83% of CenterPoint Indiana South's MISO accredited capacity. In an average year coal makes up over 94% of energy produced.

Table WDG-1: Petitioner's Current Generation Mix

Unit	Installed Capacity ICAP (MW)	Primary Fuel	Year Unit First In-service
A.B. Brown 1	245	Coal	1979
A.B. Brown 2	245	Coal	1986
F.B. Culley 2	90	Coal	1966
F.B. Culley 3	270	Coal	1973
Warrick 4[1]	150	Coal	1970
OVEC[2]	≈32	Coal	1950's-1960's
A.B. Brown 3 SCGT	80	Gas	1991
A.B. Brown 4 SCGT	80	Gas	2002
Blackfoot	3	Landfill Gas	2009
Benton County PPA	30	Wind	2008
Fowler Ridge PPA	50	Wind	2009
Oak Hill Solar	2	Sun	2018
Volkman Solar[3]	2	Sun	2018
Troy Solar	50	Sun	2021

Q. How does the relief requested in Cause No. 45501 impact CenterPoint Indiana South's existing generation fleet?

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[1] Warrick 4 is a 300 MW unit co-owned with Alcoa Power Generating, Inc. The identified net output represents CEI South's 50% ownership in the unit.
[2] OVEC has over 2,000 MW of coal-fired generation. The identified output represents CEI South's 1.5% share of net output.
[3] The Volkman site includes 1 MW of battery storage.

A. The relief sought in Cause No. 45501 was the first step in CenterPoint Indiana South's Generation Transition Plan, which requires an initial step of identifying and selecting 700 – 1000 megawatts of alternating current ("MWac") of solar generation, 300 MWac of wind generation, and approximately 460 MW of natural gas Combustion Turbine generation. Assuming the relief requested in Cause No. 45501 is approved, CenterPoint Indiana South would add a photovoltaic electric generating facility with aggregate nameplate capacity of approximately 300 MWac in Posey County, Indiana ("Posey County Solar Project") to its generation portfolio. The Posey County Solar Project is scheduled to be operational during the second half of 2023. Similarly, if the relief requested in Cause No. 45501 is approved, CenterPoint Indiana South would purchase energy and capacity from a 100 MWac solar project in Warrick County, Indiana ("Warrick County Solar Project"), which is scheduled to be operational during the second half of 2023.

The addition of the Posey County and Warrick County Solar Projects would allow CenterPoint Indiana South to replace most of the capacity provided by F.B. Culley 2 and Warrick Unit #4. F.B. Culley 2 is Petitioner's oldest, smallest (90 MWs) and least efficient (12,500-13,000 BTU/kWh) coal unit. Warrick Unit #4 is the worst performing unit in Petitioner's fleet over the 2016 – 2019 period with an annual Equivalent Forced Outage Rate of over 16 percent; and based on annual O&M cost per MWh of capacity, the most expensive unit to operate among the CenterPoint Indiana South coal units. Moreover, its long-term outlook is uncertain given Alcoa can unilaterally exit the Joint Operating Agreement ("JOA") for Warrick Unit #4 with notice. Thus, assuming the relief in Cause No. 45501 is granted, the 240 MW of capacity shown on the above table as being provided by F.B. Culley 2 and Warrick Unit #4 will be replaced with the combined 400 MWac of installed capacity provided by the Posey and Warrick County Solar Projects.

Absent these two Solar Projects, CenterPoint Indiana South would need to turn to the market to purchase additional capacity in the 2024 to 2025 timeframe, which would expose customers to the risk of market prices. Further, as Petitioner's Witness Matthew A. Rice will discuss in greater detail, even with approval of the Posey and Warrick County Solar Projects, additional capacity is needed, which is why CenterPoint Indiana South has filed this proceeding.

Q. Why file this request while Cause 45501 is pending before the IURC?

A. The CTs proposed in this proceeding, combined with the Posey and Warrick County Solar Projects proposed in Cause No. 45501, will fulfill the initial step outlined in Petitioner's Generation Transition Plan of obtaining approximately 400 MWac of solar generation and 460 MW of natural gas generation. Timing is important since a generation transition period can take a minimum of 3.5 years, depending on project selection, the MISO Interconnection Queue process, site permitting, and various other factors. As discussed in more detail by Petitioner's Witness Rice, there will be a period between the retirement of the Company's coal generation units and the new generation coming online where the Company will need to rely on the capacity market and the wholesale energy market. Therefore, we filed this proceeding on the heels of Cause No. 44501 to minimize the volume and time period of this reliance.

Q. How have CEI South's coal plants historically been operated?

A. CEI South's coal plants have historically been operated as base load units. Base load units are designed and operated to satisfy the minimum level of demand on an electric grid during an average day. Consequently, these facilities were designed and built to operate around the clock reliably and efficiently with stable output to meet customers' electric needs. For decades, CEI South's coal facilities were the most economical option for electric generation and the first to dispatch and produce on a regular basis.

Q. Have there been changes in the way these coal units operate in the past ten to fifteen years?

A. Yes. These plants were originally built with the purpose of reliably serving the electric needs of CEI South's customers and utilized Indiana coal as fuel for the units. For years, the abundance of low-cost coal mined locally in Indiana made these plants very competitive. However, plant costs began to rise as environmental regulations required investment in environmental control equipment and incremental variable costs to operate this equipment. The market in which these facilities operate also began to change. Indiana electric utilities, with encouragement from the Commission and the Federal Energy Regulatory Commission ("FERC"), transferred operation of their transmission facilities to a Regional Transmission Operator ("RTO") — MISO for CEI South. In 2005, MISO began operating an energy market that has significantly impacted the operation of CEI South's generation fleet.[4]

Q. Please describe the MISO energy market.

A. The purpose of MISO's energy market is to dispatch the lowest cost generation within the MISO footprint required to maintain system reliability, giving MISO members the lowest cost energy available. As a member of MISO, CEI South, like all MISO members, projects and submits its hourly energy needs and offers 100% of available generation for each hour of each day throughout the year into this market. MISO collects all load projections and monetary energy offers and after ensuring the grid reliability is maintained, dispatches the lowest cost generation facilities to meet the projected system needs for each hour of the day. At the beginning of the MISO market, coal-fired generation was often the lowest cost generation in the MISO region and was frequently dispatched. However, falling natural gas prices, efficient gas turbines, and the growth of renewable resources have changed how CEI South's coal-fired generation facilities are operating in MISO.

Q. How have the growth of renewable resources impacted MISO's dispatch?

A. The dispatch of renewable resources has changed the generation stack within MISO. The Production Tax Credit ("PTC") for wind incents operators of these facilities to offer generation into the market at very low to negative prices or designate them as must run resources because the tax credits are earned only if the facilities are operating. The Investment Tax Credit ("ITC") incentivizes the build of solar facilities. Once the capital is invested in solar which has zero fuel costs, they can be offered at very low prices or as must run generation. Of course, these facilities only generate energy whenever the wind or sun allows. This means that wind and solar resources are dispatched before other forms of generation unless curtailment of renewables is necessary to ensure the reliability of the grid. Due to the intermittency of wind and solar, fossil-fuel based resources are left to balance the system when the output of the renewable resources changes (for example, when the wind subsides, or cloud cover blocks the sun). This impacts the dispatch of CEI South's coal-fired generation units causing them to cycle up and down throughout the day and increases the frequency of stop and start cycles throughout the year. As mentioned earlier, coal units were designed to run continuously. The frequent cycling affects unit

[4] In my view, this addresses the interchange of power and pooling of facilities contemplated by IC 8-1-8.5-4(1)(A)&(B).

efficiency; and the thermal contraction and expansion of large masses of metal causes wear and tear, increased maintenance, and shortens life.

Q. How has the reduction in natural gas costs impacted MISO's dispatch?

A. The dramatic decline in the price of natural gas has enabled newer, more efficient natural gas-fired generation to operate at a lower cost than coal-fired generation. During periods of low electric demand, more efficient gas plants are often dispatched by MISO rather than coal-fired generation. Compared to coal-fired base load generation, these units also can ramp output up and down quickly and are built for more efficient off/on cycling.

Gas combustion turbines also inherently produce fewer regulated air emissions. CEI South has had to make significant investments in environmental controls to enable its coal-fired facilities to operate within environmental requirements. CEI South has traditionally been proud of its environmental record and the fact that its coal fleet is one of the cleanest in the mid-west; 100% controlled for sulfur dioxide ("SO_2"), 90% controlled for nitrogen oxide ("NOx"), in compliance with mercury ("Hg") and particulate emission standards and controlled for sulfuric acid ("H2SO4"). CEI South also recycles fly ash and gypsum by-products for beneficial re-use in cement and wall board manufacturing. However, the operating costs associated with the emission control systems impose additional operating costs on the coal-fired units as compared to gas-fired and renewable generation.

Q. How have these factors impacted CEI South's coal-fired generation facilities?

A. Together, these factors have made the coal-fired units less competitive, reducing their dispatch rates. The impact varies depending on the age, efficiency, and condition of the coal-fired generation unit. For example, our best unit, F.B. Culley Unit 3, has a more favorable dispatch rate than the F.B. Culley Unit 2 or the A.B. Brown units. As reflected in our IRP modeling, these factors will challenge coal units going forward.

Q. How have these factors impacted the operation of CEI South's coal units in the MISO market?

A. The output of CEI South's coal units must frequently be adjusted to follow MISO's Real Time Market 5-minute dispatch instructions, resulting in significant ramping output up and down. In addition, units are periodically cycled off and back on per MISO's Daily Market dispatch instructions. Net capacity factor of the A.B. Brown units has dropped from 77% in 2006 – 2008 to 51% in 2016 – 2020.

Q. Please describe the impacts of frequent cycling of coal units off/on and ramping up/down.

A. The industry is aware that frequently cycling coal units off, and back on, and ramping output up, and down, has long term negative impacts on the equipment in a coal-fired generation facility. A June 3, 2015 U.S. Department of Energy ("DOE") Report on coal-fired generation titled "Impact of Load Following on the Economics of Existing Coal-Fired Power Plant Operations" ("DOE Report") recognizes that "generally an increase in frequent ramping and/or shutdowns decreases the component life through damage caused by creep, fatigue, thermal shock, acid induced corrosion, erosion, and other stresses."[5] A few examples, copied in relevant part from the DOE Report, of major coal-generation components and maintenance issues from cycling are:

- **Coal Pulverizer** – Mechanical wear when cycled at low end of minimum flow rates.
- **Superheater Header & Tubes** – Overheating from low/no-flow of cooling steam (startup) and/or poor combustion gas temperature management causes thermal deformation. Internal ligament cracking. Oxidation and exfoliation from exposing metal to higher temperatures than design.
- **Feedwater Heaters** – Early tube failures due to cool-down and rapid heating during hot/warm startup cycle. Tube grooving at the support plates can occur due to poor water chemistry.
- **Steam Turbine/Generator** – Steam seals may need to be replaced to prevent steam from bypassing rotor stages. [Another] primary concern would be exhaust hood temperatures and ability to control the temperature at low steam flows.
- **Admission Valves** – Throttling increases wear and reduces efficiency.
- **Turbine Rotor** – Reducing startup time and increasing the number of annual start cycles can substantially enhance rotor material degradation, causing rotor failure. This may result in blade loss, spindle fracture, and even fast fracture from a near-bore causing catastrophic failure.
- **LP Turbine Blades** – Solid particle erosion. Impingement of droplets leads to accelerated damage of erosion shields and

[5] U.S. Department of Energy, Office of Fossil Energy, DOE/NETL-2015/1718, Impact of Load Following on the Economics of Existing Coal-Fired Power Plant Operations (2015), p. 7, *available at* https://www.eenews.net/assets/2017/11/21/document_gw_08.pdf.

blade surfaces. LP last stage blade stall flutter at low flow conditions may cause blade vibration, resulting in cycle fatigue.
- **Generator** – Retaining ring and end-turn fatigue that can lead to failure/arcing.
- **Steam Piping** – Thermal stress and fatigue cracking due to temperature fluctuations.
- **FGD Absorber** – Thermal stress and fatigue cracking due to temperature fluctuations.
- **Baghouse** – Wet gas corrosion from operating below acid dew point at low load.
- **FD/ID Fans** – Frequent start/stop of fans increases failure rates, inspection intervals, and motor-fan maintenance.

DOE Report, pages 7 and 8.

A more recent Whitepaper, entitled "Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices", published by the National Association of Regulatory Utility Commissioners ("NARUC") in January 2020 ("NARUC Whitepaper" or "Whitepaper")) states that "coal-fired power plants are operating less frequently in baseload operation, where they provide a constant level of electric output with minimal variation. Instead, they are asked to provide more operational flexibility in response to higher shares of intermittent generating resources, such as wind and solar entering the market."[6] The Whitepaper goes on to discuss how these operational changes and other factors associated with a more flexible operation can have the following effects on coal-fired plants, which are similar to the 2015 DOE Report mentioned above:

- Increased wear-and-tear on high-temperature and high-pressure plant components and associated costs
- Increased wear-and-tear on balance-of-plant components and related costs
- Shorter periods between maintenance time but more prolonged outages
- Decreased thermal efficiency at high turndown levels
- Increased fuel costs due to more frequent and inefficient unit starts, which require start-up fuel
- Difficulties in maintaining optimal steam chemistry leading to accelerated corrosion
- Potential for catalyst fouling on NOx control equipment
- Long-term loss of critical equipment life
- Efficiency losses during startup through synchronization and

[6] Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices, NARUC, January 2020, at p.15, available at: https://pubs.naruc.org/pub/7B762FE1-A71B-E947-04FB-D2154DE77D45.

loading to zero load

- Increased risk of human error in plant operations.[7]

The Whitepaper also looks at the typical start-up and cycling costs for a medium sized coal-fired unit, looking at hot, warm, and cold starts as well as load following down to 36% of capacity. The costs look at O&M and capital, forced outages, start-up fuel, auxiliary power, efficiency loss from low load operation and water chemistry cost and support. The average expected startup costs can range from $225/MW on a hot start to $417/MW on cold starts, on a per start basis spread out among the areas mentioned above.[8]

A.B. Brown unit 1 has experienced the effects of cycling firsthand as Solid Particle Erosion ("SPE") damaged a turbine by-pass valve, allowing foreign particles to enter the turbine and causing a three-month outage and $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. Turbine valves are now being inspected and changed out more frequently to prevent a similar occurrence.

Ramping units up and down also has an impact on efficiency and subsequently the cost to produce power. For example, an A.B. Brown unit operating at low load is approximately 5% less efficient than when operating at full load, which results in an increase in fuel cost on a dollar per megawatt hour ("$/MWHr") basis. Low load operation also increases the FGD chemical cost to remove sulfur dioxide ("SO_2").

The A.B. Brown plant has also experienced an increase in coal pulverizer/mill shaft failures in recent years due to more frequent cycling of coal pulverizers.

Q. Are coal unit challenges unique to CEI South?

A. No. Analysis of data compiled by S&P Global Market Intelligence, shown in Figure WDG-1 below, shows coal units constituting nearly 62 gigawatts ("GW") of capacity have been

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[7] *Ibid*. at 15.
[8] *Ibid.* at 16.

retired nationwide since 2014 with 12 GWs of those located in the MISO footprint.[9]

Figure WDG-1: Coal Retirements Since 2014

Coal retirements by ISO, 2014 through 2025 (MW)

		Future retirements		
ISO/RTO	Retired	Approved	Announced	Total
PJM	18,809	3,133	0	21,942
MISO	12,280	3,891	4,262	20,433
ERCOT	4,973	0	650	5,623
SPP	2,487	0	198	2,685
CAISO	196	1,800	0	1,996
ISO-NE	1,352	385	0	1,737
NYISO	380	0	692	1,072
Outside ISO/RTO*	21,174	8,563	3,374	33,110
U.S. total	**61,649**	**17,771**	**9,176**	**88,596**

Data compiled Jan. 7, 2020.
Retirements are approved when permission has been granted by regulatory bodies and announced pending regulatory approval.
* Includes the potential retirement of the 1,004-MW Victor J. Daniel Jr. plant conditional on the results of a reserve margin plan docket filed before the Mississippi Public Service Commission.
Source: S&P Global Market Intelligence

Another 17.7 GWs has been scheduled for future retirement in the U.S. with an additional 9 GWs likely to be retired. In total, nearly 90 GWs of coal-fired generation have been or is slated for retirement between 2014 and 2025. S&P also noted that "Moody's Investors Service projected coal could make up as little as 11% of U.S. power generation by 2030 based on scheduled and likely coal retirements alone. Similarly, Morgan Stanley projected under a base-case scenario that coal-fired electricity will decline from 27% of the total U.S. power mix in 2018 to just 8% by 2030."[10] Most of this generation is expected to be replaced with renewable and natural gas-fired resources.

Q. Has CenterPoint Indiana South evaluated the merits of continued reliance on coal-fired generation to serve such a large portion of its customers' needs?

A. Yes. Every three years, CenterPoint Indiana South prepares an Integrated Resource Plan ("IRP"). Our last two IRP's, finalized in 2016 (the "2016 IRP") and 2020 (the "2019/2020 IRP"), concluded that replacing most of our coal units is the best option for CEI South

[9] Duquiatan, Anna, et al., "US power generators set for another big year in coal plant closures in 2020," SNP Global Market Intelligence, January 13, 2020, *available at* https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/us-power-generators-set-for-another-big-year-in-coal-plant-closures-in-2020-56496107.
[10] *Id.*

customers. To maintain diversity and flexibility, CenterPoint Indiana South has chosen not to immediately retire F.B. Culley Unit 3 coal facility in 2023 as is planned with A.B. Brown units 1 & 2. Not immediately retiring F.B. Culley 3 provides a future off-ramp as suggested by the Commission since Culley Unit 3 will be capable of meeting approximately 24% of Petitioner's peak load and can be retired in the future, allowing its capacity and energy to be replaced by whatever technology makes sense at the time. This could be additional solar or wind; additional combustion turbines that burn clean hydrogen; adding a Heat Recovery Steam Generator ("HRSG") to the two proposed CTs; or adding batteries, small nuclear plants or an innovative technology that has not yet been thought of or developed.

Q. Earlier it was stated that the purpose of the CTs was to replace a portion of the capacity provided by the A.B. Brown coal units. Please explain.

A. CenterPoint Indiana South plans to retire all coal units except for F.B. Culley Unit 3. Cause No. 45501 proposed replacing a portion of the capacity supplied by F.B. Culley Unit 2 and Petitioner's 50% share of Warrick Unit #4 with 400 MWs of solar (initially 200 MWs of MISO accredited capacity). The two CTs totaling approximate 460 MWs would replace a portion of the current 490 MWs of dispatchable coal generation at the A.B. Brown plant. The remainder of the capacity need is currently planned to be supplied by additional solar and wind in a future request. This 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.

Q. Did the IRP call for the retirement of the A.B. Brown coal units?

A. Yes. The previous two IRPs identified that the retirement of the two A. B. Brown units was in the best interest of the customers. Witness Rice explains the details of how the IRP was conducted and the final outcome of the Preferred Portfolio.

Q. Please briefly discuss some of the operational considerations that were taken into account when conducting the IRP and choosing the Preferred Portfolio.

A. The primary purpose of the IRP is to determine the optimum generation portfolio to serve the customer. This requires balancing the obligation and requirement to reliably serve customer demand on a 24/7/365 basis and providing energy at a reasonable cost. The following list is not all inclusive, but some other factors that were taken into consideration when determining the future generation portfolio include:

- Diversity – having a reasonable balance of resources that includes renewables, natural gas and coal. A diverse portfolio is important in meeting customer needs and keeping the economy moving and customers safe and comfortable.
- Economic Growth – retaining current business while attracting new businesses by supplying renewable and low carbon generation to help current and new industrial and commercial customers meet renewable goals.
- Dispatchability – having adequate dispatchable resources that can start and ramp quickly to ensure reliable and cost-effective service at times when intermittent resources are not available and/or market prices are high.
- Future Off-Ramps – maintaining F.B. Culley Unit 3, CEI South's largest and most efficient coal unit, offers a future off-ramp to be replaced with low carbon dispatchable, reliable and more affordable options such as batteries, green hydrogen, or small nuclear.
- Environmental Exposure – limit CEI South's exposure to future environmental requirements related to air and water emissions.

III. CENTERPOINT INDIANA SOUTH A.B. BROWN UNITS

Q. How do CEI South's A.B. Brown units 1 & 2 compare with other coal units within Indiana?

A. The A.B. Brown units 1 & 2 at a net 245 MWs each are among the smaller, least efficient coal units remaining in the state. As a result, they will be one of the last to be dispatched by MISO; and capacity factors will continue to decline. Lower capacity factors likely result in increased cycling and when operating, higher fixed costs and variable costs per MWHr produced. The figures below (Figures WDG-2 and WDG-3) show how the A.B. Brown units 1 & 2 compare in size and heat rate among other Indiana coal units.

Figure WDG-2: Nameplate Capacity of Indiana IOU Coal Units

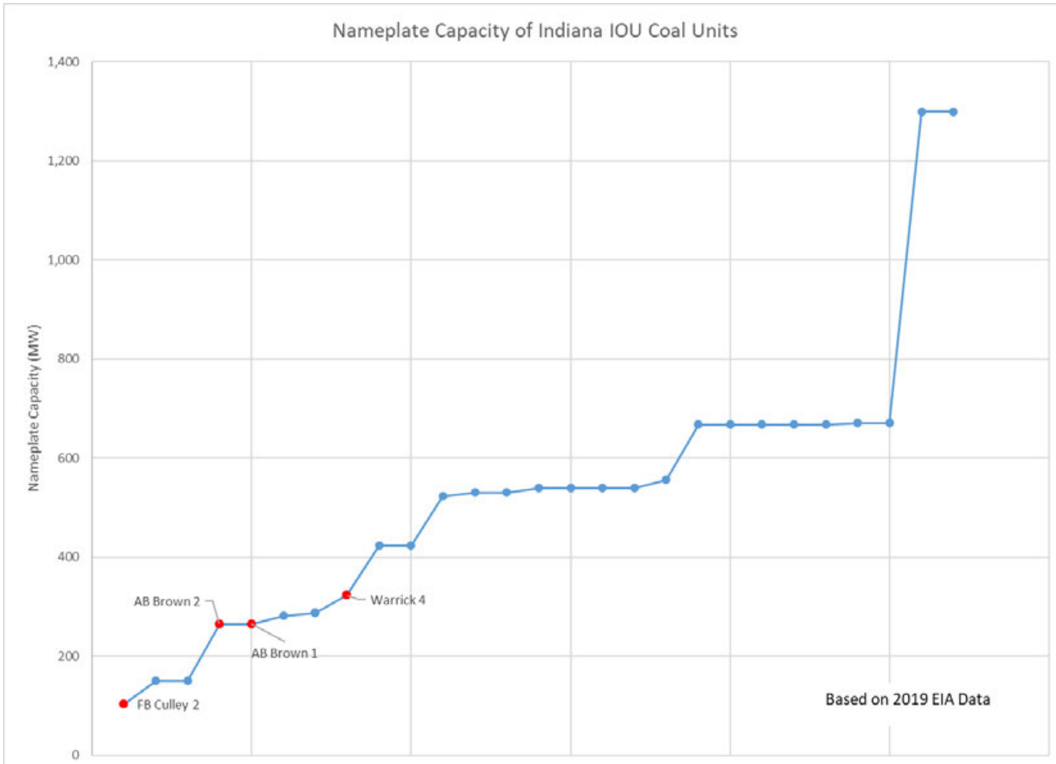
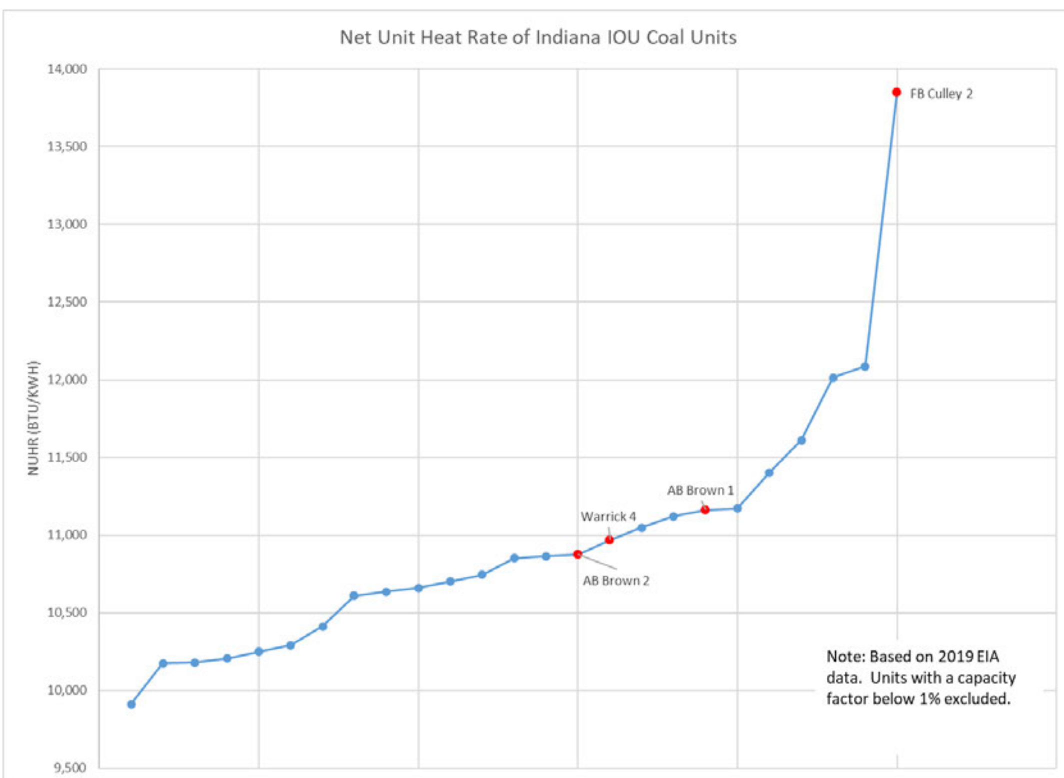


Figure WDG-3: Net Unit Heat Rate of Indiana IOU Coal Units



Q. Are there unique challenges faced by CEI South's A.B. Brown 1 & 2 Generating Units?

A. Yes. As is being described by Witness Retherford, and as I will detail further later, without substantial upgrades (approximately $150 million), these units cannot be operated past 2023 due to environmental regulations. Beyond that fundamental problem, however, the units present several unique challenges. First, A.B. Brown units 1 & 2, though the newest coal plants in CEI South's coal fleet, are not designed to support a high renewable portfolio. As mentioned earlier, coal units like A.B. Brown were built to run continuously and given the time required to bring these units on-line and producing energy – approximately 8 hours for a hot start and 16-24 hours for a cold start – A.B. Brown units 1 & 2 do not provide the flexibility required to reliably provide the back up for a large renewable portfolio in an economic manner. Then, once on-line, the A.B. Brown units 1 & 2 can only safely ramp load up or down at a rate of about 3 MWs per minute.

Second, and one of the biggest challenges, is the condition of the original Dual Alkali FGD/Scrubber systems that were installed on A.B. Brown units 1 & 2 when the plants were built in 1979 and 1986 for the purpose of removing SO_2 from air emissions. The utility industry abandoned Dual Alkali scrubbing years ago; and it is believed the two Dual Alkali scrubbers, one each on Petitioner's A.B. Brown units 1 & 2, are the only two active Dual Alkali scrubbers remaining in operation on generating facilities in the United States. These scrubbers have high operation and maintenance costs, are slow to react compared to other scrubbing options, and create a corrosive environment that impacts other plant equipment and facilities. Over the past 10 years, the Company has spent over $2.7 million annually to reinforce structural steel and other equipment and buildings due to corrosion primarily caused by A.B. Brown's Dual Alkali scrubbers. These costs will continue until these Dual Alkali FGD/Scrubber systems are replaced.

In 2018, an independent consultant completed a condition assessment on the two A.B. Brown scrubbers and concluded the Dual Alkali scrubbers have an expected life cycle of 30 years. Having surpassed the expected useful life of the Dual Alkali scrubbers, and given the then-current condition of the scrubbers, the consultant recommended Petitioner retire both scrubbers within 5-10 years.

Along with the condition of the scrubbers, another big challenge is the impact the original scrubbers have on the plant's operation and maintenance expense. The cost for chemical agents consumed to operate one of the A.B. Brown scrubbers is approximately [redacted] that of the forced oxidation scrubber used for F.B. Culley Unit 3. These chemical agents are trucked long distances creating delivery challenges. For example, during the 2020 Polar Vortex event, Petitioner experienced challenges related to the delivery vendor keeping trucks moving to deliver and maintain adequate inventory of the chemicals for Petitioner to remain in compliance. Next, the chemical solution required to remove SO_2 is stored in an approximate one-million-gallon tank that sits in the open environment, making it difficult to maintain adequate chemistry for efficient and cost-effective removal of SO_2. The chemistry of the solution is also lost due to oxidation with open air environment when the units are idled during outages or on MISO reserve shutdown. Specifically, prior to bringing a unit back on-line, the chemical solution often requires a costly chemical recharge. to ensure adequate potency to remove SO_2. – this process can take up to 24 hours to correct the balance of the chemical solution, which has resulted in compliance issues during unit start up.

Finally, the A.B. Brown Dual Alkali scrubbers produce a waste known as filter cake. Although Petitioner has made several efforts to find a way to beneficially reuse this material, there is currently no cost-effective solution. When the A.B. Brown units 1 & 2 are operating, CEI South employees load dump trucks with the filter cake by-product 24/7 and place the filter cake in an on-site landfill that requires further development and expansion as well as continued maintenance and environmental monitoring. The current developed portion of the landfill is scheduled to run out of space by the end of 2023. As described by Witness Retherford, developing the only remaining permitted landfill location will require a permit modification to comply with the CCR regulations. The development of this area will be much more expensive than previous sections of the landfill due to topography and CCR requirements.

Q. Please explain the process utilized by Petitioner to identify replacement options for the Dual Alkali FGD Scrubbers.

A. 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. In consideration thereof, CEI South employed outside engineering consultants to research options for removal of SO_2 from the stack plumes at the then current required emission rates. Based on their experience and previous work related to scrubbing technologies, Petitioner engaged AECOM, Burns & McDonnell, and Black and Veatch to collectively research and obtain cost estimates for viable scrubbing options. Black & Veatch filtered, and summarized, the information collected. Of eight options considered, four were eliminated due to inability to reliably meet the SO_2 removal requirements.

Q. Please describe the scrubbing options considered.

A. Table WDG-1 (below) shows the eight options researched and four considered for further evaluation. Capital and ongoing operation and maintenance costs were estimated and modeled for the four options as part of the 2019/2020 IRP to determine which was the lowest cost long-term option. This estimated cost was used in the 20-year modeling of continuing to operate A.B. Brown (Business as Usual or "BAU") scenario for the 20-year IRP period. For each of the four viable options, there are different by-products produced that create assorted opportunities as well as safety and storage challenges that were considered. Due to the Commission's feedback regarding not relying on off-system sales of energy, the Company felt it was not prudent to rely on potential by-product sales as part of the decision on future scrubbing technology.

Table WDG-2: Replacement Options Considered for Dual Alkali FGD Scrubbers

Technology Alternative	Technically Feasible (Yes/No)		
	Available	Applicable	Comments
Limestone Conversion of Existing Dual-Alkali FGD – Forced Oxidation (DA-LSFO)	Yes	No	Existing equipment capacity inadequate for conversion. New technology required to meet emissions criteria.
Limestone Conversion of Existing Dual-Alkali FGD – Inhibited Oxidation (DA-LSIO)	Yes	No	Existing equipment capacity inadequate for conversion. New technology required to meet emissions criteria.
Wet Limestone FGD – Forced Oxidation[1] (LSFO)	Yes	Yes	New installations are capable of meeting performance standards.
Wet Lime FGD – Inhibited Oxidation[11] (WLIO)	Yes	Yes	New installations are capable of meeting performance standards.
Spray Dryer Absorber (SDA)	Yes	No	SDA has limited SO_2 removal efficiency over the project range of fuels, which are higher sulfur contents.
Circulating Dry Scrubber (CDS) or Turbosorp	Yes	Yes	Installations comparable in size are in operation. However, no full-scale operational experience is available in the United States over the high sulfur range of the coals used at A.B. Brown.
Flash Dryer Absorber (FDA)	Yes	No	FDA has limited SO_2 removal efficiency over the high range of sulfur in the fuels.
Ammonia Scrubber (NH_3)	Yes	Yes	However, only one small non-coal US industrial application in operation and current interest limited to one Chinese supplier with no US experience.
Powerspan ECO Process	No	No	Only pilot size experience

Q. Please discuss the best option for replacing the Dual Alkali FGD Scrubbers.

A. Based on a combination of cost and risk the Wet Lime Inhibited Oxidation ("WLIO") technology to remove SO_2 from both A.B. Brown units 1 & 2 was determined to be the

[11] Alternate absorber designs in wet lime or limestone FGD (spray tower, double contact spray tower, trays, etc.) are equal for comparison purposes.

best option. The estimated capital cost to replace both scrubbers was modeled at $495 million. A single WLIO scrubber for both units can be installed at an estimated cost of $450 million, Both the $495 million and $450 million estimates are higher than what's listed in B&V's testimony as these costs are inclusive of escalation, A&G, AFUDC, owner's costs and project contingency.

Q. Please describe any challenges with meeting environmental emission requirements at the A.B. Brown facility.

A. The A.B. Brown plant continues to have challenges with meeting aggressive environmental emission limits. In 2019 and 2020, there were 235 hours when the A. B. Brown units operated out of compliance for Particulate Matter (PM), SO_2, or H2SO4 emissions. Because some of these hourly emission requirements are based on a 3-hour period or a 24-hour rolling average (depending on the unit and emission) not all these hours result in an out of compliance issue, however, they are an indication of the continued difficulty of operating within the compliance limits. There are currently 14 permit exceedances associated with A.B. Brown units 1 & 2 in 2019 and 2020 that are under review by the Indiana Department of Environmental Management ("IDEM") that could result in fines. As Petitioner's Witness Retherford discusses, it is anticipated there will be increased challenges and potential fines as environmental regulation for NOx, PM, SO_2 and H2SO4 could continue to ratchet down the volume of allowable emission rates or volumes. Recently the Revised Cross State Air Pollution Rule ("CSAPR") has required a large reduction in seasonal NOx emissions. Current banked seasonal NOx allowances are being required to be surrendered at a ratio of 8 remaining credits to 1 2021 credit. In addition, seasonal NOx allowances will be much lower. Table WDG-3 shows the number and percent reduction of seasonal NOx allowances the A.B. Brown plant will receive in 2021 and 2024 as compared to 2020.

Table WDG-3: Comparison of A.B. Brown Plant NOx Allowances

	2020	2021	2024
EPA Seasonal NO_x Allowances for the A. B. Brown Plant	**675**	**553**	**383**
Percent Reduction from 2020		**18%**	**43%**

Q. How will the reduction on seasonal NOx allowances impact CEI South customers?

A. The reduction on seasonal NOx allowances has placed CEI South in a projected short position, which will require increased cost to either: (a) reduce emissions by adding more layers of catalyst and increasing ammonia injection rates, creating challenges with ammonia slip (excess ammonia that makes its way through the catalyst without reacting with NOx) that plugs air heaters and requires outages and expense for cleaning; (b) reduce the number of hours the units operate during the May – September ozone season, forcing more uneconomic market purchases; or (c) purchase additional seasonal NOx allowances from the market. Since the implementation of the reduced seasonal NOx allowances, the market for allowances has not seen activity. In discussions with Evolution Markets, a broker used for the purchase and sales of Seasonal NOx allowances, it was shared that the current purchase bids are $1,750 with offers to sell at $3,700. Final sales normally fall somewhere in the middle of the bid and offer price. To put this in perspective CEI South purchased 800 2020 Seasonal NOx allowances at $70.00 per allowance. All of these options will result in an increase in customer energy costs.

Q. The A.B. Brown plant has recently been required to control H2SO4 emissions. Has this created any operational issues?

A. Yes. Sodium injection to control H2SO4 emissions has resulted in increased PM readings in the stacks. There are also increased outages and maintenance costs as plugged sodium spray nozzles for H2SO4 control are a constant battle to maintain and operate properly. When these spray nozzles begin to plug, the sodium-reagent does not disperse properly into the gas stream. Instead, it settles into the ductwork causing flow restrictions requiring unit outages and expense to clean and correct.

Q. What other environmental challenges exist with continued operation of the A.B. Brown facility?

A. As I mentioned and as Witness Retherford discusses in more detail, there are several environmental requirements to comply with regulations associated with the ELG, Coal CCR, and Revised CSAPR. It is estimated to cost well over $150 million in capital additions and improvements to remain in compliance while continuing to operate the A.B. Brown units. Each of these investments result in additional O&M expenditures for daily operation and maintenance. These investments would include:

- A Waste-Water Treatment or Zero Liquid Discharge system for any new scrubber technology.

- A Dry Bottom Ash system on each unit with additional cost to properly dispose of the bottom ash.
- Modifications to the Dry Fly Ash system on each unit to pull ash pneumatically from ash collection hoppers. Since ash could no longer be placed in the current ash ponds, additional handling and disposal expense is required. In the event any CCR material would need to be placed into the pond, the pond would need to be modified in a manner that is compliant with the CCR Rule, meeting ongoing operation, recordkeeping, and eventually closure and post closure requirements.
- A new process water pond to provide an adequate water source for daily plant operation. Currently the water comes from the ash pond which will be totally dewatered in preparation for the removal of all ash and clean closure.
- Upgraded water collection ponds to collect and treat various sources of water before leaving the plant site.
- Landfill expansion for scrubber by-product as the current developed landfill is projected to run out of space by the end of 2023. The only permitted landfill space remaining would need to comply with CCR regulations and is very expensive to develop due to the topography of the area.
- Additional catalyst and ammonia cost associated with reducing NOx emission as part of the Revised CSAPR Update.
- If the U.S. Environmental Protection Agency ("EPA") places tighter limits on fine particulate or the one-hour SO_2 limits are reduced, the only known option at this time to address these issues is to spend millions of dollars to add a Wet Electrostatic Precipitator ("ESP").

Plant personnel spend a great deal of time throughout the year focused on the challenges of operating the A.B. Brown units within current air and water compliance limits. Any reduction of the SO2, particulate matter, Hg, NOx, or H2SO4 limits would create additional operational challenges.

Q. Are there other anticipated but unknown environmental expenses expected in the future?

A. Yes. A couple of examples include the requirements and expense associated with any future carbon reduction rule, and any future Pollution Discharge and Elimination Systems ("NPDES") permits controlling water treatment standards. Most believe that carbon emissions will be regulated in some manner in the future. The NPDES permits have continued to be more challenging and costly with each permit renewal. Stringent limits for mercury, copper, selenium, and chlorides have been imposed during the past two permit renewals. The current A.B. Brown permit, which is renewed every five years, is due for renewal in 2022. As discussed earlier, seasonal NOx emissions, particulate matter, and SO_2 emissions will also likely be reduced in the future, creating more challenges for the A.B. Brown units.

Q. What other major expenses are required to continue to operate the A.B. Brown facility?

A. The 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. These overhauls are not part of the current plan since the units are planned to be retired in October 2023. As the coal units age and continue to cycle, there will be several million dollars spent on the boiler, turbine, generator, and balance of plant work. Examples include: boiler tube replacement, turbine overhauls, generator rewinds, cooling tower rebuilds, ESP replacement, air heater basket replacements, condenser tube leak repairs and possible retubing, high energy piping inspection and replacement, Selective Catalytic Reduction ("SCR") catalyst replacement, stack maintenance pump and motor overhauls and replacements.

Q. Did CEI South consider these costs in the 2019/2020 IRP Modeling?

A. Yes. These costs were projected based on historical spend and experience of plant subject matter experts with years of coal plant operation and maintenance experience.

Q. Are there any fuel supply concerns with the continued operation of the A.B. Brown Plant?

A. Yes. CEI South made the decision to install low capital cost mercury control equipment and an H2SO4 control method that [redacted]

[redacted].

Sunrise Coal is currently a sole source supplier to the A.B. Brown Plant and CEI South is approximately 30% of Sunrise Coal's business. With bankruptcies and continued pressure on coal mining due to low gas prices and increased renewables, there is concern Petitioner could lose the primary Indiana coal supplier [redacted].

Q. Have there been any extra expenses incurred related to annual coal costs?

A. Yes. During 2020, CEI South did not have adequate on-site inventory space to store all coal that was contractually required to be accepted. As a result, CEI South was forced to store just over [redacted] in off-site storage at a cost of $[redacted]/ton. To limit the amount of coal placed in off-site storage, CEI South implemented a coal decrement. This process used the cost to store coal off-site to determine the impact on the added cost per MWHr to produce energy at each facility. The energy offer price was then reduced by this much to increase the chance of the units being dispatched thus avoiding placing additional coal into off-site storage. By year end, an additional [redacted] at a cost of $[redacted]/ton. If [redacted] is not accepted in 2021, [redacted]. An additional $[redacted] per ton per month will be charged beginning January 1, 2022 for any remaining tons in off-site storage.

Q. Besides continued operation of the A.B. Brown plant through the 20-year IRP period, what other options did CEI South consider for continuing the operation of A.B. Brown?

A. CEI South obtained cost estimates and modeled converting the A.B. Brown units from burning coal to burning natural gas. In addition, at the request of the Indiana Coal Council ("ICC"), the Company also projected costs and modeled continuing to operate the A.B. Brown Units through 2029 without replacing the Dual Alkali Scrubbers.

Q. Please discuss the results of the evaluation of converting the A.B. Brown units from operating on coal to operating on natural gas.

A. CEI South worked with the A.B. Brown boiler manufacturer Babcock & Wilcox (B&W) as well as Bowen Engineering and Black & Veatch to determine the modifications required and estimated cost to convert the A.B. Brown units 1 & 2 from burning coal to burning natural gas in a safe and reliable manner. Although when compared to other dispatchable options explored, there are lower capital requirements and reduced environmental compliance costs due to the removal of most environmental equipment and not needing to comply with the previously discussed environmental requirements, the modeling did not produce a scenario that out-performed the 2019/2020 Preferred Portfolio. In addition, the coal to gas conversion option does not address the primary need to provide a reliable quick start and fast ramping dispatchable generation to back up the high renewable preferred portfolio. If this option was implemented, the units would serve as gas peaking units. An A.B. Brown coal to gas conversion would require a 16-24 hour start time to be dispatched to serve the market. Although the ramp rate would increase from the current 3MWs/minute on a A.B. Brown coal unit to approximately 6MWs/minute it would fall well short of the 80MWs/minute supplied by the two proposed CTs. A large amount of fuel would be burned just to get the boiler, turbine, and generator heated at the proper rate to begin producing energy. To justify this, the units would likely need to run for an extended period which is unlikely financially justified in the MISO market given the projected heat rate and resulting market offer. This option may make some sense if CEI South had other quick start fast ramping dispatchable energy sources to provide the needed back-up for a high-volume renewable portfolio and this source was only needed to provide capacity to meet the required MISO Planning Reserve Margin ("PRM"), however, this is not the case within CEI South. Although CEI South A.B. Brown Units 3 and 4 ("E" class peaking units that together provide 150-160 MWs) can start in 20-30 minutes and run for a short duration several times per day, they have a limited maximum ramp rate of 7 MWs/minute. In short, conversion would produce a generator that is neither good base load capacity, nor a good peaking capacity.

Q. Please discuss what makes up the cost estimate for the conversion of the A.B. Brown units to operate on natural gas.

A. In order to convert the A.B. Brown coal units to operate on 100 percent natural gas several alterations are required for the boiler and downstream environmental controls, and duct work. Each of the A.B. Brown coal units would require their coal burners to be converted to B&W model XCL-S natural gas burners. Along with the burners, the flame scanners, burner management system ("BMS"), instrumentation, and gas piping would need to be redesigned. The existing pulverizer and primary air fans will need to be taken out of service and their air ducts to the boiler wind boxes isolated. The regenerative air heaters, forced draft fans, and induced draft fans were determined to be reusable without modification. The existing SCR system would remain in place with the addition of an oxidation catalyst layer to treat carbon monoxide ("CO"). Flue gas will continue to flow through the fabric filter ESP; however, modifications to this equipment will be required. The existing FGD absorber towers rely on a continuous flow of absorber liquor to keep the interior liner cool and to prevent fire. Considering the FGD system will not be required to remain in service after natural gas conversion, the absorber towers and associated duct work will have to be removed and new duct work installed from the outlets of the induced draft fans to the inlets of the stacks.

Q. Are there any other requirements or expenses associated with converting the Brown coal units to operate on natural gas?

A. Yes. A larger more costly pipeline than the one required for the two CTs would need to be built, operated, and maintained. In addition, a firm delivery contract to ensure natural gas supply was available when needed would be required.

Q. Would a coal-to-gas conversion have the same or better opportunity to benefit from the ability to burn hydrogen in the future as the proposed CT's?

A. No. Research and development are currently geared towards developing CT technology to efficiently burn hydrogen as CTs have fast start and quick ramping ability to back up intermittent renewables with no carbon output. Burning hydrogen in a coal-to-gas conversion would not help CEI South increase the flexibility or reliability to provide energy to customers in a no carbon electric generating world as quick start fast ramping dispatchable technology would still be required to support the anticipated increase in intermittent renewables. Even if there was a carbon market, unless the cost of producing and storing hydrogen is drastically reduced, or the cost of carbon was extremely high, it would be very costly to burn hydrogen during the long and controlled start-up process.

Q. Please discuss the results of continuing to operate the A.B. Brown units through 2029 without replacing the Dual Alkali Scrubber.

A. Modeling results did not prove to be beneficial to the CenterPoint Indiana South customer as costs were higher than the Preferred Portfolio. CenterPoint Indiana South would still need to invest over $150 million in required environmental capital expenses discussed earlier (Dry Bottom Ash Conversion, Dry Fly Ash Modifications, expanded Landfill, a new Process Water Pond) and a Wet ESP for increased PM control as well as future NPDES and carbon requirements that are not known at this time. In addition, there would be continued capital and O&M expense impacts of unit cycling, turbine and generator overhauls, boiler tube replacement and balance of plant work as well as expense to rebuild and replace certain components of the scrubber to enable their continued safe and reliable operation in addition to continued expense associated with balance of plant equipment and buildings impacted by the corrosion from the Dual Alkali Scrubber chemistry. There would also be continued challenges with operating the units within current and future environmental compliance requirements. Lastly the continued operation of A.B. Brown would create challenges with reliably and cost effectively providing a practical back-up energy source for the high renewable portfolio proposed by the 2019/2020 IRP.

IV. <u>PROPOSED F CLASS COMBUSTION TURBINES (CTs)</u>

Q. Is CenterPoint Indiana South proposing to replace a portion of its coal-fired generation with the two CTs as recommended in its IRP?

A. Yes. Consistent with its 2019/2020 IRP results, CenterPoint Indiana South proposes to retire most of its current coal-fired generation fleet and diversify the generation portfolio by adding two F Class natural gas CTs with an output of approximately 460 MWs to replace the A.B. Brown coal plant. These CTs will support the 700 – 1,000 MWs of solar and solar + storage with 300 MWs of wind, a part of which is currently proposed to replace a portion of the 90 MWs of FB Culley Unit 2 and CenterPoint Indiana South's 150 MWs share of Warrick Unit #4. As defined by the Preferred Portfolio in the IRP, additional renewable resources are planned to be procured in the near future.

Q. Did CenterPoint Indiana South consider natural gas options other than the

proposed F Class CTs to replace A.B. Brown?

A. Yes. CenterPoint Indiana South considered a range of natural gas CT options to include the LM 6,000, LMS100, E Class and G/H class CT technologies ranging in output from 41 MWs to 280 MWs each. In addition, 1x1 F class and H class Combined Cycle Gas Turbine (CCGT) options were evaluated ranging in output from 365 MWs to 420 MWs. A larger 2x1 or 3x1 CCGT was not evaluated based on Commission feedback in Cause No. 45052, our previous CPCN filing, finding these were too large for a utility the size of CenterPoint Indiana South.

Q. What are the characteristics of the CTs CenterPoint Indiana South plans to construct?

A. F Class CTs have been in the market for over 30 years and have a proven history of solid and reliable performance. In recent years, metallurgy has been upgraded to handle multiple starts between maintenance cycles as well as start times shortened to as little as 10 minutes and ramp rates increased to 40 MWs per minute. Together the proposed CTs will be able to ramp at up to 80 MWs per minute. These 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. The heat rates of the proposed F Class turbines are among the most efficient units currently available in this class, and they have the lowest capital cost per kW vs. other new natural gas options evaluated.

Q. Why does CenterPoint Indiana South feel it's important to build two CTs with an output of approximately 460 MWs?

A. These CTs will replace the majority of the 490 MWs of capacity currently provided by the A.B. Brown units 1 and 2. As stated earlier, both A.B. Brown units face several challenges to continue operating and will require several million dollars in capital investments to remain in compliance beyond October of 2023. There are also anticipated challenges and expenses associated with continued operation. As a public utility with the obligation to serve customers on the peak hour of the peak day of the year, CenterPoint Indiana South must hold the capacity to satisfy the MISO PRM requirements imposed on load serving entities. To meet this requirement, it is critical to have reliable and affordable dispatchable technology that receives PRM credit for most of its installed capacity. The CTs should receive capacity credit for approximately 95% of the nameplate output where wind will receive approximately 10% and solar will receive 50% for the first few years then adjusted based on actual performance during specific months of the year and hours of the day.

Q. Why are the dispatchable characteristics specific to the CTs important to CenterPoint Indiana South customers?

A. In the past, dispatchable generation was designed to operate continuously and ramp up and down slowly throughout the day to meet customer demand. States with a high volume of solar are now seeing these dispatchable resources taken off-line as solar is meeting a substantial portion of demand during the sunny days. Once the sun goes down there is a high spike in demand. This demand curve often referred to as the "duck curve" will continue to become more pronounced as more renewables are added to the MISO grid. The dispatchable nature, quick start and fast ramping ability of the proposed CTs allow CenterPoint Indiana South to implement a high volume of renewable energy while still being able to reliably and cost effectively meet customer needs throughout a day, when renewable output is low, or quickly start and produce energy in the early hours of the evening when the sun goes down, and wind turbines are only producing at a fraction of their capability.

Q. Are there other reasons these CTs should be part of the generation portfolio?

A. Yes. There are several reasons:

- Installing utility scale renewable energy is important to our customer base. Petitioner's Witness Harris explains, large customers, current and prospective, are prioritizing communities with diverse, reliable, and affordable energy portfolios commenting many are striving to meet renewable initiatives. Therefore, to satisfy customer expectations, CenterPoint Indiana South must provide sustainable and reliable power (at all hours) to attract and retain such customers and help them meet their Environmental, Social, and Governance ("ESG") initiatives. In addition, Southwest Indiana is an attractive site for industrial expansions and relocations due to access to the Ohio River with ports, a robust rail system, and nearby major highway infrastructure, offering frequent opportunity for economic development activity. The characteristics of the CTs play a critical role in pursuing a portfolio with a high volume of renewable energy to attract customers to Southwest Indiana, spreading CenterPoint Indiana South's fixed cost across a larger customer base and thereby reducing electric costs for all customers.

- The CTs are an affordable option. Gas prices are projected to be low for several years and the plant will have the ability to purchase a competitive gas supply from several suppliers. The IRP modeling identified the F Class CT option as the lowest cost dispatchable generation option for CenterPoint Indiana South customers over the 20-year IRP period.
- The CTs are reliable. As mentioned earlier, F Class technology has been around for over 30 years and is a very mature technology that has few issues. Petitioner's Witness Paula J. Grizzle discusses the dedicated gas line that will be permitted and constructed by Texas Gas Transmission, LLC ("TGT") to serve the plant. CenterPoint Indiana South will hold adequate gas pipeline capacity, a firm gas supply contract, and the ability to withdraw gas supply from a nearby storage field if there are supply issues. A reliable, affordable and dispatchable resource is critical to the safety and health of our customers as well as our local and state economy.
- The 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. In addition, the quick start time reduces the amount of natural gas usage and related emissions during unit start-up as compared to operating on coal or coal-to-gas conversion.
- The dispatchable nature of the CTs allows for the addition of more renewable generation in the future when F.B. Culley Unit 3 is eventually retired.
- If hydrogen becomes affordable, the F Class technology is currently able to burn 5%-10% hydrogen and with modifications can currently burn up to 30% hydrogen, further reducing carbon emissions. GE along with other CT manufacturers are currently conducting research and development efforts with plans to get to 100% hydrogen in the future. There is also the possibility to produce green hydrogen from the nearby 300 MW solar project CenterPoint Indiana South is proposing in Cause No. 45501.
- If gas prices stay low and renewable energy cost and/or siting challenges increase in the future, CenterPoint Indiana South has the option to convert the two F Class CTs

to a CCGT by adding a HRSG that will use waste heat to create steam to power an additional generator increasing efficiency thus supplying lower cost energy.

Q. What steps is CenterPoint Indiana South taking to ensure reliability of the CTs, during the winter and summer months?

A. The proposed CTs will be designed to reliably operate within the extreme low and high ambient temperatures experienced in Southwest Indiana. Enclosures immediately surrounding the CTs will be equipped with space heaters designed to keep the temperature inside the enclosures above 50 degrees Fahrenheit in the winter and adequate ventilation will be installed for cooling in the summer. All piping and piping accessories such as valves are required to be insulated. Piping subject to freezing will also require freeze protection in the form of electric heat trace. Heating Ventilation and Air Conditioning ("HVAC") systems, designed for temperature control of equipment will be required an installed where necessary to ensure the CT's are reliable in extreme weather conditions.

Q. Where is CenterPoint Indiana South proposing to construct the CTs?

A. The Company is proposing to construct the CTs on property it already owns inside its A.B. Brown generating station.

Q. What are the benefits of constructing on the A.B. Brown Site?

A. Building on the A.B. Brown Site provides cost savings advantages for CenterPoint Indiana South's customers and the local economy. Re-using the existing facilities and a portion of equipment will lower the capital investment cost.

- The A.B. Brown Site has a designated entrance road off a main highway and rail access to the location of the proposed facility. This will allow for large sections of the new plant to be moved by rail or truck into the facility with the option to rail large sections from the manufacturing facility directly to the plant.
- The site environmental permitting will provide for emissions netting due to retiring an existing coal plant with higher emissions than the proposed CTs. This opportunity would not be available at a greenfield site. Results of an analysis by Trinity Environmental Consulting ("Trinity") show that the Proposed GE F class CTs can each operate for [redacted]

without exceeding anticipated air permit limits. A copy of a Trinity memo identifying the operating hours and unit starts for each of the three primary CT manufacturers is included in my workpapers.

- The A.B. Brown Site also holds 500 MWs of MISO grid interconnect capacity. The MISO grid interconnect rights at the A. B. Brown site can be transferred from the coal units to the CTs for up to three years after the A.B. Brown coal plants are retired. Other than cost for the MISO interconnect study, there is a minimal risk of any MISO transmission upgrade costs. If the MISO grid interconnect capacity rights expire for the A.B. Brown Site, or generation is built at another location, CenterPoint Indiana South customers will be exposed to the potential for expensive interconnect costs for transmission upgrades associated with any future generation built to serve customers. This expense can be several million dollars.
- The A.B. Brown Site already has black start capability with a diesel generator configured that will black start an existing CT which can then start the new CTs supporting any future grid restoration efforts.
- Lastly the A.B. Brown Site is located within CenterPoint Indiana South's service territory in Posey County, Indiana. Using this site will replace lost property tax base from the retirement of the A.B. Brown units.

Q. What facilities and equipment are CenterPoint Indiana South reusing at the A.B. Brown site for the CTs?

A. CenterPoint Indiana South has worked with Black & Veatch to identify the existing plant equipment that could be re-used with the new CTs. Re-use of this equipment was incorporated in the design and technical specifications for the new CTs. Examples include a maintenance shop, parts storage warehouse, administration building, well reservoir pumping station and storage tanks to supply potable water, water to the plant fire protection system and reverse osmosis system, including storage tanks to supply water to the new evaporative coolers. In addition, the oily waste system, sanitary wastewater system, 138kV and 345kV substations to distribute energy to and from the grid, and two reserve auxiliary transformers to step down grid energy to feed existing 13.8kV and 4kV switchgear to be used for starting the CTs and powering various equipment.

Q. Does the A.B. Brown Site have adequate transmission, water, and gas service for

the CTs?

A. The A.B. Brown Site does have adequate transmission and water service as a result of the A.B. Brown generating facility that is already located at the site. As mentioned earlier, the site contains a 138kV and a 345kV switchyard that directly connects the A.B. Brown Site to the electric grid. The site has a well reservoir with three pumps that provide up to 6,000 GPM for potable water, fire protection system water, and water for the reverse osmosis system to supply the evaporative coolers and other service water requirements. CenterPoint Indiana South completed construction of a 345kV transmission line and switchyard as a MISO Multi Value Reliability Project in 2010 that increases the ability to transmit energy from the A.B. Brown site into the transmission system. As described in the direct testimony of Petitioner's Witness Kenny, a pipeline to be permitted and constructed by TGT will be used to supply the necessary firm natural gas capacity. Petitioner's Witness Rice explains the inclusion of the cost of this pipeline in the IRP modeling.

Q. Are there other benefits to CenterPoint Indiana South's customers by having the CTs interconnected with CenterPoint Indiana South's transmission system?

A. Yes. As mentioned earlier, this allows CenterPoint Indiana South to use the existing MISO interconnect rights currently held by the A.B. Brown location. This avoids the risk of a large expense for transmission upgrades if the CTs were to be constructed at another site. The interconnect rights can only be held for a three-year period and will be lost if not used within that time period. It also avoids the long MISO generation interconnect approval process that can take up to three years and keeps property tax base within the CenterPoint Indiana South service area.

V. <u>COST ESTIMATE, PROCUREMENT PROCESS AND SCHEDULE for CTs</u>

Q. How did CEI South establish a cost estimate for modeling the F Class CTs in the IRP?

A. The cost estimate for F Class CTs, like all other natural gas options, was taken from the Technology Assessment completed by Burns & McDonnell ("B&McD") and used in the modeling scenarios to help determine the Preferred Portfolio. Witness Rice describes the

Technical Assessment in more detail in the IRP discussion.

Q. How did CEI South create a competitive RFP process?

A. CEI South employed consulting firms with areas of expertise needed to develop information that was critical to ensuring a sound process and procedure was in place to get the best CT solution at the best price. These firms included:

- Black & Veatch (B&V) – an engineering and construction firm with CT and EPC experience was hired to help develop a scope of work and project specifications for the RFP and to help evaluate responses to ensure each bidder included necessary information and work task.
- Power Advocate (PA) – a procurement consulting firm CNP frequently uses that specializes in developing and managing a competitive RFP process. In addition to managing the RFP they developed a balanced scorecard and led CEI South through an evaluation process to score and choose the final EPC contractor and provided leadership and guidance in negotiating the final price and project schedule.

Q. What is the cost estimate for two CTs at the Brown site?

A. The current cost estimate is $323 million.

Q. Why do you say this is the current cost estimate?

A. At the time of this filing, the CenterPoint Indiana South and Kiewit were still negotiating the final firm EPC price for the contract and what would constitute a change in the firm EPC price. The majority of the EPC price is firm with items in question related to who would take on the risk and responsibility regarding certain technical related work scope items as well as certain Commercial Terms and Conditions (T&Cs). A couple examples of technical issues to be worked out include who will be responsible for any additional structural foundation work required based on the final Kiewit Geotechnical survey and any rail upgrades Kiewit requires to ensure the CT's can be safely transported across the A.B. Brown rail spur leading into the plant. A few examples of key T&C issues related to risk tolerance to be resolved include indemnification, limitations of liability and consequential damages, definition of material change and excused delays.

Q. How has CenterPoint Indiana South accounted for these potential cost increases?

A. CenterPoint Indiana South worked with B&V to identify technical work scope issues that needed to be resolved and assigned a cost estimate to complete this work. CenterPoint Indiana South also worked with PA to identify T&C risk items where Kiewit and Petitioner were far apart and requested PA to provide a potential cost impact to reach a reasonable consensus and resolution. These dollars were added to CenterPoint Indiana Souths Owner's cost. At some point the final cost impact for resolving these issues will either move to the EPC cost or remain in the Owner's Cost estimate.

Q. Please describe the components of the cost estimate.

A. Table WDG-4 lists the primary cost estimates and total cost estimate for the project.

Table WDG-4: Estimated CT Project Costs

Description	Cost	Make-Up of Costs
EPC Estimate	$188M	Represents the low bid from a competitive bidding process. Includes costs for contractor to engineer, procure and construct 2x0 CT plant using GE 7F.05 CTs. Estimate is inclusive of direct and indirect costs including EPC overhead and profit, escalation, bonding, warranty, and builder's risk insurance.
Owner's Cost	$70M	Includes allowances for owner's project management teams, owner's engineer, support engineering and training, environmental and other permitting activities, legal fees, construction utilities such as power, fuel, and water, regulation and code changes, price escalation, owner's contingency and unresolved technical work scope and T&C items.
Internal Labor and Loadings	$10M	Estimated internal labor and loadings to support the CT project from planning through completion.
Owner's Contingencies	Cost included in owners cost until negotiations are complete	Estimate includes cost risks for all project costs; primarily unforeseen expenses during planning and construction that were not accounted for in the EPC bid or Owner's Costs as well as events such as force majeure, natural disasters, major labor strikes, etc. These project contingency costs are included in the Owners Cost category.
Administrative & General Overheads (A&G) and Allowance for Funds Used During	$35M	A&G (1%) and AFUDC (8%) applied to EPC and Owners costs.

Construction (AFUDC)		
Spare Parts	$8M	Purchase of critical and long lead time spare parts for on-site inventory
Study/Pre-work Costs	$12M	Includes generation transition asset allocation for IRP work (2016-2019) and planning/preparation work conducted from 2019 to CPCN filing in 2021. Includes costs to evaluate available gas turbine technology and EPC contractors as well as evaluate the proper siting for the CT's and determine the applicability of reusable equipment.
Total	**$323M**	Cost are estimates and include projected escalation. CPCN budget estimate does not include costs for construction of new pipeline.

Q. Is this a best cost estimate?

A. Yes. CEI South has gone to great lengths to involve consultants with technical RFP and commercial terms expertise. A competitive bid process was followed, and a fair and comprehensive scoring matrix was developed with several internal and external individuals with various expertise involved in evaluating bids. Regarding items that have not been fully negotiated CEI South has requested and included price estimates provided by external consultants with the appropriate knowledge and experience. Company overhead estimates such as A&G and AFUDC was provided by CEI South Accounting and Finance Departments. B&V assisted with establishing an owner's cost estimate and project contingency.

Q. How does the total cost estimate compare to what was used in IRP modeling?

A. The actual cost estimate of $323 million is consistent with what was modeled in the 2020 IRP for the two F class CTs and was established through a competitive RFP process.

Q. Please describe the RFP process.

A. The first RFP was sent to all three major Original Equipment Manufacturers ("OEM") of CT equipment: OEM Bidder 1, Non-Bidder 1, and OEM Bidder 2, requesting a full turnkey Engineering, Procurement and Construction ("EPC") bid as well as pricing for the direct purchase of major equipment by CEI South. The RFP was also distributed to four potential ("EPC") firms to include Non-Bidder 2, Lump Sum Turnkey ("LSTK") Bidder 1, Non-Bidder 3, and Kiewit Power. The RFP requested bidders to submit a full turnkey EPC bid as well as invited them to submit alternative proposals. EPC bidders provided equipment pricing and detailed bill of quantities to help CEI South understand EPC design and ensure bids were all inclusive and could be compared to determine the best value for CEI South customers.

Q. What was the response from the OEM and EPC bidders?

A. Regarding the three OEM's, one OEM communicated that they were not interested in bidding, leaving two OEM options. Neither of the two remaining OEMs would provide a full turnkey bid stating such was not part of their business model at the time. They did provide a bid to sell the CT equipment directly to CEI South.

Regarding the four EPC bidders, two communicated that they were not in a position to provide a bid at the time. One EPC bidder did provide a full turnkey as well as an Owner Furnished Equipment ("OFE") bid. The other EPC bidder only provided an OFE bid.

Q. How did CEI South respond to only having two EPC bidders and one full turnkey bid?

A. As CEI South preferred a full turnkey bid to reduce final cost and performance risk, CEI South requested that Power Advocate redistribute the RFP to the two original EPC bidders, emphasizing the need for their best price on a full turnkey EPC bid and to identify at least one more EPC bidder to enhance the competitive process. Both original EPC bidders were notified that CEI South was opening the EPC RFP to other bidders giving them the option to take the time to re-evaluate their first proposal. Power Advocate went back to the two original bidders that did not provide bids for the first RFP and invited a fifth EPC to participate in the second RFP. The two EPCs that declined to provide a bid for the first RFP also declined to bid the second RFP. The additional EPC bidder brought into the competitive bidding process through the second RFP as well as the two original EPCs bidders all provided full turnkey bids, one for each of the two CT OEMs.

Q. Why was a full turnkey strategy important to CEI South?

A. The primary reason for a full turnkey project is to allocate most of the project risk to the EPC contractor. CEI South would like major areas of potential disagreement, such as design coordination, delivery coordination, and construction signoffs and approvals to be the responsibility of the EPC contractor. This allows CEI South to reduce owner's contingency costs that would have otherwise been allocated for these risks. A secondary reason is to place the performance guarantees on the EPC contractor to avoid issues that could arise if CEI South provided the equipment for the EPC to install.

Q. What effort was made to verify that the RFP responses are competitive?

A. A competitive RFP was conducted by a third party (Power Advocate) that has expertise in RFP's. Power Advocate has a proprietary database with pricing of similar projects that was referred to for comparison purposes. B&V and Power Advocate along with the CEI South team spent several hours reviewing bids ensuring they were comparable with similar bill of quantities estimated for various phases of the project.

Q. Who was the winning bidder?

A. 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.

Q. How was Kiewit Chosen?

A. Power Advocate led an effort with B&V and CEIS to create a Balanced Scoring Matrix that consisted of an evaluation and rating of both commercial terms and technical information proposed by the EPC's. Commercial terms carried a 50% weighting and covered five specific topics while the technical evaluation also carried 50% weighting and consisted of seven topics. B&V, Power Advocate and several CEIS internal stakeholders had input into the final rating for the three EPC bidders. Kiewit Power ranked the highest in both the commercial and technical scores. A skeleton of the Scoring Matrix with specific items evaluated and weightings applied to each is shown in Attachment EMC-2 to the direct testimony of Petitioner's Witness Erin M. Carroll from Power Advocate, who discusses the RFP and results of the Balanced Scoring Matrix in more detail.

Q. How will CEIS provide management oversight on the project?

A. CEIS has employees on staff with project management skills and experience on large capital projects as well as subject matter experts in natural gas CT operation and maintenance, and electronic control systems used to operate generating units. In addition, CEIS plans to hire an Owners Engineer to assist with providing project oversight and monitoring safety, quality, expense, and schedule adherence throughout the project life cycle. Because the project will be built under a full turnkey method the EPC contractor holds most of the risk if the project is behind schedule and over budget.

Q. Please discuss the project schedule.

A. To get the project in service and producing energy as soon as practicable, avoiding additional capacity purchases to meet the required PRM, CEIS plans to enter a Limited Notice to Proceed ("LNTP") with a selected EPC contractor in early Q3 2021. During the LNTP period, CEIS will work with the EPC contractor to prepare for the construction of the CTs. Preparations may include site surveys, geotechnical investigations, applying for environmental permits, and limited design work. If the CPCN for the two CTs is issued, the EPC contractor will be given a Full Notice to Proceed ("FNTP"). The FNTP will allow the EPC contractor to begin the ordering process for the combustion turbines and generators and other major equipment with expected long procurement lead times. The FNTP will also allow the EPC contractor to start mobilizing workforce and equipment to the A.B. Brown site to begin site preparation activities. The CTs are expected to take approximately 15 months for design, fabrication, and delivery to the A.B. Brown site. During this time, the A.B. Brown site will be graded, foundations constructed for the CTs and other balance of plant ("BOP") equipment, and underground utilities installed. Once the CTs arrive at the A.B. Brown site the erection process is expected to take approximately eight to twelve months with the checkout, startup, and commissioning processes expected to take an additional four months. The in-service date will be driven by the date the CPCN is granted, however, the units are expected to be commercially available by Q4 of 2024. A high-level schedule is provided as Attachment WDG-1.

Q. Is CEI South requesting ongoing review of the CT Project construction pursuant to IC 8-1-8.5-6?

A. Yes. Following receipt of an Order approving the Company's request for a CPCN, the Company will provide periodic updates on the CT Project until it goes in service. CEI South is requesting ongoing review of the CT Project, including review of progress reports and any revisions to the cost estimates, as the construction proceeds, and associated ratemaking treatment consistent with such review.

Q. Were any Natural Gas CT bids received in response to the All-Source RFP?

A. No, however, there were three Natural Gas Combined Cycle ("CCGT") proposals received. Witness Bradford discusses the details and purpose of the all-source RFP.

Q. Were partnership options explored to build a natural gas CCGT or CT with another Indiana utility?

A. Yes. CEIS reached out to the other Indiana utilities regarding partnering on a CCGT or a CT build. Witness Rice discusses the results of these efforts.

VI. LONG TERM SERVICE AGREEMENT (LTSA)

Q. What is an LTSA and why does it make sense for CEI South?

A. An LTSA is a form of an extended warranty and service agreement with the equipment manufacturer to provide unit monitoring, annual inspection, maintenance, replacement parts, labor, and overhaul services for a negotiated period of time. The OEM taking on this responsibility provides CEIS with assurances that experts will be available to resolve any issues and ensure the units are properly maintained and kept reliable for CEI South customers. The LTSA provides a more predictable annual O&M spend vs. having high dollar years during major outages and stabilizes future pricing reducing volatility.

Q. Please discuss the major services received from the LTSA.

A. The services from the LTSA include:

- Dedicated OEM contact for issue resolution, guidance, and planning.
- Remote monitoring and system diagnosis services in which real time data is monitored by the OEM off site and analyzed for trends and possible operational issues which have not developed into an alarm situation.
- Annual unit borescope inspections to assess the condition of internal components.
- Emissions monitoring
- Scheduling maintenance outages to include providing planning, labor, equipment disassembly, repair and/or replacement of equipment and parts, unit reassembly and start-up support.
- Guaranteed covered parts inventory.

- Discounted pricing for any non-covered parts and services.

Q. What makes up the cost components of the LTSA?

A. The three cost components of the LTSA include:

- Initial Spare Parts Fee – purchases critical and high cost long lead time spare parts for on-site inventory. These are included in the total estimated cost of the CTs I provided earlier.
- Annual Fixed Program Fee – provides remote monitoring and diagnostic services from the OEM as well as annual inspections and a dedicated liaison to resolve issues and plan and schedule work.
- Annual Variable Fee – fee covering future scheduled major inspections and maintenance overhauls to include replacing worn components. This fee is paid based on the number of annual run hours or unit starts due to the wear and tear on the units. Run hours or number of starts determine when major maintenance and inspection activities will be scheduled and performed by the OEM. All operating hours and starts are not measured the same as the characteristics of each have a different impact on a unit. For example, a fast unit start may count as more than a single start while a slower start may only count as one start, therefore starts are measured as factored fired starts. Similar conditions apply for hours based variable fee calculations where the actual operating hours of the units could be penalized with additional hours due to load severity.

Q. What are the outages required and how long do they take?

A. The turbine OEM defines the outage maintenance intervals based on the number of fired factor operating hours and/or fired factor starts. There are two types of scheduled outages. The first is a combined Combustion and Hot Gas Path ("HGP") inspection which involves the combustion and turbine sections. This consists of disassembly, inspection and replacement of worn components and reassembly and start-up. This activity requires a 20-day outage. The second inspection is referred to as a Maintenance Inspection ("MI") which includes the HGP as well as the compressor section of the unit. Again, this involves disassembly, repair and/or replacement of worn or damaged components and reassembly and start-up of the unit and requires an approximate 30-day outage.

Q. How many operating hours or starts before a HGP and MI are scheduled?

A. General Electric will schedule a HGP at 32,000 fired factored operating hours or 1,250 fired factored starts and an MI at 64,000 fired factored operating hours or 2,500 fired factored starts.

Q. Will CEI South make a variable payment based on the operating hours or starts?

A. Given the projected low-capacity factors for the CTs and anticipated starts to support the intermittency of renewables, CEI South feels confident that the variable fee will be based on the fired factored starts.

Q. Can CEI South project the number of fired factored starts with certainty?

A. No. It would be very difficult to make this determination as there are so many variables regarding how and when MISO will dispatch the CTs. CEI South feels that 200 to 300 starts (100-150/CT) annually is a good estimate.

Q. What is the estimated cost of each of the three components that make up the LTSA?

A. Table WDG-5 shows a breakdown of the year one capital and O&M fee for each of the components of the LTSA. This estimate is based off of a 2021 LTSA quote from General Electric with a 2.2% annual escalation with the units coming on-line in late 2024 and the first full year of operation in 2025. Cost is estimated to escalate at 2.2% annually in future years.

Table WDG-5: Estimated Cost of LTSA Components

	Capital Based on 200 Annual Starts	Capital Based on 300 Annual Starts	O&M Based on 200 Annual Starts	O&M Based on 300 Annual Starts
Initial (One-Time) Spare Parts Fee	[redacted]	[redacted]		
LTSA Annual Program Fee			[redacted]	[redacted]
Variable Fee Starts	[redacted]	[redacted]	[redacted]	[redacted]

Note that the spare parts fee is a one-time fee to stock high cost long lead time parts.

Q. Why is a portion of the variable fee charged to capital?

A. The variable fee covers future maintenance cost which consists of parts and components that can be capitalized and labor that is O&M. The split, which is common in the industry, [redacted].

Q. Are there other O&M cost that will be incurred for the CTs?

A. Yes. Other costs not covered by the LTSA include CEI South fixed O&M for labor and supplies and materials for the day-to-day equipment inspections and plant operation as well as general balance of plant and site maintenance. There will also be variable O&M to replace and maintain small parts and equipment based on unit operating characteristics. Using data for 300 total annual starts Table WDG-6 indicates the year one estimate for these O&M expenses. CEI South projects that these costs will escalate at 2.2% annually in future years.

Table WDG-6: O&M Type and Estimated Cost

O&M Type	Estimated O&M Cost (Year One)
Fixed Labor and Other O&M	[redacted]
Variable O&M	
Total	

Q. How long has CEI South contracted for an LTSA?

A. CEI South is negotiating the price based on a LTSA that takes the units through the first MI. Based on 150 annual starts per unit, the MI will occur in year 17. Based on 100 starts annual starts, the MI will occur at year 25. More than 150 annual starts per unit will shorten the time of the LTSA.

Q. Why only put an LTSA in place for one MI cycle?

A. With the rapidly changing energy climate and a positive outlook for more renewables being added to the grid in future years, it is difficult to project what the operating characteristics of the CTs will be. CEI South will know more after the first MI cycle and will be in a better position to ensure any future maintenance plan is designed based on projected operation.

Q. How is the LTSA being negotiated?

A. CEI South and Kiewit Power negotiated the purchase of the CTs and the LTSA with GE at the same time to leverage our joint negotiation power to get the best price possible.

VII. DRY FLY ASH RECYCLE PROJECT

Q. Please provide an overview of the Dry Fly Ash Recycle Project ("Dry Fly Ash Project)").

A. CenterPoint Indiana South is seeking authorization to construct a Dry Fly Ash ("DFA") loading and handling system at the Archer Daniels Midland ("ADM") site, on the Ohio River, in Evansville, Indiana. The Dry Fly Ash Project includes a silo for accepting ash from A.B. Brown units 1 & 2 and Warrick Unit #4 through 2023 when the A.B. Brown units are planned to be retired and Petitioner is expected to have exited the JOA; and the F.B. Culley plant through the rest of its useful life. The Dry Fly Ash Project also includes a barge loading facility to load ash on barges to be sent to Missouri for beneficial reuse with a long-time CEI South ash customer.

All four of CEI South coal units, as well as Warrick Unit #4, have been converted to dry ash systems. (Although additional dry fly ash handling modifications would be necessary at A.B. Brown to comply with the ELG prohibition against the continued use of ash transport water, as further described by Witness Retherford.) The A.B. Brown ash has been pneumatically blown into a large storage silo near the Ohio River at the A.B. Brown site. Dry ash from F.B. Culley units and Warrick Unit #4 have been trucked to the A.B. Brown site and placed in this same ash storage silo to be loaded on barges. Since the conveyor system has been converted to handle ponded ash to be loaded on barges for beneficial reuse and the eventual closing of the A.B. Brown ash pond (as approved in Cause No. 45280), dry ash can no longer be transported and loaded on barges by the current system. As a result, a new dry ash handling system is required to continue shipping dry ash for beneficial reuse.

Q. Why is this project necessary?

A. The CCR rule prohibits CCR and non-CCR waste streams, which includes ash, from being placed in ash ponds after April 2021 unless extensions are granted. As explained in more detail by Petitioner's Witness Retherford, Petitioner has filed for timely extension requests to continue to use the existing ash ponds at both plants. The A.B. Brown plant will continue to generate fly ash through its retirement in October of 2023. The F.B. Culley and CEI South's share of ash from Warrick Unit #4 require a home other than ash ponds for approximately 100,000 tons of ash annually. [redacted] Moreover, as detailed by Witness Retherford, this investment supports Petitioner's demonstration to U.S. EPA that it has actively pursued alternative disposal capacity (ensuring the ability to continue to recycle dry fly ash) in accordance with the ash pond extension requests needed to continue to use the existing ash ponds through October 2023.

Q. What is the projected cost of the project?

A. Table WDG-7 shows the estimated capital required for the new dry ash facility:

Table WDG-7: Estimated Capital Expense for Dry Ash Facility

Capital	2020 ($)
EPC Contractor	11.0 M
CEIS Responsibility	0.1 M
Loadings	0.9 M
Total	12.0 M

Q. Is CEI South seeking a CPCN with respect to this project under IC 8-1-8.4-7?

A. Yes. The construction of the dry ash handling facilities is necessary to comply with the CCR rule as described in greater detail by Petitioner's Witness Retherford and is therefore a compliance project within the meaning of IC 8-1-8.4-2. CEI South is seeking a CPCN in order to recover federally mandated costs associated with the project.

Q. How does CEI South plan to recover the costs associated with this project?

A. Petitioner's Witness Kara R. Gostenhofer describes the proposed ratemaking and accounting treatment. Generally, project costs up to 80% will be recovered annually through the Environmental Cost Adjustment ("ECA") filing. The remaining 20% will be recovered through the next CEI South electric rate case.

Q. How will the project be managed?

A. The project will be performed under an EPC agreement with Penta Engineering who must meet project specifications and performance requirements. CEI South and the ash customer jointly agreed on Penta as the EPC contractor for this project.

Q. Does this project help increase the amount of ponded ash accepted for beneficial reuse by the ash customer in connection with the project approved in Cause No. 45280?

A. Yes. There is an estimated 6-7 million tons of ash in the A.B. Brown ash pond. CEI South is aware that not all of this ash will meet the required specification of the ash customer. Shipping the dry ash produced by all CEI South facilities helps correct some of the off-specification ash from the A.B. Brown ash pond, allowing the ash customer to accept more ponded ash. This ultimately lowers the cost of properly storing off-specification ponded ash in an above ground impoundment that meets CCR-requirements or disposing of off-specification ponded ash in an off-site landfill.

Q. Why was the ADM site chosen?

A. This was the lowest cost option over the long-term and is a central location to all plants delivering ash through 2023 and is closer to the F.B. Culley facility versus the current transport to the A.B. Brown plant. The location is also ideal for loading barges as the riverbank is high enough to avoid the majority of delays associated with high river levels that are experienced at the A.B. Brown site. ADM agreed to take responsibility to obtain permits for operating the system on the site. ADM permitting experience and current activity at this site made the permitting more timely and less complicated. ADM was also willing to make a long-term commitment to the Project while the second-best option was only willing to commit for 2-3 years. Shipping a steady supply of dry ash to the ash customer is critical to maintaining a positive relationship and meeting the expectation set out in the agreement.

Q. What other options for dry ash disposal were considered?

A. The chosen option along with alternatives explored to include capital and O&M cost estimates along with viability and related comments are displayed in Table WDG-8.

Table WDG-8: Options Considered for Dry Ash Disposal

Options Explored	Capital($)	Annual O&M ($)	Viable Solution	Comments to include Environmental and other Issues/Risks
Construct new DFA loading facility at ADM site.	12.0M	$1.35m (2022-2023 drops to $700K in 2024)	Yes	Provides long term solution for F.B. Culley ash and short-term solution for A.B. Brown and Warrick Unit #4 ash until units are retired. The ash reuser takes ownership of ash once it reaches ADM. Once ash is beneficially re-used, future environmental liabilities are mitigated. Mine disposal would serve as back-up plan followed by Municipal Landfill. Topography of riverbank at ADM site allows for consistent barge loading even when river levels are high.
Modify existing landfill or build new landfill	19M	2.9M	Yes	Building a new landfill that meets the CCR rule requirements (location restrictions, liner requirements, leachate water treatment, ground water monitoring) would result in having another site that carries environmental liability and a minimum 30-years of post-closure monitoring and maintenance. The permitting process for a new landfill is 3-5 years.
Deposit ash in coal mine	4.5M	$4.0M	Yes	Potential for future environmental regulations that would reduce or restrict the ability for mines to receive ash, potential for future liability for remediation. Mine has weather related restrictions and is not interested in full production volume. Risk of mine bankruptcy.
Municipal landfill.	4.5M	6.8M	Yes	Risk of future liability for remediation (i.e. groundwater), landfill not being able to accept large or on-going quantities of ash due to ash characteristics and space restrictions. Tipping fees are very expensive.

Separate ponded and dry loading systems at A.B. Brown	25M	1.2M	No	Space limitations, the expense of building and permitting new cells for ash loading equipment and securing barges and loading issues is more challenging and costly alternative. Due to land elevation and flooding, there are also challenges with loading barges when the Ohio River levels are high. This frequently occurs in the spring and can shut down the barge loading activity for several weeks.
Common loading system at the A.B. Brown Plant.	14.0M	1.8M	No	Switching from ponded ash to dry ash requires cleaning the belt with water. This would require capital to construct a means of getting water to the site, collecting / treating the water, along with obtaining the appropriate NPDES permitting. This would carry a risk of water spills/ releases along the entire belt path. In addition, engineering firm won't guarantee performance results.
Construct Loading System at F.B. Culley			No	There is not adequate space available to build a storage silo and barge loading facility at the Culley plant. Cost and permitting for building cells to hold loading equipment and barges is more expensive than the ADM site.
Pugging or adding and mixing water to dry ash then shipping with ponded ash.	4.5M	1.0M	No	Ash customer is not able to reliably handle the resulting material. Ash hardens in barge during transit.

Q. What is the contingency plan for ash disposal if barges cannot be loaded or the ash customer cannot accept ash for a short period of time?

A. When ash cannot be loaded on barges and delivered to the ash customer due to high river levels or plant shutdowns, CenterPoint Indiana South lowest cost option is to truck ash to a mine and pay a tipping fee for disposal. In 2020, the mine CEI South was using for ash disposal declared bankruptcy and left CEI South with no option but to truck ash several

100 miles to the ash customer or pay high tipping fees at a local municipal landfill thereby placing CEI South in a very difficult situation until an agreement was reached with an alternative mine for ash disposal. As mentioned above, the second and third option is to truck ash to the customer's site or deposit ash in the local municipal landfill. Both options are very expensive, and the local municipal landfill has limited capacity.

Q. [redacted]

A. [redacted]

Q. What is the estimated annual O&M costs associated with the new dry ash facility?

A. The following table (Table WDG-9) lays out the estimated annual O&M expense through 2023 when CEI South plans to retire certain coal units and exit the JOA with Alcoa for Warrick Unit #4 along with the estimated annual O&M beyond 2023 or handling dry ash from F.B. Culley. If F.B. Culley Unit 2 is retained through 2025, which would be possible with the F.B. Culley CCR-compliant ash pond, these numbers will change slightly.

Table WDG-9: Estimated Annual O&M Expense Associated with Dry Ash Facility

O&M	Annual ($) 2021-2023	Annual ($) 2024-XXX
Ash Transportation to Terminal (3rd party)	0.85M	0.33M
Mobile Equipment Maintenance	0.05M	0.02M
Operations and Maintenance (3rd party)	0.45M	0.35M
Total	1.35M	0.68M

Q. Please describe the basis of the agreement between CEI South and ADM.

A. CEI South has entered a sublease of the property with ADM for [redacted]. The initial term is for five years with two additional options to extend for another five years each. After the initial 5-year term, CEI South may terminate with [redacted] notice. ADM will [redacted] with CEI South providing the needed equipment and material. CEI South will be consulted for review and approval of, as well as pay for, any major maintenance on the system.

Q. Please provide a project schedule with an estimated in-service date.

A. Attachment WDG-2 is a high-level projected schedule for completing the construction of the dry ash facility and placing it in-service. [redacted]

Q. How is fly ash being disposed of until the new dry ash facility is placed in-service?

A. Dry ash is either being trucked to Missouri and delivered to the CEI South ash customer or being trucked to a coal mine for beneficial reuse or disposal. If there are issues at the mine that prevent delivery, the ash will be transported to the local municipal landfill.

VIII. COAL COMBUSTION RESIDUAL-COMPLIANT PONDS

Q. What is the CCR Part A Rule?

A. As described in more detail by Witness Retherford the CCR Part A Rule, which was published in the Federal Register in August of 2020, now requires all unlined ash ponds to close no later than April 11, 2021 unless an extension is granted by the US EPA. The CCR Part A rule became effective in September of 2020.

Q. What is required to get an extension to use ash ponds approved by the EPA?

A. The CCR Part A Rule requires that CEI South must be pursuing alternative capacity for handling CCR, and non-CCR, waste streams that are currently managed in unlined CCR impoundments in the fastest technically feasible timeframe. Cost and convenience are not to be taken into consideration when determining the fastest technically feasible option.

Q. How long can an ash pond be used if an extension is granted?

A. Until the fastest technically feasible option can be completed or October 15, 2023, whichever is sooner.

Q. Has CEI South applied for an extension to continue to use the unlined CCR ponds at Culley and Brown?

A. Yes. As described by Witness Retherford an extension for both F.B. Culley and A.B. Brown was applied for prior to the November 30, 2020 due date.

Q. What, if anything, will be required to demonstrate no alternative capacity and qualify for the extensions?

A. As detailed in the testimony of Witness Retherford, in order to demonstrate no alternative capacity and qualify to extend the use of the existing ash ponds out to October 2023, Petitioner must be actively pursuing the fastest technically feasible option for alternative capacity to dispose of CCRs. In the case of A.B. Brown the fastest feasible option for alternative capacity is a lined approximately 10-acre CCR compliance pond proposed in this proceeding that can divert a portion of CCR waste streams off the existing pond. If we do not construct this new compliance pond, we will not qualify for the extension to continue to use our existing ash ponds through October 2023 and will have to shut the units down immediately, as the cease disposal date has already passed. Even if it was technically feasible to construct a larger lined pond at A.B. Brown, by itself it would not extend the life of the Brown units beyond 2023. ELG still requires that the dry fly ash handling modifications modeled in the IRP be completed by December 2023, the landfill is still running out of space and would need a permitted and constructed extension no later than December 2023, and the wastewater treatment system necessary to ensure compliance with existing NPDES must be completed before the existing ash pond stops receiving wastewaters in October 2023. Similarly, the 2- to 3-acre pond proposed to be constructed at F.B. Culley is the fastest technically feasible option for alternative capacity and necessary to continue to operate the existing east ash pond through the extension period.

Q. Is CEI South able to avoid implementing the fastest technically feasible option for handling CCR waste streams if a unit is retired prior the October 15, 2023 date?

A. No. As Witness Retherford describes, the CCR Part A Rule does not allow CEI South to use the plant retirement provision unless all plant unit boilers are retired and ash ponds completely closed by October 17, 2023 for F.B. Culley and October 17, 2028 for A.B. Brown. Witness Retherford sets out how this is not feasible for F.B. Culley or A.B. Brown.

Q. Why can't the new storm water pond that was recently placed in service at F.B. Culley be used for the F.B. Culley Unit 2 bottom ash wastewater?

A. The newest pond at F.B. Culley (contact storm water pond), which was constructed within the footprint of the former/closed West Ash Pond cannot accept CCR because it was not constructed with the intent of being a CCR-compliant pond. Planning was underway for F.B. Culley Unit 2 retirement and installation of F.B. Culley Unit 3 dry bottom ash system and zero liquid discharge technology for F.B. Culley 3 FGD wastewater, thereby eliminating all CCR waste streams. Since that time, as discussed by Witness Retherford the CCR Part A rule requires that we obtain alternative capacity for the F.B. Unit 2 bottom ash transport water prior to the previously planned retirement date (i.e. as fast as technically feasible).

Q. What is the timeline and cost for constructing a CCR-compliant pond to handle F.B. Culley Unit 2 bottom ash wastewater?

A. The pond can be completed by March 1, 2023 at a class 5 cost estimate of $6 million. The cost estimate which is a very high-level class 5 estimate includes permitting, geotechnical analysis, project management, engineering, infrastructure, construction, equipment, construction management and contingency. A high-level schedule for the construction of a CCR compliant pond at Culley is included as attachment WDG-3.

Q. What is the fastest technically feasible option for the A.B. Brown plant?

A. The fastest technically feasible option for the A.B. Brown plant is to clean out and reconstruct the current South Side Run-off Pond ("SSRP") with a composite liner system to be compliant with the CCR rule and expand the pond to the west adding approximately 4.2 acres. The expansion will receive combined FGD wastewater and landfill runoff leachate as well as manage non-CCR plant storm water and coal pile runoff flows such as storm water, landfill runoff, and landfill leachate that is currently managed within the Ash Pond. The Wastewater treatment system designed for mercury removal would be moved or duplicated to a location adjacent to the proposed expanded, lined pond. This maximizes the number of flows that can be eliminated from the Ash Pond but will not handle A.B. Brown unit 1 & 2 bottom ash wastewater. The proposed new lined CCR-compliant pond at A.B. Brown will receive current Coal Pile Runoff flows, combined A.B. Brown unit 1 & 2 FGD wastewater and non-CCR wastewater streams.

Q. What is the timeline and cost for constructing a CCR-compliant pond at the A.B. Brown plant?

A. The pond can be completed by July 1, 2023 at a class 5 cost estimate of $13 million. The cost estimate which is a very high-level class 5 estimate includes permitting, geotechnical analysis, project management, engineering, infrastructure, construction, equipment, construction management and contingency. A high-level schedule for expanding the SSRP pond to comply with the rule is included as attachment WDG-3.

Q. Does the Company anticipate O&M expense associated with these ponds after they have been constructed?

A. Yes. Annual O&M expenditures will be required for the A.B. Brown and F.B. Culley CCR compliant ponds to include expenditures to support pond infrastructure maintenance, pond cleaning activities, discharge sampling and analysis activities and annual inspection requirements called out in the Federal CCR rule. These O&M expenses are estimated at $250,000 for the A.B. Brown Pond and $100,000 for the F.B. Culley Pond.

Q. Will the proposed A.B. Brown Pond be useful after the A.B. Brown coal units are retired?

A. Yes. Water flows received in this pond after the A.B. Brown units are retired include landfill runoff leachate, coal pile runoff until decommissioning and clean-up is complete, , contact storm water from coal units until decommissioning is complete, and continued mercury treatment and possibly existing ash pond water. The pond will also receive oily wastewater and storm water runoff from the CT's as well as sanitary wastewater from the administrative and other office and storage buildings that will support the CT's.

Q. Is CEI South seeking a CPCN with respect to the proposed F.B. Culley and A.B. Brown CCR Part A Rule compliant ash ponds under IC 8-1-8.4-7?

A. Yes. The construction of the new ash ponds is necessary to comply with the CCR rule as described in greater detail by CEI South Witness Retherford and is therefore a compliance project within the meaning of IC 8-1-8.4-2. CEI South is seeking a CPCN in order to recover federally mandated costs associated with the project.

Q. How does CEI South plan to recover the costs associated with the proposed F.B. Culley and A.B. Brown CCR-compliant ponds as required per CCR Part A Rule?

A. CEI South witness Gostenhofer describes the proposed ratemaking and accounting treatment. Generally, project costs up to 80% will be recovered annually through the Environmental Cost Adjustment ("ECA") filing. The remaining 20% will be recovered through the next CEI South electric rate case.

Q. Do these ponds potentially affect the timing of the closure of F.B. Culley 2 or Warrick Unit #4 ?.

A. Yes for F.B. Culley 2 but no for Warrick #4. As described in greater detail by Petitioner's Witness Angila Retherford, the Culley pond offers Petitioner the opportunity, subject to certain conditions, to evaluate operating F.B Culley 2 through 2025, thereby reducing the volume and time Petitioner would otherwise be required to rely on the capacity and wholesale energy markets during its generation transition period. Because this new CCR compliant pond must be constructed to qualify for an extension to continue to use the east ash pond through October 2025, and it is possible to use this new CCR compliant pond for continued disposal of the small amount of bottom ash generated by Culley Unit 2, it creates a potential opportunity to run Culley Unit 2 through 2025 under the recently finalized ELG Reconsideration rule as detailed by Witness Retherford. While Petitioner is evaluating the practicality of continuing to operate F.B. Culley 2, the timing for exiting the Warrick Unit #4 JOA remains unchanged – [redacted]

Q. Is there an opportunity to continue to operate the A. B. Brown units 1 & 2 beyond 2023 by constructing a CCR-compliant pond?

A. No. As described by Petitioner's Witness Retherford, even if it was feasible to construct a CCR-compliant pond large enough to handle the significant volume of ash transport water and FGD/Scrubber wastewaters coming off the Brown units, Petitioner would still be required to complete the dry fly ash handling modifications by December 2023 (under the ELG Reconsideration), complete the permitting and construction of the landfill expansion capacity (we are running out of space) and complete the wastewater treatment system necessary to comply with our existing NPDES limits no later than October 2023 (closure deadline for the existing unlined ash pond which currently serves as a NPDES compliance structure).

IX. <u>CONCLUSION</u>

Q. Please summarize your testimony supporting the Company's request for a CPCN for the CT Project.

A. My testimony provides the best estimate of the construction costs for the CT Project. I have described options considered by the Company, including replacement options for the Dual Alkali FGD Scrubbers, the possibility of refurbishing A.B. Brown by converting it from coal- to gas-fired, and continuing to operate with the Dual Alkali FGD Scrubbers through 2029 and the attendant challenges for each of these options. I provided background on the RFP process used to solicit bids for the CT Project, as discussed in greater detail by Petitioner's Witnesses Carroll and Zoller, which allowed the Company to ultimately develop the estimated costs for the CT Project based on competitively bid engineering, procurement, or construction contracts. My testimony describes how the RFP allowed bidders to submit firm and binding bids for the construction of the CT Project that met all of the technical, commercial and other specifications to enable ownership of the CTs to vest with the Company when the CTs become commercially available. My testimony makes clear that current and potential options for entering arrangements with other utilities related to the interchange of power, pooling of facilities, purchase of power, and joint ownership of facilities have been evaluated and are limited or unavailable to meet the needs of CEI South and its customers. Finally, I described how the CT Project fits into CEI South's generation transition plan and is consistent with the Company's 2019/2020 IRP; therefore, in my opinion the CT Project serves the public convenience and necessity and should be approved.

Q. Please summarize your testimony supporting the Company's request for a CPCN for the Dry Fly Ash Compliance Project.

A. My testimony introduces the need for the Dry Fly Ash Compliance Project based on federally mandated requirements which are discussed in greater detail by Witness Retherford. I describe the projected federally mandated costs of the project and how the project will allow CEI South to comply with the requirements described by Ms. Retherford. I have explained the alternatives that were considered which, in my opinion, demonstrate that the project is reasonable and necessary. Finally, I have explained how the Dry Fly Ash Compliance Project will allow the Company to continue operation of F.B. Culley Units 2 and 3 and Warrick Unit #4 for the time being, while complying with environmental requirements related to the handling of dry fly ash. My testimony, and the testimony of Witnesses Rice and Bradford, demonstrate the value of the operation of those units in the context of our current and future generation portfolio.

Q. Please summarize your testimony supporting the Company's request for a CPCN for the Pond Compliance Project.

A. My testimony discusses the work required by the CCR Part A Reconsideration federally mandated requirements discussed in greater detail by Witness Retherford. I have provided the projected federally mandated costs of the Pond Compliance Project to be constructed for both the Culley and Brown sites. I have described how the project will permit CEI South to comply with the CCR Part A requirements. I have explained that alternatives are unavailable, therefore demonstrating, in my opinion, that the project is reasonable and necessary. I have also described how this project will provide an opportunity for the

Company to evaluate continued operation of Culley Unit 2 through 2025, providing value by potentially reducing the volume of capacity purchased for 2024-2025.

Q. Does this conclude your direct testimony?

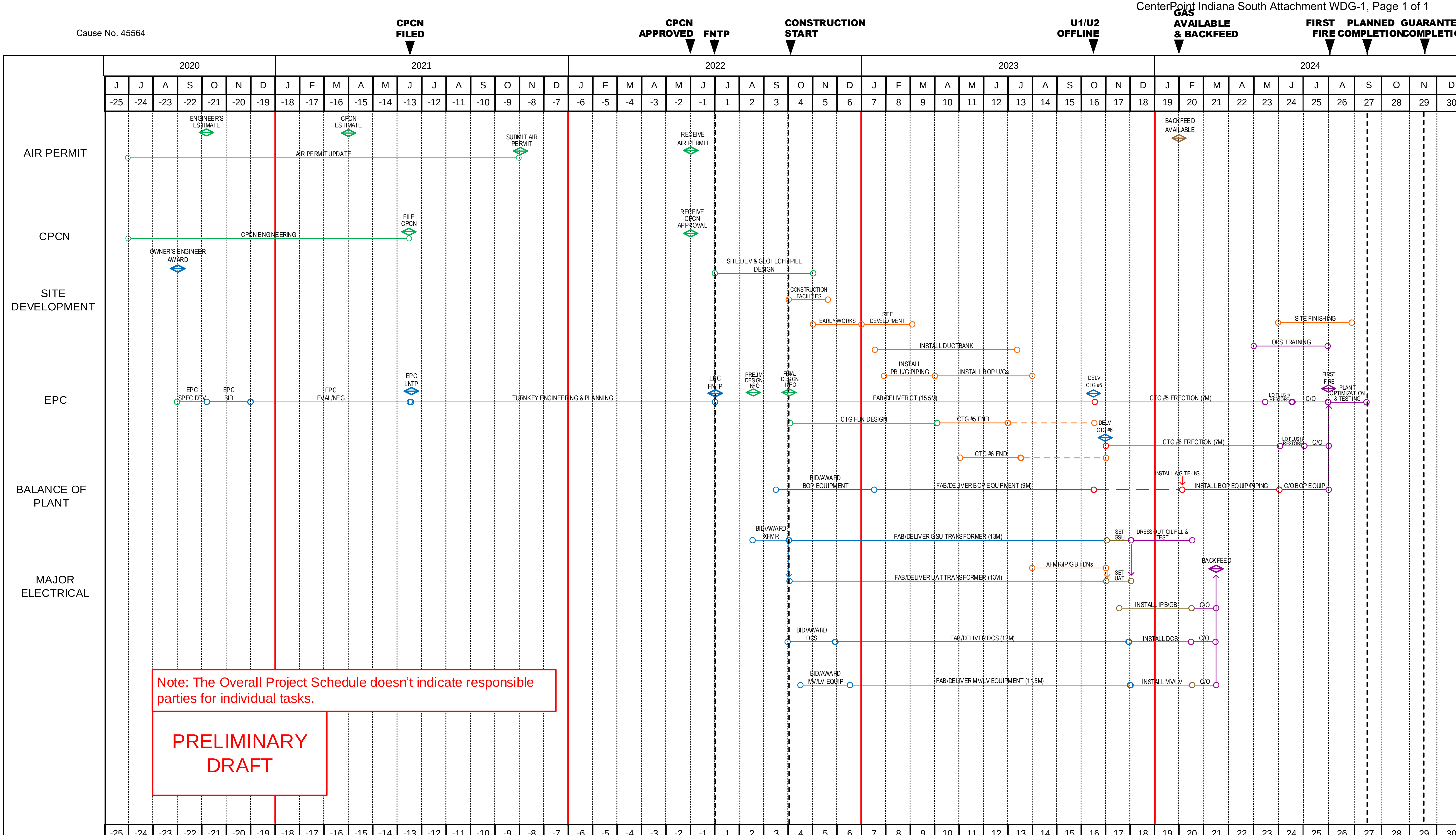
A. Yes, at the present time.

VERIFICATION

I, Wayne D. Games, Vice President Power Generation Operations for Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South, under the penalty of perjury, affirm that the answers in the foregoing Direct Testimony are true to the best of my knowledge, information and belief.

Wayne D. Games
Vice President Power Generation Operations

Cause No. 45564



REV	DATE	REVISIONS & RECORD OF ISSUE	DWN	CHK	APP
3	08-JUN-21	AIR PERMIT APPLICATON UPDATE	JHB		
2	25-MAR-21	CASH FLOW REVISIONS	JHB		
1	11-JAN-21	UPDATE FOR +/- 10% ESTIMATE	JHB		
0	25-SEP-20	REFERENCE FOR TURNKEY RFP	DJC		

BLACK & VEATCH

ENGINEERING ACTIVITIES
PROCUREMENT ACTIVITIES
CIVIL ERECTION ACTIVITIES
MECHANICAL ERECTION ACTIVITIES
ELECT/CONTROL ERECTION ACTIVITIES
STARTUP ACTIVITIES

CENTERPOINT ENERGY
DRAFT 2X0 F CLASS SIMPLE CYCLE PROJECT SCHEDULE
CURRENT CPCN ESTIMATE SCHEDULE
LEVEL 1 PROJECT SCHEDULE – SEP 2024 GSC

DRAWING NUMBER

CODE

PAGE 1 OF 1

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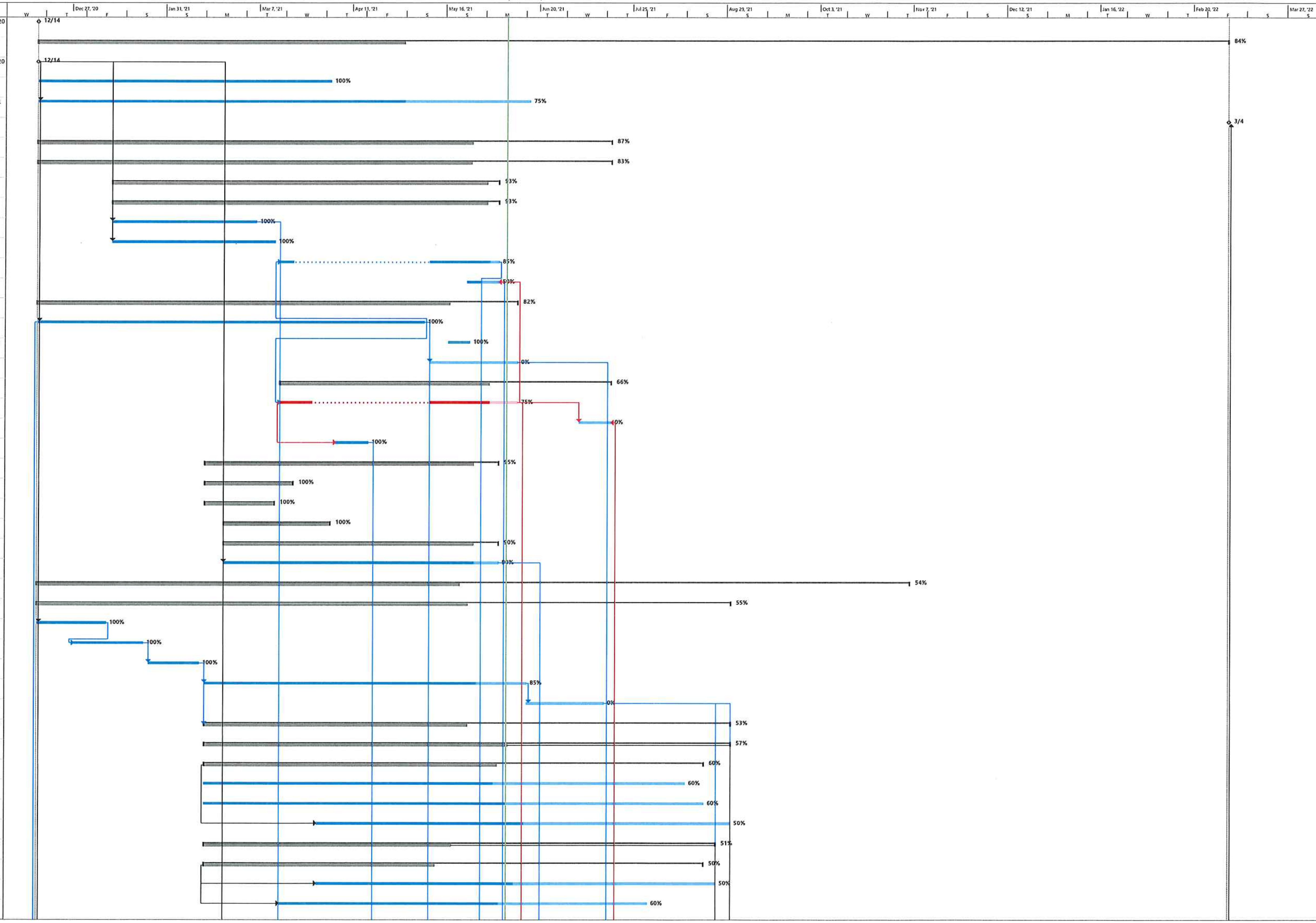
Vectren Terminal Project
PENTA Project #
3020-1211
May 31, 2021 Update

ID	Task Name	Duration	Start	Finish
1	<New Milestone>	0 wks	Mon 12/14/20	Mon 12/14/20
2	**PROJECT MILESTONES**	**64 wks**	**Mon 12/14/20**	**Fri 3/4/22**
3	Execute EPC Contract	0 days	Mon 12/14/20	Mon 12/14/20
4	Phase I Permits - Foundation/Civil	16 wks	Mon 12/14/20	Fri 4/2/21
5	Phase II Permits - Above Grade Structures	26.5 wks	Mon 12/14/20	Wed 6/16/21
6	Complete Project (dependent upon Low River Level Conditions)	0 days	Fri 3/4/22	Fri 3/4/22
7	**PRELIMINARY & DETAIL ENGINEERING**	**31 wks**	**Mon 12/14/20**	**Fri 7/16/21**
8	**PENTA**	**31 wks**	**Mon 12/14/20**	**Fri 7/16/21**
9	**Structural Engineering**	**21 wks**	**Mon 1/11/21**	**Fri 6/4/21**
10	**Foundations & Structural Steel Design IFC**	**21 wks**	**Mon 1/11/21**	**Fri 6/4/21**
11	Main Foundations	8 wks	Mon 1/11/21	Fri 3/5/21
12	Secondary Equipment Foundations	9 wks	Mon 1/11/21	Fri 3/12/21
13	Structural Steel Design IFC	5 wks	Mon 3/15/21	Fri 6/4/21
14	MCC Pad IFC Hold	2 wks	Mon 5/24/21	Fri 6/4/21
15	**Mechanical Engineering**	**26 wks**	**Mon 12/14/20**	**Fri 6/11/21**
16	IFB	21 wks	Mon 12/14/20	Fri 5/7/21
17	IFB Pipe support update	1.2 wks	Mon 5/17/21	Mon 5/24/21
18	IFC	5 wks	Mon 5/10/21	Fri 6/11/21
19	**Electrical & Controls Engineering**	**18 wks**	**Mon 3/15/21**	**Fri 7/16/21**
20	IFB	7 wks	Mon 3/15/21	Fri 6/11/21
21	IFC	2 wks	Mon 7/5/21	Fri 7/16/21
22	IFC Grounding Plan	2 wks	Mon 4/5/21	Fri 4/16/21
23	**Specialty Engineering**	**16 wks**	**Mon 2/15/21**	**Fri 6/4/21**
24	**Grading/Paving/ErosionCtrl (Premier Design)**	**5 wks**	**Mon 2/15/21**	**Fri 3/19/21**
26	**Entry/Exit Design (3I Design)**	**4 wks**	**Mon 2/15/21**	**Fri 3/12/21**
28	**RetainingWall/SheetPile (Patriot Eng)**	**6 wks**	**Mon 2/22/21**	**Fri 4/2/21**
30	**TS1 Support (Manley Bro Eng)**	**15 wks**	**Mon 2/22/21**	**Fri 6/4/21**
31	IFC	15 wks	Mon 2/22/21	Fri 6/4/21
32	**EQUIPMENT PROCUREMENT**	**47 wks**	**Mon 12/14/20**	**Fri 11/5/21**
33	**UCC - Material Handling**	**37.2 wks**	**Mon 12/14/20**	**Mon 8/30/21**
34	Finalize Vendor Pricing	4 wks	Mon 12/14/20	Fri 1/8/21
35	Issue PO	4 wks	Mon 12/28/20	Fri 1/22/21
36	Submit Approval Drawings	3 wks	Mon 1/25/21	Fri 2/12/21
37	Review	17.3 wks	Mon 2/15/21	Tue 6/15/21
38	Receive Certified Drawings	4.2 wks	Tue 6/15/21	Wed 7/14/21
39	**Fabricate and Deliver**	**28.2 wks**	**Mon 2/15/21**	**Mon 8/30/21**
40	**Barge Mounted Equipment & Piping**	**28.2 wks**	**Mon 2/15/21**	**Mon 8/30/21**
41	**Mechanical Equipment**	**27 wks**	**Mon 2/15/21**	**Fri 8/20/21**
42	DC & Rotary Feeders	26 wks	Mon 2/15/21	Fri 8/13/21
43	Compressors & Motors	27 wks	Mon 2/15/21	Fri 8/20/21
44	Conveyor and compressed air piping	22.2 wks	Mon 3/29/21	Mon 8/30/21
45	**ADM Site Equipment & Piping**	**27.5 wks**	**Mon 2/15/21**	**Wed 8/25/21**
46	**Mechanical Equipment**	**27 wks**	**Mon 2/15/21**	**Fri 8/20/21**
54	Conveyor and compressed air piping	21.5 wks	Mon 3/29/21	Wed 8/25/21
55	Silo components & Structural Material	20 wks	Mon 3/15/21	Fri 7/30/21



Vectren Flyash Terminal - Pr
Tue 6/8/21

Critical | Critical Split | Critical Progress | Task | Split | Task Progress | Manual Task | Start-only | Finish-only | Duration-only | Baseline | Baseline Split | Baseline Milestone | Milestone | Summary Progress | Summary | Manual Summary | Project Summary | External Tasks | External Milestone | Inactive Task | Inactive Milestone | Inactive Summary | Deadline

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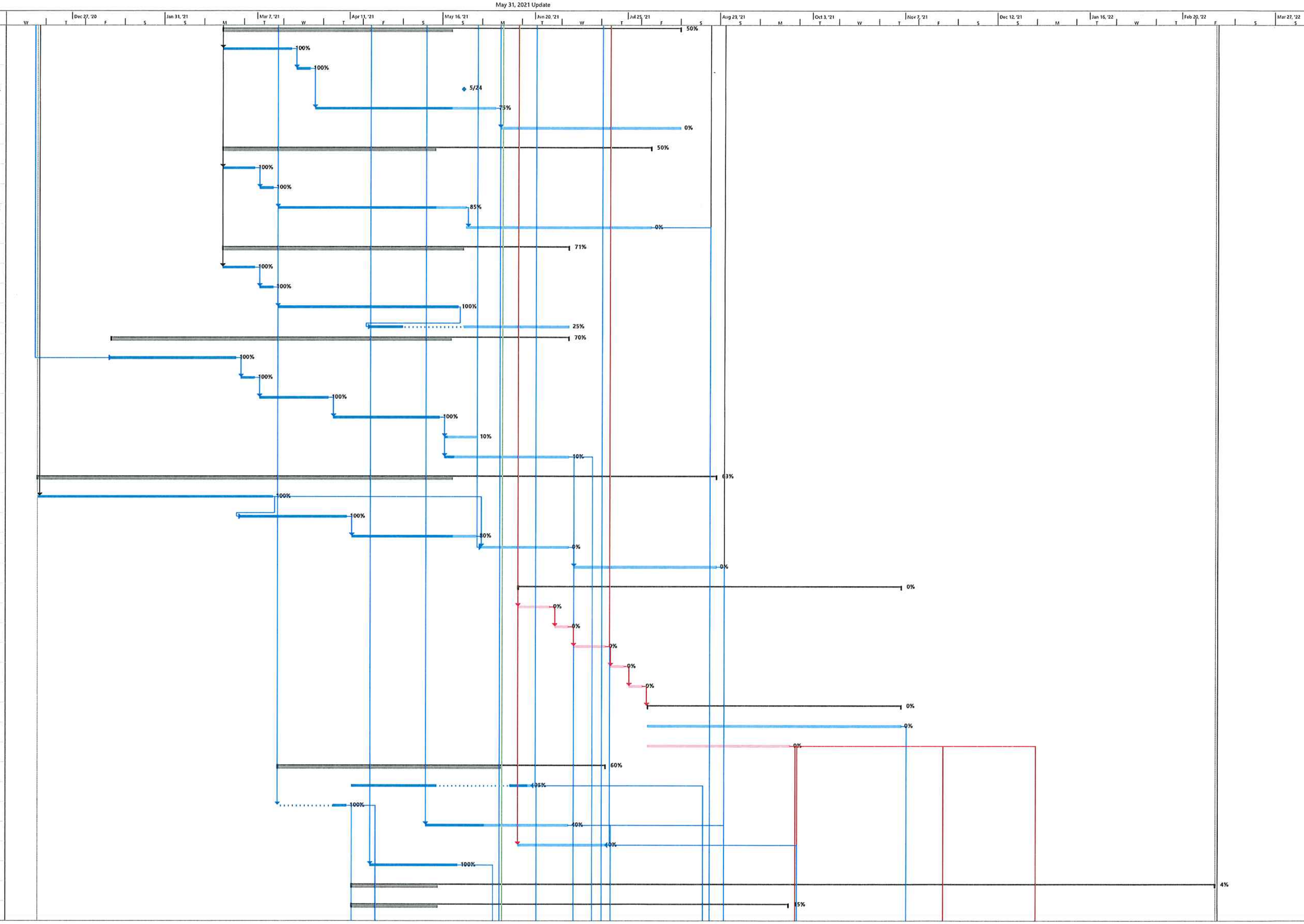
Vectren Terminal Project
PENTA Project #
3020-1211
May 31, 2021 Update

ID	Task Name	Duration	Start	Finish
56	**Gangway & Access Stair Supply**	**25 wks**	**Mon 2/22/21**	**Fri 8/13/21**
57	Finalize Vendor Pricing	4 wks	Mon 2/22/21	Fri 3/19/21
58	Issue PO	1 wk	Mon 3/22/21	Fri 3/26/21
59	Load information Received	0 wks	Mon 5/24/21	Mon 5/24/21
60	Approval & Fabrication Drawings	10 wks	Mon 3/29/21	Fri 6/4/21
61	Fabricate and Deliver	10 wks	Mon 6/7/21	Fri 8/13/21
62	**Bridge & Truck Unloading Pipe Bridge Supply**	**23.2 wks**	**Mon 2/22/21**	**Mon 8/2/21**
63	Finalize Vendor Pricing	2 wks	Mon 2/22/21	Fri 3/5/21
64	Issue PO	1 wk	Mon 3/8/21	Fri 3/12/21
65	Approval Drawings	10.2 wks	Mon 3/15/21	Mon 5/24/21
66	Fabricate and Deliver	10 wks	Tue 5/25/21	Mon 8/2/21
67	**Working Barge Jib Cranes & Hoists**	**19 wks**	**Mon 2/22/21**	**Fri 7/2/21**
68	Finalize Vendor Pricing	2 wks	Mon 2/22/21	Fri 3/5/21
69	Issue PO	1 wk	Mon 3/8/21	Fri 3/12/21
70	Certified Drawings	10 wks	Mon 3/15/21	Fri 5/21/21
71	Fabricate and Deliver	8 wks	Mon 4/19/21	Fri 7/2/21
72	**Silo Procurement**	**25 wks**	**Mon 1/11/21**	**Fri 7/2/21**
73	Finalize Vendor Pricing	7 wks	Mon 1/11/21	Fri 2/26/21
74	Issue Subcontract	1 wk	Mon 3/1/21	Fri 3/5/21
75	Submit Approval Drawings	4 wks	Mon 3/8/21	Fri 4/2/21
76	Review	6 wks	Mon 4/5/21	Fri 5/14/21
77	Receive Certified Drawings	2 wks	Mon 5/17/21	Fri 5/28/21
78	Fabricate and Deliver	7 wks	Mon 5/17/21	Fri 7/2/21
79	**Working Barge Procurement & Modification**	**37 wks**	**Mon 12/14/20**	**Fri 8/27/21**
80	Issue PO	13 wks	Mon 12/14/20	Fri 3/12/21
81	Move Barge to Henderson Dock	6 wks	Mon 3/1/21	Fri 4/9/21
82	Bid Process for Mods & Repairs/ Subcontract	7 wks	Mon 4/12/21	Fri 5/28/21
83	Shop Drawings/ Steel Fab - Submit/Review/Approve	5 wks	Mon 5/31/21	Fri 7/2/21
84	Modify Barge at Henderson Dock to Receive New Equipment	8 wks	Mon 7/5/21	Fri 8/27/21
85	**Electrical - Main Equipment**	**21 wks**	**Mon 6/14/21**	**Fri 11/5/21**
86	Finalize Vendor Pricing	2 wks	Mon 6/14/21	Fri 6/25/21
87	Issue PO	1 wk	Mon 6/28/21	Fri 7/2/21
88	Submit Approval Drawings	2 wks	Mon 7/5/21	Fri 7/16/21
89	Review	1 wk	Mon 7/19/21	Fri 7/23/21
90	Receive Certified Drawings	1 wk	Mon 7/26/21	Fri 7/30/21
91	**Fabricate and Deliver**	**14 wks**	**Mon 8/2/21**	**Fri 11/5/21**
92	Main Equipment	14 wks	Mon 8/2/21	Fri 11/5/21
93	Disconnects, Fixtures & Materials	8 wks	Mon 8/2/21	Fri 9/24/21
94	**Construction Services Procurement**	**18 wks**	**Mon 3/15/21**	**Fri 7/16/21**
95	Marine Construction Subcontract	6 wks	Mon 4/12/21	Fri 6/18/21
96	Civil & Foundation Subcontract	1 wk	Mon 3/15/21	Fri 4/9/21
97	Mechanical, Structural & Piping Subcontract	8 wks	Mon 5/10/21	Fri 7/2/21
98	Electrical & Controls Subcontract	5 wks	Mon 6/14/21	Fri 7/16/21
99	Electrical Grounding Package	5 wks	Mon 4/19/21	Fri 5/21/21
100	**SITE CONSTRUCTION**	**47 wks?**	**Mon 4/12/21**	**Fri 3/4/22**
101	**Civil & Foundation Construction**	**23.9 wks**	**Mon 4/12/21**	**Fri 9/24/21**



Vectren Flyash Terminal - Pr
Tue 6/8/21

Critical | Critical Split | Critical Progress | Task | Split | Task Progress | Manual Task | Start-only | Finish-only | Duration-only | Baseline | Baseline Split | Baseline Milestone | Milestone | Summary Progress | Summary | Manual Summary | Project Summary | External Tasks | External Milestone | Inactive Task | Inactive Milestone | Inactive Summary | Deadline

Cause No. 45564

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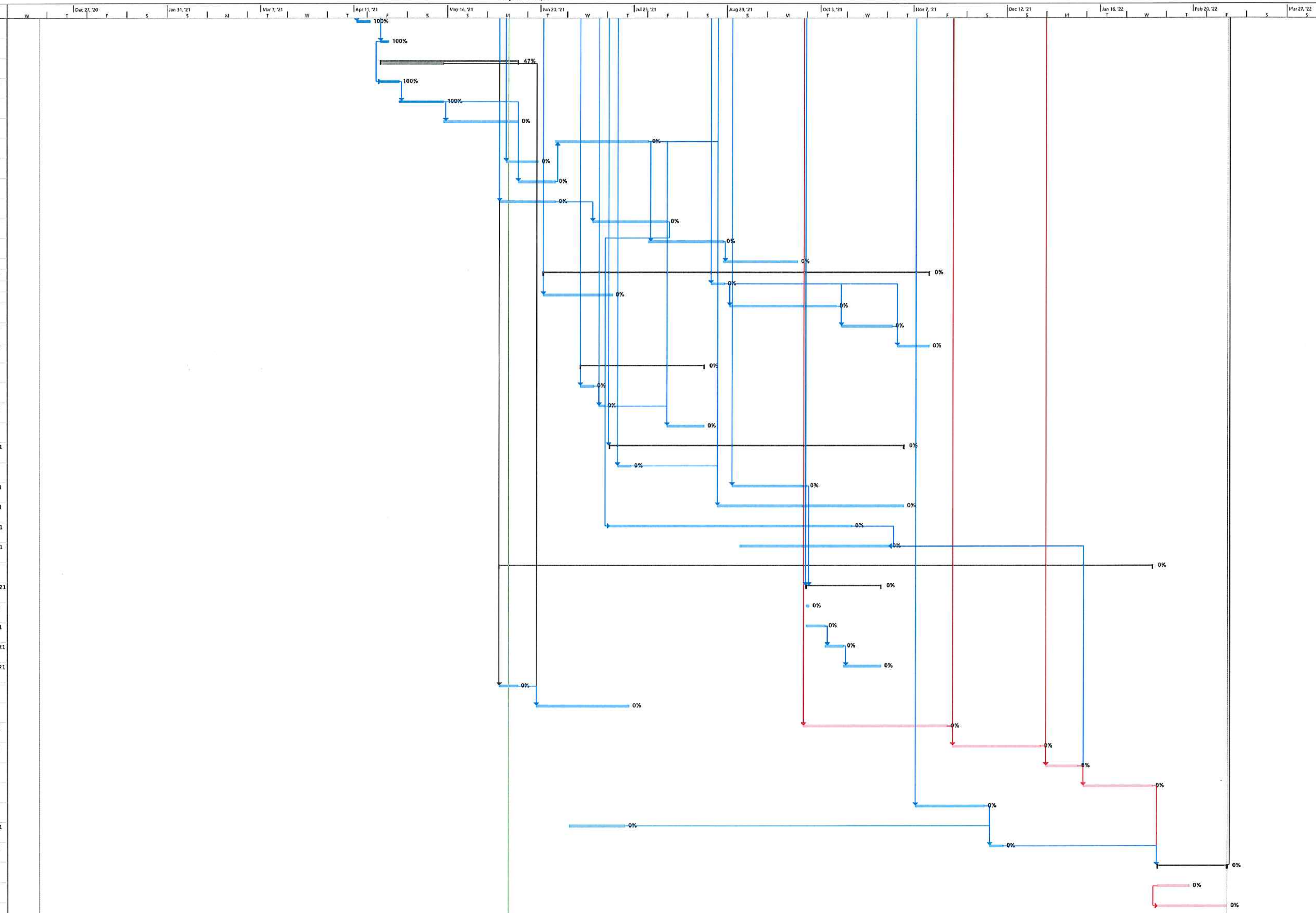
Vectren Terminal Project
PENTA Project #
3020-1211
May 31, 2021 Update

ID	Task Name	Duration	Start	Finish
102	Shop Drawings - Submit/Review/Approve/Fabricate	1 wk	Mon 4/12/21	Fri 4/16/21
103	Mobilize	3 days	Wed 4/21/21	Fri 4/23/21
104	**Civil Work**	**7.5 wks**	**Wed 4/21/21**	**Fri 6/11/21**
105	Clearing, Soil Fencing and Service Ramp	1 wk	Wed 4/21/21	Tue 4/27/21
106	Sheet Pile	2.5 wks	Wed 4/28/21	Fri 5/14/21
107	Soil Test, General Excavation and Soil Stabilization	4 wks	Fri 5/14/21	Fri 6/11/21
108	Foundations - Silo, TS-6, Compressors, Footings etc.	5 wks	Fri 6/25/21	Fri 7/30/21
109	MCC PAD	2 wks	Mon 6/7/21	Fri 6/18/21
110	Piles Land Based - Silo & TS-6	2 wks	Fri 6/11/21	Fri 6/25/21
111	Bridge Piles River Based - TS-5 Thru TS-2 (Low River Level Window)	3 wks	Fri 6/4/21	Fri 6/25/21
112	Bridge Foundations - River Based (Low River Level Window)	4 wks	Fri 7/9/21	Fri 8/6/21
113	Complete Civil Works & Grading around foundations	4 wks	Fri 7/30/21	Fri 8/27/21
114	Entrance Modifications & Final Paving	4 wks	Fri 8/27/21	Fri 9/24/21
115	**Marine Construction**	**21 wks**	**Mon 6/21/21**	**Fri 11/12/21**
116	Mobilize	1 wk	Mon 8/23/21	Fri 8/27/21
117	TS1 Pile Procurement	4 wks	Mon 6/21/21	Fri 7/16/21
118	Install Dolphins/Piles (Low River Level Window)	6 wks	Mon 8/30/21	Fri 10/8/21
119	Receive & Moore Working Barge	3 wks	Mon 10/11/21	Fri 10/29/21
120	Set Working Barge Gangway	2 wks	Mon 11/1/21	Fri 11/12/21
121	**Silo Erection**	**6.9 wks**	**Mon 7/5/21**	**Fri 8/20/21**
122	Mobilize	1 wk	Mon 7/5/21	Fri 7/9/21
123	Receive Silo	2 days	Mon 7/12/21	Tue 7/13/21
124	Erect Silo	2 wks	Fri 8/6/21	Fri 8/20/21
125	**Mechical & Structural Construction**	**15.7 wks**	**Fri 7/16/21**	**Wed 11/3/21**
126	Mobilize - ADM Site	1 wk	Mon 7/19/21	Fri 7/23/21
127	Install Working Barge Mechanical Equipment at Henderson Dock	4 wks	Tue 8/31/21	Mon 9/27/21
128	Install Structural Steel, Mechanical Equipment & Piping - ADM Site	10 wks	Wed 8/25/21	Wed 11/3/21
129	Install Barge Bridge (Low River Level Window)	13 wks	Fri 7/16/21	Thu 10/14/21
130	Complete Mechanical & Piping (Low River Level Window)	8 wks	Fri 9/3/21	Thu 10/28/21
131	**Electrical & Controls Construction**	**35.1 wks?**	**Fri 6/4/21**	**Fri 2/4/22**
132	**Barge Install at Hederson Dock**	**4 wks?**	**Tue 9/28/21**	**Mon 10/25/21**
133	Mobilize - Barge	0.2 wks?	Tue 9/28/21	Tue 9/28/21
134	Mount Disconnects & Lighting & Recepticals	1 wk	Tue 9/28/21	Mon 10/4/21
135	Install Conduit	1 wk	Tue 10/5/21	Mon 10/11/21
136	Pull cables & Make Terminations	2 wks	Tue 10/12/21	Mon 10/25/21
137	Mobilize - ADM Site	1 wk	Fri 6/4/21	Fri 6/11/21
138	Install Grounding	5 wks	Fri 6/18/21	Fri 7/23/21
139	Install Conduit & Cable Tray	8 wks	Mon 9/27/21	Fri 11/19/21
140	Pull Cables & Make Terminations	5 wks	Mon 11/22/21	Fri 12/24/21
141	Install Lighting	2 wks	Mon 12/27/21	Fri 1/7/22
142	Complete Electrical Instalation (Low River Level Window)	4 wks	Mon 1/10/22	Fri 2/4/22
143	Install Main Electrical Equipment & Devices	4 wks	Mon 11/8/21	Fri 12/3/21
144	New UG Electrical Service Installation	3 wks	Thu 7/1/21	Wed 7/21/21
145	Energization of Transformer & MCC	1 wk	Mon 12/6/21	Fri 12/10/21
146	**System Check Out & Commissioning**	**4 wks**	**Mon 2/7/22**	**Fri 3/4/22**
147	Mechanical Dry Commissioning	2 wks	Mon 2/7/22	Fri 2/18/22
148	Electrical Check-Out & Commissioning	4 wks	Mon 2/7/22	Fri 3/4/22



Vectren Flyash Terminal - Pr
Tue 6/8/21

Critical | Critical Split | Critical Progress | Task | Split | Task Progress | Manual Task | Start-only | Finish-only | Duration-only | Baseline | Baseline Split | Baseline Milestone | Milestone | Summary Progress | Summary | Manual Summary | Project Summary | External Tasks | External Milestone | Inactive Task | Inactive Milestone | Inactive Summary | Deadline

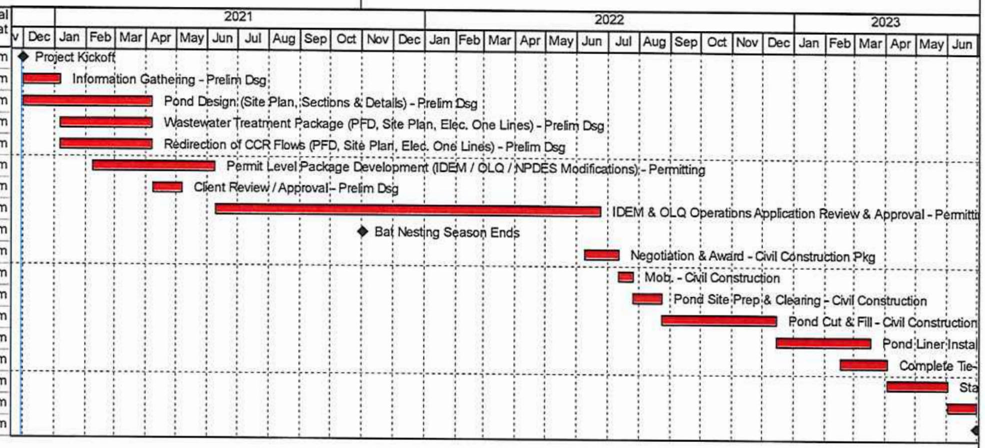
Cause No. 45564

ABB Southside Runoff Pond West Exp._RevC

RevC

Data Date: 30-Nov-20

Activity ID	Activity Name	Orig. Dur.	Start	Finish	Total Float
A1350	Project Kickoff	0.0m	01-Dec-20*		0.0m
A1000	Information Gathering - Prelim Dsg	1.0m	01-Dec-20	07-Jan-21	0.0m
A1020	Pond Design (Site Plan, Sections & Details) - Prelim Dsg	4.0m	01-Dec-20	07-Apr-21	0.0m
A1040	Wastewater Treatment Package (PFD, Site Plan, Elec. One Lines) - Prelim Dsg	3.0m	07-Jan-21	07-Apr-21	0.0m
A1430	Redirection of CCR Flows (PFD, Site Plan, Elec. One Lines) - Prelim Dsg	3.0m	07-Jan-21	07-Apr-21	0.0m
A1030	Permit Level Package Development (IDEM / OLQ / NPDES Modifications) - Permitting	4.0m	08-Feb-21	08-Jun-21	0.0m
A1450	Client Review / Approval - Prelim Dsg	1.0m	08-Apr-21	07-May-21	0.0m
A1100	IDEM & OLQ Operations Application Review & Approval - Permitting	12.0m	09-Jun-21	23-Jun-22	0.0m
A1290	Bat Nesting Season Ends	0.0m		01-Nov-21*	0.0m
A1230	Negotiation & Award - Civil Construction Pkg	1.0m	09-Jun-22	11-Jul-22	0.0m
A1240	Mob. - Civil Construction	0.5m	11-Jul-22	26-Jul-22	0.0m
A1250	Pond Site Prep & Clearing - Civil Construction	1.0m	26-Jul-22	23-Aug-22	0.0m
A1260	Pond Cut & Fill - Civil Construction	3.5m	23-Aug-22	15-Dec-22	0.0m
A1280	Pond Liner Installation - Civil Construction	2.8m	15-Dec-22	17-Mar-23	0.0m
A1630	Complete Tie-In with Pond & Install Pond Pumps - Civil Construction	1.5m	15-Feb-23	03-Apr-23	0.0m
A1370	Startup & Commissioning	2.0m	03-Apr-23	02-Jun-23	0.0m
A1380	Initial Operation	1.0m	02-Jun-23	30-Jun-23	0.0m
A1640	South Side Runoff Pond - West Expansion Complete	0.0m		30-Jun-23*	0.0m

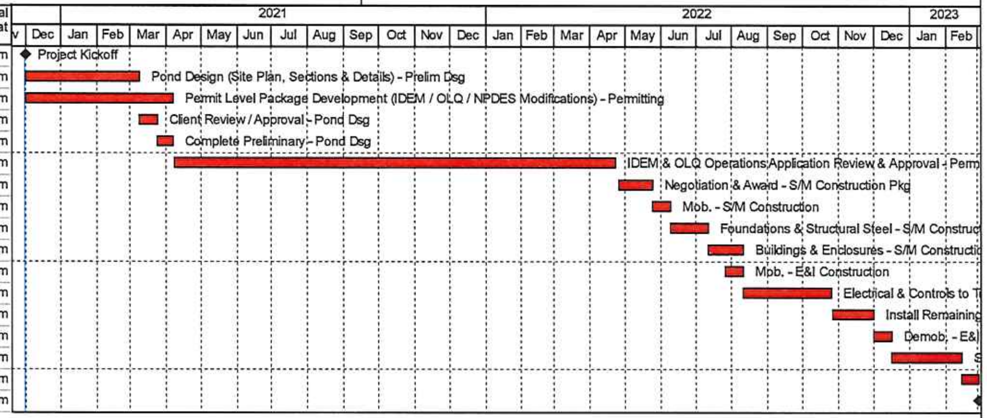


Actual Work | Critical Remaining Work | Summary
Remaining Work | Milestone

AECOM

FBC New Lined CCR Pond_RevH | RevH | Data Date: 30-Nov-20

Activity ID	Activity Name	Orig. Dur.	Start	Finish	Total Float
A1350	Project Kickoff	0.0m	01-Dec-20*		0.0m
A1020	Pond Design (Site Plan, Sections & Details) - Prelim Dsg	3.0m	01-Dec-20	09-Mar-21	0.0m
A1030	Permit Level Package Development (IDEM / OLQ / NPDES Modifications) - Permitting	4.0m	01-Dec-20	07-Apr-21	0.0m
A1450	Client Review / Approval - Pond Dsg	0.5m	09-Mar-21	24-Mar-21	0.0m
A1640	Complete Preliminary - Pond Dsg	0.5m	24-Mar-21	07-Apr-21	0.0m
A1100	IDEM & OLQ Operations Application Review & Approval - Permitting	12.0m	08-Apr-21	22-Apr-22	0.0m
A1600	Negotiation & Award - S/M Construction Pkg	1.0m	25-Apr-22	24-May-22	0.0m
A1620	Mob. - S/M Construction	0.5m	24-May-22	09-Jun-22	0.0m
A1670	Foundations & Structural Steel - S/M Construction	1.0m	09-Jun-22	11-Jul-22	0.0m
A1680	Buildings & Enclosures - S/M Construction	1.0m	11-Jul-22	10-Aug-22	0.0m
A1340	Mob. - E&I Construction	0.5m	26-Jul-22	10-Aug-22	0.0m
A1320	Electrical & Controls to Tie-Point - E&I Construction	2.5m	10-Aug-22	25-Oct-22	0.0m
A1480	Install Remaining Electrical & Controls - E&I Construction	1.0m	26-Oct-22	01-Dec-22	0.0m
A1460	Demob. - E&I Construction	0.5m	01-Dec-22	16-Dec-22	0.0m
A1370	Startup & Commissioning	1.7m	16-Dec-22	14-Feb-23	0.0m
A1380	Initial Operation	0.5m	14-Feb-23	01-Mar-23	0.0m
A1750	Cease Flows to East Ash Pond	0.0m		01-Mar-23*	0.0m



Actual Work | Critical Remaining Work | Summary
Remaining Work | ◆ Milestone

AECOM