

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)
Emergency Order: Orlando Utilities Commission
Regarding the Stanton Energy Center

Order No. 202-26-42

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

EXHIBIT 1

ORDER I



Department of Energy
Washington, DC 20585

Orlando Utilities Commission
Regarding the Stanton Energy Center

Order No. 202-26-26

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),¹ and section 301(b) of the Department of Energy (DOE or the Department) Organization Act,² and for the reasons set forth below, I hereby determine that an emergency exists within the SERC Reliability Corporation (SERC)—Florida Peninsula assessment area due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

The Stanton Energy Center (Stanton) is an electric generating facility in Orlando, Florida. Stanton Unit 1 (464.5 MW)³ is a coal-fired generator owned⁴ and operated by the Orlando Utilities Commission (OUC). Unit 1 began operations in July 1987.⁵ The OUC Board of Commissioners had approved the retirement of Unit 1 by 2025,⁶ and OUC anticipates placing Stanton Unit 1 in an “extended cold shutdown.”⁷ OUC expects to

¹ 16 U.S.C. § 824a(c).

² 42 U.S.C. § 7151(b).

³ U.S. Energy Info. Admin., *Form EIA-860M, Inventory of Operating Generators* (March 2026), (hereinafter EIA, *Form EIA-860M*) <https://www.eia.gov/electricity/data/eia860m/>. Stanton also includes a second coal-fired generation unit, Unit 2 (464.5 MW) and two natural gas-fired combined cycle generation units, Unit B (129.8 MW) and Unit B1 (203.2 MW).

⁴ nFront Consulting LLC, *Orlando Utils. Comm’n 2025 Ten-Year Site Plan*, at 2-3, <https://www.floridapsc.com/pscfiles/website-files/pdf/Utilities/Electricgas/TenYearSitePlans/2026/Orlando%20Utilities%20Commission.pdf> [hereinafter nFront, *OUC 2025 Ten-Year Site Plan*].

⁵ EIA, *Form EIA-860M*, *supra* note 3.

⁶ See, e.g., Michelle Lynch, *Fla. Mun. Elec. Ass’n, OUC’s Bd. of Comm’rs moves to retire Unit 1 coal plant by no later than 2025* (Dec. 15, 2021), <https://www.flpublicpower.com/news/oucs-board-of-commissioners-moves-to-retireunit-1-coal-plant-by-no-later-than-2025>.

⁷ nFront, *OUC 2025 Ten Year Site Plan*, at 6-2. It likely would be difficult for the coal-fired unit to resume operations once retired. Specifically, practical issues, such as employment, contracts, and permits, may greatly increase the timeline for resumption of operations during the period they are needed. Moreover, if OUC were to begin disassembling the unit or other related facilities, the associated challenges would be

make a determination as to Stanton Unit 2 by year end based on an Integrated Resource Plan currently underway.

EMERGENCY CONDITIONS

In its 2025 Long-Term Reliability Assessment (LTRA), released in January 2026, the North American Electric Reliability Corporation (NERC) notes that the SERC–Florida Peninsula assessment area is currently at a “Normal Risk” for long-term energy adequacy.⁸ Nevertheless, the 2025 LTRA highlights that within the SERC–Florida Peninsula assessment area projections for resource and transmission growth lag behind what is needed to support new data centers and other large loads that drive escalating demand forecasts.⁹ Additionally, the 2025 LTRA maintains that new data centers for artificial intelligence and the digital economy account for most of the projected increase in North American electricity demand over the next 10 years.¹⁰ As of April 2026, eight data centers are planned for construction in Florida.¹¹ Total peak demand is expected to increase from 48,628 MW in 2025/2026 to 54,931 MW in 2034/2035.¹²

The 2025 LTRA also notes that, with “the heavy dependence on natural gas in the SERC–Florida Peninsula subregion, fuel diversity could become an area of future concern.”¹³ Further, the 2025 LTRA states that:

[t]he growing penetration of renewable energy means that SERC and the SERC–Florida Peninsula entities will need to continue to monitor the resource adequacy studies and the impact that renewable resources will have. As solar generation

greatly exacerbated. The costs and time of decommissioning a coal plant are extensive, and restarting such decommissioned plants would presumably cost the same as decommissioning in dollars and time, if not more. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist. See Jennifer Lessick et al., *Business Models for Coal Plant Decommissioning*, at 9–12 (Aug. 2021), https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-31348.pdf.

⁸ N. Am. Elec. Reliability Corp., *2025 Long-Term Reliability Assessment*, at 23 (Jan. 2026), https://prod.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf [hereinafter NERC, *2025 LTRA*].

⁹ *Id.* at 6.

¹⁰ *Id.* at 9.

¹¹ See Skyler Seets & Kaitlyn Radde, *Most new data centers in the U.S. are coming to rural areas*, PEW RESEARCH CENTER (Apr. 13, 2026), <https://www.pewresearch.org/?p=299017>.

¹² See Fla. Reliability Coordinating Council, Inc., *2025 Reg'l Load & Res. Plan FRCC-MS-PL-642 Version: 1*, at 6 (2025), https://www.floridapsc.com/pscfiles/website-files/PDF/Utilities/Electricgas/TenYearSitePlans//2025/FRCC_RLRP.pdf.

¹³ See NERC, *LTRA*, *supra* note 9, at 116.

continues to grow, the need to ensure the availability of quick start generating units to meet the ramp in demand will increase.¹⁴

OUC resource adequacy concerns were most recently demonstrated during Winter Storm Fern, when OUC requested two section 202(c) emergency orders to preserve the reliability of the bulk electric power system due to anticipated unusually high load forecasts from unusual cold weather conditions throughout the entire state of Florida: (i) one application¹⁵ for 2.7 GW of specified resources (generating units)¹⁶ and (ii) another¹⁷ for 55 MW of back-up generators.¹⁸ As a result, DOE issued two 202(c) emergency orders to OUC from January 31 through February 6: (i) Order No. 202-26-11 for specified resources,¹⁹ and (ii) Order No. 202-26-15 for back-up generators.²⁰ OUC leveraged the 202(c) orders to meet demand during extreme cold weather conditions. Stanton Unit 1 produced 66,230 MWh between January 31, 2026 and February 6, 2026.²¹ The back-up generating units reported over 400 hours of run-time under the respective Order.

According to OUC, customer demand was projected to exceed record-breaking thresholds for OUC on Sunday, February 1, 2026, and again on Monday, February 2, 2026, and maybe throughout the following week.²² OUC had projected that it may not have sufficient generation available to meet the unusually high demand and may be forced to curtail load in order to maintain the security and reliability of the grid.²³ In January 2026, Stanton Units 1 and 2 produced a total of 249,473 MWh from coal-fired generation.²⁴

¹⁴ *Id.*

¹⁵ OUC 202(c) Application (Jan. 31, 2026).

¹⁶ OUC Specified Resources (Exhibit A to 202(c) Application) (Jan. 31, 2026).

¹⁷ OUC 202(c) Application – Backup Generators (Jan. 31, 2026).

¹⁸ OUC 202(c) Application Exhibit A – Backup Generators (Jan. 31, 2026).

¹⁹ *Orlando Utils. Comm’n*, Order No. 202-26-11 (Jan. 31, 2026).

²⁰ *Orlando Utils. Comm’n*, Order No. 202-26-15 (Jan. 31, 2026).

²¹ See U.S. Env’t Prot. Agency, CAMPD (Clean Air Markets Program Data), <https://campd.epa.gov/data/custom-data-download> (choose “Emissions” from “Data Type” dropdown; then choose “Daily Emissions” from “Data Subtype” dropdown; then choose “Unit (No Aggregation)” from the “Aggregation” dropdown; then click “Apply”; then click “Time Period” button and enter “January 31, 2026” as “Start Date” and February 6, 2026 as “End Date”; then click “Facility” and select “Curtis H. Stanton Energy Center”; then click “Apply Filter”; then click “Preview Data”).

²² Letter from Clint Bullock, Gen. Manager & CEO, Orlando Utils. Comm’n, to The Honorable Chris Wright, Sec’y, Dept. of Energy (Jan. 31, 2026) (requesting emergency order under FPA section 202(c)), <https://www.energy.gov/documents/ouc-202-c-application-backup-generators>.

²³ *Id.*

²⁴ EIA, *Form EIA-923, Schedule 4: Generator Data* (Apr. 2026), <https://www.eia.gov/electricity/data/eia923/>.

According to NERC’s 2026 Summer Reliability Assessment, the SERC–Florida Peninsula is a summer-peaking assessment area.²⁵ It further notes that “[t]emperature and precipitation forecasts for the coming summer show a higher likelihood of hotter-than-normal temperatures in the U.S. South”²⁶ For the SERC–Florida Peninsula, the anticipated reserve margin is projected to be 25.8%; however, the anticipated reserve margin drops to 13.6% in the event of “higher demand, outages, [or] derates in extreme conditions.”²⁷

Executive orders issued by President Donald J. Trump on January 20, 2025, and April 8, 2025, underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order No. 14156, “Declaring a National Energy Emergency,” in which he determined that the “United States’ insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation’s economy, national security, and foreign policy.”²⁸ The Executive Order adds: “Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets.” In the subsequent Executive Order No. 14262, “Strengthening the Reliability and Security of the United States Electric Grid,” President Trump emphasized that “the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing.”²⁹

Further, the Department of Energy detailed the myriad challenges affecting the Nation’s energy systems in its July 2025 “Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid,” which was issued pursuant to the President’s directive in Executive Order No. 14262. The Department concluded that, “[a]bsent decisive intervention, the Nation’s power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation.”³⁰

²⁵ North American Electric Reliability Corporation, 2026 Summer Reliability Assessment, at 28 (May 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_sra_2026.pdf.

²⁶ *Id.* at 4.

²⁷ *Id.* at 10.

²⁸ Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025), <https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency>.

²⁹ Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025), <https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid>.

³⁰ DOE, RES. ADEQUACY REP.: EVALUATING THE RELIABILITY & SEC. OF THE U.S. ELEC. GRID (Jul. 7, 2025), <https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf>.

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines “that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy,” then the Secretary has the authority “to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in [his] judgment will best meet the emergency and serve the public interest.”³¹ This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Stanton Unit 1, when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity, or a shortage of electric energy or facilities for generation or transmission of electric energy.

As described above, the conditions resulting from the combination of increasing demand and shortage will continue on in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and local businesses in the areas affected by curtailments or power outages, presenting a risk to public health, and safety.

I have determined that, under the conditions specified below, continued availability of Stanton Unit 1 is necessary to best meet the emergency arising from increased demand for electric energy, shortage of facilities for the generation of electric energy, and other causes, thus serving the public interest pursuant to FPA section 202(c).

To ensure that Stanton Unit 1 will be available if needed to address emergency conditions, it shall remain in operation through September 1, 2026.

³¹ Although the text of FPA section 202(c) grants this authority to “the Commission,” section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).

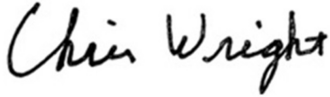
Based on my determination of an emergency set forth above, I hereby order:

- A. From June 4, 2026, OUC shall take all measures necessary to ensure that Stanton Unit 1 is not placed in extended cold shutdown and is available to operate.³² Following the conclusion of this Order, sufficient time for orderly ramp down will be permitted, consistent with industry practices.
- B. To minimize adverse environmental impacts, this Order limits operation of Stanton Unit 1 to the times and within the parameters as determined by OUC pursuant to paragraph A. OUC shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Stanton Unit 1 has operated in compliance with the allowances contained in this Order.
- C. All operations of Stanton Unit 1 must comply with applicable environmental requirements, including, but not limited to, monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency conditions or to use other geographic or temporal flexibilities available to generators.
- D. By June 18, 2026, OUC is directed to provide the Department (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Stanton Unit 1, consistent with this Order. OUC shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, as requested by the Department of Energy from time to time.
- E. OUC is directed to file with the Federal Energy Regulatory Commission any tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).
- F. This Order shall not preclude the need for Stanton Unit 1 to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.
- G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Stanton Unit 1 shall not be considered a capacity resource.

³² According to OUC, neither Florida Municipal Power Pool (FMPP) in its role as the Balancing Authority nor Florida Reliability Coordinating Council (FRCC) in its role as the Reliability Coordinator directs OUC to operate Stanton 1 in a manner similar to organized markets.

- H. This Order shall be effective from June 4, 2026, through September 1, 2026, with the exception of applicable compliance obligations in paragraph D.
- I. OUC is directed to provide the Department at least fifteen days' prior advance notice in writing before any change in operational status or otherwise of Stanton Unit 2 occurs.

Issued in Washington, D.C. on this 4th day of June 2026.



Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Florida Public Service Commissioners
Chairman Gabriella Passidomo Smith
Commissioner Gary F. Clark
Commissioner Mike La Rosa
Commissioner Bobby Payne
Commissioner Ana Ortega

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)
Emergency Order: Orlando Utilities Commission
Regarding the Stanton Energy Center

Order No. 202-26-42

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

EXHIBIT 2

DOE ORDER NO. 202-22-4



Department of Energy

Washington, DC 20585

Order No. 202-22-4

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and delegated by email correspondence (Dec. 23, 2022), and for the reasons set forth below, I hereby determine that an emergency exists in the electricity grid operated by PJM Interconnection, LLC (PJM) due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

On December 24, 2022, PJM, the Regional Transmission Operator (RTO) for 65 million people in thirteen states and the District of Columbia (the PJM Region), filed a *Request for Emergency Order Under Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department) “to preserve the reliability of the bulk electric power system.”

The PJM Region, like many regions across the country, is currently being affected by a severe winter weather system. PJM states that this weather system caused a significant drop in temperatures across the PJM Region on December 23, 2022, accompanied by high winds in excess of 40 mph. As a consequence of the impact of wind and decreasing temperatures, the demand for electricity in the PJM Region rose to an unusually high peak load on the evening of December 23, 2022, in excess of 135,000 MW. This severely cold weather is expected to last through Sunday morning.

While the vast majority of generating units in the PJM Region continue to function adequately under these stressed conditions, some units have experienced operating difficulties due to cold weather or fuel limitations, primarily gas. Specifically, approximately 45,000 MW of generating units (the majority of which are thermal) are currently outaged or derated. PJM has expressed its concern that these units will be unable to return to service over at least the next 48 hours, which coincides with the time period for which PJM is requesting this Order. Since these units may not promptly return to service, and in the event PJM experiences additional generating unit outages, PJM states that it may need to curtail some amount of firm load on December 24, December 25, or December 26, 2022 in order to maintain the security and reliability of the PJM system.

Description of Mitigation Measures

In its Application, PJM identifies the measures it is taking to ensure the supply of generation will continue to be sufficient to meet system demand and reserve requirements. On December 20, 2022, PJM issued a cold weather advisory in the PJM Region in anticipation of the forecasted weather conditions. Then on December 23, 2022, PJM issued

a PJM Region-wide cold weather alert which further highlighted PJM's expected need to call higher-than-normal generation resources in light of the anticipated weather.

On December 23, 2022, generating reserves diminished to a level that required PJM to declare an Energy Emergency Alert (EEA) Level 2 and take other emergency actions. PJM states that after having exhausted economic operation, PJM triggered a Maximum Generation Emergency Action to increase the PJM Region generation above the maximum economic level. Further, PJM triggered its load management reduction actions to provide additional load relief by using PJM-controllable load management programs. PJM called on demand response providers and curtailment service providers to reduce load. PJM also issued public appeals for consumers to reduce usage. PJM has continued to employ these emergency actions through December 24, 2022, and anticipates needing to continue them through the order end date that it has requested.

Since December 23, 2022, PJM has also taken additional measures to provide additional reserves, including:

- Reducing exports to neighboring regions and requested shared reserves for neighboring regions; consistent with joint operating agreements and other regulatory requirements, PJM has continued to communicate and collaborate with its interconnected neighboring systems when the demand on the PJM system has exceeded expected energy and reserve requirements and when emergency transfers were required to support PJM's interconnected neighboring systems;
- Issuing additional public conservation appeals;
- Running uneconomic generation during lower load periods to ensure their availability during peak conditions;
- Utilizing its Emergency Procedures to assist in maximizing the pumped storage hydro generation levels;
- Communicating and preparing transmission and distribution service providers to implement distribution voltage reduction measures; and
- Communicating and preparing transmission and distribution service providers to implement firm load shed.

In its Application, PJM committed to continue to take such actions, including utilizing other supply resources before calling upon any generators to operate in excess of permitting levels. According to PJM, it is nevertheless possible that the measures it has and will take may not be sufficient to avoid the need to curtail firm load in order to ensure system reliability.

Request for Order

PJM requests that the Secretary issue an order immediately, effective today, December 24, 2022, through 12:00 p.m. Eastern Time on Monday, December 26, 2022, authorizing the electric generating units identified in Exhibit A, as well as any other

generating units subject to emissions or other permit limitations in the PJM Region to operate up to their maximum generation output levels under the limited circumstances described in this Order, notwithstanding air quality or other permit limitations. The generating units (Specified Resources) that this Order pertains to are listed on the Order 202-22-4 Resources List, as described below.

ORDER

Given the emergency nature of the expected load stress, the responsibility of PJM to ensure maximum reliability on its system, and the ability of PJM to identify and dispatch generation necessary to meet the additional load, I have determined that, under the conditions specified below, additional dispatch of the Specified Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on, among other things:

- The emergency nature of the expected load stress caused by the current cold weather event threatens to cause loss of power to homes and local businesses in the areas that may be affected by curtailments, presenting a risk to public health and safety.
- The expected shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes in the PJM Region demonstrate the need for the Specified Resources to contribute to the reliability of the PJM Region.
- PJM is responsible to ensure maximum reliability on its system, and, with the authority granted in this Order, its ability to identify and dispatch generation, including the Specified Resources, necessary to meet the additional load resulting from the cold weather event is enhanced.

In line with the anticipated circumstances precipitated by the cold weather event, this Order is limited to the period beginning with the issuance of this Order on December 24, 2022 through 12:00 pm Eastern Time on December 26, 2022. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the “hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable,” be consistent with any applicable environmental law and minimize any adverse environmental impacts. PJM anticipates that this Order may result in exceedance of emissions of sulfur dioxide, nitrogen oxide, mercury, and carbon monoxide emissions, as well as wastewater release limits. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes.

Based on my determination of an emergency set forth above, I hereby order:

A. From the time this Order is issued on December 24, 2022, to 12:00 pm Eastern Time on December 26, 2022, in the event that PJM determines that generation from the Specified Resources is necessary to meet the electricity demand that PJM anticipates in the PJM Region during this event, I direct PJM to dispatch such unit or units and to order their operation only as needed to maintain the reliability of the power grid in the PJM Region when the demand on the PJM system exceeds expected energy and reserve requirements. Specified Resources are those generating units set forth on the Order 202-22-4 Resource List, subject to updates directed here and as described in paragraph D, which the Department shall post on www.energy.gov.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes. Consistent with good utility practice, PJM shall exhaust all reasonably and practically available resources, including available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions, to the extent that such resources provide support to maintain grid reliability, prior to dispatching the Specified Resources. PJM shall provide a daily notification to the Department reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

In furtherance of the foregoing and, in each case, subject to the exhaustion of all available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions available to support grid reliability:

- (i) For any generation resource whose operator notifies PJM that the unit is unable, or expected to be unable, to produce at its maximum output due to an emissions or other limit in any federal environmental permit, and during the pendency of a PJM-triggered Maximum Generation Emergency Action, at any point before 12:00 Eastern Time on Monday, December 26, 2022, the unit will be allowed to exceed any such limit only during any period for which PJM has declared an Energy Emergency Alert (EEA) Level 2 or Level 3 (during which time PJM will have triggered a Maximum Generation Emergency Action), except as described in item (iii) below in certain limited circumstances in anticipation of an EEA Level 2. Once PJM declares that the EEA Level 2 event has ended, the unit would be required to immediately return to operation within its permitted limits. And at all other times, the unit would be required to operate within its permitted limits, except for the limited exceptions provided herein for operations in anticipation of an EEA Level 2 to prevent the cycling of units or facilitate the charging or pumping of other resources necessary for the EEA Level 2.
- (ii) For any generation resource whose operator notifies PJM that the unit is offline or would need to go offline at any point before 12:00 Eastern Time on Monday, December 26, 2022, due to an emissions or other limit in any

federal environmental permit, PJM may direct the unit operator to bring the unit online, or to keep the unit online, and to operate at the level consistent with its permits but subject to the exceptions set forth in this Order. In this circumstance, the operator is allowed to make all of the unit's capacity available to PJM for dispatch during any period for which PJM has declared an EEA Level 2 or 3 (during which time PJM has triggered a Maximum Generation Emergency Action), except as described in item (iii) below in certain limited circumstances in anticipation of an EEA Level 2. Once PJM declares that such an EEA Level 2 event has ended and the Maximum Generation Emergency Action is discontinued, the unit would be required to immediately return to operating at a level below the higher of its minimum operating level or the maximum output allowable under the permitted limit.

- (iii) PJM is hereby granted authority to operate the Specified Units that are combined cycle generating units in certain limited circumstances in advance of declaring an EEA Level 2, Maximum Generation Emergency, or in between such events, where such operation or continued operation of the Specified Resource is reasonably necessary to avoid shutting down and restarting the Specified Unit. PJM has represented that such cycling of units can cause reliability issues regarding restarting, delays, and increased emissions during startup. PJM is further authorized to operate the Specified Units in certain limited circumstances in advance of the declaring an EEA Level 2, Maximum Generation Emergency where such operation or continued operation of the Specified Resource is reasonably necessary to facilitate charging storage resources or pumping for pumped storage facilities that will be needed during an anticipated EEA Level 2. PJM is required to take measures to dispatch units for which cycling would otherwise be required in a manner reasonably intended to limit the duration and operating level of those units in such a way as to minimize exceedance of permit limitations consistent with the security and reliability of the PJM Region.
- (iv) To minimize adverse environmental impacts as set forth herein, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes. Consistent with good utility practice, and notwithstanding standard merit order dispatch, PJM shall exhaust all reasonably and practically available resources, including available imports, demand response and identified behind-the-meter generation resources selected to minimize an increase in emissions to the extent that such resources provide support to maintain grid reliability prior to dispatching the Specified Resources at levels above their permitted emissions levels. PJM shall provide a daily notification to the Department reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

C. All operation of the Specified Resource must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. In the event that PJM identifies additional generation units that it deems necessary to operate in excess of federal environmental permitting limits in order to maintain the reliability of the power grid in the PJM Region when the demand on the PJM system exceeds expected energy and reserve requirements, PJM shall provide prompt written notice to the Department of Energy at AskCR@hq.doe.gov with the name and location of those units that PJM has identified, as well as additional notice by the same means through updating Exhibit A to its Application with such additional generation units, the fuel type of such unit, and the anticipated category of environmental impact, at 09:00 Eastern Time or 21:00 Eastern Time, whichever follows closest in time to the unit identification by PJM to the greatest extent feasible. Such additional generation unit shall be deemed a Specified Resource for the purpose of this Order for the hours prior to the required written notice to the Department updating Exhibit A, and PJM may dispatch such additional generation units, provided that if the Department of Energy notifies PJM that it does not approve of such generation unit being designated as a Specified Resource, such generation unit shall not constitute a Specified Resource upon notification from the Department. The Department shall post an updated Order 202-22-4 Resource List as soon as practicable following notification from PJM under this paragraph.

E. PJM shall provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time. By January 26, 2023, PJM shall report all dates between December 24, 2022, and December 26, 2022, inclusive, on which the Specified Resources were operated, the hours of operation, and exceedance of permitting limits, including sulfur dioxide, nitrogen oxide, mercury, carbon monoxide, and other air pollutants, as well as exceedances of wastewater release limits. PJM shall submit a final report by February 27, 2023, with any revisions to the information reported on January 26, 2023. The environmental information submitted in the final report shall also include the following information:

- (i) Emissions data in pounds per hour for each Specified Resource unit, for each hour of the operational scenario, for CO, NO_x, PM₁₀, VOC, and SO₂;
- (ii) Emissions data must include emissions (lbs/hr) calculated consistent with reporting obligations pursuant to operating permits, permitted operating/emission limits, and the actual incremental emissions above the permit limits;

- (iii) The number and actual hours each day that each Specified Resource unit operated in excess of permit limits or conditions, e.g., “Generator #1; December 25, 2022; 4 hours; 04:00-08:00 CT”;
- (iv) Amount, type and formulation of any fuel used by each Specified Resource;
- (v) All reporting provided under the Specified Resource’s operating permit requirements over the last three years to the United States Environmental Protection Agency or local Air Quality Management District for the location of a Specified Resource that operates pursuant to this Order;
- (vi) Additional information requested by DOE as it performs any environmental review relating to the issuance of this Order; and
- (vii) Information provided by the Specified Resource describing how the requirements in paragraph C above were met by the Specified Resource while operating under the provisions of this Order.

In addition, PJM shall provide information to the Department quantifying the net revenue in aggregate associated with generation in excess of environmental limits in connection with orders issued by the Department pursuant to Section 202(c) of the Federal Power Act.

F. PJM shall take reasonable measures to inform affected communities where all Specified Resources operate that PJM has been issued this Order, in a manner that ensures that as many members of the community as possible are aware of the Order, and explains clearly what the Order allows PJM to do. At a minimum, PJM shall post a description of this Order on its website (with a link to this Order) and identify the name, municipality or other political subdivision, and zip code of Specified Resources covered by this Order, as the Specified Resources may be updated pursuant to paragraph D above. In addition, in the event that a Specified Resource operates pursuant to this Order, a general description of the action authorized by this Order will be included in any press release issued by PJM with respect to the cold weather event and will include a reference to the website posting required by the preceding sentence for further information. PJM shall describe the actions taken to comply with this paragraph in the reports delivered to the Department pursuant to paragraph E above.

G. This Order shall not preclude the need for the Specified Resource to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

H. PJM shall be responsible for the reasonable third-party costs of performing analysis of the environmental and environmental justice impacts of this Order, including any analysis conducted pursuant to the National Environmental Policy Act.

I. This Order shall be effective upon its issuance, and shall expire at 12:00 Eastern Time on Monday, December 26, 2022, with the exception of the reporting requirements in

Department of Energy Order No. 202-22-4

paragraph E. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 5:30 PM Eastern Standard Time on this 24th day of December 2022.

Undersecretary of Energy for Infrastructure

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)
Emergency Order: Orlando Utilities Commission
Regarding the Stanton Energy Center

Order No. 202-26-42

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

EXHIBIT 3

RMI ANALYSIS OF COAL PLANTS' THREATS TO RELIABILITY

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ARTICLE

August 12, 2025

Reality Check: We Have What's Needed to Reliably Power the Data Center Boom, and It's Not Coal Plants

A range of clean, resilient solutions can help us meet the electrical needs of our growing digital economy while saving Americans money.

By Gabriella Tosado, Ashtin Massie, and Joe Daniel

After decades of relatively flat electricity demand, the US power sector is expecting demand to grow due, in large part, to new data centers. These energy-intensive facilities are reshaping the grid, with some utilities now projecting over 20 percent load growth by 2035. In places like Virginia, which constitutes 13 percent of all reported data center capacity globally and 25 percent of the data center capacity in the United States, data centers already account for over a quarter of some utilities' total electric demand, and their footprint is only growing.

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of electricity demand, are a brittle, outmoded technology that threatens to undermine the very grid resilience they're being proposed to protect.

Reality #1: Aging coal plants are failing to consistently deliver under stress

Coal plants face a fundamental constraint: they are aging and increasingly unreliable. Most of the coal fleet was built in the 1970s and 1980s, and years of wear and tear have led to a rise in unplanned outages. In many cases the sheer cost to maintain and modernize these plants did not make sense with the availability of more reliable and affordable alternatives — and that's still the case.

According to the Energy Systems Integration Group (ESIG) *Ensuring Efficient Reliability* report, a coal plant's capacity accreditation, or the amount of time it can contribute to peak demand, is only 83 percent when adjusted for real-world performance. PJM also has capacity accreditation of coal plants at 83 percent and some plants fare even worse. Gridlab's reliability study found Colstrip, a large regional coal plant in Montana, operating with a capacity accreditation of only 54 percent — meaning it's effectively unavailable nearly half the time it's needed.

Extreme weather exacerbates these vulnerabilities. Cold snaps, heat waves, and storms have all exposed coal's fragility during grid stress events. Reliability is not just about being dispatchable, it's about delivering performance under stress. Coal plants struggle to do that consistently. For coal plants to truly meet the constant demands of data centers, they would need to run at high-capacity factors and avoid major outages, all of which fly in the face of current performance trends. If a large coal plant trips offline while supporting a cluster of data centers, the sudden loss of supply could lead to cascading failures across the grid. This is because generation must equal load at all times, datacenter or no datacenter. As a result, relying on coal plants to support these

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supporting large, fast-changing loads like data centers. Coal units are inherently inflexible: they ramp slowly, respond poorly to sudden load shifts, and are difficult to turn on or off quickly. This rigidity is a poor match for the dynamic and often unpredictable nature of data center demand. Further, inflexible coal plants can worsen grid congestion; by occupying limited transmission capacity with inflexible generation, they prevent cheaper or cleaner resources from being delivered. This issue has already been flagged by independent market monitors in regions like MISO — which covers 15 US states and a Canadian province — where congestion-related market distortions have cost over \$1 billion a year. Coal plants displace faster-responding resources that are better suited to follow load. And the stakes are high.

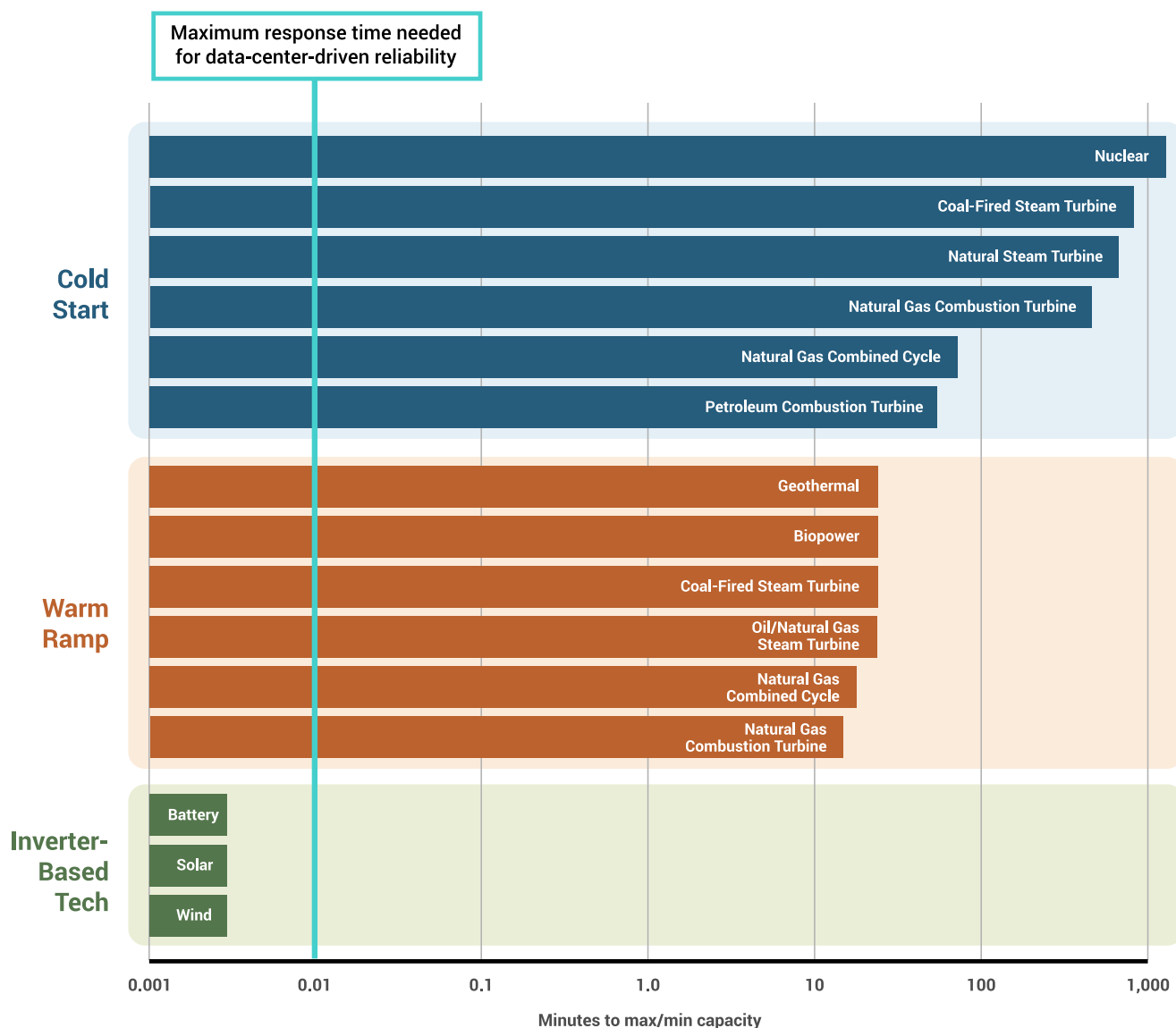
As noted by the North American Electric Reliability Corporation (NERC), large, voltage-sensitive loads like data centers require flexible, responsive grid solutions, not slow-ramping generators that can take 12 or more hours to come online. NERC's recent *Incident Review and Guidance on Voltage-Sensitive Large Load Integration* describes an event in 2024 where a transmission fault triggered a sudden disconnection of 1,500 megawatts of voltage-sensitive data center load, leading to sharp frequency and voltage spikes that required operator intervention. The incident exposes the system's vulnerability to instability when inflexible generation cannot respond to large load fluctuations.

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Minutes needed for a power plant to reach max/min capacity



If a data center either loses access to load or goes offline rapidly, a grid's generation needs to respond at sub-second speeds. The average coal plant ramp rate is 4 percent per minute which translates to spending over 20 minutes to respond to a large load event. From a cold start, the average coal plant would take over 12 hours to reach max

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The good news is that we don’t need to rely on brittle coal plants to meet the needs of a digital economy. A range of cleaner, more resilient solutions is already available – and scalable. For example, we recently found that more than 95 percent of future demand can be met with fast, scalable, and clean solutions:

Alternative near-term solutions to meet load growth

Technology	Opportunity
Energy Efficiency	Over 50 GW of energy efficiency can be deployed – by both creating programs for new loads and expanding existing programs aligned with system needs. Energy efficiency can unlock benefits beyond system cost savings , improving comfort and resilience in homes.
Virtual Power Plants	60 GW of virtual power plants can be deployed by 2030, with programs stood up and enrolled in under 6 months. Policymakers in Virginia recently passed a bill that requires 450 MW of VPPs deployed rapidly to meet growing demand.
Advanced Transmission Technologies	Grid enhancing technologies and reconductoring can unlock over 80 GW of incremental peak capacity by reducing transmission and interconnection constraints. Lawmakers in New Mexico passed a bill requiring utilities to assess the use these technologies in plans to get more out of the existing grid.
Clean Repowering	There is 14 GW of fossil-fuel generation expected to retire , that could serve as sites for quick addition of new renewable energy and storage while reducing system costs. Market operators like PJM are enabling clean repowering by updating rules to allow for surplus interconnection .
	New load can be co-located with renewable energy at the

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Technologies like battery storage, demand flexibility, and clean energy portfolios offer practical, cost-effective options that align with modern load dynamics. As we noted in a recent [article](#), by running coal plants only when it is economical to do so and using the extra transmission headroom that creates to reinvest with clean energy upgrades, our grid can support the next wave of economic growth with the flexibility it demands. There are reasons to manage the shift to new, clean resources [thoughtfully and intentionally](#), but propping up coal plants that are not suited for the job is a step in the wrong direction.

Related Topics

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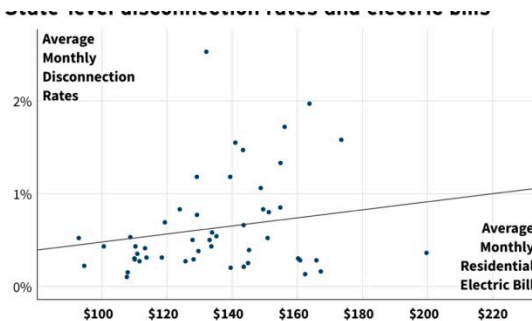


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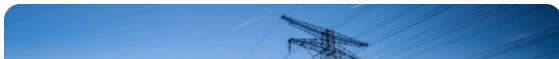


Clean Energy 101: The Changing Electricity Grid

101

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)
Emergency Order: Orlando Utilities Commission
Regarding the Stanton Energy Center

Order No. 202-26-42

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

EXHIBIT 4

DOE ORDER NO. 202-17-4 SUMMARY OF FINDINGS

Summary of Findings Department of Energy Order No. 202-17-4

September 14, 2017

Section 202(c) of the Federal Power Act (FPA) (codified at 16 U.S.C. § 824a(c)), through section 301(b) of the Department of Energy Organization Act (codified at 42 U.S.C. § 7151(b)), authorizes the Secretary of Energy, upon finding “that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes,” to issue an order “requir[ing] . . . such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in [the Secretary’s] judgment will best meet the emergency and serve the public interest.” 16 U.S.C. § 824a(c)(1). If the order “may result in a conflict with [an] environmental law or regulation,” then the Secretary must “ensure that such order requires generation, delivery, interchange, or transmission of electric energy only during hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable, is consistent with any applicable . . . environmental law or regulation and minimizes any adverse environmental impacts.” *Id.* § 824a(c)(2). Orders issued under FPA section 202(c) “that may result in a conflict with [an] environmental law or regulation” expire 90 days after they are issued, but the Secretary “may renew or reissue such order[s] . . . for subsequent periods, not to exceed 90 days for each period, as [the Secretary] determines necessary to meet the emergency and serve the public interest.” *Id.* § 824a(c)(4)(A).

The Department’s regulations implementing FPA section 202(c) define the term “emergency” to mean, among other situations, “a specific inadequate power supply situation.” 10 C.F.R. § 205.371. The regulations do not exhaustively list what qualifies as an emergency, but they note specifically that “[e]xtended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities can result in an emergency as contemplated in these regulations.” *Id.*

On June 13, 2017, PJM filed a *Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (Order Application) (included in the docket¹ of this Order) with the Department “to preserve the reliability of [the] bulk power transmission system in the North Hampton Roads area.” Virginia Electric and Power Company² (Dominion), the electric utility serving the area, owns the coal-fired, power generating Units 1 and 2 at the Yorktown Power Station in Yorktown, Virginia. In November 2011 and October 2012, Dominion notified PJM of its plan to deactivate Units 1 and 2, respectively, effective December 31, 2014, because the units were not equipped to

¹ The docket of this Order is available at <https://www.energy.gov/oe/downloads/federal-power-act-section-202c-dominion-energy-virginia-june-2017>.

² See Dominion Energy, Inc., Form 10-Q filing, at 1 (Aug. 3, 2017), included in the docket of this Order.

comply with the Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards (MATS), 40 C.F.R. part 63 subpart UUUUU. On June 24, 2014, pursuant to 40 C.F.R. § 63.6(i)(4)(i)(A), the Virginia Department of Environmental Quality granted Dominion a one-year MATS compliance extension for Yorktown Units 1 and 2.

On April 16, 2016, pursuant to section 113(a) of the Clean Air Act, 42 U.S.C. § 7413(a)(3) and (4), the EPA issued an Administrative Compliance Order (ACO) through April 15, 2017. The ACO implemented a 2011 MATS Enforcement Policy regarding issuance of section 113(a) administrative orders to sources that are unable to comply with the MATS but that may need to operate for up to a year to address a specific and documented reliability concern. The 2011 MATS Enforcement Policy was limited in application to units critical for reliability purposes. The EPA found that operation of Yorktown Units 1 and 2 met the policy criteria, as verified by the Federal Energy Regulatory Commission (FERC). Dominion has not achieved full compliance with the MATS for Yorktown Units 1 or 2 since the ACO expired, and section 113(a) of the Clean Air Act bars further compliance extensions.

Since Dominion's decision to retire the coal-fired Yorktown units, PJM has planned for their permanent deactivation by including required transmission upgrades in its own Regional Transmission Expansion Planning Process. PJM is subject to federal reliability standards enforced by the North American Electric Reliability Corporation (NERC), the Electric Reliability Organization designated by FERC. PJM holds the highest-level reliability responsibilities for the system it manages as a certified Reliability Coordinator, Balancing Authority, and Transmission Operator. PJM is also registered with NERC as a Planning Coordinator and Transmission Planner, among other functions. NERC Compliance Registry Active Entities List (updated Sept. 7, 2017), included in the docket of this Order. PJM applies reliability criteria to evaluate transmission system conditions and then develops the transmission solutions needed to ensure compliance with the reliability standards. The PJM Board of Managers approves those solutions in a Regional Transmission Expansion Plan (RTEP). Through its Transmission Expansion Advisory Committee (TEAC) and Sub-Regional RTEP Committees, PJM works with stakeholders throughout the RTEP's development. PJM Manual 14B, "Regional Planning Process," included in the docket of this Order. The PJM Board of Managers approved the transmission upgrades necessitated by the retirement of Yorktown Units 1 and 2 on May 17, 2012. TEAC Recommendations to the PJM Board (PJM Staff Whitepaper), May 2012, at 12, included in the docket of this Order.

PJM's approved solution was the Skiffes Creek Transmission Project, which consists of three components: a 500kV line, a 230kV line rebuild, and a new switching station. United States Army Corps of Engineers (Army Corps), Memorandum for the Record re: Department of the Army Environmental Assessment and Statement of Findings for the Above-Referenced Standard Individual Permit Application, CENAO-WR-RS (NAO-2012-00080 / 13-V0408), at 1, included in the docket of this Order. A

number of issues in the North Hampton Roads area, many of which are interrelated, needed to be addressed to avoid overloading transmission lines with too much power, as detailed in PJM's Deactivation Study. Yorktown Units 1 and 2 Generator Deactivation Notification: Deactivation Study Results – updated June 26, 2017 (PJM Deactivation Study), included in the docket of this Order. *See also Va. Elec. & Power Co.*, Commission Comments on Requests for EPA Administrative Orders, Docket No. AD16-11-000, 153 FERC ¶ 61,265 at PP 14-16 (2015).

PJM completed a series of analyses consistent with RTEP procedures, finding that only the Skiffes Creek Transmission Project—and none of the stakeholder-proposed alternatives—addressed the full range of potential reliability violations. Order Application, app. I, at 16. For example, reliance on operation of the oil-fired Yorktown Unit 3 generator would not address thermal overload and voltage violations on the 230kV and 115kV bulk electric system that PJM identified because of significant environmental operating restrictions and other plant operation constraints associated with that unit, including an 8 percent capacity factor limitation. *See id.*, app. II, at 18. As a result, PJM did not recommend reliance on Yorktown Unit 3 as a sustainable alternative solution to the identified reliability criteria violations. *Id.*

As part of PJM's analyses, Dominion transmission staff provided PJM with an analysis of system needs as well as potential solutions to the retirement of generating units at Yorktown and elsewhere. Dominion Update to Retirement Study Results (Mar. 10, 2012), included in the docket of this Order. Dominion's analysis, which was based on PJM's initial determination of reliability criteria violations that needed to be addressed, was independently validated by PJM and publicly vetted through the PJM stakeholder process before PJM staff recommended that the Board of Managers approve the Skiffes Creek Transmission Project. PJM Staff Whitepaper at 12, included in the docket of this Order.

PJM, as the Regional Transmission Organization (RTO) responsible for transmission system operation across multiple states, including Virginia, maintains its expert determination that the Skiffes Creek Transmission Project is the most effective and efficient solution to address the identified reliability criteria violations. Order Application, app. I, at 16. As recently as March 1, 2017, PJM provided the Army Corps with an analysis of proposed alternatives and found that none of them sufficiently resolved the identified violations. Letter to Col. Jason E. Kelly, U.S. Army Corps of Engineers (Mar. 1, 2017), included in the docket of this Order. PJM's subsequent RTEP materials reaffirm the need for the Skiffes Creek Transmission Project, even considering the updated, steadily rising load forecasts in the recently released 2017 PJM Load Forecast Report (included in the docket of this Order). *See* PJM Interconnection, L.L.C., 2017 RTEP Process Scope & Input Assumptions, rev. 1, at 25-27 (Aug. 3, 2017), included in the docket of this Order.

Construction of the Skiffes Creek Transmission Project began in July 2017 and is expected to take approximately 18-20 months. *Order No. 202-17-2 Renewal Application Filing* (Renewal Application) at 3. Until the Project is completed, a plan known as the North Hampton Remedial Action Scheme (RAS) remains in effect. According to NERC's Glossary of Terms, a RAS is "[a] scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation ([megawatts] and [megavolt amperes (reactive)]), tripping load, or reconfiguring a System(s)." Glossary of Terms Used in NERC Reliability Standards (updated Aug. 1, 2017), at 24, included in the docket of this Order.

To preserve the grid's reliability, the North Hampton RAS would allow PJM, the grid operator, to drop load—that is, shut off power to certain customers—to prevent voltage collapse. Dominion presented this RAS to PJM in January 2017, and the SERC Reliability Corporation, the NERC-delegated regional reliability enforcement entity, approved it that same month. See Dave Rees, *Dominion Virginia Power Sets Plan for Emergency Blackouts*, Daily Press, Jan. 13, 2017, included in the docket of this Order. If Yorktown Units 1 and 2 were unavailable, many N-1-1 contingencies could result in voltage collapse and thermal overloads. New Remedial Action Scheme, North Hampton RAS (Presentation to PJM), at 4, included in the docket of this Order; PJM Deactivation Study, included in the docket of this Order. According to FERC, "An N-1-1 contingency is a sequence of events consisting of an initial loss of a single generator or transmission element, followed by system adjustment, followed by another loss of a single generator or transmission element." *Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket No. AD14-14-000, 153 FERC ¶ 61,221 at P 30 n.61 (2015).

The North Hampton RAS is on standby for use at PJM's discretion. If PJM detects the loss of certain facilities, it could trip the remaining feeds to the Yorktown area and drop service to approximately 150,000 customers, preventing voltage collapse. Rotating outages would follow until the system returns to normal operating parameters. New Remedial Action Scheme, North Hampton RAS (Presentation to PJM), at 6, included in the docket of this Order. According to U.S. Census estimates, the region PJM identifies as the North Hampton Roads load area in its Order Application had a population of more than 660,000 as of July 2016. At a minimum, rotating outages under the RAS would therefore impact, directly or indirectly, several hundred thousand people. United States Census Bureau, QuickFacts database, available at <https://www.census.gov/quickfacts/fact/table/US/PST045216>.

On July 3, 2017, the Army Corps issued a permit to Dominion for the Skiffes Creek Transmission Project pursuant to section 10 of the Rivers and Harbors Act of 1899 (33 U.S.C. § 403) and section 404 of the Clean Water Act (33 U.S.C. § 1344). On July

10, 2017, Dominion commenced construction of the Skiffes Creek Transmission Project. Renewal Application at 3.

On August 24, 2017, PJM filed its Renewal Application with DOE. The filing included all reports required by Order No. 202-17-2 (included in the docket of this Order). PJM said that construction of the Project was still expected to take 18-20 months, and that periodic transmission outages would be necessary to proceed apace with the Project. The same day, Dominion wrote to the Department that it “agrees with the Renewal Application and will operate in accordance with its provisions.” Further, Dominion acknowledged that a 202(c) order “is not a long term solution to the reliability issues in the North Hampton Roads area on the Virginia Peninsula.” The Skiffes Creek Transmission Project, underway as of July 2017, is the long-term solution.

On September 7, 2017, the Department received comments from Sierra Club opposing PJM’s renewal request. On September 13, 2017, the Department received an answer to Sierra Club’s comments from PJM. Both documents are included in the docket of this Order.

Discussion

Order No. 202-17-2 directs operation of Yorktown Units 1 and 2 as needed to address reliability issues, subject to a dispatch methodology submitted to the Department for review. The reliability issues noted in Order No. 202-17-2 were described as Scenario One, increased load due to weather-related temperature extremes, and Scenario Two, decreased transmission capacity required by the RTEP upgrade. Scenario Two was contemplated but not yet applicable when Order No. 202-17-2 was issued because the Army Corps permit application for the Skiffes Creek Transmission Project was still pending. On July 3, the Army Corps issued Permit No. NAO-2012-00080, resulting in the potential need to operate Yorktown Units 1 and 2 to address both Scenario One and Two reliability issues. To date, in accordance with Order No. 202-17-2, PJM has directed operation of Yorktown Units 1 and/or 2 for all or part of 13 days. PJM Interconnection, L.L.C., Report on Yorktown Units 1 and 2 Operations Pursuant to Order No. 202-17-2, Attachment 1, included in the docket of this Order; Telephone call to Steven Pincus, Associate General Counsel, PJM, Sept. 11, 2017.

Scenario One applies when load conditions exceed a certain threshold due to local transmission issues that would cause PJM to operate the system outside its normal operating parameters.³ Weather-related temperature extremes are one example of such a local transmission issue. Scenario Two is also triggered when load conditions exceed a certain threshold, but the threshold is lowered depending on the particular construction-related transmission outages in effect as the Skiffes Creek Transmission Project is built.

³ Exact load thresholds were submitted as critical electric infrastructure information and are thus not described here so as not to provide vulnerability information on critical infrastructure.

Because the Project minimizes environmental impacts by utilizing existing transmission line rights-of-way to the extent possible, portions of existing transmission lines must be taken offline for upgrades. Under either scenario, when the relevant thresholds are exceeded, to prevent system overload and uncontrolled power disruptions, PJM must implement the North Hampton RAS. The only sufficient alternative to the RAS and its resulting outages for up to approximately 150,000 customers is the emergency operation of Yorktown Units 1 and 2. The demand response available to PJM is a small fraction of the load threshold and is “not sufficient to ensure reliable service.” Order Application, app. II, at 18. Likewise, Dominion has limited demand-side management and curtailment capabilities, insufficient for reliability purposes even when fully deployed. *See id.*, app. III, at 21.

Activating the RAS would immediately interrupt service to load in the North Hampton Roads area. PJM asserts that, according to the RAS, during certain high load conditions, this “load shedding” could result in the loss of roughly 950 MW of electric power—that is, the loss of service to over 150,000 North Hampton Roads area customers. Order Application at 9. This service interruption could last hours or even days. *See* North Hampton RAS Presentation to PJM, at 8, included in the docket of this Order. Activating the RAS is not a gradual approach that presents a wide range of likely impacts; it is an extreme measure with immediate consequences to 150,000 customers. While the RAS is designed to prevent more catastrophic, uncontrolled grid impacts from occurring, load shedding of this magnitude is significant, and would trigger mandatory reporting both to DOE and FERC. DOE Form OE-417 requires reporting within one hour for “[l]oad shedding of 100 Megawatts or more implemented under emergency operational policy,” and within six hours for “[l]oss of electric service to more than 50,000 customers for 1 hour or more.” This is the same level of reporting triggered by a cyber or other hostile attack on grid resources. Form OE-417, Electric Emergency Incident and Disturbance Report, https://www.oe.netl.doe.gov/docs/OE417_Form_03312018.pdf. Similarly, FERC and NERC mandate notification for a variety of serious events including when a bulk electric system emergency triggers automatic load shedding of 100 MW or more, as in the RAS. *See* North American Electric Reliability Corporation, Reliability Standard EOP-004-3 (Event Reporting), http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-004-3&title=Event%20Reporting.

To underscore the potential impact of RAS activation, the estimated 150,000 impacted customers are counted by meter, not individual. One or more meters could translate to large household or commercial or industrial facilities, including those critical to health and safety systems. Whether counted as 150,000 or that amount multiplied several times over, the anticipated impact of this emergency situation is on par with or exceeds the impacts described in prior 202(c) orders. *Crisp Cnty. Power Comm’n v. Ga. Power Co.*, 35 FPC 629, 630-31 (1966) (ordering interconnection to prevent, in part,

outages lasting more than an hour and affecting 500 to 2,000 customers on Crisp County, Georgia's system). *City of Cleveland, Ohio v. Cleveland Elec. Illuminating Co.*, 47 FPC 747, 749 (1972) (ensuring reliable service was provided to the approximately 20% of the city's consumers). Cleveland's 1970 Census-reported population was 750,903, suggesting that just over 150,000 individuals were affected by the 1972 202(c) order. See <https://www.census.gov/population/www/documentation/twps0027/tab20.txt>. As described earlier, the U.S. Census estimated the population of the North Hampton Roads load area at nearly 661,000 people just over a year ago.

A benefit of the planning efforts mandated by federal reliability standards is that entities such as PJM can accurately forecast the impacts to the bulk power system in steady-state and various contingency event situations. Thus, as reliability planning continues to mature, there should be fewer electric energy shortages that take bulk power system owners, operators, and regulators by surprise. That planners can identify conditions under which shortages may occur, however, does not rule out electric energy shortages constituting emergencies under FPA section 202(c) and the Department's implementing regulations. It is impossible to plan for every contingency, and challenges may arise even when implementing the most prudent plans. FPA section 202(c) affords the Secretary of Energy discretion in finding when an emergency exists and how best to meet the emergency and serve the public interest.

Here, an emergency exists due to the imminent possibility of implementing the North Hampton RAS under a range of both steady-state and contingency events, including potential transmission congestion preventing the delivery of available generation to the North Hampton Roads area. PJM Deactivation Study at 1-2, included in the docket of this Order. The RAS would leave approximately 150,000 customers without power, including residential, industrial, commercial, health and safety facilities, major national defense, and educational institutions. See Order Application, app. IV, at 30-31. That creates serious health and safety issues. Issuance of today's Order meets the emergency and serves the public interest.

In these circumstances, transmission outages, like those contemplated for or otherwise in connection with the construction of the Skiffes Creek Transmission Project, constitute an emergency for purposes of a section 202(c) order. As stated earlier, the Department's implementing regulations, in their current form since 1981, contemplate that "[e]xtended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities [may create] an emergency." 10 C.F.R. § 205.371. The regulations add that "[i]n such cases, the impacted 'entity' will be expected to make firm arrangements to resolve the problem until new facilities become available, so that a continuing emergency order is not needed." *Id.* PJM, the impacted entity in this case, requested today's Order. Through the RTEP, PJM made firm arrangements to resolve the problem through the Skiffes Creek Transmission Project, which is now permitted and under construction. That construction was delayed due to events beyond

PJM's control has no bearing on the likelihood of power outages for 150,000 customers. Such a power loss event would also constitute an emergency as contemplated by FERC in its Public Utility Regulatory Policies Act of 1978 regulations, which define "system emergency" as "a condition on a utility's system which is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property." 18 C.F.R. § 292.101(b)(4). The risk faced by 150,000 customers will continue, assuming the Skiffes Creek Transmission Project construction schedule is met, for approximately another 18 months. Today's Order is limited in time and specifically tailored to address an emergency contemplated both in the authorizing statute and the Department's implementing regulations.

Between 2005 and 2007, DOE issued orders under similar circumstances, directing the Mirant Potomac River Generation Station to operate until two new 230kV transmission lines could be built to ensure reliability to a portion of the District of Columbia. See Order No. 202-5-3 (relying on DOE regulatory definition of emergency as including extended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities). In a series of orders under FPA section 202(c), the Secretary ordered operation of the generation units while the two existing 230kV lines that supplied the central District of Columbia area were temporarily and sequentially removed from service to connect the new lines. Neither the problems leading up to the closure of the generating units nor the need for a particular transmission solution were unexpected. Nevertheless, the Department found that imminent power shortages, faced if contingency events occurred, constituted an emergency under the Federal Power Act. Order Nos. 202-5-3, 202-6-1, 202-6-2, 202-7-1, and 202-7-2.

In this matter, the likelihood of RAS activation is not theoretical. While Order No. 202-17-2 was in effect, PJM had to call upon Yorktown Units 1 and/or 2 on 13 days over three months. Absent Order No. 202-17-2, the RAS would have been activated instead. The alternatives available to PJM and Dominion are not sufficient to ensure reliability without available capacity from Yorktown Units 1 and 2. As described, PJM and Dominion cannot mobilize adequate alternatives to counter the loss of transmission during construction of the Skiffes Creek Transmission Project. For example, demand response resources, while potentially helpful at the margin, are insufficient to address either Scenario One or Scenario Two. See Order Application, app. II, at 18. Further, PJM's recent RTEP Input Assumptions and Scope Whitepaper indicates that Dominion theoretically has up to 130 MW of distributed solar generation available during the summer. 2017 RTEP Process Scope and Input Assumptions, rev. 1, tbl.3.2, at 18 (Aug. 3, 2017), included in the docket of this Order. Outside of ramp-up and ramp-down times, each Yorktown Unit typically ran at 100 MW output or higher, day or night, when operational while Order No. 202-17-2 was in effect. PJM Interconnection, L.L.C., Report on Yorktown Units 1 and 2 Operations Pursuant to Order No. 202-17-2, Attachment 1. Distributed generation is an intermittent resource; even under ideal conditions, with full-capacity, daytime generation and load reduction at the height of the

summer, distributed generation generally would still not have offset the baseload generating capacity needed to ensure reliability on the North Hampton Roads area grid. And any flexibility for scheduling the Skiffes Creek Transmission Project's construction during historically low-load periods ended when the EPA ACO expired, as expeditious completion of the Project is now the priority. Therefore, even if PJM and Dominion made full use of available alternatives, capacity from Yorktown Unit 1, 2, or both would still be necessary to meet the emergency and serve the public interest.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law or regulation be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable, [be] consistent with any applicable . . . environmental law or regulation and minimize[] any adverse environmental impacts." Certain load conditions may necessitate operation of Yorktown Units 1 and 2.

To minimize the hours of operation and adverse environmental impacts, the Order contains certain limitations. First, DOE maintains consistency with EPA's approach in the 2016 ACO by authorizing operation of Yorktown Units 1 and 2 only when called upon by PJM for reliability purposes. The Department consulted with EPA and has reviewed data provided by PJM and Dominion on operations, air emissions, and water usage. This Order will continue the operational limitations described in EPA's above-referenced ACO, AED-CAA-113(a)-2016-0005. Second, DOE requires that PJM and Dominion, consistent with good utility practice, first exhaust all reasonably and practically available resources, including demand response and behind-the-meter generation resources, before operating Yorktown Units 1 and 2. Third, DOE requires continued compliance with the June 27 dispatch methodology, which was reviewed by the Department, and which remains subject to continuing oversight by the Department. In particular, the dispatch methodology establishes Yorktown Units 1 and 2 commitment procedures, describes the utilization and trip conditions of the North Hampton RAS for mitigating congestion on the Virginia Peninsula or North Hampton Roads area, and describes Dominion's mitigation options for the existing James River tower contingency. The dispatch methodology is an operating protocol that limits the ability of PJM to dispatch Yorktown Units 1 and 2 only when needed to mitigate reliability issues associated with scheduled and emergency transmission outages directly related to the Skiffes Creek Transmission Project and other local transmission issues. The EPA ACO recognized that such a dispatch methodology, under which PJM determines when the Yorktown units are needed for reliability issues, serves the objective of minimizing emissions. ACO at 8-9, included in the docket of this Order. Fourth, to track when Yorktown Units 1 and 2 are operated to maintain grid reliability and to monitor associated air emissions and water usage, reports will be required every two weeks going forward. If the Department becomes concerned with PJM or Dominion's compliance with this Order, enforcement actions are available, up to and including termination of the underlying order.

While DOE has constrained PJM's operations with regard to Yorktown Units 1 and 2, it is necessary to preserve reasonable discretion for PJM, as a Transmission Operator, to address the second-to-second operational challenges of grid management. This follows DOE's practice in earlier orders issued under FPA section 202(c), which prioritized reliability concerns as identified and assessed by the operator. For example, Order No. 202-02-1 (Aug. 16, 2002) ordered Cross-Sound Cable Company, LLC to operate a cable across Long Island Sound, limiting "transmission and delivery of . . . electric capacity and/or energy [to that] necessary in the judgment of the New York Independent System Operator [ISO] to meet the supply and essential reserve margin needs of the Long Island Power Authority [LIPA]," but only "in order for LIPA to serve its firm retail customers after it has implemented all available load reduction measures consistent with good utility practice." Order No. 202-03-1 (Aug. 14, 2003) directed operation of the same cable, but specifically ordered the New York ISO and ISO New England to require Cross-Sound Cable Company to operate the cable. That order also required both RTOs to "consult with each other and with appropriate reliability organizations." Today's Order similarly requires PJM to identify and mitigate reliability issues in accordance with DOE's specified operational limitations.

In considering renewal or reissuance of an order under FPA section 202(c) that may conflict with an environmental law or regulation, DOE is required to "consult with the primary Federal agency with expertise in the environmental interest protected by such law or regulation" and to include "conditions as such Federal agency determines necessary . . . to the extent practicable." 16 U.S.C. § 824a(c)(4). The EPA is the primary federal agency in this case with expertise in the protected environmental interest, specifically MATS and section 316(b) of the Clean Water Act, and the Department consulted with EPA after receiving the Renewal Application. Email from Acting Assistant Administrator Starfield, Office of Enforcement and Compliance Assurance, to Acting Under Secretary for Science and Energy Hoffman (Sept. 11, 2017), included in the docket of this Order. After consulting with EPA, and consistent with that consultation, the Department found that the only appropriate short-term emissions limitation on Yorktown Units 1 and 2 would be to curtail operating hours to the maximum extent practical for reliability purposes.

Pursuant to the National Environmental Policy Act of 1969, the Department has determined that issuance of this Order fits within the category of actions included in Categorical Exclusion (CX) B4.4 and otherwise meets the requirements for application of a CX. The Order fits within the category of actions because it authorizes "[p]ower marketing services and power management activities (including, but not limited to, storage, load shaping and balancing, seasonal exchanges, and other similar activities), provided that the operations of generating projects would remain within normal operating limits." Records of Categorical Exclusion Determination, Order No. 202-17-4, Sept. 11, 2017, included in the docket of this Order.

Summary of Findings for Department of Energy Order No. 202-17-4

For the reasons stated above, the Secretary of Energy finds that an emergency exists threatening imminent electric energy shortages, and that this Order is necessary to address the emergency and serve the public interest in the North Hampton Roads area. The limitations on operation set forth in Order No. 202-17-4 and outlined above are, to the maximum extent practicable, consistent with applicable environmental laws or regulation and minimize any adverse environmental impacts, and the reporting requirements for operations and estimated emissions ensure transparency of implementation.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)
Emergency Order: Orlando Utilities Commission
Regarding the Stanton Energy Center

Order No. 202-26-42

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

EXHIBIT 5

OUC 2026 TYSP



Orlando Utilities Commission 2026 Ten-Year Site Plan

Prepared by:
nFront Consulting LLC
April 2026



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1.0 EXECUTIVE SUMMARY

This report documents the 2026 Orlando Utilities Commission (“OUC”) Ten-Year Site Plan pursuant to Section 186.801 Florida Statutes and Section 25-22.070 of Florida Administrative Code. OUC’s Ten-Year Site Plan provides information required by this rule and consists of the following additional sections:

- Utility System Description (Section 2.0)
- Strategic Issues (Section 3.0)
- Forecast of Peak Demand and Energy Consumption (Section 4.0)
- Demand-Side Management (Section 5.0)
- Forecast of Facilities Requirements (Section 6.0)
- Supply-Side Alternatives (Section 7.0)
- Economic Evaluation Criteria and Methodology (Section 8.0)
- Analysis and Results (Section 9.0)
- Environmental and Land Use Information (Section 10.0)
- Conclusions (Section 11.0)
- Ten-Year Site Plan Schedules (Section 12.0)

In December 2020 OUC finalized an Electric Integrated Resource Plan (“EIRP”), which provides a roadmap to enable OUC to achieve its goal of Net Zero Carbon by 2050, as well as interim goals of 50% carbon emissions reductions by 2030 and 75% carbon emissions reductions by 2040 as compared to 2005 levels. The first major steps outlined to achieve these carbon reduction targets were to convert one coal fired generating unit (Stanton Energy Center Unit 1) to cleaner-burning natural gas no later than 2025, convert the other coal unit (Stanton Energy Center Unit 2) to cleaner-burning natural gas no later than 2027, and install 1,524 MWac of solar and 350 MW of energy storage by 2030. OUC anticipates refreshing its EIRP within the next 12 months.

In September 2021, OUC purchased the Osceola Generating Station (“OGS”), which better enables large-scale solar farms by mitigating the intermittency of solar power, the utility’s most viable source of renewable energy. The purchase of OGS also allows OUC to place its oldest coal-fired power plant, Stanton Unit 1 located in East Orange County at the utility’s Stanton Energy Center (“SEC”), into extended cold shutdown by the end of May 2026 in lieu of converting this unit to cleaner burning natural gas. The OGS purchase further provides OUC an extra layer of resiliency with emergency backup fuel to help prevent power disruption events as seen in Texas in early 2022 and elsewhere in the United States since then.

The purchase of OGS from Genova, a Texas-based private ownership group, will further diversify OUC’s generation fleet. OGS is comprised of three separate turbines, known in the industry as “peakers,” which can turn on and off quickly as opposed to the larger, Stanton Unit 1 turbine that requires more fuel and takes many hours to turn on. OGS can power up in just minutes. The acquisition of OGS and placing Stanton Unit 1 into extended cold shutdown will change OUC’s generation portfolio, making it more flexible in managing intermittent resources, and most importantly, as OUC’s primary goal, reducing carbon dioxide (“CO₂”) emissions.

OUC remains committed to meeting the EIRP’s objectives, which include increasing solar energy and other renewable resources for electric generation, and reducing carbon dioxide emissions by 50% by 2030 and 75% in 2040 as compared to 2005 levels before reaching Net Zero emissions by 2050.

OUC continues to increase solar energy, having added approximately 256 MW since late 2020. Meanwhile, OUC is exploring energy storage solutions and the use of other clean energy assets in addition to investing in electrification programs that would result in further carbon dioxide reductions and cleaner air for our community.

OUC continues to assume responsibility for supplying all of the City of St. Cloud (“St. Cloud”) loads through calendar year 2042. Load forecasts for OUC and St. Cloud have been integrated into one forecast, and details of the aggregated load forecast are provided in Section 4.0, including base-case growth, high-growth, and low-growth scenarios.

OUC has contracts to provide power to the City of Winter Park (“Winter Park”) through calendar year 2026, the City of Mount Dora (“Mt. Dora”) through 2030, the City of Chattahoochee (“Chattahoochee”) through 2027, and Lakeland Electric (“Lakeland”) through 2026. The power OUC is currently planning to provide to Winter Park, Mt. Dora, Chattahoochee, and Lakeland is summarized in Section 2.0.

OUC is a member of the Florida Municipal Power Pool (“FMPP”), which consists of OUC, Lakeland, and the Florida Municipal Power Agency (“FMPA”) All-Requirements Project. Power for OUC is supplied by units owned entirely by OUC, as well as units in which OUC maintains joint ownership and power purchases. OUC’s total capacity as of January 1, 2026, including capacity from units owned by OUC, St. Cloud’s entitlement to Stanton Energy Center Unit 2, and OUC’s current power purchases (including natural gas, landfill gas, and solar resources), provides total net summer capacity of approximately 2,593 megawatts (“MW”) and total net winter capacity of approximately 2,502 MW¹.

As discussed throughout this Ten-Year Site Plan, consideration of OUC’s current generating resources (including existing and planned power purchase agreements) and OUC’s current base-case load forecast indicate that OUC is projected to have adequate capacity to satisfy forecast reserve margin requirements through 2035.

¹ Net seasonal capacity ratings as of January 1, 2026. Includes capacity owned by OUC and St. Cloud, as well as OUC’s contractual power purchases.

2.0 UTILITY SYSTEM DESCRIPTION

At the turn of the 20th century, John M. Cheney, an Orlando, Florida judge, organized the Orlando Water and Light Company and supplied electricity on a part-time basis with a 100-kilowatt (“kW”) generator. Twenty-four-hour service began in 1903. The population of the City of Orlando (“City”) had grown to roughly 10,000 by 1922, and Cheney, realizing the need for wider services than his company was capable of supplying, urged his friends to work and vote for a \$975,000 bond issue to enable the citizens of Orlando to purchase and municipally operate his privately-owned utility. The bond issue passed by a margin of almost three to one, as did a subsequent issue for additional improvements. The citizens of Orlando acquired Cheney’s company and its 2,795 electricity and 5,000 water customers for a total initial investment of \$1.5 million.

In 1923, OUC was created by the state legislature as an independent statutory commission with its own Board as a part of the government of the City. OUC was granted full authority to operate electric and water municipal utilities. The business was a paying venture from the start. By 1924, the number of customers had more than doubled. When Orlando citizens took over operation of their utility, the City’s population was less than 10,000; by 1925, it had grown to 23,000.

OUC has full authority over the management and control of the electric and waterworks plants in the City, those it has built or acquired and has been approved by the Florida legislature to offer these services in Osceola County, as well as Orange County. OUC’s charter has been amended a number of times since 1923 and it now allows it to undertake, among other things, the acquisition, construction, operation, and maintenance of electric generation, transmission, and distribution systems, chilled water systems, as well as water production, transmission, and distribution systems, to meet the requirements of its customers. In addition, OUC offers a variety of energy and compliance services through interlocal agreements with other municipal utilities.

In 1997, OUC entered into an Interlocal Agreement with the City of St. Cloud in which OUC assumed operational control of St. Cloud’s electric systems and the responsibility for supplying all of St. Cloud’s loads for the 25-year term of the agreement, which added an additional 150 square miles of service area. OUC also assumed management of St. Cloud’s existing generating units and power purchase contracts. This agreement has been extended through 2042.

2.1 Existing Generation System

Presently, OUC has ownership interests in four electric generating plants, which are described further in this section. Table 2-1 summarizes OUC’s generating facilities as of January 1, 2026, which include:

- Stanton Energy Center Units 1 and 2, Stanton A, and Stanton B.
- Indian River Plant Combustion Turbine Units A, B, C, and D².
- Osceola Generating Station Units 1, 2, and 3.
- Florida Power & Light Company (“FPL”) St. Lucie Unit 2 Nuclear Generating Facility.

² As discussed throughout this report, OUC has purchased the steam units at the Indian River site; however, the units are currently in extended cold shutdown and, therefore, are not included in calculations of OUC’s available capacity.

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Table 2-1 Summary of OUC Generation Facilities

(As of January 1, 2026)

PLANT NAME	UNIT NO.	LOCATION (COUNTY)	UNIT TYPE	FUEL		FUEL TRANSPORT		COMMERCIAL IN-SERVICE MONTH/YEAR	EXPECTED RETIREMENT MONTH/YEAR	NET CAPABILITY	
				Pri	Alt	Pri	Alt			Summer MW	Winter MW
Indian River	A	Brevard	GT	NG	FO2	PL	TK	06/89	Unknown	16 ⁽¹⁾	18 ⁽¹⁾
Indian River	B	Brevard	GT	NG	FO2	PL	TK	07/89	Unknown	16 ⁽¹⁾	18 ⁽¹⁾
Indian River	C	Brevard	GT	NG	FO2	PL	TK	08/92	Unknown	83 ⁽²⁾	88 ⁽²⁾
Indian River	D	Brevard	GT	NG	FO2	PL	TK	10/92	Unknown	83 ⁽²⁾	88 ⁽²⁾
Stanton Energy Center	1	Orange	ST	BIT	NG	RR	PL	07/87	Unknown ⁽³⁾	453 ⁽⁴⁾	453 ⁽⁴⁾
Stanton Energy Center	2	Orange	ST	BIT	NG	RR	PL	06/96	Unknown	352 ⁽⁵⁾	352 ⁽⁵⁾
Stanton Energy Center	A	Orange	CC	NG	FO2	PL	TK	10/03	Unknown	184 ⁽⁶⁾	189 ⁽⁶⁾
Stanton Energy Center	B	Orange	CC	NG	FO2	PL	TK	02/10	Unknown	292	307
St. Lucie	2	St. Lucie	NP	UR	--	TK	--	06/83	Unknown	60 ⁽⁷⁾	62 ⁽⁷⁾
Osceola Generating Station	1	Osceola	GT	NG	FO	PL	TK	12/2001	Unknown	157	157
Osceola Generating Station	2	Osceola	GT	NG	FO	PL	TK	12/2001	Unknown	157 ⁽⁸⁾	157 ⁽⁸⁾
Osceola Generating Station	3	Osceola	GT	NG	FO	PL	TK	06/2002	Unknown	157	157
⁽¹⁾ Reflects an OUC ownership share of 48.8 percent. ⁽²⁾ Reflects an OUC ownership share of 79.0 percent. ⁽³⁾ As discussed throughout this 10-Year Site Plan, OUC currently anticipates placing Stanton Energy Center Unit 1 into extended cold shutdown by the end of May 2026. ⁽⁴⁾ Reflects 100 percent OUC ownership as of January 1, 2026. ⁽⁵⁾ Reflects an OUC ownership share of 71.6 percent and St. Cloud entitlement of 3.4 percent. ⁽⁶⁾ Reflects an OUC ownership share of 28.0 percent. ⁽⁷⁾ OUC owns approximately 6.1 percent of St. Lucie Unit No. 2. Reliability exchange divides 50 percent power from Unit No. 1 and 50 percent power from Unit No. 2. ⁽⁸⁾ Osceola Generating Station Unit 2 is currently not able to provide power to OUC but expected to be able to provide power to OUC by the summer 2026 peak period.											

The Stanton Energy Center is located 12 miles southeast of Orlando, Florida. The 3,280-acre site contains Units 1 and 2, as well as Units A and B, and the necessary supporting facilities. Stanton Unit 1 was placed in commercial operation on July 1, 1987, followed by Stanton Unit 2, which was placed in commercial operation on June 1, 1996. Both units are fueled primarily by pulverized coal and can generate up to approximately 70 MW each on natural gas, utilize natural gas igniters, and operate at emission levels that are within the Environmental Protection Agency (“EPA”) and the Florida Department of Environmental Protection (“FDEP”) requirement standards for sulfur dioxide (“SO₂”), nitrogen oxides (“NO_x”), and particulates (“PM”). Stanton Unit 1 is a 453 MW net coal-fired facility; as of January 1, 2026 OUC owns 100 percent of this unit, which provides approximately 453 MW of capacity to the OUC system. Stanton Unit 2 is a 463 MW net coal-fired generating facility; OUC maintains a 71.6 percent (approximately 336 MW) ownership share of this unit. OUC anticipates placing Stanton Unit 1 into extended cold shutdown by the end of May 2026 and converting Stanton Unit 2 to be capable of operating only on natural gas by the end of 2027; OUC is in the process of determining the final timing of these changes.

OUC entered into an agreement with Kissimmee Utility Authority (KUA), FMPA, and Southern Company-Florida LLC (“SCF”, an affiliate of Southern Power), which governs the ownership of Stanton A, a combined cycle unit at the Stanton Energy Center that began commercial operation on October 1, 2003. NextEra Energy purchased Southern Power’s interest in Stanton A, and as such, discussion of Stanton A’s ownership structure refers to NextEra Energy throughout this Ten-Year Site Plan, as appropriate. OUC, KUA, FMPA, and NextEra Energy are joint owners of Stanton A, with OUC maintaining a 28 percent ownership share (and purchases 52 percent), KUA and FMPA each maintaining 3.5 percent ownership shares, and NextEra Energy maintaining the remaining 65 percent of Stanton A’s capacity. Stanton A is a 2 X 1 combined cycle utilizing General Electric combustion turbines. Stanton A is dual-fueled with natural gas as the primary fuel and No. 2 oil as the backup fuel.

Stanton B is a 1 X 1 combined cycle utilizing General Electric combustion turbines. Stanton B is dual-fueled with natural gas as the primary fuel and No. 2 oil as the backup fuel. OUC is the sole owner of Stanton B.

The Indian River Plant is located four miles south of Titusville on US Highway 1. The 160-acre Indian River Plant site contains three steam electric generating units (No. 1, 2, and 3) and four combustion turbine units (A, B, C, and D). The three steam turbine units were sold to Reliant Energy in 1999, with OUC subsequently repurchasing the units in 2012. Given their current condition (the units are currently in extended cold shutdown), the Indian River steam units do not provide generating capacity for OUC, but do provide OUC with future options for new generating capacity. The combustion turbine units are primarily fueled by natural gas, with No. 2 fuel oil as an alternative. OUC has a partial ownership share of 48.8 percent (approximately 16 MW summer and 18 MW winter, per unit) in Indian River Units A and B, as well as a partial ownership share of 79 percent (approximately 83 MW summer and 88 MW winter, per unit) in Indian River Units C and D.

OUC has a 6.08951 percent ownership share in St. Lucie Unit 2 (a nuclear generating facility operated by FPL), providing approximately 60 MW of summer and 62 MW of winter generating capacity to OUC. A reliability exchange with St. Lucie Unit 1 results in half of the capacity being supplied by St. Lucie Unit 1 and half by St. Lucie Unit 2.

St. Cloud has an entitlement to capacity from Stanton Unit 2 associated with its purchase through FMPA (related to FMPA's participation in the Stanton II Project). FMPA's ownership stake in Stanton Unit 2 through the Stanton II Project is 23.2 percent, and St. Cloud's purchase from FMPA's Stanton Unit 2 ownership is 14.67 percent (providing approximately 15 MW).

The Osceola Generating Station is comprised of three separate turbines, with each unit providing 157 MW of summer and winter capacity. OUC anticipates completion of all necessary transmission system improvements to allow all three of the Osceola Generating Station units to provide power to OUC by the summer 2026 peak period.

2.2 Purchase Power Resources³

OUC has a purchase power agreement ("PPA") with NextEra Energy for 80 percent of NextEra Energy's 65 percent ownership share of Stanton A through December 2031, as well as an additional PPA with NextEra Energy to purchase the remaining 20 percent of NextEra Energy's 65 percent ownership share of Stanton A through December 2028.

2.3 Power Sales Contracts

OUC has the following contractual power sales:

- a contract to provide power to the City of Winter Park ("Winter Park") through 2026.
- a contract to provide power to the City of Mt. Dora ("Mt. Dora") through 2030.
- a contract to provide power to the City of Chattahoochee ("Chattahoochee") through 2027.
- a contract to provide power to Lakeland Electric ("Lakeland") through 2026.

For purposes of this Ten-Year Site Plan, OUC has assumed the winter and summer capacities and annual energy presented in Table 2-2 will be provided to Winter Park, Lakeland, Mt. Dora, and Chattahoochee.

³ OUC's renewable power purchases are discussed in Section 2.4 of this Ten-Year Site Plan.

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Table 2-2 Projected Annual Summer and Winter Peak Capacity (MW) and Annual Net Energy for Load (GWh) to be Provided to Winter Park, Mt. Dora, Chattahoochee, and Lakeland

	SUMMER MW			
Calendar Year	Winter Park	Mt. Dora	Chattahoochee	Lakeland
2026	17	26	9	100
2027	0	26	9	0
2028	0	27	0	0
2029	0	27	0	0
2030	0	27	0	0
2031	0	0	0	0
2032	0	0	0	0
2033	0	0	0	0
2034	0	0	0	0
2035	0	0	0	0
	WINTER MW			
Calendar Year	Winter Park	Mt. Dora	Chattahoochee	Lakeland
2026	17	20	7	50
2027	0	20	7	0
2028	0	20	0	0
2029	0	20	0	0
2030	0	21	0	0
2031	0	0	0	0
2032	0	0	0	0
2033	0	0	0	0
2034	0	0	0	0
2035	0	0	0	0
	ANNUAL GWh			
Calendar Year	Winter Park	Mt. Dora	Chattahoochee	Lakeland
2026	98	108	37	35
2027	0	110	37	0
2028	0	112	0	0
2029	0	114	0	0
2030	0	116	0	0
2031	0	0	0	0
2032	0	0	0	0
2033	0	0	0	0
2034	0	0	0	0
2035	0	0	0	0
All Summer and Winter MW are non-coincident. All rounded to nearest MW or GWh.				

2.4 OUC's Renewable Energy and Sustainability Initiatives and Community Activities

OUC is actively incorporating renewable technologies into its diverse generation portfolio and taking other steps to reduce carbon dioxide ("CO₂") emissions. In 2020, OUC established new clean energy goals to achieve a 50 percent reduction in CO₂ emissions by 2030⁴, a 75 percent reduction in CO₂ emissions by 2040⁵, and net-zero CO₂ emissions by 2050. These targets require investments in technologies such as solar photovoltaic ("PV") and energy storage. Such technologies will allow OUC to meet customer electricity demand while reducing CO₂ emissions.

Renewable energy, energy efficiency, sustainability and community engagement are crucial to achieving OUC's clean energy goals. OUC's recent renewable energy and sustainability initiatives, as well as activities in the community and customer education programs, are discussed in the following subsections⁶.

2.4.1 Solar and Batteries

2.4.1.1 Customer Facing Solar and Battery Programs

OUC actively provides more opportunities for its customers to participate in solar projects and programs. These initiatives include TruNet Solar, a Battery Storage Rebate, OUCommunity Solar, SunChoice®, and the Solar Thermal rebate Program.

- TruNet Solar is OUC's net metering program whereby all energy delivered by OUC to the customer will be billed using standard retail rates and customers are credited for all energy supplied by them to OUC based on a credit rate per kWh until June 30, 2030 that equals the community solar energy rate (currently 4.567¢/kWh) and the levelized fuel charge thereafter. This amount is subject to change based on market conditions. This program went into effect July 1, 2025 and is for customers not grandfathered under the Solar Net Metering program (including those taking over an account on or after July 1, 2025, from a grandfathered customer). The existing rooftop solar customers that have submitted a complete interconnection application for their current premises before June 30, 2025 ("grandfathered customer") will be reimbursed for excess energy generation as follows:
 - The credit rate per kWh until June 30, 2045, shall equal the sum of the non-fuel base and fuel charge (currently 10.65¢/kWh for residential customers). This amount is subject to change based on market conditions.
 - For residential customers the non-fuel base charge shall not include the conservation adder for all additional kWh over 1,000.
 - For time of use ("TOU") customers the energy supplied to OUC by the customer will be measured and credited by distinct TOU time periods.
 - After June 30, 2045, the credit rate per kWh shall equal the levelized fuel charge.
- OUC offers rebates for battery storage system purchase and installation to customers who export excess energy under the Community Solar Energy Rate. Eligible customers with rooftop solar systems sized below 20 kW can receive a rebate of \$150 per rated kWh up to \$2,000 for adding battery storage to their solar installations. The battery storage must be directly

⁴ Compared to a 2005 CO₂ baseline.

⁵ Compared to a 2005 CO₂ baseline.

⁶ Please refer to Section 5.0 of this Ten-Year Site Plan for discussion of OUC's conservation and demand-side management programs.

connected to the customer's solar system to qualify for this incentive. This program follows a successful pilot program conducted in 2019.

- Residential and commercial customers enrolled in the OUC Community Solar program can get access to sustainable, maintenance-free solar energy without the costs associated with installing panels on their homes or businesses. Those enrolled subscribe at a small premium to receive between 10 percent to 100 percent of their energy from OUC's solar resources.
- In 2024, OUC introduced its SunChoice® program, which allows commercial customers to demonstrate their commitment to the deployment of utility scale solar arrays and secure Renewable Energy Certificates ("RECs") as evidence of their commitment to offsetting their consumption with renewable energy sources. The program costs are in addition to a customer's standard utility bill. Customers subscribe a percentage of their actual consumption in 10 percent tranches. Customers pay tiered prices associated with their subscription level. OUC retires the RECs in the customer's name annually based on their subscription level and the actual quantity of energy they consume.
- Residential customers participating in the Solar Thermal Program receive a rebate of \$900 for installing a solar water heating system. Federal incentives, including the investment tax credit, are available to eligible customers to help minimize costs of solar PV, energy storage and solar thermal systems.

2.4.1.1 Utility Scale Solar and Batteries

As part of a pilot program, a 4-megawatt, 8-megawatt-hour utility scale battery energy storage system ("BESS") was installed at OUC Substation 29 in east St. Cloud. Substation 29 is connected to transmission lines that support the solar array at the Harmony Solar Energy Center.

In order to better utilize solar energy and increase its reliability during cloudy weather, OUC has embarked in designing its own advanced algorithms and control schemes. These algorithms are being tested at OUC's Grid Integration Lab ("GIL"), formerly known as "Nanogrid", a living laboratory for testing the interoperability of multiple distributed energy resources and the ability to self-operate at OUC's Gardenia facility. GIL currently is comprised of 64 kWdc of floating solar, 100 kW/129kWh lithium iron phosphate batteries, 120kW DC fast charging, 194 kW DC-coupled battery fast charger, 28kW of Level 2 EV charging, and 16kW/64kWh flywheel energy storage. The site is used in partnership opportunities with UCF and local startups, such as developing an intelligent control system and testing capacitors for enhanced microgrid operations. The research into dispatch and control of assets at GIL will enable solar to become more reliable during intermittent weather as well as help to drive down costs for energy storage.

OUC completed installation of a 1.6 MWac floating array on a Florida Department of Transportation ("FDOT") pond in late 2025. Plans are in place to develop a roadmap for a larger deployment of floating solar throughout OUC's territory.

Table 2-3 presents a summary of OUC's existing contracts for purchases of solar power.

Table 2-3 OUC's Existing Solar Purchase Power Contracts

Facility	Operational Year	Purchased Capacity (Nameplate; MWac)
Stanton Energy Center	2011	5.1
Kenneth P. Ksionek	2017	8.9
Harmony	2020	34.0
Taylor Creek	2020	74.5
Harmony II	2024	74.5
Storey Bend	2024	74.5

2.4.2 Landfill Gas

Methane or landfill gas is created by the decomposition of wet organic waste under anaerobic, or oxygenless, conditions in a landfill. This gas is considered a renewable energy source because the anaerobic digestion process continues as waste materials are constantly added to the landfill.

In partnership with Orange County, OUC captures methane gas emissions from county landfill cells and pipes it to the Stanton Energy Center where it is co-fired with coal. In addition to helping to reduce greenhouse gas emissions, this 8 MW project has the potential to displace more than three percent of the coal burned at the Stanton Energy Center. It will be capable of producing in excess of 100,000 megawatt-hours ("MWh") of reduced-emissions power – offsetting about 44,000 tons of coal each year.

Table 2-4 presents a summary of OUC's existing contracts for purchases of landfill gas power.

Table 2-4 OUC's Existing Landfill Gas Purchase Power Contracts

Facility	Operational Year	Purchased Capacity (MW)
Port Charlotte/Collier	2011	4.00
Monarch Hills	2016	6.00
Holopaw JED	2017	9.00

2.4.3 Carbon Reduction

With more than 720 vehicles – ranging from plug-in hybrids to bucket trucks – OUC's fleet logs more than 2.7 million miles annually. OUC currently has ten line trucks employing the Jobsite Energy Management System (JEMS). JEMS is a great application for hybrid technology since much of the vehicle's work is done when stationary. The hybrid diesel-electric system allows the main engine to be turned off while crews operate entirely off the battery, therefore reducing the production of greenhouse gases and reducing fuel consumption for idling. OUC reduces its carbon footprint by using alternative fuels, purchasing electric vehicles and recycling automotive products to help the environment. As part of an overall plan to reduce emissions in its fleet, OUC uses "B20" – a blend of 80 percent petroleum diesel and 20 percent biodiesel –

a clean-burning alternative fuel made from new or used vegetable oils and animal fats, including recycled cooking grease. B20 has been integrated seamlessly into the fueling system without any changes to vehicles or fuel storage and distribution equipment. OUC uses biodiesel at the Pershing Fleet Center and the Gardenia site. OUC has installed two 10,000-gallon fuel tanks that store E85 fuel at its Pershing and Gardenia sites.

OUC's Fleet Division has incorporated several eco-conscious policies, including the use of earth-friendly products and special care taken to dispose contaminated fuels according to environmental standards. Tires, batteries, and oil filters are recycled through vendors, while antifreeze and motor oil are handled on-site. OUC recycles about 20,000 gallons of used oil each year. OUC also has a vehicle idling policy that requires the engine to be turned off after five minutes of idling.

Embracing fuel-efficient technology as a commitment to green initiatives, OUC has grown the commitment to include fourteen all-electric cars, two plug-in electric hybrids, and twenty-six hybrids in the fleet.

OUC has installed more than 300 public charging stations. In July 2023, OUC commissioned the Robinson Mobility Recharge Hub with 21 high-speed chargers located in downtown Orlando. An OUC-led partnership that includes the City of Orlando, Orange County and Power Electronics, the manufacturer of the EV charging equipment, received a \$500,000 grant from the Florida Department of Environmental Protection to build the station. A second Hub with 6 fast charging stations was installed near the Orange County Convention Center in September 2024. OUC has provided an additional 40 level 2 charging stations to meet the needs of its employees and fleet.

2.4.4 Energy Efficiency and Sustainability

OUC's commitment to efficiency and sustainability is also demonstrated by Reliable Plaza, OUC's energy and water efficient center on West Anderson Street. Reliable Plaza earned Gold Leadership in Energy and Environmental Design ("LEED") certification in 2009, recognizing the 10-story administration and customer service center as the "Greenest Building in Downtown Orlando." Reliable Plaza also holds a Florida Water Star certification, a voluntary program for new and existing construction that encourages water efficiency in appliances, plumbing fixtures, irrigation systems and landscapes. Reliable Plaza utilizes a number of environmentally friendly features designed to use 28 percent less energy and 40 percent less water than a similarly sized facility.

OUC's 24-acre St. Cloud Operations & Maintenance Facility is the first net-zero energy campus for a Florida utility, combining state-of-art technology with sustainability. The campus uses 50 percent less energy and 40 percent less water than conventional facilities of similar size. It supports permanent fleet and logistic operations, as well as being designed to accommodate a future new substation based on projected load growth. It will also serve as an alternative emergency response center for OUC operations.

OUC's Commercial Indoor Lighting Program helps customers convert old, inefficient lighting to high-efficiency technology. Since launching the program in 2002, more than 45 million kWh and 10.5 MW demand has been saved in buildings like public schools, churches, theme parks and hospitals, resulting in annual energy cost savings of about \$16 million.

The Home Utility Report Program (“HUR”) is a free service offered to OUC customers designed to help them save energy, water, and money. The report compares a customer’s energy and water consumption to similar households, as well as provides personalized tips that show how much they can save by changing their behavior. Participants receive a free HUR monthly email report or bi-monthly printed report. To administer the HUR program, OUC works with a third-party company that helps utilities meet their efficiency goals through effective customer engagement. There is also an online portal available to customers to obtain additional information on how to save energy and water.

2.5 Transmission System

OUC’s existing transmission system in Orlando consists of 31 substations interconnected through approximately 340 miles of 230 kV and 115 kV lines. OUC is integrated into the Florida Reliability Coordinating Council (“FRCC”) regional transmission grid through multiple utilities. Additionally, OUC is responsible via an Interlocal Agreement for planning, operating and maintaining St. Cloud’s nine substations interconnected through approximately 85 miles of 230 kV and 69 kV transmission lines.

3.0 STRATEGIC CONSIDERATIONS

OUC incorporates a number of strategic considerations while planning for the electrical system. This section provides an overview of a number of these strategic considerations.

3.1 Strategic Business Units

OUC 's Electric and Water operations is organized into three strategic business units: Electric & Water Production ("EWP"), Transmission ("TRAN") and Electric and Water Distribution ("EWD") that report to a Chief Operating Officer.

3.1.1 Energy and Water Production Business Unit

The EWP business unit has structured its operations based on a competitive environment that assumes that even OUC's customers are not captive. EWP will only be profitable if it can produce electricity and water that is competitively priced in the open market. In line with this strategy, OUC is continually studying strategic options to improve or reposition its generating assets.

OUC's generating system has been designed over the years to take advantage of fuel diversity and the resultant system reliability and economic benefits. OUC's longstanding intent to achieve diversity in its fuel mix is evidenced by its participation in other generating facilities in the State of Florida. The first such endeavor occurred in 1977 when OUC secured a share of the Crystal River Unit 3 nuclear plant (which is now retired), followed by the acquisition of an ownership share in Lakeland Electric's McIntosh Unit 3 coal-fired unit (which is now retired) in 1982. In 1983, OUC acquired a share of the St. Lucie Unit 2 nuclear unit. OUC also modified the Stanton Energy Center coal units to allow the units to offset a portion of their coal usage with natural gas. Additional details of OUC's generating facilities are presented in Table 2-1 and Schedule 1 of Section 12.0 of this Ten-Year Site Plan.

OUC's fuel diversity is further enhanced by the renewable energy resources that are discussed in detail in Section 2.4 of this Ten-Year Site Plan.

In 2020 the Business Unit led the Electric Integrated Resource Plan that calls for a review of OUC's generation needs in light of the growing penetration of distributed energy resources, such as solar power, and a call to move to Net Zero Carbon by 2050. Florida-specific factors were taken into consideration because renewable resources are limited relative to other regions in the country and could impact fuel diversity. Currently, wind, hydroelectric and geothermal are not economically and/or technically viable in Florida – and biomass and landfill gas, while technically viable, are only available in small quantities. While solar is feasible, it poses intermittency challenges, and back up resources will be necessary to ensure that power is always available. OUC will continue to evaluate wind-by-wire generation and monitor emerging clean technologies such as hydrogen, offshore wind and small modular nuclear power plants.⁷

Table 3-1 summarizes OUC's existing (owned and purchased) capacity by fuel type, including renewable energy resources. The ability to generate up to approximately 70 MW while operating on natural gas in each of Stanton Units 1 and 2 further enhances the percentage of generating capacity fueled by natural gas.

⁷ OUC anticipates refreshing its Electric Integrated Resource Plan within the next 12 months.

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Table 3-1 Capacity (MW) Owned and Purchased by OUC by Fuel Type
(As of January 1, 2026)

PLANT NAME	WINTER CAPACITY						SUMMER CAPACITY					
	Coal	Nuclear	Gas/ Oil	PV	LFG	Total	Coal	Nuclear	Gas/ Oil	PV	LFG	Total
Stanton ⁽¹⁾⁽²⁾	682		1,055			1,737	682		1,028	7		1,717
Indian River			213			213			197			197
St. Lucie		62				62		60				60
Osceola ⁽³⁾			471			471			471			471
Other (MW)					19	19				129	19	148
Total (MW)	682	62	1,739	0	19	2,502	682	60	1,696	136	19	2,593
Total (percent)	27%	2%	69%	0%	1%	100%	26%	2%	65%	5%	1%	100%
⁽¹⁾ "Coal" capacity includes OUC's share of the landfill gas burned in Stanton Units 1 and 2. ⁽²⁾ Stanton Units 1 and 2 can each generate up to approximately 70 MW while operating on natural gas., which is included in "Gas/Oil" capacity ⁽³⁾ Reflects Osceola Generating Station Units 1 through 3. Osceola Generating Station Unit 2 is currently not able to provide power to OUC but expected to be able to provide power to OUC by the summer 2026 peak period.												

3.1.2 Transmission Business Unit

The OUC Transmission Business Unit is responsible for the planning, engineering, construction, and maintenance of all substations and lines operating at 69kV or higher. To maintain reliable and economic service and proactively plan for the future, OUC plans and evaluates various upgrades to its transmission system.

3.1.3 Energy and Water Distribution Business Unit

OUC's EWD business unit focuses on providing OUC's customers with the safest and most reliable electric service possible.

OUC's leadership in providing reliable electric distribution service is demonstrated by its commitment to making initial investments in high quality material and equipment. Additionally, more than 68 percent of OUC's distribution system is underground, protecting it from trees and high winds. OUC's dependability is also attributable to its proactive maintenance programs to identify and correct potential problems, proactive replacement of old equipment, and a tree-trimming program that minimizes tree-related service disruptions.

3.2 Florida Municipal Power Pool

In 1988, OUC joined Lakeland Electric and FMPP's All-Requirements Project members to form the Florida Municipal Power Pool ("FMPP"). Later, KUA joined FMPP. Over time, FMPP's All-Requirements Project has added members as well. FMPP is an operating-type electric pool, which dispatches all the pool members' generating resources in the most economical manner to meet the total load requirements of the pool. The central dispatch provides savings to all parties via reduced commitment costs and lower overall fuel costs. OUC serves as the FMPP dispatcher and handles all accounting for the allocation of fuel expenses and savings. The term of the pool agreement is three years and automatically renews until terminated by the consent of all participants.

OUC's participation in FMPP provides significant savings from the joint commitment and dispatch of FMPP's units. Participation in FMPP also provides OUC with a ready market for any excess energy available from OUC's generating units.

3.3 Security of Power Supply

OUC currently maintains interchange agreements with other utilities in Florida to provide electrical energy during normal and emergency conditions. The reliability of the power supply is enhanced by metered interconnections with other Florida utilities, including twelve interconnections with Duke Energy Florida, four with KUA, two with Tampa Electric Company, two with FPL, one with Lakeland Electric, one with Central Florida Tourism Oversight District, two with St. Cloud, and one with NextEra. Along with enhancing reliability, these interconnections also facilitate the marketing of electric energy by OUC to and from other electric utilities in Florida.

3.4 Environmental Performance⁸

As the quality of the environment is important to Florida, and especially important to the tourism-driven economy of Central Florida, OUC is committed to protecting human health and preserving the quality of life and the environment in Central Florida. To demonstrate this commitment, OUC has chosen to operate its generating units with emission levels below those required by permits and licenses by equipping its power plants with the best environmental protection systems available at the time of their construction and continuously enhancing these systems over time. Unit 2 is the first unit of its size and kind in the nation to use selective catalytic reduction (“SCR”) to remove nitrogen oxides (“NO_x”). Using SCR and low-NO_x burner technology, Stanton 2 successfully meets the stringent air quality requirements imposed upon it. Stanton A incorporates environmentally advanced technology and enables OUC to diversify its fuel mix while adding more flexibility to OUC’s portfolio of owned generation and purchased power. Stanton B further contributes to OUC’s environmentally responsible portfolio of generating resources.

This superior environmental performance not only preserves the environment, but also results in many economic benefits, which help offset the costs associated with the superior environmental performance. Additionally, OUC has installed natural gas igniters for both Stanton 1 and Stanton 2, eliminating the use of No. 6 fuel oil and reducing the amount of coal burned during operations when economical to do so.

Further demonstrating its environmental commitment to clean air, OUC has harnessed the power of methane. Methane gas, if not captured and burned, is released into the atmosphere and is considered 20 times more intense than carbon dioxide in terms of possible global warming effects. As discussed in Section 2.4.2, OUC has signed a contract to burn methane gas collected from the Orange County landfill adjacent to Stanton Energy Center. Both Stanton 1 and Stanton 2 have the capability of burning methane. Additionally, OUC receives the energy generated from the burning of methane gas collected from the Port Charlotte/Collier, Holopaw JED and Monarch Hill Landfills.

OUC has also voluntarily implemented a product substitution program not only to protect workers’ health and safety but to minimize hazardous waste generation and to prevent environmental impacts. The Environmental Compliance and Safety Departments constantly review and replace products to eliminate the use of hazardous substances. To further prevent pollution and reduce waste generation, OUC also reuses and recycles many products.

3.4.1 Emphasis on Sustainability

OUC completed its first greenhouse gas inventory for the entire company in 2008 and updates the inventory annually. This report helps OUC analyze how it impacts the environment and details operating emissions. The report is made available to customers, typically commercial, that request it.

3.5 Community Engagement, Connecting with Our Customers, and Economic Development

3.5.1 Community Engagement

As Orlando’s hometown utility, OUC is committed to helping the community it serves. Individuals and organizations know they can rely on the utility when it matters most—through board involvement, support,

⁸ Please refer to Section 2.4 of this Ten-Year Site Plan for a detailed discussion of OUC’s renewable generating technologies and other environmental initiatives.

employee volunteerism and more. OUC supports more than 300 nonprofit and business-based organizations that focus on the four pillars of social impact, environmental stewardship, education and economic development and participates in nearly 150 events each year, while employees annually volunteer between 5,000 and 10,000 hours in the community. Many events incorporate sustainability messaging, encouraging the efficient use of energy and water.

From unique solar pavilions and sculptures at high visibility locations like Lake Lorna Doone Park, Inter & Co Stadium and St. Cloud's Lakefront Park, to H₂OUC Hydration Stations at parks and neighborhood centers, OUC's commitment to sustainability can be seen all around town.

OUC also supports a diverse group of business chambers within its service territory, including Ivanhoe Village, Lake Nona, , and Hispanic chambers. While actively engaging with the St. Cloud, Indian American, Prospera, Caribbean, Haitian, African-American, and Asian communities. OUC is also actively involved with economic gardening and business development organizations such as Orlando Economic Partnership, Downtown Orlando Partnership, Central Florida Hotel and Lodging, and technical associations.

In 2021, OUC unveiled a 200-square-foot "home" on wheels that served as a model of sustainable living for anyone to experience. The Tiny Green Home, a partnership between OUC, the City of Orlando and Orlando Science Center ("OSC"), was an educational resource showcasing the benefits of energy and water conservation, renewable energy, sustainability rebates, vehicle electrification, composting, growing food and sustainability programs offered by OUC, the city and OSC. Stationed on OSC property in Loch Haven Park, the micro-dwelling also includes a functioning roof-top solar array and a rain barrel to collect and conserve water, among other green features visitors could add to their own homes. The Science Center was responsible for staffing, operating and maintaining the exhibit, which was accessible with admission. Retired in 2025, the Tiny Green Home hosted more than 20,000 visitors through community events and OSC tours.

In 2023, OUC partnered with the Orlando Science Center to launch a new interactive exhibit that focuses on water and energy conservation. Designed to educate and engage, the exhibit highlights the importance of managing these essential resources responsibly and explores innovative solutions for the future. Through an interactive and gamified experience, concepts such as IoT (Internet of Things), Smart Grid technology, Micro Grids are introduced. The "Power Play" game challenges visitors to route power to a city as quickly and efficiently as possible. Participants select where a city's buildings, solar panels and power plants are connected to create a balanced power grid. The goal: link all elements so power production and consumption are balanced. The fast-paced game provides a practical and engaging introduction to energy management and the complexity of maintaining a reliable power grid.

3.5.1.1 Utility and Community Volunteerism

OUC launched Project CARE, its utility assistance fund, in 1994. The program, managed by Heart of Florida United Way 2-1-1, a local, nonprofit organization, provides rapid response to customers in need through case management. Since its inception, Project CARE has allocated more than \$8 million, assisting more than 30,000 households and thousands of families and individuals. For every \$1 donated by customers, OUC contributes \$2 to the program.

With the onset of the COVID-19 pandemic in 2020, OUC took immediate steps to help impacted customers. OUC suspended electric and water disconnections for nonpayment and waived late payment

fees with a \$12.1 million customer-relief package that included \$7.5 million to lower electric fuel rates; a \$2.6 million contribution to Project CARE, in partnership with the City of Orlando; \$1.5 million for utility bill payment assistance to qualified small businesses; and \$500,000 for new OUC Power Pass customers. Payment plans and deferred payment arrangements were offered to customers for up to 12 months depending on qualifying criteria. By the end of 2020, more than 6,500 customers accessed Project CARE funds while more than 1,800 small businesses took advantage of the OUC relief program targeting them. Meanwhile, OUC connected more than 2,800 customers to the federal government's Low-Income Home Energy Assistance Program ("LIHEAP") and helped more than 40,000 set up payment plans, amounting to millions of dollars in deferred revenues.

With prices rising for so many products and services, we know our customers are feeling the strain. That's why OUC is continuing to invest in OUC's utility assistance program—Project Care. Below shows the assistance provided in the last three fiscal years. In OUC's fiscal year 2025, OUC provided more than \$229,000 in utility assistance to help nearly 1,000 households with a plan to increase funding for fiscal year 2026.

In FY2023: October 1, 2022 – September 30, 2023

- Total Assistance Amount: \$799,864
- Households Assisted: 2,694
- Average Assistance Amount: \$296.91

In FY2024: October 1, 2023 – September 30, 2024

- Total Assistance Amount: \$302,682
- Households Assisted: 1,020
- Average Assistance Amount: \$296.75

In FY2025: October 1, 2024 – September 30, 2025

- Total Assistance Amount: \$229,064
- Households Assisted: 721
- Average Assistance Amount: \$317.70

Regarding volunteerism, OUC's Proud Volunteer program encourages and rewards employees for their volunteer work in the community. Employees volunteer over 6,000 hours every year and help support a variety of nonprofit organizations in the community including quarterly volunteer events specifically for employees with one of the four events focused on environmental clean-up.

The annual OUC Charity Golf Tournament has raised over \$1 million for more than 87 Central Florida non-profits since its inception in 1995. In 2025, OUC raised \$58,000 for 4 central Florida non-profit organizations in support of OUC's four pillar approach to community investment.

3.5.1.2 Water Color Project

Since 2006, OUC has hosted the Water Color Project, a conservation-themed art program that encourages students to highlight the importance of saving water through their artwork. While fourth- and fifth-grade students compete to have their artworks featured in OUC's Water Conservation Calendar, middle and high school students paint water-inspired themes on rain barrels. Their completed works are displayed in

a traveling exhibit, judged and later sold in a silent auction, with the proceeds going back to the winning schools' art programs. More than 40,000 students from over 250 local schools have participated in this program. Launched in 2020, OUC now hosts an annual public auction of the rain barrels painted by the local middle and high school students who participated in our annual Water Color competition. Proceeds directly benefit the Orange County Public Schools Visual Arts Department.

With the success of the Water Color Project, OUC launched the program in St. Cloud and rebranded it as the Watts Savings Project with a focus on energy conservation. OUC kicked off this inaugural project in 2025 and since then have had 14 schools and almost 2,000 students participate in the calendar contest. Each year, OUC employees vote for the top 13 calendar designs, which are featured in the yearly calendar. With such a successful launch, OUC will expand this program in the next school year to grow and include additional schools in its territory.

3.5.1.3 Project AWESOME

OUC and the Orlando Science Center deliver energy and water conservation workshops to every fifth grader in OUC's service territory via Project AWESOME (Alternative Water & Energy Supply; Observation, Methods & Education). The educational program promotes both water and energy conservation through a hands-on curriculum using content approved by OUC that meets Common Core Standards. As part of an electric and water conservation and alternative sources educational program, the projects include modeling the flow of electricity from coal and solar power sources through substations before being distributed to industrial and residential consumers and designing and creating a drip irrigation system for a city park. Project AWESOME, which launched in 2009, delivers two 90-minute classroom workshops (one per semester), as well as hands-on labs and pre- and post-classroom activities. Energy is covered as part of the earth science section that's taught in the fall semester while water is the focus of the spring semester's life science section. Due to COVID and schools turning to virtual learning in early 2020, Project AWESOME workshops shifted to online. In 2021, OSC shifted back into the classrooms but continues to offer a virtual option to all the teachers for convenience and accessibility. Since 2009, more than 139,000 students have gone through the curriculum.

3.5.1.4 Strategic Partnerships Promote Awareness

OUC partners with highly visible, professional sports teams in Central Florida to highlight OUC's commitment to sustainability, conservation, and impactful economic development efforts. As of 2026, some of these partnerships include: Orlando Magic, Orlando City Soccer Club, and United States Tennis Association ("USTA").

Our current partnership with the Orlando Magic focuses on promoting energy and water conservation through interactive activations at games, in-game LED banners and videos. In addition to our game-day activities, we also partner with the Magic to host B2B events designed to promote commercial conservation efforts. These events provide an opportunity to engage businesses customers and partners in energy and water efficiency practices, offering valuable insights and resources to help them reduce their environmental impact while also driving cost savings.

In the past, OUC played a significant role in the design phase of the Orlando Magic's LEED-certified home, the Kia Center (formerly the Amway Center), contributing to its energy and water efficiency features. We highlighted the facility's LEED certification and sustainability efforts through educational signage and digital media. Additionally, from 2019 to 2022, OUC supported the Orlando Magic's Community Assist Program—donating one tree for every assist made by a Magic player during the season. Now concluded,

it was a key initiative that helped plant more than 5,000 trees in the Central Florida community. Today, OUC continues to focus on its commitment to energy and water conservation in collaboration with the Orlando Magic.

Since 2015, OUC has been the official and exclusive electric and water utility partner for Orlando City Soccer Club and Orlando Pride. Within Inter&Co Stadium (formerly Exploria Stadium), OUC branded all water fountains and showcases the savings that can be achieved through sustainability initiatives. Both permanent and transitional signage highlights energy and water efficiency features incorporated into the facility. In November 2020, OUC unveiled “Gyration,” a soccer-ball shaped solar sculpture designed by UCF students. The sculpture generates 1,264 kWh of clean energy annually, achieving net-zero carbon output. In 2023, OUC also installed EV charging equipment at the stadium. Additionally, OUC serves as the presenting sponsor for the Club’s sustainability initiative, which is focused on maintaining a zero-waste facility.

OUC’s partnership with the USTA at the Home of American Tennis in Lake supports sustainability. OUC is exclusively designated as the “Official Sustainability & Utility Sponsor” and highlights energy, water, and emerging technology through initiatives such as EV charging stations, hydration stations, and solar arrays on the roofs of shade pavilions. The facility hosts more than 250 events and attracts approximately 400,000 unique visitors per year.

3.5.1.5 OUC Empowerment Zone

OUC has a multi-year commitment to revitalizing one of the most economically disadvantaged zip codes in its territory, 32805. The Empowerment Zone program encourages broad-based economic prosperity and community support, ensures improved access to OUC programs and improves the overall health and wellness of the community. In short: OUC’s Empowerment Zone seeks to build thriving communities by leveraging OUC’s resources and partnerships to enhance three pillars: educational opportunities, sustainable housing, and health and wellness. Examples include:

- Virtual Tutoring Programs with ELEVATE Orlando, which OUC supported by donating a total of 20 laptops to two middle schools. OUC employees participated in weekly sessions tutoring ten students.
- In 2019, OUC employees raised \$42,000 for New Image Youth Center (“NIYC”), as part OUC’s annual workplace giving campaign, OUCares. NIYC works with at-risk students in grades K-12 in the Parramore community and provides academic support, social development, health and wellness programs and crisis intervention services. In addition, OUC donated 25 laptops to the New Image Youth Center to support their education assistance programs.
- OUC created a pre-apprenticeship program to meet the goals of creating career opportunities vs. job opportunities; prioritizing diversity, equity and inclusion; and raising median incomes for the community. This approach is helping to combat unemployment; increase livable wages; eliminate financial burdens on students; and provide a measurable impact. To date, OUC has sponsored three pre-apprenticeship cohorts. All 11 members of the inaugural class, who graduated in October 2021, landed full-time jobs paying more than \$30,000 a year, plus benefits and paid apprenticeship training classes to help them with career advancement. Seven students graduated from the 2022-23 program, with participants attending classes at PKZ and West Oaks Academy. The 2024 and 2025 program graduated 19 students.

- OUC is working with Career Source of Central Florida to provide opportunities for high school students to learn about careers in the utilities industry hosting site tours and providing speakers to assist in raising awareness of the utility industry as a potential employer.
- OUC partnered with the Central Florida Housing Trust - Parramore Asset Stabilization Fund on an affordable housing project. OUC's contribution to the initiative included improving the efficiency of 83 residential units, with such upgrades as attic insulation and weather stripping, duct work repair, irrigation improvements, LED lighting, Energy Star® windows, hybrid water heaters and energy efficient AC systems. Residents of these homes realized annual utility savings of approximately \$575 annually.
- OUC also is developing cost-saving programs and providing conservation education through neighborhood advisory councils. OUC partnered with LIFT Orlando, a local nonprofit, to help revitalize the City of Orlando's Lake Lorna Doone Park, which is in the Empowerment Zone. OUC's is sponsoring the recently built 4,800-square-foot OUC Solar Pavilion at Lake Lorna Doone Park and EV charging stations and hydration stations in the park. The pavilion will serve as a hub for community events and activities while providing 42kWac of renewable energy.
- With the goal of inspiring young and old residents to read books, OUC and community partners set up nine Little Free Libraries in the Parramore neighborhood since May of 2021. Painted by OUC volunteers, each Little Free Library resembles a miniature wooden house with a pitched roof and glass door that opens to two shelves of books, two dozen or so in all. To date more than 4,000 books have been distributed across the eleven libraries.
- Recognizing that personal health and wellness are critical to community revitalization, OUC has undertaken a number of initiatives to improve health and wellness in the Parramore Empowerment Zone. Working with Shepherd's Hope, OUC sponsors the HEAL program – promoting healthy eating and an active lifestyle with focus on topics from obesity and mental health to cardiovascular risks and nutrition. Average attendance of 33 senior citizens and 27 high school students was observed in sessions held in 2022 and 2023. Activities including distribution of more than 3,600 pieces of educational material and 252 bags of fresh food, along with completion of 15 home energy audits, resulted from the HEAL program. Additionally, attendees were connected with Shepherd's Hope who offer free healthcare and condition management programs as part of their mission.

3.5.2 Connecting with Our Customers

From providing better online access to their consumption history to designing convenient and effective conservation programs, OUC arms customers with the information and tools they need to optimize the efficiency of their homes and businesses. This includes the community outreach previously discussed in this report as well as a mix of new technologies and programs designed to provide customers with the information, control and options they desire.

3.5.2.1 Self-Service Options

OUC's informational website, self-service portal and automated phone system are transacted with millions of times each year by many customers.

Customers are able to find tips, videos on ways to save, and frequently asked questions regarding their services. Through their myOUC online profile, they are able to pay their bills, make service requests, request payment extensions and more. The Usage Dashboard and OUC Power Pass program continue to

drive adoption of the website. The site is mobile friendly and accessible from a range of devices including tablets and smartphones.

3.5.2.2 Traditional Media and Digital Outreach

OUC utilizes a comprehensive, multi-channel approach to reach our customers through print, digital, television, radio, social, outdoor media and community partnerships. By diversifying and targeting media, OUC can effectively reach the right customer with the right message. Campaigns cover a range of topics, from safety to storm prep to sustainability. These campaigns reinforce OUC's commitment to showing customers how to reduce their energy and water use and ultimately their utility bills while promoting programs and initiatives important to the community.

Launched in February 2024 and still actively running OUC's "Get Green" campaign continues to drive engagement and increased rebate redemptions through targeted and segmented messaging. By tailoring email content to specific customer segments, including water and energy usage patterns, and utilizing seasonal scheduling, the campaign remains relevant and resonates across a wide audience. The strategic use of data, including DMV information for EV rebates and detailed customer attributes like home age and income to ensure the right messages reaches the right customers.

The campaign continues to leverage multiple channels to maximize its reach, including Meta ads, Google Display Ads, OTT streaming ads, direct-to-home postcards and organic social media posts. A dedicated landing page on OUC's website (ouc.com/getgreen) is the central hub for the campaign, driving significant traffic. In 2025, the site had 59,591 sessions and an active user base of 54,883. Additionally, email marketing remains a key focus, with monthly emails and follow-ups along with A/B testing ensuring optimal communication. The campaign's success is reflected not only in its rebate redemptions but also in its ability to generate long-term energy and water savings, proving to be a valuable tool in OUC's conservation efforts.

3.5.2.3 Connections

Connections is a monthly newsletter sent to all OUC customers whether they receive a paper statement or e-bill. The newsletters are posted on www.OUC.com and feature OUC's programs, community events, sustainability initiatives, and energy- and water-saving tips.

3.5.2.4 OUC Blog

In 2019, OUC launched a blog called OUConnect (www.oucblog.com). On OUConnect, customers can learn ways to save energy, water and money and how OUC is creating innovative products and services to meet the ever-growing needs of Central Florida. Customers will also read articles about community initiatives, as well as profiles on employees making a difference both at work and in their hometowns.

3.5.2.5 OUConnect E Newsletter

In April 2019, OUC launched a monthly email newsletter to all residential and commercial customers with email addresses (170,000). This newsletter keeps customers informed and connected to OUC's programs, products, provides conservation tips and more.

3.5.2.6 Social Media

Instagram, Facebook, X (formerly Twitter), YouTube, and NextDoor allow OUC to update customers about the Commission's community involvement, as well as provide them with conservation tips, outage and

restoration updates, and other need-to-know, real-time information that may affect them. Social media platforms also serve as additional customer service outlets, allowing customers to notify OUC about issues needing quick resolution, and provide additional opportunities for the Commission to build interactive relationships with customers and potentially diffuse negative situations.

3.5.2.7 Digital Meters

OUC's entire service area was upgraded with nearly 370,000 digital electric and water meters. The digital meters are easier to read and provide detailed information about customers' daily energy and water use. Meters can be monitored remotely, which reduces costs and time while ensuring an accurate and timely reading for the customer. Remote monitoring also allows OUC to better predict and prevent outages and restore power faster. OUC created Florida's first meter farm consisting of 120 electric meters and four water meters at its Pershing facility. The farm provides information and shows OUC exactly how updates are installed to ensure the meters are working correctly.

3.5.2.8 OUC Power Pass Program

OUC Power Pass is a program that allows customers to pay-as-you-go or pay in advance for utility services allowing the option of avoiding deposits, late fees and a monthly bill. Statistics have shown that pay-before-consumption programs result in less electricity and water usage because customers are more aware of how much they are using. Customers can check on their electric bill or water usage every day using the OUC Power Pass portal or receive alerts via text, email and/or phone. More than 20,000 customers are enrolled in the program to date.

3.5.2.9 Usage Dashboard

Digital meter technology allows customers to monitor electric and water consumption on 15 minute basis instead of waiting until the end of the month to receive their bills. The ability to track usage patterns and adjust lower energy bills was one of the items most frequently requested by OUC customers. To accommodate their needs, OUC released the OUC Usage Dashboard to most residential customers through their myOUC online profile. Because the new system also provides high-consumption alerts via email, changes in usage can be made immediately, and costs can be kept in check.

3.5.2.10 Online Rebate Application

OUC is continuing the use of software through the next few years and implemented a new software solution for rebate processing in 2022. OUC provides an online rebate application tool for customers to apply for rebates without the hassle of paperwork. It offers more convenience for customers and reduces transaction time. Customers are able to access the tool through their myOUC online profile.

3.5.2.11 PowerShift & PeakShift

In 2019, OUC launched a pilot project to offer Time of Use ("TOU") rates – internally known as PowerShift – to explore the viability of extending a new rate structure as an option for customers. The pilot formally ended in 2023. During an exploratory phase, OUC gauged interest from each customer segment and ultimately accepted 700 customers to participate in the pilot. Beginning in April 2021, the 700 pilot customers were billed utilizing On-Peak (2 p.m.-8 p.m.) and Off-Peak rates, the latter being the lowest, offering customers the opportunity to save on their monthly bills and to also smooth OUC's power demand curve. At the conclusion of the pilot, OUC offered participating customers the option to continue on the TOU rate. Of the initial 700 customers enrolled, 474 have chosen to remain in the program past the pilot phase. As part of the pilot, OUC created numerous marketing and communication materials to

ensure customers are equipped with the tools and resources to be successful in the program. Feedback gathered via quarterly customer surveys helped shape the program messaging OUC is using data from these surveys, as well as other data points and metrics gathered during the pilot to determine the future of TOU rates.

Building on the success of the PowerShift Pilot Program, in December of 2024, the OUC Board of Commissioners approved *PeakSHIFT*, a multiyear pricing plan to empower customers with new opportunities to save money, better align costs with how electricity is used and help shift OUC's system electric peak. As OUC implements this modernized pricing structure, the utility will continue to engage with customers and the community. The program has three primary components:

- **DemandLevel Pricing:** Anticipated to go live in November 2026, this program reduces variable non-fuel energy cost per kWh and adds a tiered fixed charge to encourage reducing distribution peak demand (the point where each residential and small commercial customer's usage is at its highest 15-minute average within the month), rebalance costs and reflect individual customers' usage of the electric grid.
- **TruNet Solar:** Anticipated to go live in November 2026, this program adjusts compensation for rooftop solar customers who apply for solar interconnection after June 30, 2025 to reflect industry changes and address systemwide cost equity concerns to ensure affordability of rates for all OUC customers.
- **Shift & Save:** Anticipated to go live in 2027, introduces a time-of-day pricing plan to enable customers to save money by shifting part of their electricity usage to "off-peak" periods for those that want additional incentives to save money.

3.5.2.12 Outage Alerts

OUC launched the first phase of its OUC Alerts program with Outage Alerts in December 2017. The system allows customers to receive information about service outages, including the cause and an estimated restoration time, via text, voice or email.

3.5.2.13 Billing Alerts

In January 2019, the second phase of OUC's Alerts program expanded to include Billing Alerts. The new feature lets customers set an alert, via text, email or voice, to let them know when their new bill is ready to view and when payment is due. This alert, along with Outage Alerts, launched in 2017, are among new "two-way communication" initiatives OUC has introduced to provide customers. Future OUC Alerts program phases to consider include consumption notifications and marketing messages.

3.5.3 Economic Development

Orlando has undergone a radical transformation over the years to diversify its economy and attract high-wage positions in technology, medicine, life sciences, and modeling and simulation. With Orlando's increasing emphasis on recruiting, retaining and expanding commercial customers, OUC has become a major player in the region's economic development. Working in partnership with Enterprise Florida, the Orlando Economic Partnership, and city and county governments, the utility is attracting more companies to Orlando and St. Cloud and helping them grow into vital and valuable members of the business community.

To attract large businesses that enhance the vitality of the community, OUC offers two rates. For large power users who qualify, OUC is able to negotiate its already-affordable rates to fit their business needs. The Economic Development Rider ("EDR") is available to new or expanding businesses representing select

target industries. Companies must add a minimum of 500 kW demand of new electric load and must create at least 25 new jobs at or above the 150 percent median income level to qualify. The Commercial Industrial Service Rider (“CISR”) is available to companies that have minimum load of 2,000 kW or greater, served by a single meter. Companies must provide validation of a lower rate offering outside OUC’s service territory to qualify.

Details of these rates and other incentives are outlined at www.oucpowersgrowth.com – a website that assists site selectors and businesses seeking to locate and learn more about Orlando and OUC. The site includes property search functionality and is mobile friendly.

4.0 FORECAST OF PEAK DEMAND AND ENERGY CONSUMPTION

OUC prepares a set of sales, energy, and demand forecast models each year to support its budgeting and financial planning process as well as long-term planning requirements. In preparing the forecasts, OUC uses internal records, company knowledge of the service territory and customers, and economic projections. OUC draws on outside expertise as needed. S&P Global provides economic projection data. Itron provides the primary forecasting software, analysis of end-use equipment saturation and efficiencies, and technical expertise. In this forecast, the National Renewable Energy Laboratory was utilized to provide adoption curves used to project rooftop solar within OUC's service territory while the midpoint of multiple different industry electric vehicle curves was used to forecast electric vehicle sales.

4.1 Forecast Methodology

OUC has adopted a Statistically Adjusted Engineering ("SAE") modeling technique developed by Itron. This approach entails specifying end-use variables (xHeat for heating, xCool for cooling, and xOther for other use) and utilizing these variables in multi-regression models to forecast sales. SAE variables allow anticipated shifts in customer end-use consumption driven by the type, saturation and efficiency of heating and cooling equipment, and other end-use devices to be represented along with econometric drivers and the effects of photovoltaic systems ("PV") and electric vehicles ("EV") in the forecast models. Itron reviews OUC's application of these techniques and provides data on heating, cooling, and other end-use load trends. These techniques are used to develop the forecasts for both the OUC and St. Cloud service territories.

4.1.1 Residential

The residential sales forecast consists of both a customer forecast model and an average use per customer model. Monthly average usage models were estimated using actual data for the period 2011 to 2024. This provides 14 years of historical data and enough observations to estimate strong regression models. Once models showing the number of expected customers and the expected average use per customer are developed, the projected residential sales by year (y) and month (m) are calculated as the product of the customer and average usage forecasts:

$$Sales_{y,m} = Customers_{y,m} \times Average\ Usage_{y,m}$$

4.1.1.1 Residential Customer Forecast

Residential customers are forecast as a function of household growth for Orange County for the OUC service territory and Osceola County for the St. Cloud service territory. There is a strong correlation between historical changes in customer counts and historical changes in households. The multi-regression model for residential customers is represented as:

$$Customers_{y,m} = \beta_0 + \beta_1(Households_{y,m})$$

The coefficients (β) are outputs of the multi-regression models.

4.1.1.2 Average Use Forecast

The residential forecast models utilize multi-regression modeling made up of three major components:

1. Changes in the economy, such as median household income and household size.
2. End-use equipment index variables, which capture the long-term net effect of equipment saturation and equipment efficiency improvements.
3. Weather variables, which serve to allocate the seasonal impacts of weather throughout the year.

The SAE model framework begins by defining energy use for an average customer in year (y) and month (m) as the sum of energy used by heating equipment (xHeat_{y,m}), cooling equipment (xCool_{y,m}), and other equipment (xOther_{y,m}). The xHeat, xCool and xOther variables are defined as a product of an annual equipment index and a monthly usage multiplier. This model is represented as:

$$\text{Average Usage}_{y,m} = \beta_1(\text{xHeat}_{y,m}) + \beta_2(\text{xCool}_{y,m}) + \beta_3(\text{xOther}_{y,m})$$

Where:

$$\text{xHeat}_{y,m} = \text{Economics}_{y,m} \times \text{HeatingEquipment}_{y,m} \times \text{HDD_Index}_{y,m}$$

$$\text{xCool}_{y,m} = \text{Economics}_{y,m} \times \text{CoolingEquipment}_{y,m} \times \text{CDD_Index}_{y,m}$$

$$\text{xOther}_{y,m} = \text{Economics}_{y,m} \times \text{OtherEquipment}_{y,m}$$

A customer's monthly usage level is impacted by several economic factors, including household size and household income in real dollars.

$$\text{Economics}_{y,m} = \left(\frac{\text{HH Size}_{y,m}}{\text{HH Size}_{\text{base } y,m}} \right)^{0.542} \times \left(\frac{\text{HH Income}_{y,m}}{\text{HH Income}_{\text{base } y,m}} \right)^{0.130}$$

The annual equipment variables (HeatEquip, CoolEquip, OtherEquip) are defined as a weighted average across equipment types multiplied by equipment saturation levels normalized by operating efficiency levels.

$$\text{HeatEquip}_y = \sum_{\text{tech}} \text{Weight} \times \left(\frac{\text{Saturation}_y / \text{Efficiency}_y}{\text{Saturation}_{\text{base } y} / \text{Efficiency}_{\text{base } y}} \right)$$

$$\text{CoolEquip}_y = \sum_{\text{tech}} \text{Weight} \times \left(\frac{\text{Saturation}_y / \text{Efficiency}_y}{\text{Saturation}_{\text{base } y} / \text{Efficiency}_{\text{base } y}} \right)$$

$$\text{OtherEquip}_y = \sum_{\text{tech}} \text{Weight} \times \left(\frac{\text{Saturation}_y / \text{Efficiency}_y}{\text{Saturation}_{\text{base } y} / \text{Efficiency}_{\text{base } y}} \right)$$

The following degree day index variables serve to allocate the seasonal impacts of weather throughout the year. For historic periods, actual heating degree days ("HDD") and cooling degree days ("CDD") are used. Normal HDDs and CDDs are used for forecast periods.

$$\text{HDD_Index}_{y,m} = \frac{\text{HDD}_{y,m}}{\text{Normal HDD}_y}$$

$$\text{CDD_Index}_{y,m} = \frac{\text{CDD}_{y,m}}{\text{Normal CDD}_y}$$

4.1.2 Non-Residential

4.1.2.1 General Service Non-Demand ("GSND")

The General Service Non-Demand ("GSND") and General Service Demand Secondary ("GSD Secondary") classes are modeled as a combined General Service Secondary class ("GS Secondary") because the historic data indicates customer migration has occurred back and forth between the two classes. The result is a single model, which produces predicted values with a higher correlation than that of two separate models. The forecast is later split between GSND and GSD Secondary using the monthly relationships between the two classes in the most recent year of actual data.

The framework for the GS secondary class sales forecast is similar to the residential class sales forecast except modeled on a total sales basis instead of by average use. It also has three major components and utilizes the SAE model framework. The end-use equipment variables are based on commercial appliance and equipment saturation and efficiency projections. The economic driver in the model is Orlando Standard Metropolitan Statistical Area (“SMSA”) Gross Metro Product in real dollars. The third component is the weather variable, which is entirely composed of CDDs. HDDs are not used in the GS Secondary model because no statistically valid correlation between HDDs and sales could be identified. The xCool and xOther variables used in the GS secondary forecast use the same methodology as the residential forecast but with different economic assumptions.

The GS Secondary sales model is represented as:

$$Sales_{y,m} = \beta_1(xCool_{y,m}) + \beta_2(xOther_{y,m})$$

GS secondary customers are forecast as a function of population for Orange County for the OUC service territory and Osceola County for the St. Cloud service territory. There is a strong correlation between historical changes in customer counts and historical changes in the Orange County population. St. Cloud historical customers also correlate well with the Osceola County population.

The GS Secondary customer model is represented as:

$$Customers_{y,m} = \beta_0 + \beta_1(Population_{y,m})$$

4.1.2.2 General Service Demand (“GSD”)

Forecast sales to GSD Secondary customers were modeled as discussed above. In addition to the customers taking service at secondary voltage, OUC serves 27 customers (excluding 6 OUC water plants) at primary voltage. These primary customers are forecasted as a whole on a total sales basis similar to the GSD secondary forecast.

Sales from the various GSD models are totaled to complete the GSD forecast.

4.1.2.3 Streetlights

Private and public lighting consumption is forecast separately. Both classes are not impacted by the weather, and the SAE modeling approach does not apply. Therefore, simple regression models are used to generate both forecasts. The forecast for private streetlights includes a linear trend to capture the historic organic growth that is expected to continue within the forecast period. The forecast for public streetlights does not include a linear trend as any growth in the number of lights has been offset by the replacement of traditional HPS and MH fixtures with LED fixtures.

4.1.2.4 OUC Use

OUC Use sales are those to OUC Water Plants, OUCooling Plants, and OUC facilities. The OUC Use models utilize CDDs, but not HDDs or the factors included in the “Other” SAE modeling variable.

4.1.3 Net Energy for Load (“NEL”) and Peak Demand Forecast

The individual OUC and St. Cloud net energy for load forecasts are generated based on the respective sales forecasts described above and the historic relationship between actual monthly sales and NEL. Peak demand forecasts are then developed for each system based on the forecast NEL and the historic relationship between NEL, peak demand and daily weather.

4.2 Base-Case Forecast Assumptions

Incorporated into the forecast regression models are sets of underlying economic, demographic, and weather assumptions.

4.2.1 Economics & Demographics

The economic and demographic assumptions are derived from forecasts for Orange County, Osceola County, and the Orlando SMSA provided by S&P Global.

4.2.1.1 Median Household Income

The residential sales forecast models use Median Household Income in real dollars, as shown in Table 4-1.

4.2.1.2 Gross Metro Product

The commercial average usage forecast models use Gross Metro Product in real dollars, as shown in Table 4-1.

4.2.1.3 Households and Population

The residential and commercial customer forecast models use households and population, respectively. The primary demographic drivers in the residential average usage forecast models are the number of households and the population (see Table 4-1). The population data is divided by the household data to determine household size used in the residential average usage forecast models.

Table 4-1 Economic & Demographic Projections

Year	Orlando SMSA Median Household Income ¹	Orlando SMSA Gross Metro Product (\$ Billions) ²	Orange County (Thousands)		Osceola County (Thousands)	
			Households	Population	Households	Population
2026	\$58,247	\$197.1	616.2	1,559.5	185.3	497.7
2031	\$60,520	\$223.3	655.2	1,635.0	212.9	566.1
2035	\$62,287	\$247.5	693.1	1,715.2	235.3	622.6
Average Annual Increase						
26 - 31	0.8%	2.5%	1.2%	1.0%	2.8%	2.6%
26 - 35	0.7%	2.6%	1.3%	1.1%	2.7%	2.5%
(1) 2009 dollars (2) 2017 dollars						

4.2.3 Weather

Weather is a key factor affecting electricity consumption for indoor cooling and heating. Monthly CDDs are used to capture electric cooling load requirements while HDDs are used to capture electric heating load requirements. CDDs and HDDs are calculated from the daily average temperatures as reported by the National Weather Service for the weather station at the Orlando International Airport. CDDs are calculated using a 65°F base temperature as follows:

$$CDD_d = (Avg Temp_d - 65°F) \text{ when } Avg Temp_d \geq 65°F$$

The daily CDD values are then aggregated to yield monthly CDDs for each year as follows:

$$CDD_{y,m} = \sum CDD_{y,m,d}$$

Daily HDD values are calculated in a similar manner using a base temperature of 65°F as follows:

$$HDD_d = (65^{\circ}F - Avg Temp_d) \text{ when } Avg Temp_d \leq 65^{\circ}F$$

The daily HDD values are then aggregated to yield monthly HDDs for each year as follows:

$$HDD_{y,m} = \sum HDD_{y,m,d}$$

Due to historic weather trending warmer that escalation was continued to the forecast period in order to come up with “Normal” monthly weather with CDDs increasing and HDD decreasing annually over the forecast period.

4.3 Base-Case Load Forecast

A long-term annual base-case forecast was developed using the methodology and assumptions outlined above.

4.3.1 Customer and Sales Forecast Results

Total customers and retail sales for OUC and St. Cloud are expected to increase as shown in Table 4-2 through Table 4-5.

4.3.1.1 Residential Forecast

Increasing average usage per residential customer due to electric vehicle adoption is projected to be mitigated by increased appliance efficiency, increased customer conservation, increased penetration of rooftop solar, and declining household size, resulting in an increase in average usage per residential customer over the forecast period 2026 through 2035. Residential sales are projected to grow for OUC at an average annual rate of 2.8 percent and 4.4 percent in St. Cloud over this same period. The number of residential customers is projected to grow at an average annual rate of 1.4percent for OUC and 3.7percent for St. Cloud over this same period.

4.3.1.2 GSND Forecast

GSND is comprised of small commercial customers. GSND sales are projected to grow at an average annual rate of 1.2 percent and 2.0percent for OUC and St. Cloud, respectively, between 2026 and 2035. The number of GSND customers is projected to grow at an average annual rate of 0.5 percent and 2.3 percent, respectively, for OUC and St. Cloud over this same period.

4.3.1.3 GSD Forecast

GSD is comprised of large commercial and industrial customers. Sales are projected to grow at an average annual rate of 1.6 percent and 2.1 percent for OUC and St. Cloud, respectively, between 2026 and 2035. The number of GSD customers is projected to grow at an average annual rate of 0.5 percent and 2.3 percent, respectively, for OUC and St. Cloud over this same period.

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Table 4-2 OUC Long-Term Sales Forecast (GWh)

Year	Residential	GSND	GSD	Lighting	OUC Use	Total Retail
2026	2,276	453	3,518	59	172	6,478
2031	2,616	478	3,842	61	173	7,170
2035	2,923	506	4,051	62	173	7,715
Average Annual Increase						
26 - 31	2.8%	1.1%	1.8%	0.7%	0.1%	2.1%
26 - 35	2.8%	1.2%	1.6%	0.6%	0.1%	2.0%

Table 4-3 OUC Average Number of Customers Forecast

Year	Residential	GSND	GSD	Total Retail
2026	202,662	24,561	4,725	231,948
2031	217,053	25,339	4,873	247,265
2035	228,901	25,792	4,960	259,653
Average Annual Increase				
26 - 31	1.4%	0.6%	0.6%	1.3%
26 - 35	1.4%	0.5%	0.5%	1.3%

Table 4-4 St. Cloud Long-Term Sales Forecast (GWh)

Year	Residential	GSND	GSD	Lighting	Total Retail
2026	806	71	171	3	1,051
2031	1,015	78	190	3	1,286
2035	1,190	85	206	3	1,484
Average Annual Increase					
26 - 31	4.7%	1.9%	2.1%	0.0%	4.1%
26 - 35	4.4%	2.0%	2.1%	0.0%	3.9%

Table 4-5 St. Cloud Average Number of Customers Forecast

Year	Residential	GSND	GSD	Total Retail
2026	57,488	4,564	390	62,442
2031	70,273	5,109	437	75,819
2035	79,804	5,582	478	85,864
Average Annual Increase				
26 - 31	4.1%	2.3%	2.3%	4.0%
26 - 35	3.7%	2.3%	2.3%	3.6%

4.3.2 Forecast Hourly Peak Demand and NEL

Peak demand growth is driven by the aggregate retail load forecasts for OUC and St. Cloud. Seasonal hourly peaks and annual NEL are presented for OUC and St. Cloud in Tables 4-6 and 4-7, respectively. Table 4-8 represents the combined seasonal coincident hourly peak demand and NEL forecasts for OUC and St. Cloud.

Table 4-6 OUC Forecast Hourly Peak Demand (Summer and Winter) and NEL

Year	Summer (MW)	Winter (MW)	NEL (GWh)
2026	1,272	1,007	6,568
2031	1,322	1,117	7,270
2035	1,395	1,178	7,823
Average Annual Increase			
26 - 31	0.8%	2.1%	2.0%
26 - 35	1.0%	1.8%	2.0%

Table 4-7 St. Cloud Forecast Hourly Peak Demand (Summer and Winter) and NEL

Year	Summer (MW)	Winter (MW)	NEL (GWh)
2026	296	224	1,227
2031	341	275	1,501
2035	388	313	1,733
Average Annual Increase			
26 - 31	2.9%	4.2%	4.1%
26 - 35	3.0%	3.8%	3.9%

Table 4-8 System Forecast Coincident Hourly Peak Demand (Summer and Winter) and NEL (Total of OUC and St. Cloud)

Year	Summer (MW)	Winter (MW)	NEL (GWh)
2026	1,565	1,162	7,795
2031	1,659	1,299	8,770
2035	1,776	1,420	9,556
Average Annual Increase			
26 - 31	1.2%	2.2%	2.4%
26 - 35	1.4%	2.3%	2.3%

4.4 High and Low Load Scenarios

In addition to the base-case, two long-term forecast scenarios representing a high and low range around the forecast peak demand and NEL were constructed to test for sensitivity of uncertain economic conditions and

customer growth. Weather conditions deviating from normal were not included in sensitivity testing due to non-growth-related impacts and an equal probability of affecting any given year either negatively or positively. The high and low load scenarios represent alternatives to the base-case forecast and are defined by 0.5 percent higher and 0.5 percent lower economic growth rates, respectively. Table 4-9 represents a summary of the high and low load scenarios.

Table 4-9 High and Low Scenario System Forecast Peak Demand (Summer and Winter) and NEL (Total of OUC and St. Cloud)

High Load Scenario			
Year	Summer	Winter	NEL
	(MW)	(MW)	(GWh)
2026	1,567	1,162	7,801
2031	1,672	1,307	8,837
2035	1,802	1,438	9,683
Average Annual Increase			
26 - 31	1.3%	2.4%	2.5%
26 - 35	1.6%	2.4%	2.4%
Low Load Scenario			
Year	Summer	Winter	NEL
	(MW)	(MW)	(GWh)
2026	1,564	1,162	7,789
2031	1,645	1,290	8,705
2035	1,751	1,403	9,432
Average Annual Increase			
26 - 31	1.0%	2.1%	2.2%
26 - 35	1.3%	2.1%	2.1%

5.0 DEMAND-SIDE MANAGEMENT

Sections 366.80 through 366.83, and 403.519, Florida Statutes (“F.S.”), are known collectively as the Florida Energy Efficiency and Conservation Act (“FEECA”). Section 366.82(2), F.S., requires the Florida Public Service Commission (“PSC”) to adopt appropriate goals designed to increase the conservation of expensive resources, such as petroleum fuels, to reduce and control the growth rates of electric consumption and weather-sensitive peak demand. Pursuant to Section 366.82(6), F.S., the PSC must review the conservation goals of each utility subject to FEECA at least every five years. The six utilities subject to FEECA are Florida Power & Light Company (“FPL”), Duke Energy Florida, LLC. (“DEF”), Tampa Electric Company (“TECO”), Florida Public Utilities Company (“FPUC”), OUC, and JEA (referred to collectively as the “FEECA utilities”).

OUC’s residential and commercial/industrial numeric conservation goals for the 2025 through 2029 period were established by the PSC pursuant to Order No. PSC-2024-0433-FOF-EG issued September 20, 2024, as amended by Order No. PSC-2024-0433A-FOF-EG issued September 24, 2024. These PSC-established annual demand-side management (“DSM”) goals are presented in Tables 5-1 and 5-2.

OUC committed to a 1 percent goal of energy efficiency as a percent of retail sales. This includes measures beyond those measured through FEECA. Because OUC must operationally plan to generate enough energy to meet demand at all times, and because OUC can incentivize, but not control, actual adoption, this forecast is being used for purposes of this Ten-Year Site Plan.

Table 5-1 Residential DSM Goals Approved by the PSC

Calendar Year	Summer (MW)	Winter (MW)	Annual (GWh)
2025	0.111	0.181	1.072
2026	0.113	0.192	1.129
2027	0.114	0.203	1.186
2028	0.116	0.214	1.243
2029	0.118	0.225	1.301

Table 5-2 Commercial/Industrial DSM Goals Approved by the PSC

Calendar Year	Summer (MW)	Winter (MW)	Annual (GWh)
2025	0.485	0.380	3.207
2026	0.534	0.411	3.508
2027	0.577	0.438	3.769
2028	0.620	0.463	4.019
2029	0.661	0.485	4.247

OUC has continued to promote its DSM and conservation programs to increase customer awareness of such programs. Not only do these programs help customers save money by saving energy, but the programs also help OUC reduce emissions of carbon dioxide (CO₂) and better position OUC to meet possible future greenhouse gas regulations. It should be noted that government mandates have forced manufacturers to increase their efficiency standards of appliances, thereby decreasing the incremental amount of cost-effective energy savings achievable, and the efficiency of new power generation equipment has increased. Appliance and generating unit efficiency improvements have muted the effectiveness of DSM and conservation programs, as overall efficiency increases in the marketplace partially offset the benefit of such programs.

The conservation programs included in OUC's 2025 DSM Plan (approved by the PSC on April 15, 2025) and offered to OUC's customers in 2025 consist of the following:

- Residential Existing Home Rebates Program
- Residential Efficiency Delivered Program
- Residential New Home Rebates Program
- Commercial/Industrial Prescriptive Rebates Program
- Commercial/Industrial Lighting Rebates Program
- Commercial/Industrial Custom Incentives Rebates Program

The remainder of this section describes OUC's residential home energy surveys and commercial/industrial energy audits (Section 5.1), and each of the DSM and conservation programs outlined above (Sections 5.2 and 5.3). Incentives and rebate amounts included in the program descriptions are current as of the time this report was prepared. In addition to offering these programs, OUC continues to play an active role in promoting conservation through community relations as discussed in Section 2.4 and Section 3.6 of this Ten-Year Site Plan.

5.1 *Energy Survey Programs*⁹

5.1.1 *Residential Home Energy Survey Program*

OUC has been offering home energy surveys dating back to the 1980's. The home energy walk-through surveys are designed to provide residential customers with recommended energy efficiency measures and practices that customers can implement and to encourage participation in various OUC rebate programs. The home energy surveys are available to both single family and multi-family residential customers.

The Residential Energy Walk-Through Survey includes a review of the customer's electric consumption history as well as a walk-through review of the attic; heating, ventilation, and air conditioning (HVAC) system; air duct and air returns; window caulking; weatherstripping around doors; and, if applicable faucets, toilets and lawn sprinkler systems. OUC provides participating customers specific tips on conserving electricity and water as well as details on customer rebate programs. OUC Conservation

⁹ As noted in OUC's 2025 DSM Plan, discussion of OUC's Residential Home Energy Survey and Commercial/Industrial Energy Audit programs is included for informational purposes as OUC has continued to offer the programs. Demand and energy reductions associated with these programs are not treated as contributing to the numeric conservation goals established by the FPSC for OUC.

Specialists use this walk-through type of audit technique as a means of motivating OUC customers to participate in other conservation programs and qualify for appropriate rebates.

One of the primary benefits of the Residential Energy Survey Program is the education it offers customers on energy conservation measures and the ways lifestyle and behavior can directly affect energy use. Customers participating in the Energy Survey Program are provided with historical energy usage and a list of relevant recommended conservation measures for implementation. Customers receive an analysis report that includes pro forma estimates of implementation costs, savings, and payback periods for recommended measures. Customers benefit from the increased comfort experienced and decreased electric and water bills when efficiency measures are implemented.

The Home Energy Survey rates a customer's home energy use efficiency and where improvements can yield lower utility bills. To participate, OUC customers may request an appointment for a Walk-Through Energy Survey by calling the OUC Customer Service Call Center. Participation is tracked through service orders that are produced when appointments are scheduled and completed.

5.1.2 Commercial/Industrial Energy Audit Program

OUC's Commercial/Industrial Energy Audit Program has been offered for several years. These audits are focused on increasing the energy efficiency and energy conservation of commercial buildings. Each audit includes a free survey comprised of a physical walk-through inspection of the commercial facility performed by trained and experienced energy experts. The survey examines heating and air conditioning systems including duct work, refrigeration equipment, lighting, water heating, motors, process equipment, and the thermal characteristics of the building including insulation. Following the inspection, the customer receives a written report detailing cost-effective recommendations to improve the energy and water efficiency of the building. Participating customers are encouraged to consider other recommended OUC commercial programs and directly benefit from energy conservation measures, which decrease their electric and water bills.

OUC customers may participate by calling the OUC Customer Service Call Center or contacting their assigned key account manager and requesting an appointment for a Walk-Through Energy Survey. Participation is tracked through service orders that are produced when appointments are scheduled and completed.

5.2 Residential Programs

5.2.1 Residential Existing Home Rebates Program

OUC's Residential Existing Home Rebate Program provides rebates for the following six measures:

- Heat Pump Water Heater Rebates
- Heat Pump A/C Rebates
- Ceiling Insulation Rebates
- Duct Repair Rebates
- ENERGY STAR® Windows Rebates
- Smart Thermostat Rebates

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These six measures are common to all three of OUC's Residential DSM program; all measures except the Smart Thermostat Rebates measure, which is slated to be released in 2026, are measures that OUC has been offering through its 2020 DSM Plan and earlier DSM program offerings. Customers may participate by submitting a rebate application online at <http://www.OUC.com/rebates> or via email, mail, in-person, or facsimile. Proof of purchase and/or receipts are required to be included in the application and repairs can be carried out by a contractor or the customer. Participation is tracked based on the number of rebates processed. Typically, these rebates are credited on the customer's bill, or a check can be processed and sent to the customer or the property owner who may have paid for the improvement.

Heat Pump Water Heater Rebate Measures

Commonly referred to as hybrid electric heat pump water heaters, heat pump water heaters with a Uniform Energy Factor (UEF) in excess of 2.2 can cut water heating electric use and costs by more than half. Across all three of OUC's Residential DSM Programs, OUC currently offers a rebate of \$500 for heat pump water heaters; this rebate amount may be adjusted in the future at OUC's discretion.

Heat Pump A/C Rebate Measures

Across all three of OUC's Residential DSM Programs, OUC offers separate rebate amounts for the following two Air Source Heat Pump measures: CEE Tier 2 and ENERGY STAR®/CEE Tier 1. This measure provides rebates to qualifying customers in existing or new homes who install heat pumps having a seasonal energy efficiency ratio (SEER2) of 15.2 or higher, along with a Heating Season Performance Factor of greater than 9.0. Customers receive a rebate in the form of a credit on their bill ranging up to \$1,150, depending upon the SEER or SEER2 rating and capacity (tons) of the new heat pump. The following table illustrates the rebate values available depending on the size and efficiency of the Heat Pump installed; these rebate amounts may be adjusted in the future at OUC's discretion.

		SEER2 Upgraded To:								
SEER2		15.2 - 15.99	16.0 - 16.99	17.0 - 17.99	18.0 - 18.99	19.0 - 19.99	20.0 - 20.99	21.0 - 21.99	22.0 - 22.99	
SEER		16.00 - 16.99	17.0 - 17.99	18.0 - 18.99	19.0 - 19.99	20.0 - 20.99	21.0 - 21.99	22.0 - 22.99	23.0 - 23.99	
AC Size (Tons)	1	-	-	\$55	\$85	\$115	\$140	\$165	\$185	
	1.5	-	\$55	\$110	\$155	\$200	\$240	\$275	\$305	
	2	-	\$90	\$165	\$230	\$285	\$340	\$385	\$425	
	2.5	\$45	\$130	\$220	\$300	\$370	\$435	\$495	\$550	
	3	\$65	\$165	\$275	\$370	\$455	\$535	\$605	\$670	
	3.5	\$90	\$200	\$330	\$440	\$540	\$635	\$715	\$790	
	4	\$110	\$235	\$385	\$510	\$625	\$730	\$825	\$910	
	5	\$150	\$310	\$490	\$655	\$795	\$925	\$1,045	\$1,150	
SEER2 is the main rating that determines the rebate value.										
If only SEER listed on AHRI, use corresponding SEER column above.										

Ceiling Insulation Rebate Measures

The attic is often the easiest place to add insulation and lower total energy consumption throughout the seasons. OUC has previously offered Ceiling Insulation rebates as a separate program, but as with other measures, in OUC's 2025 DSM Plan, ceiling insulation rebates are now offered as a qualified measure across all three of OUC's Residential DSM Programs. OUC's Ceiling Insulation measure is designed to encourage customers to upgrade their attic insulation to save energy and reduce OUC's peak demand and to save

customers money by reducing their electric bills. Participating customers receive a rebate of \$0.12 per square foot for upgrading their attic insulation to R-38 or higher; the rebate amount may be adjusted in the future at OUC's discretion. The rebate is available for insulation added to conditioned areas only.

Duct Repair Rebate Measures

Beginning in 2000, OUC offered a Duct Repair Rebates Program designed to encourage customers to repair leaking ducts on existing systems. In OUC's 2025 DSM Plan, duct repair is offered as a qualified measure across all three of OUC's Residential DSM Programs. Ducts must be sealed with mastic and fabric tape or any other Underwriters Laboratory (UL) approved duct tape. Participating customers receive a rebate for 100 percent of the cost of duct repairs on their homes, up to \$100; the rebate amount may be adjusted in the future at OUC's discretion.

ENERGY STAR® Windows Rebate Measures

Installation of energy-efficient windows can help reduce energy consumption of heating, cooling, and lighting, thereby reducing utility generation capacity and saving customers money on their power bills. OUC has historically offered rebates to support efficient window installations through its High-Performance Windows Rebates program; beginning with OUC's 2025 DSM Plan, this offering has been converted to a measure that is available in all three of OUC's Residential DSM Programs and this measure has been modified to offer rebates only for windows that meet ENERGY STAR® criteria consisting of National Fenestration Rating Council (NFRC) certification, meets ENERGY STAR® southern regionally accepted standards of a U-Factor ≤ 0.32 and a Solar Heat Gain Coefficient (SHGC) ≤ 0.23 . Participating customers receive a rebate of \$1.50 per square foot for the purchase of ENERGY STAR® rated energy efficient windows; the rebate amount may be adjusted in the future at OUC's discretion.

Smart Thermostat Rebate Measures

The only new residential DSM measure submitted in OUC's 2025 DSM Plan is the Smart Thermostat Rebate Measure. A Smart Thermostat is like a programmable thermostat, but the Smart Thermostat utilizes internet connectivity to allow the customer or their designated surrogates to more actively control the home's heating, cooling, and ventilation system behavior. The benefits of Smart Thermostats include more precise control of comfort, automated control of conditioned space based on actual occupancy, schedule and environmental conditions and the ability to permit remote access to the thermostat to pre-condition a space – all of which assist customers by saving money on their bills and reducing need for utility generation capacity. OUC's Smart Thermostat measure provides a rebate amount of \$50 per installation; the rebate amount may be adjusted in the future at OUC's discretion.

5.2.2 Residential Energy Efficiency Delivered Program

What was originally referred to as the 'home energy fix-up program' was subsequently revamped and expanded to allow for any OUC customer (energy, water, or both energy and water) to participate and renamed the 'Efficiency Delivered' program. By 2020, the program was expanded to allow for participation by all residential customers regardless of home type (single family and multi-family) and regardless of ownership status (owned or rented with landlord approval).

OUC's Residential Efficiency Delivered Program is available to residential customers and provides support for up to \$2,500 of energy and water efficiency upgrades based on the assessed needs of the customer's home and the customer's household income. OUC determines its contribution toward the cost of

improvements utilizing three household income tiers:

Household Income	OUC Contribution
Less than \$40,000	85% of the actual cost of repairs and upgrades
\$40,001–\$60,000	50% of the actual cost of repairs and upgrades
Greater than \$60,000	Rebates only

1. \$40,000 or less: OUC contributes 85 percent of total cost, not exceeding \$2,125
2. \$40,001 to \$60,000: OUC contributes 50 percent of the total cost, not exceeding \$1,250 and
3. greater than \$60,000: OUC will contribute the value of the current rebate incentives that apply toward the measures employed.

To participate in the Residential Efficiency Delivered Program, a customer must request and complete a no-charge Residential Home Energy Survey. A Conservation Specialist from OUC performs a survey at the customer's home and determines which home improvements have the potential to save the customer the most money. Ordinarily, Energy Survey recommendations require a customer to spend money replacing aging equipment or adding energy conservation measures; however, customers may not have discretionary income to implement these measures - especially those customers with lower household incomes. To be eligible for this program, the customer's account must be in good credit standing, with the exception that low-income customers can participate if they have a current balance that is not delinquent. Under this program, OUC arranges for a licensed, approved contractor to perform the necessary repairs based on OUC negotiated and contracted rates. The remaining portion of the cost for which the customer is responsible (i.e., the 15 or 50 percent customer share depending on household income), is paid directly to OUC or recovered interest-free over a 24-month period on the participant's monthly electric bill.

The purpose of the Residential Efficiency Delivered Program is to achieve utility energy and water conservation goals and to reduce customers' energy and water costs, especially for low-income households. Implementation of measures offered through the Efficiency Delivered program helps to dampen the impact of seasonal billing changes due to weather variation for customers for which a larger portion of household income is required to pay the utility bill. Through this program, OUC helps customers achieve lower utility bills, while providing the additional benefit of decreasing the likelihood of incurring costly service disconnect fees and late charges resulting from an inability to pay the utility bill. OUC believes that this program particularly helps low-income customers better afford other essential living expenses. For all participating customers, this program offers a single point of contact to facilitate the implementation of a whole suite of conservation measures leveraging OUC's purchasing power to receive reasonable costs with installation offered by pre-screened qualified contractors.

OUC's Residential Efficiency Delivered Program includes each of the measures included in OUC's Residential Existing Home Rebates Program (please refer to Section 5.2.1 herein for descriptions of those measures), as well as measures related to air sealing infiltration control (i.e., attic stair cover insulation, door sweeps and caulking and weatherstripping) and heating and cooling system maintenance (i.e., maintenance checks and air filter replacements).

5.2.3 Residential New Home Rebates Program

OUC's Residential New Home Rebates Program provides a flexible "a la carte" program through which a home buyer can select a limited number of measures available through OUC's Residential Existing Home Rebates Program (including Heat Pump Water Heaters, Heat Pump Air Conditioners, Solar Thermal Water Heaters, and a collection of water conservation devices). This program structure has evolved from earlier DSM program offerings based on feedback from the residential building community and OUC's efforts to streamline the marketing and administration of all its residential DSM programs and measure offerings. This program encourages builders to build structures and install equipment above current building code to maximize energy savings achievable.

5.3 Commercial/Industrial Programs

5.3.1 Commercial/Industrial Prescriptive Rebates Program

OUC's Commercial/Industrial Prescriptive Rebates Program consists of the following measures:

- Ceiling Insulation Rebates
- Duct Sealing Rebates
- ENERGY STAR® Windows Rebates
- Heat Pump Water Heater Rebates
- LED Lighting and Occupancy Sensors Rebates
- Reflective Roof Treatment (including Cool Roof) Rebates
- Smart Thermostat Rebates
- Solar Thermal Water Heating Rebates
- Window Shade Film Rebates

All measures except the Smart Thermostat Rebates measure, which is new to the current DSM Plan, are measures that OUC included in its 2020 DSM Plan and earlier DSM program offerings. Commercial and industrial customers in good standing may participate in the Commercial/Industrial Prescriptive Rebates Program. Customers can initiate participation in this program in any combination of measures they choose by calling a customer service representative at OUC or by submitting an application online at <http://www.OUC.com/rebates> to take advantage of any of the measures offered through the Program. As applicable to specific measures, proof of purchase and/or receipts are required to be included in the application, and repairs or installation of qualifying equipment can be performed by a contractor or by the customer. Participation is tracked based on the number of rebates processed; typically, these rebates are credited to the customer's bill, or a check can be processed and sent to the business owner or landlord who may have paid for the improvements associated with measures selected by the customer.

Ceiling Insulation Rebate Measures

OUC offers Ceiling Insulation rebates to enable customers to increase their facility's resistance to heat loss and gain, which saves energy and reduces system peak demand and saves customers money by reducing their electric bills. Participating customers receive a rebate of \$0.12 per square foot for upgrading their ceiling insulation to R-38 or higher; the rebate amount may be adjusted in the future at OUC's discretion. The rebate is available for insulation added to conditioned areas only.

Duct Sealing Rebate Measures

This measure is designed to encourage customers to repair and maintain the ductwork on existing HVAC systems to improve the overall efficiency of their HVAC systems. OUC will rebate 100 percent of costs, up to \$100; the rebate amount may be adjusted in the future at OUC's discretion. Ducts must be sealed with mastic and fabric tape or other Underwriters Laboratory approved duct tape on all accessible boots, joints, and seams of the air duct system. Commercial and industrial customers with systems greater than 5.5 tons are eligible for rebates through OUC's Commercial/Industrial Custom Incentive Rebates Program. Invoices must include separately itemized amounts for each system repair and must reflect the repair or sealing method used.

ENERGY STAR® Windows Rebate Measures

Energy-efficient windows help minimize consumption by heating, cooling, and lighting, thereby reducing utility generation capacity and saving customers on their power bills. OUC has historically offered rebates to support efficient window installations through its High-Performance Windows Rebates program and as an eligible measure through its Commercial Custom Incentive Program; beginning with OUC's 2025 DSM Plan, this offering has been converted to a measure that is available to commercial and industrial customers through the Commercial/Industrial Prescriptive Rebates Program (and also through the Commercial Custom Program). This measure has been modified to provide rebates for windows that meet ENERGY STAR® criteria. Participating customers receive a rebate of \$1.50 per square foot for the purchase of ENERGY STAR® rated energy efficient windows; the rebate amount may be adjusted in the future at OUC's discretion.

Heat Pump Water Heaters Rebate Measures

Commonly referred to as hybrid electric heat pump water heaters, heat pump water heaters with a coefficient of performance (COP) of greater than 2.0 can cut water heating electric use and costs by more than half. OUC offers the same rebates to commercial and industrial customers as it offers to residential customers who install heat pump water heaters. OUC currently offers a rebate of \$500 for heat pump water heaters; this rebate amount may be adjusted in the future at OUC's discretion. Commercial and industrial customers who wish to install heat pump water heaters with greater capacity than residential units are eligible for rebates through OUC's Commercial/Industrial Custom Incentive Rebates Program.

LED Lighting and Occupancy Sensors Rebate Measures

Commercial and industrial customers that upgrade the efficiency of their lighting (i.e., LED lighting, occupancy sensors, and refrigerated display case LED lighting) may be eligible to receive a rebate of \$250/kW through the lighting rebates measures that are available through OUC's Commercial/Industrial Prescriptive Rebates Program, Commercial/Industrial Lighting Rebates Program, and Commercial/Industrial Custom Incentive Rebates Program; this rebate amount may be adjusted in the future at OUC's discretion. Participation is open to facilities located within OUC's service area that receive electric service under an OUC commercial rate. Participants or customers may be any of the following:

- Individual customers who install more efficient lighting in their own facilities.
- National or local companies that install more efficient lighting.
- Local contractors, design/build firms, architectural and engineering firms, and commercial property developers working on behalf of OUC commercial customers.

Reflective Roof Treatment (Including Cool Roof) Rebate Measures

This measure is designed to reflect the sun's rays and lower roof surface temperature while increasing the lifespan of the roof. OUC will rebate customers at \$0.12 per square foot for ENERGY STAR® cool/reflective roofing that has an initial solar reflectance greater than or equal to 0.70; this rebate amount may be adjusted in the future at OUC's discretion.

Smart Thermostat Rebate Measures

A Smart Thermostat is like a programmable thermostat, but the Smart Thermostat utilizes internet connectivity to allow the customer or their designated surrogates to more actively control the structure's heating, cooling, and ventilation system behavior. The benefits of Smart Thermostats include more precise control of comfort levels, automated control of conditioned space based on actual occupancy, schedule and environmental conditions and the ability to allow remote access to the thermostat to pre-condition a space – all of which assist customers by saving money on their bills and reduce need for utility generation capacity. OUC's Smart Thermostat measure provides a rebate amount of \$50 per installation; the rebate amount may be adjusted in the future at OUC's discretion.

Solar Thermal Water Heating Rebate Measures

Solar water heating provides an efficient and carbon-neutral alternative to conventional water heating methods. OUC's Solar Thermal Water Heating Rebate measure provides rebate incentives to commercial and industrial customers who install this technology based on the volume (in kW) of conventional capacity avoided by the installation. The amount of the rebate is \$900; this rebate amount may be adjusted in the future at OUC's discretion.

Window Shade Film Rebate Measures

Window shade film reduces the energy and demand cooling loads placed on OUC's electric system by heat gain in conditioned space. To reduce energy and peak demands, and to enable customers to reduce their electric bills, OUC offers a rebate of \$0.55 per square foot of film installed in a customer's conditioned space; this rebate amount may be adjusted in the future at OUC's discretion.

5.3.2 Commercial/Industrial Lighting Rebates Program

Commercial and industrial customers that upgrade the efficiency of their lighting (i.e., LED lighting, occupancy sensors, and refrigerated display case LED lighting) may be eligible to receive a rebate of \$250/kW through the lighting rebates measures that are available through OUC's Commercial/Industrial Prescriptive Rebates Program, Commercial/Industrial Lighting Rebates Program, and Commercial/Industrial Custom Incentive Rebates Program; this rebate amount may be adjusted in the future at OUC's discretion. Participation is open to facilities located within OUC's service area that receive electric service under an OUC commercial rate. Participants or customers may be any of the following:

- Individual customers who install more efficient lighting in their own facilities.
- National or local companies that install more efficient lighting.
- Local contractors, design/build firms, architectural and engineering firms, and commercial property developers working on behalf of OUC commercial customers.

5.3.3 Commercial/Industrial Custom Incentives Rebates Program

OUC has designed the Commercial/Industrial Custom Incentive Rebates Program to encourage electric demand reductions that go above and beyond the efficiency gains typically achieved in retrofit or replacement projects. Consequently, demand savings credit is based only on reductions that exceed current state and federal minimum efficiency standards, wherever such standards (e.g., Florida's Energy Efficient Building Code Standards) apply. In cases where these standards do not exist, savings credit is based on improvements relative to a customer's documented electric demand prior to participating in the program. The following measures are included in the Commercial/Industrial Custom Incentives Rebates Program; all of these are measures that OUC has been offering through its 2020 DSM Plan and earlier DSM program offerings:

- High Efficiency Packaged Terminal Air Conditioners Rebates
- High Efficiency Packaged Terminal Heat Pumps Rebates
- LED Lighting Rebates
- Occupancy Sensors Rebates
- Refrigerated Display Case LED Lighting Rebates
- Other Commercial Custom Incentive Measure Rebates

Through the Commercial/Industrial Custom Incentive Rebate Program, commercial and industrial customers receive incentives based on the demonstrated reduction in peak demand their projects achieve plus the value of the first-year energy savings. Energy and demand saving incentives are paid for the maximum one-hour average demand reduction that occurs during Summer Demand period defined as weekdays, between 1 p.m.– 6 p.m., from April through October. Pre- and post-installation inspections are required. Incentives and other program considerations are summarized below and may be changed in the future at OUC's discretion.

- \$250 per kW reduction incentive for all lighting measures.
- \$550 per kW reduction incentive plus \$0.032 per kWh for all non-lighting measures.
- Incentives shall not exceed 50% of project cost.
- Incentives may be paid at 50% on project completion and remainder at one year depending on performance results.
- All incentives will be paid as a credit appearing on the customer's OUC statement.
- Simple return on investment must be greater than 2 years.
- Energy and demand conservation measures should have a useful life of at least 10 years.
- A maximum incentive of \$200,000 per customer annually; this amount was increased from \$100,000 by OUC in August 2025.

The following requirements must be met prior to work beginning:

1. Customer prepares and submits a Project Application. Customer downloads the application at: <https://WWW.OUC.COM/SAVEYOURWAY>
2. Customer schedules on-site inspection(s) and meeting(s) with OUC to review proposed project.
3. Customer works with OUC through the incentive funding commitment and approval process.
4. OUC provides customer project approval and incentive funding commitment.

5. Customer performs any required pre-installation Measurement and Verification (M&V).

After work is complete, the following must occur:

1. Customer submits Installation Report
2. Customer performs post-installation M&V
3. Customer documents the kW and kWh savings.
4. Customer schedules on-site inspection(s) by OUC to confirm installation and M&V results.
5. Customer obtains final approval from OUC and receives rebate in the form of a billing credit on OUC monthly statement.

In addition to the residential and commercial programs previously discussed, OUC continues to do more to reduce energy consumption through supply-side initiatives, including:

- Conservation Voltage Reduction (CVR) - The Conservation Voltage Reduction (CVR) Project is made possible by OUC's investment in its Advanced Meter Infrastructure (AMI) and more sophisticated distribution equipment. The availability of AMI customer load and voltage interval data provides an opportunity to optimize voltage control and thereby reduce energy consumption based on better awareness and monitoring of system conditions at customer service points. Benefits of CVR include conservation related reductions in customer energy usage and line losses (with associated reductions in fuel usage) and lower demands on generation resources. As of December 2025, OUC had 157 feeders of the total of 190 feeders under CVR control.
- OUC District Cooling's Chilled Water District(s) Efficiency Improvements – District Cooling currently serves over 200 customers and provides more than 61,000 tons of cooling. The value of District Cooling is attributed to more efficient and less costly generation and delivery of chilled water when compared to what a customer would likely produce independently. District Cooling invests in higher efficiency chillers and equipment and optimizes its operations on a continuous basis to provide a lower cost and more efficient solution for subscribing customers.

6.0 FORECAST OF FACILITIES REQUIREMENTS

6.1 Existing Capacity Resources

6.1.1 Existing Generating Capacity

OUC's total owned generating capability for OUC and St. Cloud (as of date this Ten-Year Site Plan was prepared) is 2,046 MW in the winter and 2,009 MW in the summer. OUC's existing generating capability (described in more detail in Section 2.0) consists of the following:

- Sole ownership of Stanton Energy Center Unit 1 (as of January 1, 2026)
- Joint ownership shares in Stanton Energy Center Unit 2 and Stanton A
- Sole ownership of Stanton Energy Center Unit B (Stanton B)
- Joint ownership shares of the Indian River combustion turbine units
- Joint ownership share of St. Lucie Unit 2 Nuclear Generating Facility
- Sole ownership of the Osceola Generating Station

St. Cloud's entitlement to capacity from Stanton Unit 2 is included as generating capability in Tables 6-2 and 6-3, consistent with the Interlocal Agreement described in Section 2.0.

6.1.2 Power Purchase Agreements

Corresponding to the construction of Stanton A, OUC entered into a PPA with SCF to purchase capacity from SCF's 65 percent ownership share of Stanton A. The original Stanton A PPA was for a term of 10 years and allowed OUC, KUA, and FMPA to purchase all of SCF's 65 percent capacity share. The utilities originally had options to extend the PPA beyond its initial term. OUC's Stanton A PPA has been extended through December 2031, and OUC has purchased an additional 87 MW from Stanton A through December 31, 2028. As discussed in Section 2, NextEra Energy has purchased SCF's interest in Stanton A.

As discussed in Section 2, OUC added 108.5 MWac of solar capacity (nameplate) in June 2020 through PPAs with NextEra, and added 149 MWac of solar capacity (nameplate) in December 2024, also through PPAs with NextEra. OUC also has PPAs associated with purchases of energy generated from landfill gas, as discussed in Section 2.

In 2020, OUC completed a comprehensive Electric Integrated Resource Plan ("EIRP") to guide OUC through the next 30 years¹⁰. Based on the results of the EIRP, OUC anticipates entering into PPAs for approximately 1,491 MWac of solar (nameplate) and 800 MWac of energy storage by the end of 2034 as summarized in Table 6-1.

¹⁰ OUC anticipates refreshing its Electric Integrated Resource Plan within the next 12 months.

Table 6-1 Anticipated Solar and Energy Storage PPAs

Commercial Operation Date	Nameplate Capacity (MWac) w/o Energy Storage	Energy Storage (MW)
June 2027	149	100
June 2029	149	0
June 2030	149	0
June 2031	149	100
June 2032	149	150
June 2033	373	250
June 2034	373	200

6.1.3 Power Sales Agreements

OUC's power sales to Winter Park, Mt. Dora, Chattahoochee, and Lakeland Electric are described in Section 2.3.

6.1.4 Retirements and Modifications of Generating Facilities

As mentioned previously, OUC currently anticipates placing Stanton Energy Center Unit 1 into extended cold shutdown by the end of May 2026 and converting Stanton Unit 2 to be capable of operating only on natural gas by the end of 2027 (OUC is in the process of determining the final timing of the natural gas conversion). One factor affecting potential unit modifications and/or retirements is the impact of pending future environmental regulations. OUC will continue to monitor future environmental regulations that may impact its operating fleet and decisions related to generating units, and develop appropriate corresponding compliance plans.

6.2 Reserve Margin Requirements

The FPSC has established a minimum planned reserve margin criterion of 15 percent in 25-6.035 (1) Florida Administrative Code for the purposes of sharing responsibility for grid reliability. The 15 percent minimum planned reserve margin criterion is generally consistent with practice throughout much of the industry. OUC has adopted the 15 percent minimum reserve margin requirement as its planning criterion.

6.3 Future Resource Needs

6.3.1 Generator Capabilities and Requirements Forecast

Tables 6-2 and 6-3 (presented at the end of this section) display the forecast reserve margins for the combined OUC and St. Cloud systems for the winter and summer seasons, respectively. OUC's capacity from renewable projects (discussed in Section 2.4) that is projected to be available at the time of peak demand is also reflected in Tables 6-2 and 6-3.

Table 6-2 and Table 6-3 indicate that OUC is projected to have adequate generating capacity to maintain the 15 percent reserve margin requirements through the period considered in this Ten-Year Site Plan (i.e.

through 2035). As such, this Ten-Year Site Plan does not include any further new capacity additions, beyond the solar and energy storage purchases associated with OUC's EIRP and discussed throughout this Ten-Year Site Plan.

6.3.2 Transmission Capability and Requirements Forecast

OUC continuously monitors and upgrades the bulk power transmission system as necessary to provide reliable electric service to its customers. OUC's current transmission system planning criteria are summarized in its annual filing to the Federal Energy Regulatory Commission. Please see OUC's FERC Form 715 for additional information.

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Table 6-2 Projected Winter Reserve Requirements – Base-Case

Year	Retail and Wholesale Peak Demand (MW) ¹						Available Capacity (MW)					Reserves (MW)			Excess/ (Deficit) Capacity to Maintain 15% Reserve Margin (MW) ⁽⁷⁾
	OUC and STC	Mt. Dora	Chattahoochee	Lakeland	Winter Park	Total	Installed ⁽²⁾⁽⁸⁾	SEC A PPA	Landfill Gas	Solar ⁽³⁾	Energy Storage ⁽³⁾	Total ⁽⁴⁾	Required ⁽⁵⁾	Available ⁽⁶⁾	
2025/26	1,231	20	7	50	17	1,325	1,889	437	19	0	0	2,345	185	1,020	836
2026/27	1,279	20	7	0	0	1,306	1,593	437	19	0	0	2,049	192	743	551
2027/28	1,322	20	0	0	0	1,342	1,593	437	19	0	100	2,149	198	807	609
2028/29	1,345	20	0	0	0	1,365	1,593	350	19	0	100	2,062	202	697	495
2029/30	1,368	21	0	0	0	1,389	1,593	350	19	0	100	2,062	205	673	468
2030/31	1,392	0	0	0	0	1,392	1,593	350	19	0	100	2,062	209	670	462
2031/32	1,416	0	0	0	0	1,416	1,593	0	19	0	200	1,812	212	396	183
2032/33	1,439	0	0	0	0	1,439	1,593	0	19	0	350	1,962	216	523	307
2033/34	1,464	0	0	0	0	1,464	1,593	0	19	0	600	2,212	220	749	529
2034/35	1,491	0	0	0	0	1,491	1,593	0	19	0	800	2,412	224	922	698

(1). Peak Demands shown are non-coincident.

(2). Includes existing net capability to serve OUC and St. Cloud.

(3). Capacity of Solar reflects capacity projected to be available at time of seasonal peak demand, which is assumed to be 0% for winter and 100% of nameplate capacity of energy storage.

(4). "Totals" may not add due to rounding.

(5). "Required Reserves" include 15 percent reserve margin on OUC and St. Cloud retail peak demand. OUC is not responsible for providing reserves to Mt. Dora, Chattahoochee, Lakeland, or Winter Park.

(6). "Available Reserves" equals the difference between total available capacity and total peak demand.

(7). Calculated as the difference between "Available Reserves" and "Required Reserves."

(8). Osceola Generating Station Unit 2 is currently not able to provide power to OUC but expected to be able to provide power to OUC by the summer 2026 peak period. Capacity from Stanton Energy Center Unit 1 no longer included beginning winter 2026/27 as OUC anticipates placing the unit in extended cold shutdown by May 31, 2026.

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Table 6-3 Projected Summer Reserve Requirements – Base-Case

Year	Retail and Wholesale Peak Demand (MW) ¹						Available Capacity (MW)					Reserves (MW)			Excess/ (Deficit) Capacity to Maintain 15% Reserve Margin (MW) ⁽⁷⁾
	OUC and STC	Mt. Dora	Chattahoochee	Lakeland	Winter Park	Total	Installed ⁽²⁾⁽⁸⁾	SEC A PPA	Landfill Gas	Solar ⁽³⁾	Energy Storage ⁽³⁾	Total ⁽⁴⁾	Required ⁽⁵⁾	Available ⁽⁶⁾	
2026	1,568	26	9	100	17	1,720	1,556	429	19	136	0	2,140	235	420	184
2027	1,614	26	9	0	0	1,649	1,556	429	19	210	100	2,314	242	665	423
2028	1,636	27	0	0	0	1,663	1,556	429	19	210	100	2,314	245	651	406
2029	1,613	27	0	0	0	1,640	1,556	342	19	285	100	2,302	242	662	420
2030	1,630	27	0	0	0	1,657	1,556	342	19	359	100	2,376	244	720	475
2031	1,664	0	0	0	0	1,664	1,556	342	19	434	200	2,551	250	887	638
2032	1,692	0	0	0	0	1,692	1,556	0	19	508	350	2,433	254	742	488
2033	1,721	0	0	0	0	1,721	1,556	0	19	695	600	2,870	258	1,149	890
2034	1,750	0	0	0	0	1,750	1,556	0	19	881	800	3,256	263	1,506	1,243
2035	1,783	0	0	0	0	1,783	1,556	0	19	881	800	3,256	267	1,474	1,206

(1). Peak Demands shown are non-coincident.

(2). Includes existing net capability to serve OUC and St. Cloud.

(3). Capacity of Solar reflects capacity projected to be available at time of seasonal peak demand, which is assumed to be 50% of nameplate capacity for summer solar without energy storage and 100% of nameplate capacity of energy storage.

(4). "Totals" may not add due to rounding.

(5). "Required Reserves" include 15 percent reserve margin on OUC and St. Cloud retail peak demand. OUC is not responsible for providing reserves to Bartow, Winter Park, Mt. Dora, Chattahoochee, or Lakeland. Wholesale sale shown to Lake Worth includes reserves.

(6). "Available Reserves" equals the difference between total available capacity and total peak demand.

(7). Calculated as the difference between "Available Reserves" and "Required Reserves."

(8). Osceola Generating Station Unit 2 is currently not able to provide power to OUC but expected to be able to provide power to OUC by the summer 2026 peak period. Capacity from Stanton Energy Center Unit 1 no longer included beginning summer 2026 as OUC anticipates placing the unit in extended cold shutdown by May 31, 2026.

7.0 SUPPLY-SIDE ALTERNATIVES

As discussed previously, consideration of OUC's current generating resources (including existing and planned PPAs) and OUC's current base-case load forecast indicates that OUC is projected to have adequate capacity to satisfy forecast reserve margin requirements through 2035 (the final year considered in this Ten-Year Site Plan). As such, no new capacity additions have been evaluated as part of this Ten-Year Site Plan, beyond the solar and energy storage purchases discussed throughout this Ten-Year Site Plan.

8.0 ECONOMIC EVALUATION CRITERIA AND METHODOLOGY

This section presents the economic evaluation criteria and methodology used for OUC's current planning processes.

8.1 Economic Parameters

The economic parameters are summarized below and are presented on an annual basis.

8.1.1 Inflation and Escalation Rates

The general inflation rate, construction cost escalation rate, fixed O&M escalation rate, and nonfuel variable O&M escalation rate are each assumed to be 2.0 percent.

8.1.2 Present Worth Discount Rate

The present worth discount rate is assumed to be 7.5 percent.

8.2 Fuel Price Forecasts

The natural gas and fuel oil price forecasts reflected in this Ten-Year Site Plan were developed based on a combination of the NYMEX forward curve and projections provided by PIRA Energy Group ("PIRA"). PIRA was founded in 1976 and is an international energy consulting firm specializing in global energy market analysis and intelligence. Among other services, PIRA offers consulting on a broad range of subjects in the international crude oil, petroleum products, natural gas, electricity, coal, biofuels, and emissions markets. PIRA's clients include international and national integrated oil and gas companies, independent producers, refiners, marketers, oil and gas pipelines, electric and gas utilities, industrials, trading companies, financial institutions, and government agencies.

The coal forecast reflected in this Ten-Year Site Plan was developed based on projections by Energy Ventures Analysis, Inc. ("EVA") for use by OUC as well as recent offers from suppliers of Illinois Basin coal. EVA is a consulting firm that engages in a variety of projects for private and public sector clients related to energy and environmental issues. In the energy area, much of EVA's work is related to analysis of the electric utility industry and fuel markets, particularly oil, natural gas, and coal. EVA's clients in these areas include coal, oil, and natural gas producers; electric utility and industrial energy consumers; and gas pipelines and railroads. EVA also works for a number of public agencies, such as state regulatory commissions, the US EPA, and the US DOE, as well as interveners in utility rate proceedings, such as consumer counsels and municipalities. Another group of clients include trade and industry associations, such as the Electric Power Research Institute, the Gas Research Institute, and the Center for Energy and Economic Development. EVA has provided testimony to numerous state public utility commissions, including the Florida Public Service Commission. Furthermore, the firm has filed testimony in a number of cases in both state and federal courts, as well as before the Federal Energy Regulatory Commission.

9.0 ANALYSIS AND RESULTS

As discussed previously, consideration of OUC's existing generating resources (including existing and planned PPAs) and OUC's current base-case load forecast indicates that OUC is projected to have adequate capacity to satisfy forecast reserve margin requirements through 2035 (the final year considered in this Ten-Year Site Plan).

For informational purposes, OUC utilized PCI GenTrader to obtain the annual production costs associated for various load, fuel, and other sensitivity cases. GenTrader is a computer-based chronological production costing model developed for use in power supply system planning. GenTrader simulates the hour-by-hour operation of a power supply system over a specified planning period. Required inputs include the performance characteristics of generating units, fuel costs, and the system hourly load profile for each year.

The cumulative present worth cost ("CPWC") calculations presented in this section account for annual system costs (i.e. fuel and energy, non-fuel variable O&M, and startup costs) for each year of the expansion planning period and discounts each back to 2026 at the present worth discount rate of 7.5 percent. These annual present worth costs are then summed over the 10-year forecast period to calculate the total CPWC of the expansion plan being considered.

9.1 CPWC Analyses

9.1.1 Base-Case Analysis

The base-case considers the base load forecast presented in Section 4 and the base fuel price forecasts. The CPWC associated with the base-case analysis is approximately \$2.640 billion.

9.1.2 Sensitivity Analyses

As part of its capacity planning process, OUC considers a number of sensitivity analyses to measure the impact of variations to critical assumptions. Among the numerous sensitivities that OUC may consider in its planning processes are high and low fuel prices, high and low load and energy growth projections, a case in which the differential between natural gas and coal price projections is held constant over time, and a high present worth discount rate case. Of these sensitivities, only the high load and energy growth projection sensitivity would potentially impact the timing of unit additions as compared to the base-case analysis. For informational purposes, the following subsections describe the high and low load and energy growth, the high and low fuel price, the constant differential fuel price, and the high present worth discount rate sensitivities.

9.1.2.1 High Load Forecast Sensitivity

The high load forecast is presented in Section 4.0; as with the base-case load forecast, OUC is anticipated to have sufficient capacity to maintain its 15 percent reserve margin under the high load forecast sensitivity. The CPWC associated with the high load analysis is approximately \$2.660 billion.

9.1.2.2 Low-Load Forecast Sensitivity

The low-load forecast is presented in Section 4.0; as with the base-case load forecast, OUC is anticipated to have sufficient capacity to maintain its 15 percent reserve margin under the low load forecast sensitivity. The CPWC associated with the low-load analysis is approximately \$2.620 billion.

9.1.2.3 High Fuel Price Forecast Sensitivity

OUC's contractual arrangements for coal delivery will mitigate the effects of volatility in coal prices; however, for purposes of this analysis, this factor was not considered. The CPWC associated with the high natural gas and coal price forecast sensitivity is approximately \$3.014 billion.

9.1.2.4 Low Fuel Price Forecast Sensitivity

OUC's contractual arrangements for coal delivery will mitigate the effects of volatility in coal prices; however, for purposes of this analysis, this factor was not considered. The CPWC associated with the low natural gas and coal price forecast sensitivity is approximately \$2.266 billion.

9.1.2.5 Constant Differential Natural Gas and Coal Price Forecast Sensitivity

The constant differential natural gas and coal price forecast sensitivity assumes that the differential in prices between coal and natural gas projected for 2026 will remain constant through 2035. The CPWC associated with the constant differential natural gas and coal price forecast sensitivity is approximately \$2.647 billion.

9.1.2.6 High Present Worth Discount Rate Sensitivity

The high present worth discount rate sensitivity assumes a 10 percent present worth discount rate instead of the 7.5 percent present worth discount rate used in the other economic analyses discussed in this section. The CPWC associated with the high present worth discount rate sensitivity is approximately \$2.393 billion.

10.0 ENVIRONMENTAL AND LAND USE INFORMATION

As discussed previously, consideration of OUC's current generating resources (including existing and planned PPAs) and OUC's current base-case load forecast indicates that OUC is projected to have adequate capacity to satisfy forecast reserve margin requirements through 2035 (the final year considered in this Ten-Year Site Plan).

11.0 CONCLUSIONS

As discussed previously, consideration of OUC's current generating resources (including existing resources and anticipated PPAs) and OUC's current base-case load forecast indicates that OUC is projected to have adequate capacity to satisfy forecast reserve margin requirements through 2035 (the final year considered in this Ten-Year Site Plan).

In 2020, OUC completed a comprehensive Electric Integrated Resource Plan ("EIRP") to guide OUC through the next 30 years, and is in the process of refreshing the EIRP. OUC anticipates refreshing its Electric integrated Resource Plan within the next 12 months. Results of the 2020 EIRP have been discussed throughout this Ten-Year Site Plan. Relevant highlights of the 2020 EIRP and OUC's 2026 Ten-Year Site Plan include:

- OUC anticipates entering into PPAs for approximately 1,491 MWac of solar (nameplate) and 800 MW of energy storage by 2034.
- OUC anticipates placing the coal-fired Stanton Energy Center Unit 1 into extended cold shutdown by the end of May 2026.
- OUC anticipates converting the coal-fired Stanton Energy Center Unit 2 to be capable of operating on 100 percent natural gas by the end of 2027.
- OUC has pledged to achieve Net Zero carbon emissions by 2050, with interim targets of 50% carbon emissions reductions by 2030 and 75% carbon emissions reductions by 2040, both as compared to 2005 levels.

12.0 TEN-YEAR SITE PLAN SCHEDULES

This section presents the schedules required by the Ten-Year Site Plan rules for the FPSC. The information contained within the FPSC Schedules is representative of the combined OUC and City of St. Cloud systems, consistent with all sections of the 2026 OUC Ten-Year Site Plan.

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Schedule 1
Existing Generating Facilities
As of December 31, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Plant Name	Unit No.	Location	Unit Type	Fuel Pri	Fuel Alt	Fuel Transport Pri	Fuel Transport Alt	Alt. Fuel Days Use	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen. Max. Nameplate KW ⁽¹⁾	Net Capability Summer MW	Net Capability Winter MW
Indian River	A	Brevard	GT	NG	DFO	PL	TK	0.2	06/89	Unknown	41,400	16 ⁽²⁾	18 ⁽²⁾
Indian River	B	Brevard	GT	NG	DFO	PL	TK	0.2	07/89	Unknown	41,400	16 ⁽²⁾	18 ⁽²⁾
Indian River	C	Brevard	GT	NG	DFO	PL	TK	0.2	08/92	Unknown	130,000	83 ⁽³⁾	88 ⁽³⁾
Indian River	D	Brevard	GT	NG	DFO	PL	TK	0.2	10/92	Unknown	130,000	83 ⁽³⁾	88 ⁽³⁾
Stanton Energy Center	1	Orange	ST	BIT	NA	RR	UN	UN	07/87	Unknown ⁽⁴⁾	464,500	311 ⁽⁵⁾	311 ⁽⁵⁾
Stanton Energy Center	2	Orange	ST	BIT	NA	RR	UN	UN	06/96	Unknown	464,500	352 ⁽⁶⁾	352 ⁽⁶⁾
Stanton Energy Center	A	Orange	CC	NG	DFO	PL	TK	3	10/03	Unknown		184 ⁽⁷⁾	189 ⁽⁷⁾
Stanton Energy Center	B	Orange	CC	NG	DFO	PL	TK	3	02/10	Unknown	333,000	292	307
St. Lucie ⁽⁸⁾	2	St. Lucie	ST	NUC	NA	TK	UN	UN	08/83	Unknown		60	62
Osceola Generating Station ⁽⁹⁾	1	Osceola	GT	NG	DFO	PL	TK	3	12/2001	Unknown	197,000	157	157
Osceola Generating Station ⁽⁹⁾	2	Osceola	GT	NG	DFO	PL	TK	3	12/2001	Unknown	197,000	157	157
Osceola Generating Station ⁽⁹⁾	3	Osceola	GT	NG	DFO	PL	TK	3	6/2002	Unknown	197,000	157	157

NOTES:

⁽¹⁾ Nameplate ratings are reported for units which OUC maintains majority ownership. Values reported are for the entire unit (not just OUC's ownership share)

⁽²⁾ Reflects an OUC ownership share of 48.8 percent.

⁽³⁾ Reflects an OUC ownership share of 79.0 percent.

⁽⁴⁾ As discussed throughout OUC's 2026 10-Year Site Plan, OUC currently anticipates placing Stanton Energy Center Unit 1 into extended cold shutdown by the end of May 2026.

⁽⁵⁾ Reflects an OUC ownership share of 68.6 percent. As of January 1, 2026, OUC's owns 100% of Stanton Energy Center 1.

⁽⁶⁾ Reflects an OUC ownership share of 71.6 percent and St. Cloud entitlement of 3.4 percent.

⁽⁷⁾ Reflects an OUC ownership share of 28.0 percent.

⁽⁸⁾ OUC owns approximately 6.1 percent of St. Lucie Unit No. 2. Reliability exchange divides 50 percent power from Unit No. 1 and 50 percent power from Unit No. 2.

⁽⁹⁾ Osceola Generating Station Unit 2 is currently not able to provide power to OUC but expected to be able to provide power to OUC by the summer 2026 peak period.

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Schedule 2.1
History and Forecast of Energy Consumption and
Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Population	Members per Household	Rural and Residential Average No. of Customers GWH	Average KWH Consumption Per Customer	Average KWH Consumption Per Customer	GWH	Commercial Average No. of Customers	Average KWH Consumption Per Customer
HISTORY:								
2016	514,813	2.56	2,491	201,424	12,369	401	23,991	16,719
2017	576,536	2.79	2,481	206,959	11,987	424	24,323	17,440
2018	577,895	2.74	2,576	210,899	12,212	475	25,020	18,966
2019	615,376	2.85	2,599	216,113	12,026	474	25,751	18,424
2020	634,982	2.86	2,750	221,756	12,402	459	26,391	17,408
2021	631,387	2.76	2,701	228,707	11,808	461	27,128	16,997
2022	642,220	2.72	2,798	236,057	11,851	484	28,013	17,285
2023	633,874	2.62	2,857	242,199	11,795	506	28,065	18,020
2024	655,296	2.64	2,923	248,682	11,752	506	28,394	17,814
2025	653,828	2.57	2,971	254,550	11,670	529	28,833	18,331
FORECAST:								
2026	667,321	2.57	3,081	260,150	11,845	524	29,125	17,979
2027	679,116	2.56	3,197	265,673	12,035	530	29,405	18,030
2028	691,014	2.55	3,303	271,127	12,183	537	29,679	18,077
2029	703,645	2.54	3,410	276,531	12,331	544	29,944	18,153
2030	716,270	2.54	3,516	281,932	12,471	550	30,199	18,205
2031	728,497	2.54	3,631	287,326	12,638	556	30,448	18,268
2032	740,752	2.53	3,754	292,699	12,825	564	30,690	18,366
2033	752,927	2.53	3,878	298,053	13,012	572	30,925	18,485
2034	765,150	2.52	3,993	303,391	13,162	581	31,153	18,642
2035	777,672	2.52	4,113	308,705	13,324	591	31,374	18,842

Notes:
Represents total of OUC and St. Cloud.

Schedule 2.2
History and Forecast of Energy Consumption and
Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Year	GWH	Industrial Average No. of Customers	Average KWH Consumption Per Customer	Railroads and Railways GWH	Street & Highway Lighting GWH	Other Sales to Public Authorities GWH	Total Sales to Ultimate Consumers GWH
HISTORY:							
2016	3,506	5,811	603,333	0	61	142	6,601
2017	3,480	5,839	595,929	0	59	124	6,568
2018	3,513	5,709	615,262	0	61	146	6,769
2019	3,544	5,579	635,318	0	61	145	6,823
2020	3,336	5,301	629,406	0	62	131	6,740
2021	3,447	5,210	661,681	0	62	136	6,807
2022	3,557	5,102	697,124	0	63	141	7,042
2023	3,587	5,075	706,729	0	44	162	7,155
2024	3,638	5,103	712,958	0	62	167	7,295
2025	3,708	5,109	725,731	0	61	191	7,459
FORECAST:							
2026	3,689	5,115	721,258	0	62	172	7,529
2027	3,816	5,158	739,748	0	63	172	7,778
2028	3,905	5,199	751,185	0	63	172	7,981
2029	3,951	5,238	754,336	0	63	173	8,141
2030	3,990	5,275	756,413	0	64	173	8,292
2031	4,031	5,310	759,182	0	64	173	8,455
2032	4,079	5,344	763,352	0	64	173	8,634
2033	4,131	5,376	768,405	0	64	173	8,818
2034	4,190	5,407	774,894	0	65	173	9,002
2035	4,257	5,438	782,838	0	65	173	9,200

Notes:
Represents total of OUC and St. Cloud.

Schedule 2.3
History and Forecast of Energy Consumption and
Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)
Year	Sales for Resale GWH	Utility Use & Losses GWH	Net Energy for Load GWH	Other Customers (Average No.)	Total No. of Customers
HISTORY:					
2016	1,100	278	7,979	0	231,226
2017	1,032	302	7,902	0	237,121
2018	1,040	189	7,998	0	241,628
2019	644	295	7,762	0	247,443
2020	665	220	7,625	0	253,448
2021	534	206	7,547	0	261,045
2022	505	217	7,764	0	269,172
2023	578	239	7,972	0	275,339
2024	575	337	8,206	0	282,179
2025	503	260	8,222	0	288,492
FORECAST:					
2026	278	266	8,073	0	294,390
2027	147	278	8,202	0	300,236
2028	111	288	8,379	0	306,005
2029	112	297	8,550	0	311,713
2030	114	306	8,712	0	317,406
2031	0	315	8,770	0	323,084
2032	0	325	8,959	0	328,733
2033	0	335	9,153	0	334,354
2034	0	345	9,347	0	339,951
2035	0	356	9,556	0	345,517

Notes:

Represents total of OUC and St. Cloud.

Historical "Sales for Resale" includes sales to various entities to which OUC provided power.

Forecast "Sales for Resale" includes aggregated projected sales to City of Winter Park, City Mt. Dora, City of Chattahoochee, and Lakeland Electric as summarized in Section 2 of OUC's 2026 Ten-Year Site Plan.

"Net Energy for Load" may not match other Schedules due to rounding.

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Schedule 3.1
History and Forecast of Summer Peak Demand
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand
HISTORY:									
2016	1,620	252	1,368	0	0	0.5	0.0	2.5	1,617
2017	1,638	255	1,383	0	0	0.4	0.0	5.0	1,633
2018	1,541	207	1,334	0	0	0.4	0.0	3.7	1,537
2019	1,634	199	1,431	0	0	0.5	0.0	3.4	1,630
2020	1,590	224	1,362	0	0	0.8	0.0	2.3	1,586
2021	1,653	246	1,404	0	0	0.6	0.0	1.9	1,650
2022	1,666	243	1,420	0	0	0.5	0.0	2.0	1,663
2023	1,795	241	1,551	0	0	0.8	0.0	1.6	1,792
2024	1,811	300	1,509	0	0	0.7	0.0	1.4	1,809
2025	1,822	198	1,622	0	0	0.5	0.0	1.7	1,820
FORECAST:									
2026	1,720	152	1,568	0	0	0.0	0.0	0.0	1,720
2027	1,649	35	1,614	0	0	0.0	0.0	0.0	1,649
2028	1,664	27	1,636	0	0	0.0	0.0	1.0	1,663
2029	1,641	27	1,613	0	0	0.0	0.0	1.0	1,640
2030	1,659	27	1,630	0	0	1.0	0.0	1.0	1,657
2031	1,666	0	1,664	0	0	1.0	0.0	1.0	1,664
2032	1,694	0	1,692	0	0	1.0	0.0	1.0	1,692
2033	1,724	0	1,721	0	0	1.0	0.0	2.0	1,721
2034	1,753	0	1,750	0	0	1.0	0.0	2.0	1,750
2035	1,786	0	1,783	0	0	1.0	0.0	2.0	1,783

Notes:

"Retail" represents total of OUC and St. Cloud. "Wholesale" represents peak demand for entities to which OUC provided wholesale power. Peak demands may not match other schedules and tables in OUC's 2026 Ten-Year Site Plan due to non-coincidence of peaks and/or rounding.

Historical "Residential Conservation" and "Comm/Ind. Conservation" represent annual demand reductions associated with new participants in OUC's DSM programs.

Forecast "Residential Conservation" and "Comm/Ind. Conservation" represent cumulative annual demand reductions associated with new participants in OUC's DSM programs described in Section 5 of OUC's 2026 Ten-Year Site Plan.

Historical "Wholesale" includes sales to various entities to which OUC provided power.

Forecast "Wholesale" includes aggregated projected sales to City of Winter Park, City Mt. Dora, City of Chattahoochee, and Lakeland Electric as summarized in Section 2 of OUC's 2026 Ten-Year Site Plan.

"Wholesale" and "Retail" are net of "Conservation" reductions.

ORLANDO UTILITIES COMMISSION
2026 TEN-YEAR SITE PLAN

Schedule 3.2
History and Forecast of Winter Peak Demand
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand
HISTORY:									
2015/16	1,320	243	1,077	0	0	0.4	0.0	1.3	1,319
2016/17	1,194	210	984	0	0	0.3	0.0	4.4	1,189
2017/18	1,410	182	1,228	0	0	0.3	0.0	4.7	1,405
2018/19	1,134	76	1,055	0	0	0.3	0.0	3.5	1,131
2019/20	1,160	67	1,090	0	0	0.8	0.0	2.0	1,157
2020/21	1,307	169	1,134	0	0	1.0	0.0	2.0	1,304
2021/22	1,348	190	1,156	0	0	0.7	0.0	1.7	1,346
2022/23	1,521	291	1,228	0	0	1.0	0.0	1.6	1,519
2023/24	1,351	221	1,128	0	0	0.7	0.0	1.0	1,349
2024/25	1,663	381	1,280	0	0	0.5	0.0	1.5	1,661
FORECAST:									
2025/26	1,326	94	1,231	0	0	0.5	0	0.4	1,325
2026/27	1,308	27	1,279	0	0	1.0	0	0.8	1,306
2027/28	1,345	20	1,322	0	0	1.6	0	1.2	1,342
2028/29	1,369	20	1,345	0	0	2.2	0	1.7	1,365
2029/30	1,394	21	1,368	0	0	2.9	0	2.2	1,389
2030/31	1,398	0	1,392	0	0	3.6	0	2.7	1,392
2031/32	1,424	0	1,416	0	0	4.3	0	3.2	1,416
2032/33	1,448	0	1,439	0	0	5.0	0	3.7	1,439
2033/34	1,474	0	1,464	0	0	5.8	0	4.3	1,464
2034/35	1,502	0	1,491	0	0	6.6	0	4.8	1,491

Notes:

"Retail" represents total of OUC and St. Cloud. "Wholesale" represents peak demand for entities to which OUC provided wholesale power. Peak demands may not match other schedules and tables in OUC's 2026 Ten-Year Site Plan due to non-coincidence of peaks and/or rounding.

Historical "Residential Conservation" and "Comm/Ind. Conservation" represent annual demand reductions associated with new participants in OUC's DSM programs.

Forecast "Residential Conservation" and "Comm/Ind. Conservation" represent cumulative annual demand reductions associated with new participants in OUC's DSM programs described in Section 5 of OUC's 2026 Ten-Year Site Plan.

Historical "Wholesale" includes sales to various entities to which OUC provided power.

Forecast "Wholesale" includes aggregated projected sales to City of Winter Park, City Mt. Dora, City of Chattahoochee, and Lakeland Electric as summarized in Section 2 of OUC's 2026 Ten-Year Site Plan.

"Wholesale" and "Retail" are net of "Conservation" reductions.

ORLANDO UTILITIES COMMISSION
2026 TEN-YEAR SITE PLAN

Schedule 3.3
History and Forecast of Annual Net Energy for Load - GWH
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation	Comm./Ind. Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor %
HISTORY:								
2016	7,992	1.2	12.3	6,601	1,100	278	7,979	55.4%
2017	7,934	0.8	31.0	6,568	1,032	302	7,902	55.3%
2018	8,033	0.8	34.7	6,769	1,040	189	7,998	59.4%
2019	7,778	1.0	14.3	6,823	644	295	7,762	54.4%
2020	7,558	1.6	9.0	6,740	665	220	7,625	52.2%
2021	7,570	11.5	11.4	6,807	534	206	7,547	52.2%
2022	7,770	1.1	4.8	7,042	505	217	7,764	53.3%
2023	7,983	1.9	8.5	7,155	578	239	7,972	50.8%
2024	8,216	1.7	8.2	7,295	575	337	8,206	51.8%
2025	8,234	1.0	10.4	7,459	503	260	8,222	51.6%
FORECAST:								
2026	8,077	1.0	3.0	7,529	278	266	8,073	53.6%
2027	8,211	2.0	7.0	7,778	147	278	8,202	56.8%
2028	8,391	2.0	10.0	7,981	111	288	8,379	57.5%
2029	8,569	4.0	15.0	8,141	112	297	8,550	59.5%
2030	8,737	6.0	19.0	8,292	114	306	8,712	60.0%
2031	8,800	7.0	23.0	8,455	0	315	8,770	60.2%
2032	8,996	9.0	28.0	8,634	0	325	8,959	60.5%
2033	9,196	10.0	33.0	8,818	0	335	9,153	60.7%
2034	9,396	12.0	37.0	9,002	0	345	9,347	61.0%
2035	9,611	13.0	42.0	9,200	0	356	9,556	61.2%

Notes:

"Retail" represents total of OUC and St. Cloud. "Wholesale" represents energy for entities to which OUC provided wholesale power. Energy may not match other schedules and tables in OUC's 2026 Ten-Year Site Plan due to rounding.

Historical "Residential Conservation" and "Comm/Ind. Conservation" represent annual energy reductions associated with new participants in OUC's DSM programs.

Forecast "Residential Conservation" and "Comm/Ind. Conservation" represent cumulative annual energy reductions associated with new participants in OUC's DSM programs described in Section 5 of OUC's 2026 Ten-Year Site Plan.

Historical "Wholesale" includes sales to various entities to which OUC provided power.

Forecast "Wholesale" includes aggregated projected sales to City of Winter Park, City Mt. Dora, City of Chattahoochee, and Lakeland Electric as summarized in Section 2 of OUC's 2026 Ten-Year Site Plan.

"Wholesale" and "Retail" are net of "Conservation" reductions.

Schedule 4
Previous Year and 2-Year Forecast of Retail Peak Demand and Net Energy for Load by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Month	2025 Actual		2026 Forecast		2027 Forecast	
	Peak Demand MW	NEL GWH	Peak Demand MW	NEL GWH	Peak Demand MW	NEL GWH
January	1,190	584	1,231	579	1,279	598
February	1,122	502	1,170	519	1,216	536
March	1,156	539	1,168	584	1,202	605
April	1,240	608	1,277	611	1,320	632
May	1,461	722	1,493	690	1,545	713
June	1,410	737	1,451	725	1,493	749
July	1,553	799	1,512	777	1,558	802
August	1,575	796	1,568	781	1,614	807
September	1,379	714	1,460	720	1,505	744
October	1,238	634	1,395	660	1,446	681
November	1,291	540	1,246	570	1,300	591
December	998	546	1,216	579	1,289	599

Notes:

Represents the total of OUC and St. Cloud retail peak demands and net energy for load. Wholesale sales are not included.

Peak demands may not match other schedules and tables in OUC's 2026 Ten-Year Site Plan due to non-coincidence of OUC and St. Cloud peaks and/or rounding. NEL may not match other schedules and tables in OUC's 2026 Ten-Year Site Plan due to rounding.

ORLANDO UTILITIES COMMISSION
2026 TEN-YEAR SITE PLAN

Schedule 5
Fuel Requirements

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Fuel Requirements		Units	Actual 2024	Actual 2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
(1)	Nuclear		Trillion BTU	5	5	6	5	6	6	6	6	6	6	6	6
(2)	Coal		1000 Ton	793	1,036	696	632	0	0	0	0	0	0	0	0
(3)	Residual	Total	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(4)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(5)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)		Other	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(8)	Distillate	Total	1000 BBL	28	4	0	0	0	0	0	0	0	0	0	0
(9)		Steam	1000 BBL	0	4	0	0	0	0	0	0	0	0	0	0
(10)		CC	1000 BBL	3	0	0	0	0	0	0	0	0	0	0	0
(11)		CT	1000 BBL	26	0	0	0	0	0	0	0	0	0	0	0
(12)		Other	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	Total	1000 MCF	43,247	47,009	40,700	38,942	52,827	52,050	51,106	49,299	50,154	43,834	38,034	39,568
(14)		Steam	1000 MCF	4,552	3,514	2,246	1,173	9,106	9,371	9,991	10,176	14,973	15,596	11,880	11,648
(15)		CC	1000 MCF	37,683	42,752	34,661	35,527	39,768	38,582	37,080	34,156	27,566	25,095	21,888	23,260
(16)		CT	1000 MCF	1,012	743	3,794	2,242	3,952	4,097	4,035	4,967	7,615	3,143	4,265	4,660
(17)	Other (Specify)		Trillion BTU	0	0	0	0	0	0	0	0	0	0	0	0

Notes:

Represents fuel required to serve OUC and St. Cloud, and sales to wholesale customers.

Natural gas CC includes purchases from Stanton A PPA

ORLANDO UTILITIES COMMISSION
2026 TEN-YEAR SITE PLAN

Schedule 6.1
Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 2024	Actual 2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
(1)	Firm Inter-Region Interchange		GWH	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Nuclear		GWH	433	469	503	496	504	502	503	503	505	503	503	503
(3)	Coal		GWH	1,608	2,105	1,398	1,281	0	0	0	0	0	0	0	0
(4)	Residual	Total	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(5)		Steam	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CC	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(7)		CT	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(8)		Other	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(9)	Distillate	Total	GWH	4	1	0	0	0	0	0	0	0	0	0	0
(10)		Steam	GWH	0	1	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWH	2	0	0	0	0	0	0	0	0	0	0	0
(12)		CT	GWH	2	0	0	0	0	0	0	0	0	0	0	0
(13)		Other	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	GWH	5,753	5,059	5,443	5,341	6,789	6,601	6,398	6,093	5,911	5,203	4,487	4,696
(15)		Steam	GWH	384	287	225	119	817	791	827	874	1,409	1,453	1,094	1,079
(16)		CC	GWH	5,303	4,731	4,898	5,035	5,639	5,471	5,235	4,805	3,835	3,477	3,019	3,206
(17)		CT	GWH	65	41	320	187	333	339	336	414	667	273	374	411
(18)	NUG		GWH	0	0	0	0	0	0	0	0	0	0	0	0
(19)	Renewables	Total	GWH	408	588	729	1,084	1,086	1,447	1,811	2,174	2,543	3,447	4,356	4,356
(20)		Biofuels	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(21)		Biomass	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(22)		Hydro	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(23)		Landfill Gas	GWH	139	110	70	61	61	61	61	61	61	61	61	61
(24)		MSW	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(25)		Solar	GWH	268	478	659	1,023	1,025	1,386	1,749	2,113	2,482	3,386	4,295	4,295
(26)		Wind	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(27)		Other	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(28)	Other (Specify)		GWH	0	0	0	0	0	0	0	0	0	0	0	0
(29)	Net Energy for Load		GWH	8,206	8,222	8,073	8,202	8,379	8,550	8,712	8,770	8,959	9,153	9,347	9,556

Notes:

Represents GWh required to serve OUC and St. Cloud, and sales to wholesale customers.
Total Net Energy for Load may not correspond to other Schedules due to rounding.
Natural Gas CC includes purchases from Stanton A PPA

ORLANDO UTILITIES COMMISSION
2026 TEN-YEAR SITE PLAN

Schedule 6.2
Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 2024	Actual 2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
(1)	Firm Inter-Region Interchange		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(2)	Nuclear		%	5.3%	5.7%	6.2%	6.0%	6.0%	5.9%	5.8%	5.7%	5.6%	5.5%	5.4%	5.3%
(3)	Coal		%	19.6%	25.6%	17.3%	15.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(4)	Residual	Total	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(5)		Steam	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(6)		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(7)		CT	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(8)		Other	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(9)	Distillate	Total	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(10)		Steam	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(11)		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(12)		CT	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(13)		Other	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(14)	Natural Gas	Total	%	70.1%	61.5%	67.4%	65.1%	81.0%	77.2%	73.4%	69.5%	66.0%	56.8%	48.0%	49.1%
(15)		Steam	%	4.7%	3.5%	2.8%	1.4%	9.8%	9.3%	9.5%	10.0%	15.7%	15.9%	11.7%	11.3%
(16)		CC	%	64.6%	57.5%	60.7%	61.4%	67.3%	64.0%	60.1%	54.8%	42.8%	38.0%	32.3%	33.5%
(17)		CT	%	0.8%	0.5%	4.0%	2.3%	4.0%	4.0%	3.9%	4.7%	7.4%	3.0%	4.0%	4.3%
(18)	NUG		%												
(19)	Renewables	Total	%	5.0%	7.2%	9.0%	13.2%	13.0%	16.9%	20.8%	24.8%	28.4%	37.7%	46.6%	45.6%
(20)		Biofuels	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(21)		Biomass	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(22)		Hydro	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(23)		Landfill Gas	%	1.7%	1.3%	0.9%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.6%
(24)		MSW	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(25)		Solar	%	3.3%	5.8%	8.2%	12.5%	12.2%	16.2%	20.1%	24.1%	27.7%	37.0%	46.0%	44.9%
(26)		Wind	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(27)		Other	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(28)	Other (Specify)		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(29)	Net Energy for Load		%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Notes:

Represents GWh required to serve OUC and St. Cloud, and sales to wholesale customers.
Natural Gas CC includes purchases from Stanton A PPA

ORLANDO UTILITIES COMMISSION
2026 TEN-YEAR SITE PLAN

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Year	Total Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	QF MW	Total Capacity Available MW	System Firm Summer Peak Demand MW	Reserve Margin before Maintenance MW	% of Peak	Scheduled Maintenance MW	Reserve Margin after Maintenance MW	% of Peak
FORECAST:											
2026	1,556	584	0	0	2,140	1,720	420	27%	0	420	27%
2027	1,556	758	0	0	2,314	1,649	665	42%	0	665	42%
2028	1,556	758	0	0	2,314	1,663	651	40%	0	651	40%
2029	1,556	746	0	0	2,302	1,640	662	40%	0	662	40%
2030	1,556	820	0	0	2,376	1,657	720	43%	0	720	43%
2031	1,556	995	0	0	2,551	1,664	887	52%	0	887	52%
2032	1,556	877	0	0	2,433	1,692	742	42%	0	742	42%
2033	1,556	1,314	0	0	2,870	1,721	1,149	63%	0	1,149	63%
2034	1,556	1,700	0	0	3,256	1,750	1,506	81%	0	1,506	81%
2035	1,556	1,700	0	0	3,256	1,783	1,474	77%	0	1,474	77%

Notes:

"Firm Capacity Import" includes OUC's existing and future power purchase agreements, including renewables.

"System Firm Summer Peak Demand" includes OUC and St. Cloud peak demand, as well as OUC's wholesale power sales, and is non-coincident.

"Reserve Margin (MW)" calculated as "Total Available Capacity" minus "System Firm Summer Peak Demand."

"Reserve Margin (% of Peak)" calculated as "Reserve Margin (MW)" divided by "System Firm Summer Peak Demand" after adjusting for sales to Winter Park, Mt. Dora, Chattahoochee, and Lakeland.

OUC is not responsible for providing reserves to Winter Park, Mt. Dora, Chattahoochee, or Lakeland.

"Scheduled Maintenance (MW)" is zero, as no units are scheduled for maintenance during peak periods.

Forecast "System Firm Summer Peak Demand" may not exactly match up with peak demands presented in the OUC's 2026 Ten-Year Site Plan due to coincidence and rounding.

Reflects anticipated dates by which the Osceola Generating Station Unit 2 will be capable of delivering power to OUC following completion of necessary maintenance and transmission system improvements (summer of 2026). Capacity from Stanton Energy Center Unit 1 no longer included beginning summer 2026 as OUC anticipates placing the unit in extended cold shutdown by May 31, 2026.

ORLANDO UTILITIES COMMISSION
2026 TEN-YEAR SITE PLAN

Schedule 7.2
Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Year	Total Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	QF MW	Total Capacity Available MW	System Firm Winter Peak Demand MW	Reserve Margin before Maintenance MW	% of Peak	Scheduled Maintenance MW	Reserve Margin after Maintenance MW	% of Peak
FORECAST:											
2025/26	1,889	456	0	0	2,345	1,325	1,020	81%	0	1,020	81%
2026/27	1,593	456	0	0	2,049	1,306	743	57%	0	743	57%
2027/28	1,593	556	0	0	2,149	1,342	807	60%	0	807	60%
2028/29	1,593	469	0	0	2,062	1,365	697	51%	0	697	51%
2029/30	1,593	469	0	0	2,062	1,389	673	47%	0	673	47%
2030/31	1,593	469	0	0	2,062	1,392	670	45%	0	670	45%
2031/32	1,593	219	0	0	1,812	1,416	396	26%	0	396	26%
2032/33	1,593	369	0	0	1,962	1,439	523	34%	0	523	34%
2033/34	1,593	619	0	0	2,212	1,464	749	45%	0	749	45%
2034/35	1,593	819	0	0	2,412	1,491	922	54%	0	922	54%

Notes:

"Firm Capacity Import" includes OUC's existing and future power purchase agreements, including renewables.

"System Firm Summer Peak Demand" includes OUC and St. Cloud peak demand, as well as OUC's wholesale power sales, and is non-coincident.

"Reserve Margin (MW)" calculated as "Total Available Capacity" minus "System Firm Summer Peak Demand."

"Reserve Margin (% of Peak)" calculated as "Reserve Margin (MW)" divided by "System Firm Summer Peak Demand" after adjusting for sales to Winter Park, Mt. Dora, Chattahoochee, and Lakeland.

OUC is not responsible for providing reserves to Winter Park, Mt. Dora, Chattahoochee, or Lakeland.

"Scheduled Maintenance (MW)" is zero, as no units are scheduled for maintenance during peak periods.

Forecast "System Firm Summer Peak Demand" may not exactly match up with peak demands presented in the OUC's 2026 Ten-Year Site Plan due to coincidence and rounding.

Reflects anticipated dates by which the Osceola Generating Station Unit 2 will be capable of delivering power to OUC following completion of necessary maintenance and transmission system improvements (summer of 2026). Capacity from Stanton Energy Center Unit 1 no longer included beginning summer 2026 as OUC anticipates placing the unit in extended cold shutdown by May 31, 2026.

Schedule 8
Planned and Prospective Generating Facility Additions and Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Plant Name	Unit No.	Location	Unit Type	Fuel		Fuel Transport		Const. Start Mo/Yr	Commercial In-Service Mo/Yr	Expected Retirement Mo/Yr	Gen. Max. Nameplate KW	Net Capability		Status
				Pri	Alt	Pri	Alt					Summer MW	Winter MW	
Stanton Energy Center	1	Orange	ST	BIT	N/A	RR	N/A	-	N/A	Unknown ⁽¹⁾	464,500	-453	-453	OS
Stanton Energy Center	2	Orange	ST	NG	N/A	PL	N/A	-	N/A	04/27	464,500	352 ⁽²⁾	350 ⁽²⁾	OT

Notes:

1. As discussed throughout OUC's 2026 10-Year Site Plan, OUC currently anticipates placing Stanton Energy Center Unit 1 into extended cold shutdown by the end of May 2026. Changes to Net Capability for Stanton Energy Center Unit 1 represents reduction in output for OUC's 100% ownership share of Stanton 1 following unit being placed into extended cold shutdown.
2. Changes to Stanton Energy Center Unit 2 represents conversion from coal to natural gas. Net Capability shown is not incremental but rather the net capability following conversion.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

- (1) Plant Name and Unit Number:
- (2) Capacity
 - a. Summer:
 - b. Winter:
- (3) Technology Type:
- (4) Anticipated Construction Timing
 - a. Field construction start-date:
 - b. Commercial in-service date:
- (5) Fuel
 - a. Primary fuel:
 - b. Alternate fuel:
- (6) Air Pollution Control Strategy:
- (7) Cooling Method:
- (8) Total Site Area:
- (9) Construction Status:
- (10) Certification Status:
- (11) Status with Federal Agencies:
- (12) Projected Unit Performance Data
 - Planned Outage Factor (POF):
 - Forced Outage Factor (FOF):
 - Equivalent Availability Factor (EAF):
 - Resulting Capacity Factor (%):
 - Average Net Operating Heat Rate (ANOHR):
- (13) Projected Unit Financial Data
 - Book Life (Years):
 - Total Installed Cost (In-Service Year \$/kW):
 - Direct Construction Cost (\$/kW):
 - AFUDC Amount (\$/kW):
 - Escalation (\$/kW):
 - Fixed O&M (\$/kW-Yr):
 - Variable O&M (\$/MWH):
 - K Factor:

Notes:

As discussed throughout OUC's 2026 Ten-Year Site Plan, consideration of OUC's current existing generating resources (including existing PPAs), OUC's expected future PPAs, and OUC's current base-case load forecast indicates that OUC is projected to have adequate capacity to satisfy forecast reserve margin requirements through 2035 (the final year considered in the 2026 Ten-Year Site Plan). As such, no new capacity additions are included in the 2026 Ten-Year Site Plan.

Schedule 10
Status Report and Specifications of Proposed Directly Associated Transmission Lines

- (1) Point of Origin and Termination:
- (2) Number of Lines:
- (3) Right-of-Way:
- (4) Line Length:
- (5) Voltage:
- (6) Anticipated Construction Timing:
- (7) Anticipated Capital Investment:
- (8) Substations:
- (9) Participation with Other Utilities:

Notes:
OUC's 2026 Ten-Year Site Plan does not include any proposed directly associated transmission lines. Therefore, Schedule 10 is not applicable.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)
Emergency Order: Orlando Utilities Commission
Regarding the Stanton Energy Center

Order No. 202-26-42

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

EXHIBIT 6

OUC RESPONSE TO DOE RFI



April 22, 2026

VIA EMAIL

Alex Fitzsimmons
Under Secretary of Energy (Acting)
Director, Office of Cybersecurity, Energy Security & Emergency Response
U.S. Department of Energy
1000 Independence Avenue SW
Washington, DC 20585
Attn: askcr@hq.doe.gov

Re: Response to Information Request for Stanton Energy Center

Dear Under Secretary Fitzsimmons:

Transmitted herewith is the Orlando Utilities Commission's (OUC) responses to the U.S. Department of Energy's (DOE) April 8, 2026 information request regarding the Stanton Energy Center. OUC recognizes the Department's responsibility to ensure the adequacy, reliability and security of the Nation's energy supply and appreciates the opportunity to support this important effort.

OUC has completed Exhibit 1 in full, providing detailed information regarding the Stanton Energy Center's generating units, operating characteristics, fuel usage, planned retirements, potential conversions, regulatory considerations and other matters identified in the Department's request.

OUC remains committed to maintaining reliable, affordable, resilient, and sustainable electric service for our customers and to coordinating with federal, state, and regional partners on matters affecting grid reliability and energy security. We appreciate DOE's engagement on these issues and stand ready to provide any additional information or clarification that may assist in your review.

Please let me know if you have any questions or need any additional information.

Sincerely,

Clint P. Bullock
General Manager & Chief Executive Officer
Orlando Utilities Commission

Enclosure:

Responses to DOE Exhibit 1 – Stanton Energy Center

ORLANDO UTILITIES COMMISSION

Orlando Utilities Commission (OUC) Responses to U.S. Department of Energy's April 8, 2026 Information Request for Stanton Energy Center

Please see below for Orlando Utilities Commission (OUC)'s responses to the U.S. Department of Energy's April 8, 2026 *Information Request for Stanton Energy Center*.

- Please identify the full legal name of the generating facility, its physical address, the Facility ID Number, and also the owner and operator names.**

Response:

Stanton Energy Center
 5100 S. Alafaya Trail
 Orlando, Florida 32831
 Energy Information Administration Plant Code: 564
 Owner: Please see Table 1 below
 Operator: Please see Table 1 below

Table 1. Stanton Energy Center Owner/Operator Information		
Unit Name	Owner	Operator
Stanton Energy Center Unit 1	Orlando Utilities Commission (100%)	Orlando Utilities Commission
Stanton Energy Center Unit 2	Orlando Utilities Commission (71.6%) Florida Municipal Power Agency (28.4%)	Orlando Utilities Commission
Stanton Energy Center Unit A	NextEra Energy (65%) Orlando Utilities Commission (28%) Florida Municipal Power Agency (3.5%) Kissimmee Utility Authority (3.5%)	NextEra Energy
Stanton Energy Center Unit B	Orlando Utilities Commission (100%)	Orlando Utilities Commission
Stanton Solar Farm	Deriva Energy (100%)	Deriva Energy
Kenneth P. Ksionek Community Solar	Greenwood Sustainable Infrastructure LLC (100%)	Greenwood Sustainable Infrastructure LLC

- Please identify the Generator/Unit Information for each unit at the facility, including the Generator/Unit Name, the types of fuel it uses, whether it is dual fuel, its nameplate capacity in MW and its operating status. For example, an acceptable response would be Unit 1, coal, not dual fuel, 125MW, down for periodic maintenance.**

Response:

Please see Table 2 below. Operating status is as of the date this response was prepared.

Table 2. Stanton Energy Center Unit Summary				
Unit Name	Fuel Types	Dual Fuel	Nameplate Capacity	Operating Status
Stanton Energy Center Unit 1	Coal	N	464.5 MW	Operational
Stanton Energy Center Unit 2	Coal	N	464.5 MW	Operational
Stanton Energy Center Unit A	Natural Gas (Primary) Distillate Fuel Oil (Alternate)	Y	688 MW	Operational
Stanton Energy Center Unit B	Natural Gas (Primary) Distillate Fuel Oil (Alternate)	Y	333 MW	Operational
Stanton Solar Farm	Solar	N	5.1 MW	Operational
Kenneth P. Ksionek Community Solar	Solar	N	8.9 MW	Operational

- 3. Please explain how the unit is currently used (e.g. peaking, baseload, backup), its planned retirement date (if applicable), whether retirement has been previously accelerated or delayed, the reasons for the planned retirement, and the relevant local, state, or federal laws related to retirement.**

Response:

Each of Units 1, 2, A, and B at the Stanton Energy Center are currently used as baseload/intermediate units, and retirement dates for the units have not been identified. In the event OUC decides to retire any of the units, OUC will do so in compliance with applicable local/state/federal laws related to retirement.

In late 2021 OUC purchased three natural gas combustion turbines (with the ability to utilize fuel oil as a backup fuel). Referred to as the Osceola Generating Station, the units are owned and operated by OUC and provide OUC with 510 MW of generating capacity (each unit is 170 MW), which is more than the 453 MW from Stanton Energy Center Unit 1.

In the 2022 timeframe, OUC considered retirement of Stanton Energy Center Unit 1 by the end of 2025. However, OUC has since determined the best course of action is to place Stanton Energy Center Unit 1 into extended cold shutdown by May 2026. While in extended cold shutdown, Stanton Energy Center Unit 1 will be maintained in a manner such that the unit would be capable of being brought on-line to be operational as needs may arise. This change took into account how OUC could utilize all of its generating resources to continue to reliably service its customers' energy requirements.

Similar to other municipal utilities in Florida, OUC utilizes a 15 percent reserve margin for resource planning purposes. Considering OUC's current forecast of peak demand and existing generating resources, OUC's reserve margins are projected to exceed 15 percent through 2031 without considering the capacity associated with Stanton Energy Center Unit 1. OUC is in the process of evaluating whether keeping Stanton Energy Center Unit 1 in extended cold shutdown for a prolonged period of time is appropriate.

With respect to Stanton Energy Center Unit 2, OUC currently anticipates making modifications to allow the unit to operate on 100 percent natural gas by the end of 2027. OUC will continue to evaluate these modifications before making a final decision related to implementation.

- 4. If you were at some previous point considering a retirement or sale of the facility and are now considering delaying retirement or sale of the unit please describe the circumstances.**

Response:

The only unit at Stanton Energy Center that OUC had considered retiring is Stanton Energy Center Unit 1; however, as discussed in response to Question No. 3, OUC decided to place Stanton Energy Center Unit 1 into extended cold shutdown rather than retiring the unit. When initially contemplating retirement of Unit 1, and after the purchase of Osceola Generating Station, OUC had sufficient generating resources to allow it to continue to reliably serve its customer's energy requirements, and retirement of Unit 1 was anticipated to reduce costs to OUC's customers.

- 5. If you are considering a retirement or sales of the unit, please identify and explain with detail and particularity:**
- a. If the facility is not in an 1S0/RTO market how is a loss of generation from the planned retirement expected to be replaced?**
 - b. Are there any relevant local, state, or federal laws regarding generation from the type of facility at issue?**
 - c. Is it possible for the facility to operate on a going forward basis without conflicting with federal, state, or local laws? If so, for how long and under what operating conditions?**
 - d. Would continued operation of the facility/units planned for retirement result in significantly increased costs for consumers? If yes, how? Would these costs be offset by increased reliability?**

Response:

This question is not applicable as OUC is not considering retirement at this time of any units at the Stanton Energy Center.

- 6. If you are considering a conversion to natural gas, please identify the planned conversion date and general timeline, explain whether the conversion will result in units maintaining or increasing nameplate capacity and/or an increase in capacity factor, and whether there will be a result in cost savings for customers.**

Response:

OUC currently anticipates making modifications to Stanton Energy Center Unit 2 to allow the unit to operate on 100 percent natural gas by the end of 2027. OUC does not anticipate that such modifications would affect the nameplate capacity or the net generating capacity. OUC will continue to evaluate these modifications before making a final decision related to implementation and such analysis will consider how changes in the operation of Stanton Energy Center Unit 2 will affect the capacity factor and cost to operate Unit 2 to support OUC's ability to continue to reliably serve its customers' energy needs.

- 7. If you are considering a conversion to natural gas, please explain with detail and particularity the actions being taken to minimize the length of outage for the conversion (e.g. use of existing turbines), explain whether external factors (e.g. laws, company policy) are driving the conversion, and any other relevant information.**

Response:

OUC currently anticipates making modifications to Stanton Energy Center Unit 2 to allow the unit to operate on 100 percent natural gas by the end of 2027. When OUC moves forward with the modifications, OUC does not expect that the modifications will require Unit 2 to be out of service for an extended period of time and will perform this modification consistent with its scheduling criteria for major planned outages.

- 8. Please explain with detail and particularity:**
- a. Are there any major operating limitations for any units at the facility;**

Response:

There are no major operating limitations for any units at the Stanton Energy Center.

b. Are there any safety considerations with continued operations; and

Response:

There are no safety considerations with continued operations of any units at the Stanton Energy Center.

c. Are there any workforce, fuel availability, contractual, or permitting complications at issue?

Response:

There are no workforce, fuel availability, contractual, or permitting complications at the Stanton Energy Center.

9. Regarding each generating facility footprint, please identify and explain with detail and particularity:

a. The Balancing Authority;

Response:

OUC is a member of the Florida Municipal Power Pool (FMPP).

b. The Reliability Coordinator;

Response:

Florida Reliability Coordinating Council (FRCC).

c. The name of the state utility regulatory commission and its relevant regulatory authority as it relates to the facility; and

Response:

The Florida Public Service Commission (FPSC) is the state utility regulatory commission for the State of Florida. As a municipal electric utility, OUC's rates are not regulated by the FPSC. However, OUC has reporting obligations to the FPSC including reports on energy provided by OUC to its customers and wholesale entities, resource plans, numeric conservation goals (through the FPSC's Florida Energy Efficiency and Conservation Act requirements), and reports on renewable energy and conservation and demand-side management.

d. Any other relevant parties.

Response:

The units located at the Stanton Energy Center are operated and maintained in accordance with all applicable local/state/federal requirements.

10. If the facility is not in an ISR/RTO market, please explain with detail and particularity, how energy and capacity, as applicable, from the facility is purchased. Are there any unique requirements/laws that affect the sale of energy and/or capacity from the facility?

Response:

Energy from OUC's generating resources located at the Stanton Energy Center are utilized as part of OUC's generating system (which includes resources located at sites other than the Stanton Energy Center) through its membership in the Florida Municipal Power Pool (FMPP). FMPP is an operating-type electric pool, which dispatches all the pool members' generating resources in the most economical manner to meet the total load requirements of the pool.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

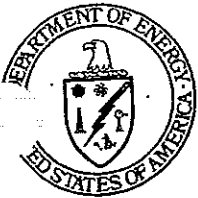
Federal Power Act Section 202(c)
Emergency Order: Orlando Utilities Commission
Regarding the Stanton Energy Center

Order No. 202-26-42

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

EXHIBIT 7

DOE ORDER NO. 202-02-1



Department of Energy

Washington, DC 20585

Order No. 202-02-1

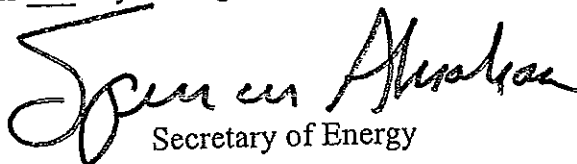
Pursuant to the authority vested in me by section 202(c) of the Federal Power Act, 16 U.S.C. 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. 7151(b), I hereby determine that an emergency exists on Long Island in the State of New York due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, a shortage of facilities for the transmission of electric energy and other causes, and that issuance of this order will alleviate the emergency and serve the public interest. Based on this determination, I hereby order:

From the effective date and time of this order until 12:01 a.m. Eastern Daylight Time, October 1, 2002, Cross-Sound Cable Company, LLC is directed to operate the Cross-Sound Cable and related facilities connecting substations in New Haven, Connecticut and Shoreham, Long Island, New York, to transmit and deliver electric capacity and/or energy when, as and in such amounts as may be scheduled and purchased by the Long Island Power Authority (LIPA), and to take such actions as are necessary in order to enable it to do so, including but not limited to energizing and continuing to energize the facilities of Cross-Sound Cable Company, LLC; *provided*, that this order otherwise shall be limited to requiring the transmission and delivery of such electric capacity and/or energy as is necessary in the judgment of the New York Independent System Operator to meet the supply and essential reserve margin needs of LIPA, in order for LIPA to serve its firm retail customers after it has implemented all available load reduction measures consistent with good utility practice, including curtailing and/or terminating service to interruptible customers, public appeals for conservation, reducing 30 minute reserves to zero, and implementing voltage reductions; *and provided further*, that prior to exercising its judgment as required by this order, the New York Independent System Operator must consult with ISO New England, Inc. to ensure that the scheduling of such electric capacity and/or energy will not violate system operating criteria, and the New York Independent System Operator should, as practicable, consult with appropriate reliability organizations. If necessary, just and reasonable terms for the transmission and delivery of electric capacity and/or energy pursuant to this order, including the compensation therefor, shall be established by a supplemental order issued pursuant to Federal Power Act section 202(c).

Nothing in this order shall preclude use of the energized Cross-Sound Cable and its related facilities connecting substations in New Haven, Connecticut and Shoreham, Long Island, New York, to transmit and deliver electric capacity and/or energy from Long Island to Connecticut or from Connecticut to Long Island in accordance with the operating and scheduling protocols and decisions of the New York Independent System Operator and ISO New England, Inc.

This order shall be effective upon its issuance.

Issued in Washington, D.C. at 2:38PM this 16th day of August, 2002.


Secretary of Energy



BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)
Emergency Order: Orlando Utilities Commission
Regarding the Stanton Energy Center

Order No. 202-26-42

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

EXHIBIT 8

OUC EIRP

Orlando Utilities Commission 2020 Electric Integrated Resource Plan Report

Orlando Utilities Commission
November 2020

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1. Executive Summary

Orlando Utilities Commission (OUC) operates as a statutory commission created by the legislature of the State of Florida. Established in 1923, OUC – The *Reliable One*, Orlando’s hometown utility, is the second largest municipal utility in Florida and 14th largest municipal in the country, providing electric, water, chilled water and lighting services to approximately 250,000 customers in Orlando, St. Cloud and parts of unincorporated Orange and Osceola counties. The OUC Commission consists of five members, including the Mayor of the City of Orlando, who is an ex-officio member. Members must be OUC customers and at least one member must reside outside the City of Orlando limits in the unincorporated area of Orange County.

OUC’s long history of Sustainability was reinforced in February 2020 when the utility adopted a new strategic plan. As part of its strategic commitments, OUC will continue to make significant investments in energy innovation – particularly in solar, energy storage, electric vehicles (EVs), efficiency and conservation through 2030.

- OUC has committed \$420 million to solar technology. Further commitments include investing an additional \$90 million in energy storage. As part of these investments, OUC has already committed to providing 270 megawatts of solar energy to customers.
- \$45 million has been committed to innovative electrification programs including support for e-buses, dealership programs, and additional EV charging stations, bringing OUC’s total installed charging stations from 200 currently to nearly 300 by Spring 2021 – maintaining Orlando’s position as one of the Top 10 most-EV ready cities in the nation¹.
- OUC expects to meet its strategic commitment to achieve 1% of savings of retail sales in 2020. Additionally, OUC has a \$30 million investment planned in efficiency and conservation efforts by 2030, including enhancements to low-income programs and technology solutions.

OUC Management recommends significantly reducing coal-fired generation no later than 2025 and eliminating it no later than 2027, using coal-to-gas conversion as a technology bridge, positioning solar as the main source of new energy, investing in energy storage, and leveraging other future clean technologies. The resulting recommendation balances the key Attributes of Affordability, Reliability, Resiliency and Sustainability.

¹ In 2012, Orlando was named one of the Top 10 Most EV-Ready Cities in the U.S. by PlugShare, a mobile app that helps EV owners find charging stations. In summer 2020, Orange County was recognized in a report presented by the League of Women Voters in Florida as one of five “top tier” counties for EV readiness. Rankings were based on four measures, including percent of EV sales compared to total registered cars and trucks, charging and fast-charging infrastructure, and policy.

1.1 Situation

To prepare for a clean energy future, OUC has taken another critical step toward finalizing the Electric Integrated Resource Plan (EIRP).

1.1.1 The EIRP Process

The EIRP is an energy roadmap that guides how OUC generates and supplies electricity in a way that balances Affordability, Reliability, Resiliency and Sustainability through 2050. Currently, OUC relies on a diverse fuel mix of coal, natural gas, nuclear, solar and landfill gas. As confirmed by the OUC Board in February 2020's public strategy workshop, and in furthering OUC's decades-long commitment to Sustainability, the utility pledged to achieve Net Zero CO₂ Emissions by 2050 goal, as well as interim targets of 50% CO₂ emissions reduction by 2030 and 75% by 2040 compared to 2005 levels². OUC's Net Zero CO₂ by 2050 commitment directionally aligns with City of Orlando Mayor Buddy Dyer's 2017 aspirational proclamation to achieve 100% renewable energy generation for Orlando by 2050.

EIRPs are standard, responsible, due-diligence practices for utilities that typically look across a 20-year horizon, as driving forces in the energy industry change. However, OUC extended the time horizon to 30 years to explore the feasibility of 100% renewable generation. With stakeholder engagement at its core, the EIRP process considers factors affecting power generation and transmission – from individual customer needs to broader issues such as the utilization of existing assets and resources, advances in renewable energy technologies, and potential events that could impact energy supply and demand (e.g., government regulations, hurricanes, etc.).

1.1.2 Considerations

Florida-specific factors were taken into consideration because renewable resources are limited relative to other regions in the country. Currently, wind, hydroelectric and geothermal are not economically and/or technically viable in Florida – and biomass and landfill gas, while possible resources, are available only in small quantities³. That leaves the state's utilities with one feasible renewable asset: sunshine – which poses its own challenges. With solar power, electricity is not produced at night or at scale on cloudy days. With an average of 277 partly cloudy days⁴ per year in Orlando – nearly 76% of the year – intermittency is a concern, and backup resources are necessary to ensure that power is always available.

Transmission infrastructure, which facilitates the transfer of high-voltage energy between Florida and the rest of the country, is a major component when considering Resiliency of the system. Largely due to Florida being a peninsula, the state can import energy only from its northern border. Unlike many other states where there are

² Data from 2005 is a widely used baseline, including in the 2018 Paris Agreement.

³ [U.S. Energy Information Administration, Florida: State Profile and Energy Estimates – Analysis](#)

⁴ [National Oceanic and Atmospheric Administration – Cloudy and Sunny Days Analysis](#)

multiple paths to receive high-voltage energy, Florida has a lower overall import capacity. Compared to California, which has physical capacity to import 20% of its power, Florida has a lower overall transmission import capacity of approximately 6% of total forecast summer peak load in 2020⁵.

These realities restrict Florida's renewable energy portfolio until further technology advancements and additional transmission access alters the landscape. To combat this, as shown in the utility's strategic commitments in the prior section and the following recommendation, OUC is investing in a balance of sustainable solutions to propel Central Florida toward a cleaner, greener future.

This document summarizes the EIRP methodology, process, and findings that led to OUC Management's recommended clean energy roadmap to generate and supply electric power to our community while achieving the goal of Net Zero CO₂ Emissions by 2050.

1.2 Future Challenges and Opportunities

The transition from a fossil-based generating portfolio to a clean portfolio introduces both challenges and opportunities:

- **Intermittency:** As intermittent energy resources, such as solar, expand their viability as primary energy generation sources, OUC must take steps to ensure energy sufficiency by adding more energy storage and portfolio diversity.
- **Rate Competitiveness:** The cost, maturity and availability of technology advancements and supporting infrastructure must be balanced to ensure Affordability is maintained.
- **Limited Energy Diversity:** Unlike other parts of the country, Florida's only viable renewable option is solar energy⁶ – although wind-by-wire generation may become more widely available in the future. OUC will continue to evaluate and monitor emerging clean technologies, such as hydrogen, offshore wind and small modular nuclear power plants.
- **Transmission:** OUC will have greater reliance on transmission infrastructure. As a result, greater geographical diversity of renewable energy will be required to minimize the risk of extreme weather, and generation diversity will need to remain part of the OUC strategy.

⁵ Various studies and reports presented at the Florida Reliability Coordinating Council (FRCC) regarding the Florida/Southern 500kV Interconnection and FRCC regional load forecasts

⁶ "Florida has few other renewable energy assets. The state has no significant wind resources and no installed utility-scale wind power generating capacity, although some wind power components are manufactured in Florida. Potential for a small amount of additional hydroelectric generation exists in the northern part of the state that is not close to sea level." (Source: U.S. Energy Information Administration)

1.3 EIRP Consultants

OUC engaged Siemens PTI to support the development of the EIRP and to evaluate a list of energy portfolio “candidates” for the utility to consider. Siemens PTI developed and analyzed seven possible Candidate Portfolios designed to provide sufficient energy to meet OUC demand under expected conditions – and also achieve multiple Sustainability goals by 2050. To determine the best resource mix for OUC, these portfolios were evaluated on the basis of four key Attributes: Affordability, Reliability, Resiliency and Sustainability.

To facilitate the critical stakeholder engagement process for the EIRP, which was used to rank the four key Attributes, OUC also engaged Essence Partners, an independent, national marketing firm specializing in the energy sector.

1.4 Stakeholder Engagement

Key Points:

- Community engagement included a wide variety of options for the community to provide feedback.
- A 12-member, independent, Advisory Council met multiple times, and after analyzing community input, determined how key Attributes should be weighted: Reliability at 35%, Affordability at 24%, Sustainability at 22% and Resiliency at 19%.

Stakeholder engagement is the foundation of the EIRP process. To ensure that OUC captured a comprehensive vision for the community’s energy future, the EIRP included input from stakeholders in Orlando, Orange County and St. Cloud. Stakeholders were represented through a 12-member, independent Advisory Council nominated by elected officials and staff from Orange County, the City of Orlando and the City of St. Cloud. Members represented a cross-section of the community, composed of residential and commercial customers, including community partners, environmental groups, OUC program participants, and Orange and Osceola County residents. The Advisory Council met in November 2019, January 2020, and virtually in March 2020.

An online survey received input from 1,377 participants. To increase community engagement, five in-person community forums were held, generating additional feedback from 306 community members. Commercial customers were also engaged in a forum and interviews. All forums offered education on the EIRP to provide participants with a basic level of understanding and an opportunity to vote on the key Attributes. Essence Partners conducted all forums and gathered and analyzed all voting data.

After gathering input from stakeholders, Essence Partners provided the voting data to the Advisory Council and facilitated the group’s ranking of the key Attributes which determined how they would be weighted when scoring the Candidate Portfolios. The Advisory Council rankings were: Reliability, with the most weight at 35%, Affordability at 24%, Sustainability at 22% and Resiliency at 19%.

Definitions of Key Attributes

- **Reliability:** An electric system's ability to effectively produce and deliver the energy required by customers with minimal interruptions and consistent quality while maintaining compliance.
- **Affordability:** An electric system's ability to produce and deliver energy at an affordable cost with minimal price fluctuations.
- **Sustainability:** An electric system's ability to produce energy in a way that proactively reduces pollution and impacts on the surrounding ecosystem.
- **Resiliency:** An electric system's ability to adapt to uncontrollable events (such as weather extremes like hurricanes, major storms, heat waves, cloud cover, and other severe weather events), maintain physical and cyber security, and quickly bounce back following an interruption.

1.5 Objectives and Criteria

Key Points:

- All Candidate Portfolios were analyzed for their ability to meet key Attributes of Reliability, Affordability, Sustainability and Resiliency.
- OUC reviewed seven Candidate Portfolios.
- The Leading Portfolio meets OUC's goal of Net Zero CO₂ Emissions by 2050, as well as interim targets of 50% CO₂ emissions reduction by 2030 and 75% by 2040.

The main EIRP objectives were to develop a portfolio strategy that: 1) achieved the best performance relative to the Attributes of Reliability, Affordability, Sustainability and Resiliency required to meet our community's future energy needs, and 2) met OUC's strategic Net Zero CO₂ Emissions by 2050 goal, as well as interim targets of 50% CO₂ emissions reduction by 2030 and 75% by 2040.

Candidate Portfolios were developed using several different pathways and mathematical optimization techniques to achieve these objectives. Siemens PTI then used these objectives as guiding principles to develop, define and subsequently measure the performance of the following seven Candidate Portfolios using stochastic simulations.

1. **Net Zero CO₂ 2050 Portfolio** – designed to test a portfolio that achieves Net Zero CO₂ emissions by 2050.
2. **100% Renewable by 2050 Portfolio** – designed to test the performance of a 100% renewable OUC generation fleet by 2050.
3. **Coal Retirement 2022/2026 Portfolio** – designed to test retiring a Stanton coal unit in 2022 and the other in 2026, replacing that capacity with renewables and energy storage only, based on the Synapse Energy Economics Report (August 2018) – a review of the U.S. electric system completed by Synapse Energy Economics.

4. **Gas Conversion 2026/2029 Portfolio** – designed to test converting a Stanton coal unit to natural gas in 2026 and the other in 2029.
5. **Gas Conversion 2036/2040 Portfolio** – designed to test converting a Stanton coal unit to natural gas in 2036 and the other in 2040.
6. **Wind-by-Wire Portfolio** – designed to test the impact of out-of-state wind capacity late in the forecast horizon.
7. **The Modular Nuclear Portfolio** – designed to test the impact of adding modular nuclear capacity.

In addition to the Net Zero CO₂ Emissions reduction by 2050 goal, each Candidate Portfolio was evaluated and ranked based on the four key Attributes using specific metrics for each:

- **Reliability:** Each portfolio was designed to meet or exceed the Reliability requirement of 100% energy sufficiency under expected conditions without reliance on neighboring utilities. Additionally, Siemens PTI measured this Attribute using metrics related to the first year of energy shortages, which occur when customer demand exceeds available supply resources (due to significant cloud cover during highest demand week occurring in August). The second metric is the technology diversity of the portfolio at the end of the forecast horizon.
- **Affordability:** To measure each Candidate Portfolio for Affordability, Siemens PTI used metrics related to the portfolio costs of generation and transmission, including fixed cost recovery, and the uncertainty of those costs over the 30-year planning horizon.
- **Sustainability:** Siemens PTI measured this Attribute by determining the probability of meeting the Net Zero CO₂ Emissions reduction by 2050 goal and interim targets, as well as the percentage of clean (non-CO₂ emitting technologies) energy generation in 2050.
- **Resiliency:** To measure each portfolio for Resiliency, Siemens PTI used scenario analysis that simulated system shocks such as hurricanes and gas pipeline disruptions, as well as metrics related to energy shortages.

The performance of the portfolios across all metrics is summarized in the Balanced Scorecard (Exhibit 1). Numerical scores indicate how each portfolio was ranked (where 1 is the best, and 8 is the worst) relative to other portfolios on a given metric. The final score is the weighted average ranking using the weights provided by the Advisory Council (Reliability, 35%; Affordability, 24%; Sustainability, 22%; Resiliency, 19%).

Exhibit 1: Final Balanced Scorecard

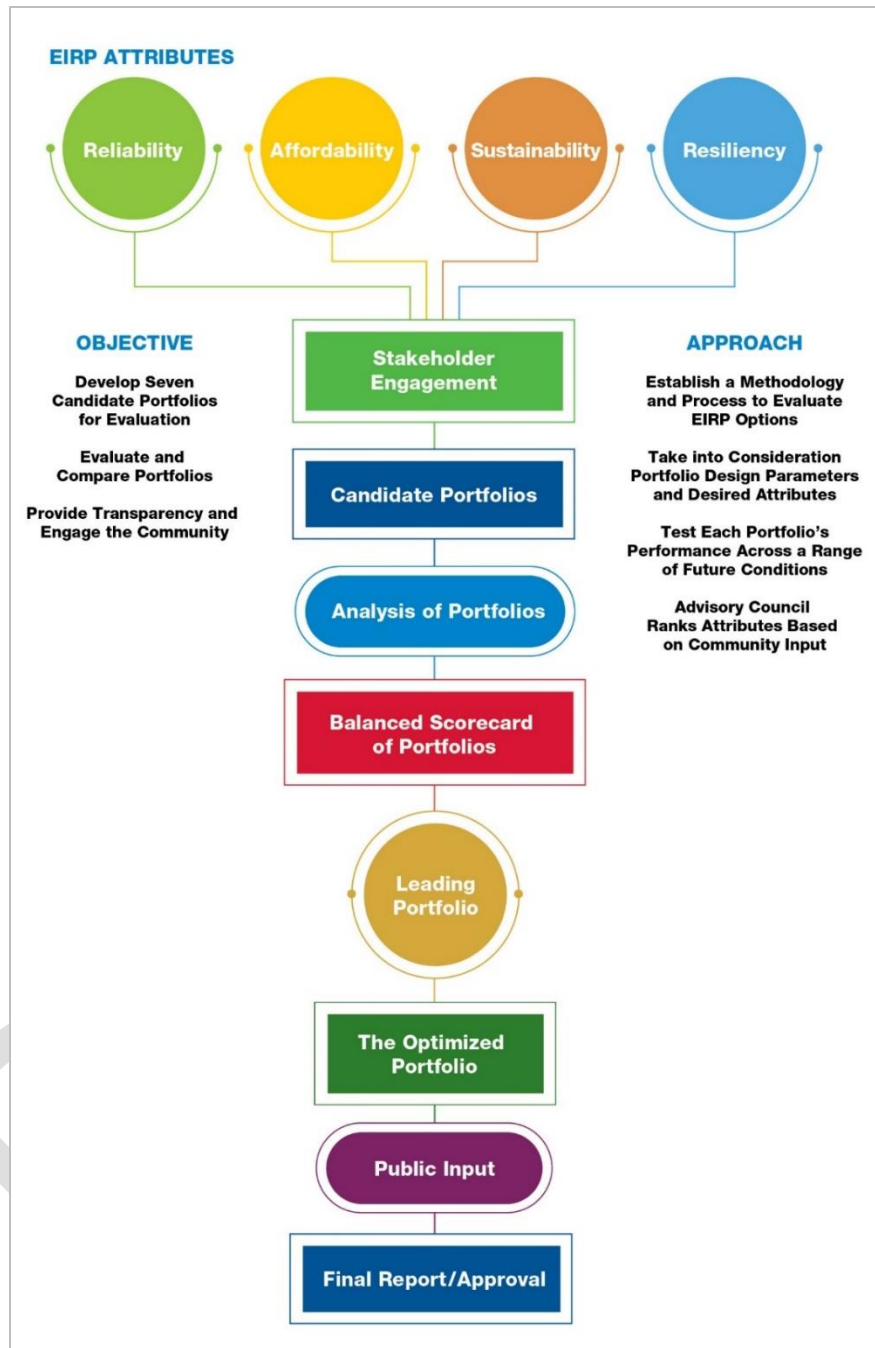
Attributes	Weight	Net Zero CO ₂ by 2050	100% Renewable by 2050	Gas Conversion 2026/2029	Gas Conversion 2036/2040	Coal Retirement 2022/2026	Wind-by- Wire	Modular Nuclear
Reliability	35%	3.5	3.0	2.0	2.0	4.0	3.0	1.5
Affordability	24%	5.2	6.2	5.1	4.7	5.8	5.5	4.4
Sustainability	22%	1.5	1.5	1.0	2.0	1.0	1.8	1.5
Resiliency	19%	3.0	4.3	4.3	4.0	8.0	5.0	4.0
Total	100%	3.4	3.7	3.0	3.0	4.5	3.7	2.7

*These Portfolios meet all of the Interim Emission Targets
Scores: 1 is the best. 8 is the worst

Source: Siemens PTI

While the Balanced Scorecard ranked Gas Conversion 2026/2029, Gas Conversion 2036/2040 and the Modular Nuclear as the most favorable Candidate Portfolios across the four Attributes, only Gas Conversion 2026/2029 accomplishes the Sustainability Attribute of achieving the Net Zero CO₂ Emissions by 2050 goal, as well as interim targets of 50% CO₂ Emissions reduction by 2030 and 75% by 2040. As a result, it became the "The Leading Portfolio."

Exhibit 2: Overall EIRP Process



Source: Costa, Siemens PTI

1.6 OUC Management Clean Energy Roadmap Recommendation:

1.6.1 The Optimized Portfolio

Key Points:

- The Leading Portfolio was further refined into The Optimized Portfolio.
- This refinement meets OUC’s Sustainability goals at the best value and increases levels of Reliability and Resiliency by limiting investments in new gas-fired generation and avoiding stranded costs.

Building upon the strengths of the Leading Portfolio, the Optimized Portfolio delivers on several key objectives including earlier coal retirement dates, accomplishment of interim Net Zero CO₂ Emissions, avoidance of stranded costs and long-term enhanced generation diversity.

The Balanced Scorecard was used as a guide for determining The Optimized Portfolio by including strategies that scored well and insights that were gained in the analysis of the Candidate Portfolios.

Exhibit 3: Leading Portfolio and Optimized Portfolio Comparison

	Gas Conversion 2026/2029 “Leading Portfolio”	Optimized Portfolio
Conversion Builds	2026, 2029	2025, 2027
Conversion Retirement	After 2050	By 2040
Primary New Energy Resources	Solar and Energy Storage	Solar, Energy Storage and Wind by Wire Generation
Non-FL Wind Generation	None	Contingent upon transmission access

Source: Costa

The elements of the strategy, along with the insights and validating metrics, allow OUC to achieve Net Zero CO₂ Emissions by 2050 goal, as well as interim targets of 50% CO₂ emissions reduction by 2030 and 75% by 2040, in directional alignment with the City of Orlando goals, while striking a balance of the four key Attributes – Reliability, Affordability, Sustainability and Resiliency.

Specifically:

- **Significantly reducing coal-fired generation no later than 2025 and eliminating it no later than 2027.** The C.D. McIntosh Unit 3, a 340-megawatt, primarily coal-fired unit in Lakeland, Florida, is expected to shutter by the end of 2024⁷. Both

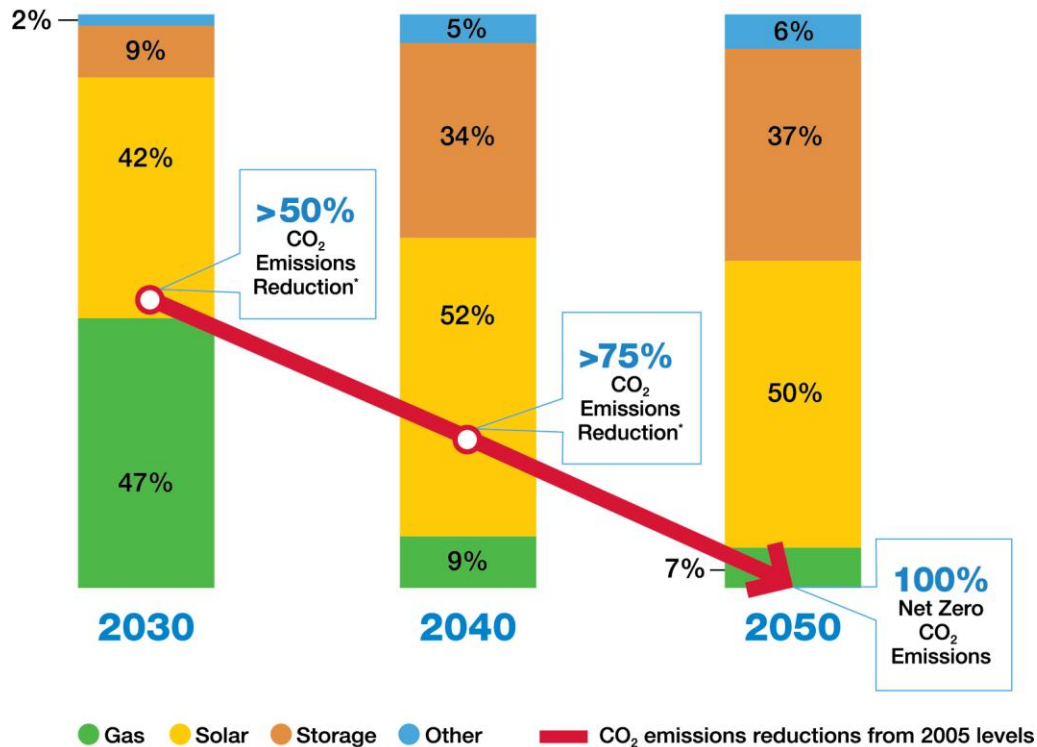
⁷ OUC owns a 40% share of this unit, which came online in 1982 and is operated by Lakeland Electric.

Stanton coal-fired units will be converted from coal to natural gas. The natural gas conversion units would be retired no later than 2040 to achieve greater Sustainability and avoid stranded costs.

- **Accelerating solar and energy storage as primary strategies.** Energy storage technologies will be used to provide energy during non-solar energy production periods.
- **Leveraging future clean technologies to ensure diversity for Reliability.** According to the EIRP analysis, the addition of wind-by-wire generation would greatly reduce the amount of solar and energy storage required to achieve energy sufficiency. Like solar, wind is an intermittent resource, but is highly complementary to solar generation. Generally, energy from wind resources is also available at different times of day, which is important for Reliability and Resiliency. While wind energy is currently not available for import into OUC's service territory due to transmission constraints, it is anticipated to be an option as access to transmission lines from the Midwest expand. OUC will continue to monitor its availability, along with other emerging clean resources such as hydrogen, offshore wind and small modular nuclear power plants.
- **Striving to maintain competitive rates while achieving strategic goals.** Advancements of this magnitude require significant investments. However, The Optimized Portfolio delivers the best value. Gas conversion capital costs are 5-10% of the cost of a new combined cycle gas plant, allowing for OUC to retire converted gas-fired units by 2040.

Exhibit 4: Optimized Portfolio Energy Resource Mix and CO₂ Emissions

OUC Management Clean Energy Roadmap Recommendation



*Emissions reductions based on 2005 base levels
Other includes nuclear, wind and gas peaker
EV offsets used in 2050 only
OUC will significantly reduce coal-fired generation no later than 2025 and eliminate it no later than 2027.

Source: Costa

OUC will continue to monitor performance developments and technology enhancements for new and existing clean technologies, such as hydrogen and small modular reactors, to ensure the highest performance relative to the key Attributes.

2. EIRP Overview

The EIRP is a comprehensive decision support tool and roadmap to aid OUC's objective of meeting its expected electric energy demand. The EIRP looks at a varying set of resources (generation, storage, demand side management) across Candidate Portfolios, subject to changing market circumstances, to ensure the OUC system remains Reliable, Affordable, Sustainable, and Resilient as well as flexible, diverse, and other more qualitative considerations.

2.1 Background on Orlando Utilities Commission

OUC operates as a statutory commission created by the legislature of the State of Florida as a separate part of the government of the City. Since 1923, OUC has provided residents and businesses with reliable electricity. OUC's charter allows it to undertake, among other things, the construction, operation, and maintenance of electric generation, transmission, and distribution systems to meet the requirements of its customers.

Established in 1923 by a special act of the Florida Legislature, OUC—The Reliable One is the second largest municipal utility in Florida and 14th largest municipal in the country. OUC provides electric, water, chilled water and/or lighting services to approximately 250,000 customer accounts in Orlando, St. Cloud and parts of unincorporated Orange and Osceola counties.

OUC is a member of the Florida Municipal Power Pool (FMPP), which consists of OUC, Lakeland Electric (Lakeland), and the Florida Municipal Power Agency (FMPA) All-Requirements Project. Electrical power for OUC is generated by Stanton B, a unit owned entirely by OUC, as well as units in which OUC maintains joint ownership and power purchases. OUC's available capacity as of January 1, 2020, including capacity from units owned by OUC, St. Cloud's entitlement to Stanton Energy Center Unit 2, and OUC's current power purchases (including natural gas, as well as landfill gas and solar resources), provides total net summer capacity of approximately 1,877 megawatts (MW) and total net winter capacity of approximately 1,902 MW⁸.

OUC operates within the North American Electric Reliability Corporation (NERC) region of the SERC Reliability Corporation (SERC), which subsumed the Florida Reliability Coordinating Council (FRCC) in July 2019. Siemens PTI's analysis in this EIRP included

⁸ Net seasonal capacity ratings as of January 1, 2020. Includes capacity owned by OUC and St. Cloud, as well as OUC's contractual power purchases.

the broader, newer SERC region. Presently, OUC has ownership interests in four electric generating plants. Appendix D summarizes OUC's generating facilities:

- Stanton Energy Center Units 1 and 2, Stanton A, and Stanton B
- Indian River Plant Combustion Turbine Units A, B, C, and D
- Lakeland Electric McIntosh Unit 3 (To be retired 12/1/2024 per Lakeland)
- Florida Power & Light Company (FPL) St. Lucie Unit 2 Nuclear Generating Facility

2.2 EIRP Central Considerations

2.2.1 Structured Approach

For each of the portfolio options, the EIRP followed a process designed to identify the preferred course of action that balances the key Attributes of Reliability, Affordability, Sustainability, and Resiliency, further discussed in Section 2.2.2.

Exhibit 5. Overall EIRP Process

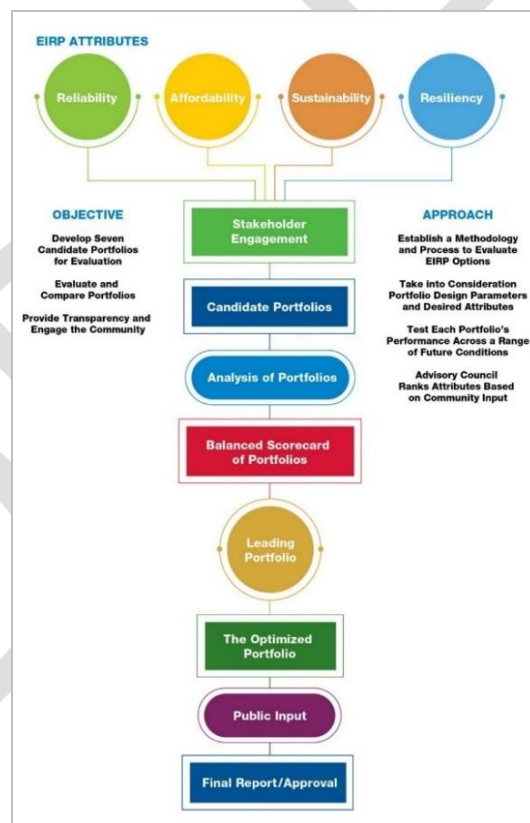


Exhibit 5 depicts the process followed to conduct this EIRP study.

1. Develop objectives, attributes, metrics and overall assumptions.
2. Identify resources that reasonably could be included in plans to meet the load including both supply and demand-side resources (screening).

3. Produce a load projection through 2050 showing fuel costs, emission costs, technology costs and performance (e.g. heat rates, capacity factors etc.) to be applied to the existing and new resource options.
4. Develop portfolios under the various parameters that meet certain pathways and conditions. These portfolios follow each scenario or pathway and used to perform additional risk analysis that subjects each portfolio to a wide range of future outcomes.
5. Perform Stochastic Modeling through 200 iterations (range of uncertainties) for each Candidate Portfolio to assess how well each portfolio performs under a range of market, technology, and regulatory uncertainties.
6. Prepare a balanced scorecard using the objectives and metrics defined in step 1 to rank supply options and select the Leading Portfolio.
7. Adjust the Leading Portfolio to produce the Optimized Portfolio.
8. Prepare a report with findings and recommendations for next steps.

2.2.2 Attributes

While Affordability is a key fundamental Attribute, the EIRP was centered on more than just costs. Ultimately, the Leading Portfolio for OUC is one that performs best against all relevant Attributes and metrics over a range of future conditions, while also accounting for non-analytical, qualitative considerations. As with any integrated resource plan, there will be tradeoffs between the competing objectives of Reliability, Sustainability, Affordability, and Resiliency. Exhibit 6 summarizes the metrics used in the evaluation of Candidate Portfolios.

Exhibit 6: EIRP Attributes and Definitions

ATTRIBUTES	DEFINITION
Reliability	an electric system's ability to effectively produce and deliver the energy required by customers with minimal interruptions and consistent quality while maintaining compliance.
Affordability	an electric system's ability to produce and deliver energy at an affordable cost with minimal price fluctuations.
Sustainability	an electric system's ability to produce energy in a way that proactively reduces pollution and impacts on the surrounding ecosystem.
Resiliency	An electric system's ability to adapt to uncontrollable events (such as weather extremes like hurricanes, major storms, heat waves, cloud cover, and other severe weather events), maintain physical and cyber security, and quickly bounce back following an interruption.

Source: Siemens PTI

2.2.3 Stakeholder Input

Essense Partners launched OUCRoadmap.com in May 2019 as the central stakeholder engagement hub for the EIRP. OUC customers and stakeholders were directed to the microsite to learn about the EIRP process and provide their input on the direction of the EIRP. Website users were required to watch a short video detailing what an EIRP is, why OUC is engaging in this process, and the importance of the four Attributes (Reliability, Resiliency, Affordability, and Sustainability) before accessing the input form.

The input form for customers included both a ranked choice question and free-response questions. The ranked choice question assessed the relative importance of four Attributes in relation to OUC's electric energy future. Free-response questions offered an area to address any additional concerns and explanations for why the customer ranked the Attributes in the order they chose.

Community members and stakeholders were also invited to a series of five, in-person community forums, hosted in the Orlando and St. Cloud areas in December 2019 and January 2020. Participants were given a presentation by Essense and Siemens, based on the information presented on OUCRoadmap.com, and were shown the video hosted on the microsite. After the presentation and video, participants were given the same Attribute ranking and free response questions as the ones on the microsite.

On January 29, a commercial forum was held at the Orlando Economic Partnership's office in downtown Orlando. To maintain consistency with residential community forums, commercial customers were shown the same presentation given by Essense and Siemens and were shown the same EIRP overview video. After watching the video, attendees were asked to rank the four Attributes and provide justifications for their rankings. Concurrently, Essense conducted one-on-one interviews with representatives from OUC's key accounts, defined as the largest commercial customers in terms of electric energy usage. Interviewees were asked to watch the video prior to meeting with Essense. After discussing the purpose and goals of the EIRP, interviewees then ranked the Attributes and provided justifications for their rankings.

The rankings and feedback from the online input form, the community forums, the commercial forum and the key account interviews were then presented to the Advisory Council. Throughout this process, Advisory Council members were also advised to engage with members of the stakeholder groups they represented. Members were then asked to rank the Attributes based on the input received from the four primary engagement opportunities and from their own interactions with community members. The final Advisory Council vote was given to Siemens as the stakeholder recommendation for Attribute weights.

2.3 Strategies and Portfolios Analyzed

The overarching objective of this EIRP is to identify a portfolio of generation resources that best aligns across all key OUC Attributes of Reliability, Affordability, Sustainability, and Resiliency. Specifically, the Candidate Portfolios were designed to satisfy the two underlying requirements: 100% reliable and meet OUC's Net Zero CO₂ targets by 2050. The EIRP process was designed to adapt with the analysis, incorporating updated market information, operational considerations, and logistical limits as they became available.

The process began with the development of a Calibration Portfolio, which served as a business-as-usual (BAU) outlook of expected market conditions and expected load. The Calibration Portfolio is based on the status quo of today's policies and regulations, thus serving as a benchmark to measure the performance of other portfolios that are designed to meet potential policy and regulation goals.

Using the same load and market forecasts as in the Calibration Portfolio, the process then advanced to the development of Pathways and Conditions to be evaluated in comparison with the project goals. The defined pathways and conditions and the role they served in the analysis are described in further detail in the section following.

2.3.1 Original Pathways and Conditions

To meet the objectives set out by this EIRP report, OUC and Siemens PTI developed multiple pathways and conditions to provide the ability to observe different ways to meet these objectives. Developing these pathways and conditions provides guidelines for the design of the Candidate Portfolios.

Original Pathways

The 2050 Pathways in the original EIRP process included five potential Pathways:

1. **Net Zero CO₂ by 2050:** Both CO₂-free and CO₂-generating resources are used.
2. **100% Renewable Energy by 2050 w/ Intermediate Targets:** Meets the City of Orlando's target of generating 100% renewable energy by 2050.
3. **100% Renewable Energy by 2050 w/ Intermediate Targets including Nuclear:** Same as Pathway 2 but with Nuclear and Biomass included as potential resources.
4. **100% Net Zero CO₂ by 2050 (OUC+FL):** Same as Pathway 1 but with all Florida Utilities required to offset their CO₂.
5. **Stanton Plant Retirement (Stanton Phase-Out):** Follows the first unaffiliated Synapse report (circa 2018) that posits the retirement of the Stanton 1 coal unit and the Stanton 2 coal unit, with only renewable energy and storage capacity allowed to backfill.

Using these five Pathways, the development process of the Candidate Portfolios was initiated. Each Candidate Portfolio has a different capacity expansion build-out but

ensures that it follows the requirements set out by at least one of the pathways described to achieve OUC's Sustainability targets. The process began by meeting the load outlook with a combination of resources through an optimization process.

Conditions

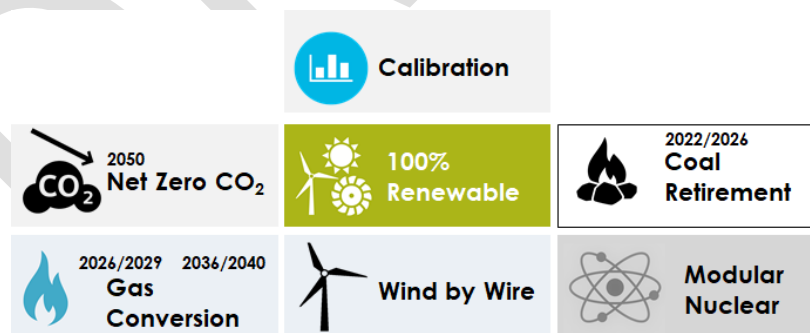
The EIRP process also included three potential future national market conditions, which were used to guide the development of portfolios for evaluation:

1. **High Technology:** In this future, technology advances lead to substantial demand growth; breakthrough advances in renewable energy and storage technologies incentivize and catalyze deployment, reducing the need for backup dispatchable gas and leading to increased coal retirements.
2. **Low Economy/High Regulation:** In this future, heavy regulations on CO₂ and fossil fuels lead to high CO₂, natural gas, and coal costs, more coal retirements, an acceleration of renewable energy via mandates, and a low level of load growth from a sluggish economy.
3. **High Economy/Low Regulation:** In this future, no significant U.S. regulations are promulgated. Economic growth and load growth are relatively robust. Natural gas prices rise with strong load growth, and coal retirements are extended, which creates headwinds for renewable energy deployment.

Portfolios

Together, these five Pathways and three conditions were the basis for developing and optimizing a total of seven Candidate Portfolios shown in Exhibit 7.

Exhibit 7: Calibration and Candidate Portfolios



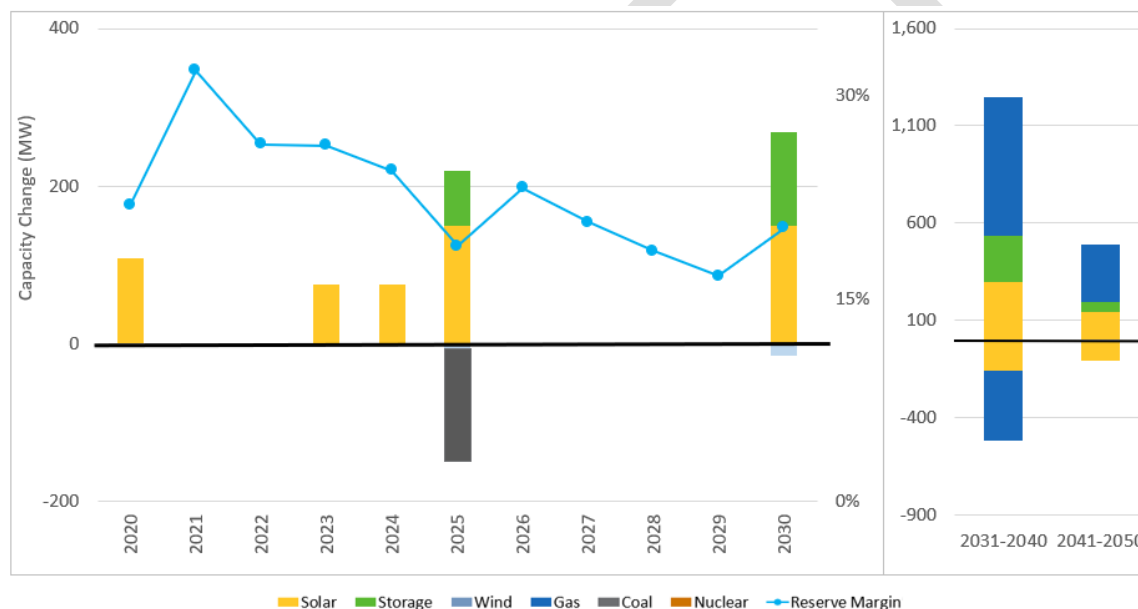
Source: Siemens PTI

2.3.2 Calibration Portfolio

The Calibration Portfolio serves as a business-as-usual (BAU) portfolio which is used to benchmark the metrics of the Candidate Portfolios. Since this is a BAU case, it does not account for meeting any Net Zero CO₂ Targets. This portfolio mainly adds natural gas

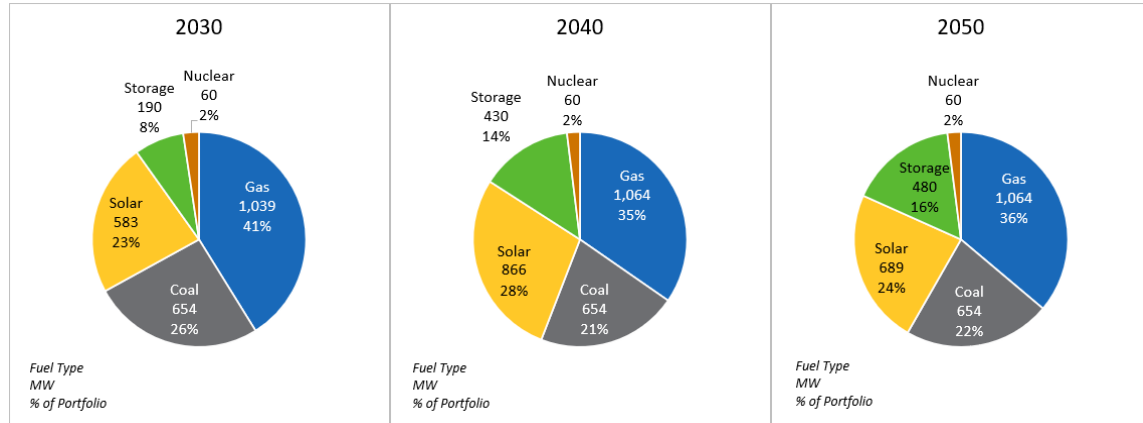
capacity as well as some solar and storage units. These resources were chosen following economics and portfolio diversity incentives. Similar to the Candidate Portfolios, the Calibration Portfolio is able to serve all of OUC's load without having to rely on any purchases or sales. Most of the costs that occur in this portfolio are a result of the capital costs from building the natural gas-fired units, as well as the infrastructure needed to increase the natural gas transportation for the added natural gas capacity. One aspect that differentiates this portfolio from the Candidate Portfolios is that the reserve margin remains relatively low throughout the whole forecast. Also, this portfolio maintains the Stanton coal units, keeping the costs low compared to other portfolios that replace the coal units with renewable energy or convert the units to natural gas-fired units. The portfolio build-out is outlined in Exhibit 8 with a detailed break-out in the 2020-2030 timeframe.

Exhibit 8: Calibration Portfolio Build-Out (2020-2050)



Source: Siemens PTI

To gain a better understanding of the resource diversity within the Calibration portfolio, Exhibit 9 provides the installed capacity in 2030, 2040, and 2050. As Exhibit 9 shows, the Calibration Portfolio manages to maintain a highly diverse portfolio with each technology representing a balanced portion of the total capacity mix. The total added capacity for each technology within the forecast time frame is: 996 MW solar, 480 MW Storage, 1,010 MW natural gas-fired capacity. The retirements for this portfolio per technology are: 108 MW solar (PPAs and contracts' expiration), 360 MW natural gas-fired plants (Stanton A PPA expiration), 144 MW coal plants (OUC's CD McIntosh portion).

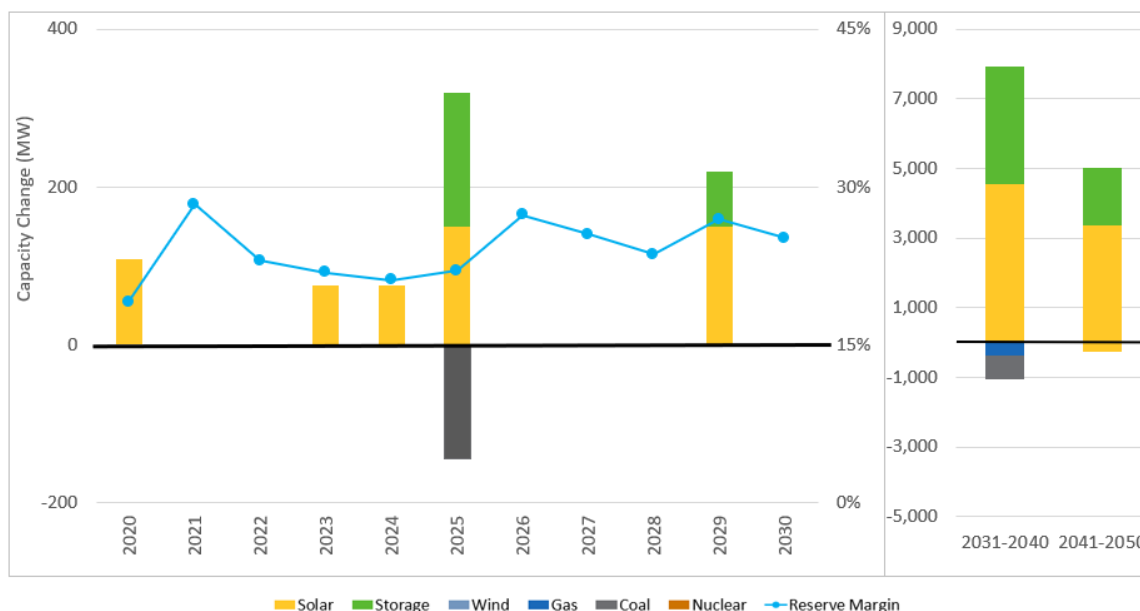
Exhibit 9: Calibration Portfolio Installed Capacity

Source: Siemens PTI

2.3.3 Net Zero CO₂ by 2050

The Net Zero CO₂ by 2050 Portfolio retires the Stanton 1 and 2 coal units in 2036 and 2040. Solar and storage additions are utilized to replace the capacity lost from retiring the Stanton coal units. As Exhibit 10 shows, when a dispatchable fossil-fuel fired unit is retired, the amount of solar and storage capacity needed to counter the loss in capacity far exceeds the capacity lost from the retirement of the fossil units. Solar energy is an intermittent resource for electricity generation, so it is not a one-to-one replacement for fossil plants. Storage can be utilized to capture solar energy and dispatch it later in the day when solar energy is not available. However, to have excess energy to charge the battery storage, extra solar capacity is built with the sole purpose to charge the battery storage. Additionally, for this analysis, the battery storage units are able to store 4 hours of energy, requiring extra storage capacity to ensure that all demand during non-solar hours is served. This trend drives up the reserve margin of the portfolio, making the reserve margin a less important metric to ensure energy sufficiency in high renewable/storage portfolios. This trend can be observed in all Candidate Portfolios discussed in this EIRP report.

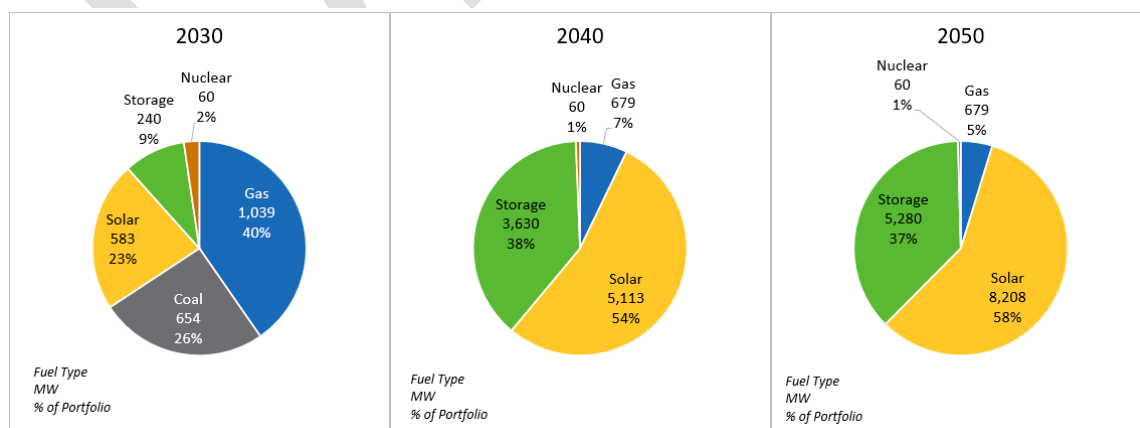
Exhibit 10: Net Zero CO₂ by 2050 Portfolio Build-Out (2020-2050)



Source: Siemens PTI

Because the Net Zero CO₂ by 2050 Portfolio retires the Stanton coal units to meet the Net Zero CO₂ target, the portfolio ends up with a much less diverse portfolio build-out. Exhibit 11 shows the installed capacity by technology within this portfolio. In 2030, when the coal units are still online, the portfolio mix remains diverse with each resource representing a fair balance of the resource mix. The total added capacity per technology for this portfolio is: 8,452 MW solar, 5,280 MW storage. The retirements per technology for this portfolio are: 108 MW solar (PPAs and contracts), 360 MW natural gas-fired plants (Stanton A PPA), and 801 MW coal (OUC's portion of CD McIntosh and Stanton 1 and 2).

Exhibit 11: Net Zero CO₂ by 2050 Portfolio Installed Capacity

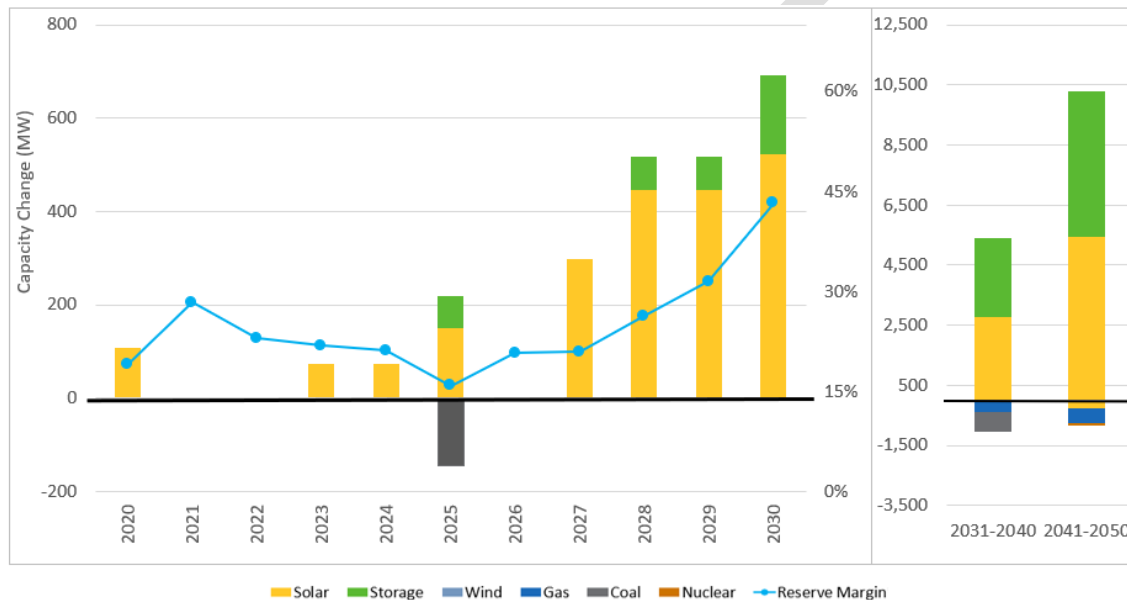


Source: Siemens PTI

2.3.4 100% Renewable by 2050

The 100% Renewable by 2050 Portfolio retires all the fossil, nuclear, and landfill gas units by 2050. However, compared to the Net Zero CO₂ by 2050 Portfolio, this portfolio maintains both coal units until 2040. OUC's portion of the St. Lucie powerplant is retired (or sold) by 2043. The Stanton A and B combined cycle units are retired by 2044 and 2048. Finally, the Indian River gas peaker units are retired by 2049. Thus, by 2050 this portfolio operates solely on solar and storage capacity. As a result, by the end of the forecast the reserve margin increases by almost 300%.

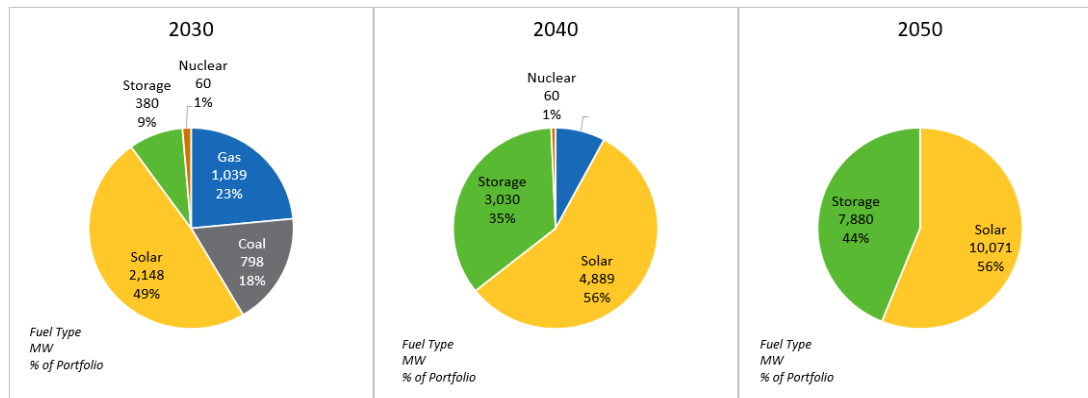
Exhibit 12: 100% Renewable by 2050 Portfolio Build-Out (2020-2050)



Source: Siemens PTI

Since the 100% Renewable by 2050 Portfolio is only able to utilize solar and storage capacity to back-fill the retirement of coal, gas, nuclear, and landfill gas, the portfolio ends up with a build-out much less diverse than all other Candidate Portfolios by 2050 (Exhibit 13). Similar to the Net Zero CO₂ by 2050 Portfolio, this portfolio maintains a diverse portfolio in 2030. However, after the retirements of the Stanton coal units we can observe the impact on the diversity of the portfolio in 2040. By 2050, the only resource within the portfolio technology mix are solar and storage. The capacity additions per technology for this portfolio are: 10,315 MW solar and 7,880 MW storage. The capacity retirements per technology for this portfolio are: 108 MW solar (PPAs and contracts), 875 MW gas-fired (Stanton A PPA, OUC's portion of Stanton A and B, Indian River peaker units), and 801 MW coal (OUC's portion of CD McIntosh and Stanton 1 and 2 coal units).

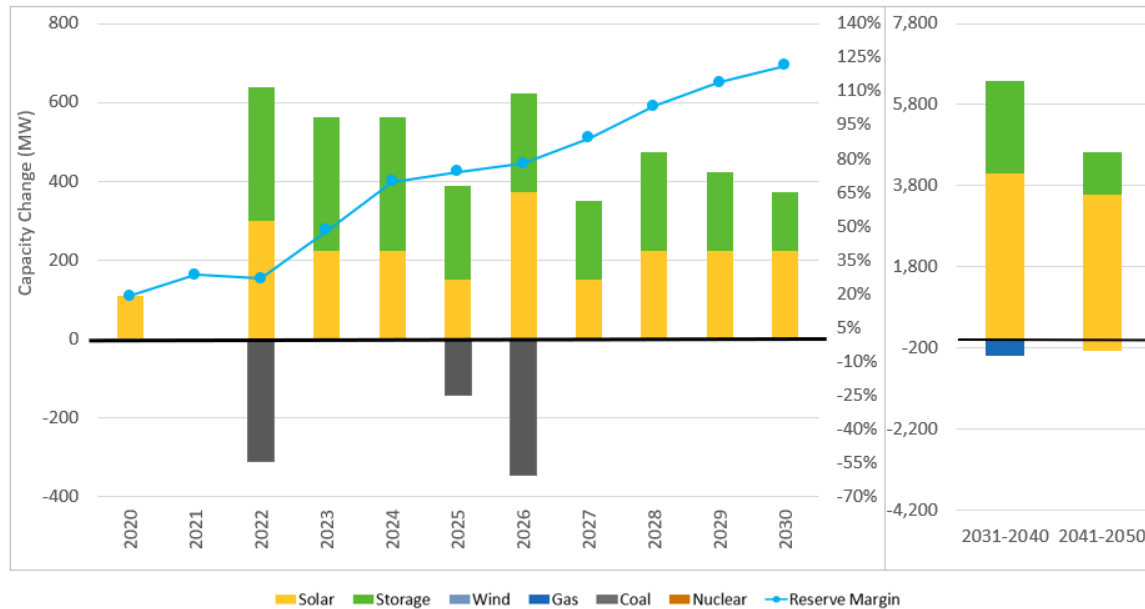
Exhibit 13: 100% Renewable by 2050 Portfolio Installed Capacity



Source: Siemens PTI

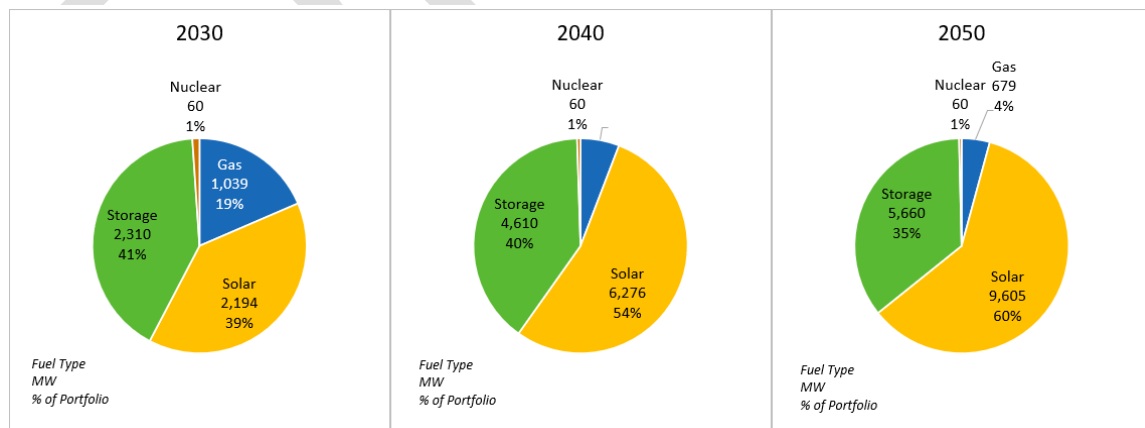
2.3.5 Coal Retirement 2022/2026

The Coal Retirement 2022/2026 Portfolio is based on the 2019 report conducted by Synapse. In Synapse's report, the Stanton 1 coal unit is retired in 2020 and the Stanton 2 unit is retired soon thereafter. For this EIRP report, Stanton 1 and Stanton 2 are retired by 2022 and 2026. The only technologies used to replace the coal units are solar and storage capacity. Because this portfolio retires the coal units without converting them to natural gas, we observe a heavy storage and solar build-out early in the forecast. Since this portfolio only retires Stanton 1 and 2, the expected retirement of CD McIntosh Jr. 3 coal unit by 2024 and the expiration of the Stanton A PPA in 2032, the required solar and storage build-out is lower than the 100% Renewable by 2050 Portfolio. Exhibit 14 shows the build-out of the Coal Retirement 2022/2026 Portfolio with a detailed build-out for the 2020-2030 timeframe, as well as a high-level overview of the capacity changes from 2030-2050.

Exhibit 14: Coal Retirement 2022/2026 Portfolio Build-Out (2020-2050)

Source: Siemens PTI

The Coal Retirement 2022/2026 Portfolio retires the coal units early and replaces them with storage and solar capacity, thus impacting the resource diversity of the portfolio early in the forecast (Exhibit 15). By 2030, most of the capacity remaining in the portfolio consisting of solar and storage (80%). The capacity additions for this portfolio per technology are: 9,868 MW solar and 5,660 MW storage. The retired capacity per technology for this portfolio is: 108 MW solar (PPAs and contracts), 360 MW gas-fired (Stanton A PPA), and 801 MW coal (OUC's portion of CD McIntosh and Stanton 1 and 2).

Exhibit 15: Coal Retirement 2022/2026 Portfolio Installed Capacity

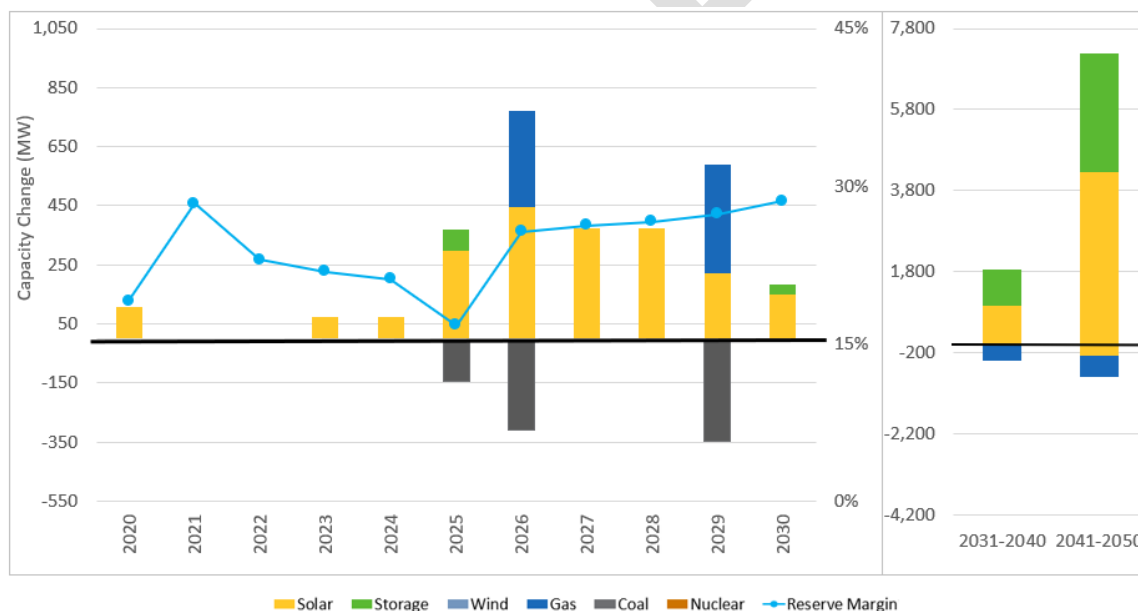
Source: Siemens PTI

2.3.6 Gas Conversion 2026/2029

Like the Net Zero CO₂ by 2050 Portfolio, the Gas Conversion 2026/2029 Portfolio is designed to achieve the Net Zero CO₂ target by 2050. Using this logic, the Gas Conversion 2026/2029 Portfolio maintains some dispatchable fossil-fuel fired capacity, significantly reducing the required solar and storage builds to meet OUC's load.

In this portfolio the Stanton coal units are converted to natural gas-fired power plants. OUC will be required to retire the Stanton A and Stanton B natural-gas-fired combined cycle by 2050 to meet its Net Zero CO₂ goal by 2050. This means that by the end of the forecast, the only fossil fuel units that remain in operation are the Indian River gas peaker units and the converted Stanton 1 and Stanton 2 units. OUC's portion of St. Lucie (60MW nuclear) and the landfill gas PPA's remain operational as well. Exhibit 16 shows a detailed portfolio build-out graphic for the 2020-2030 timeframe and a high-level overview of the capacity changes thereafter for the Gas Conversion 2026/2029 Portfolio.

Exhibit 16: Gas Conversion 2026/2029 Portfolio Build-Out (2020-2050)



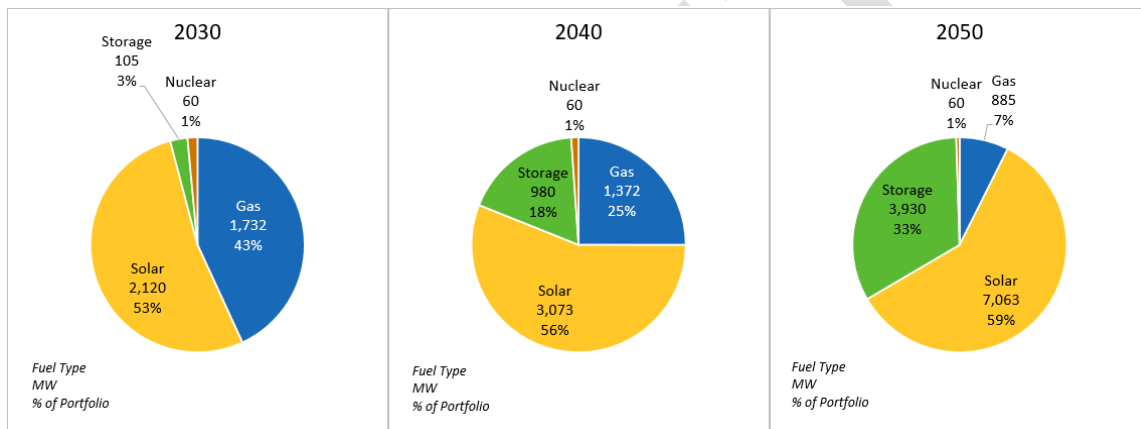
Source: Siemens PTI

Similar to the Net Zero CO₂ by 2050 Portfolio, the Gas Conversion 2026/2029 Portfolio is allowed to maintain some fossil-fuel fired capacity, as long as the emissions from these resources remain below the levels allowed through the CO₂ offsets. Regardless of the flexibility, this portfolio has a relatively low diversity throughout the forecast (Exhibit 17). In 2030, the resource diversity is low, with 96% of the capacity installed as solar and gas-fired resources. This portfolio can maintain a relatively low storage capacity in 2030 because the converted units can act as fast-ramping resources and serve load in hours when solar is unavailable. In 2040, more storage capacity is added

due to a combination of the loss of the Stanton A PPA and an increase in load compared to 2030. This results in a more diverse resource mix compared to 2030, although solar remains the dominating resource. Ultimately, in 2050, the gas capacity is reduced even further to meet the 2050 Net Zero CO₂ target and is replaced with storage and solar capacity.

The overall capacity additions within this portfolio per technology are: 7,335 MW solar, 3,390 MW storage, and 693 MW natural gas-fired capacity. The retirements within this portfolio per technology are: 108 MW solar (PPAs and contracts), 880 MW gas-fired (Stanton A PPA and OUC's share of Stanton A and B), and 801 MW coal (OUC's portion of CD McIntosh and Stanton 1 and 2).

Exhibit 17: Gas Conversion 2026/2029 Portfolio Installed Capacity



Source: Siemens PTI

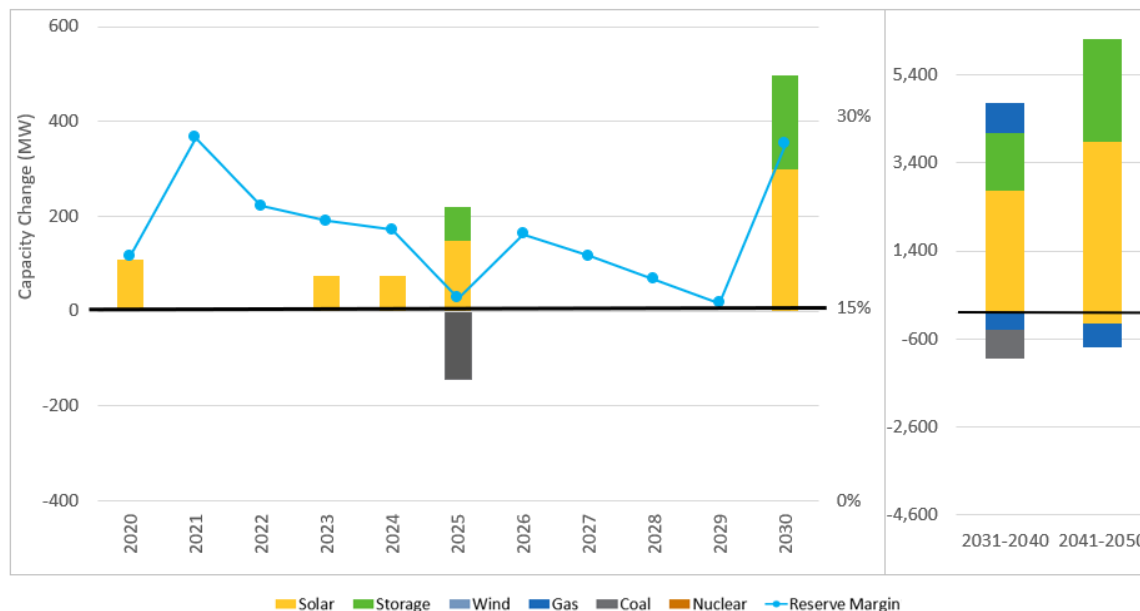
2.3.7 Gas Conversion 2036/2040

This portfolio is similar to the Gas Conversion 2026/2029 Portfolio in many ways. It converts the Stanton coal units to use natural gas as its main fuel but pushes the conversion of these units back to 2036 and 2040. Since this portfolio maintains the coal-fired capacity of Stanton 1 and 2 through the early 2030s, it runs a higher risk of violating the emission reduction targets, especially the 2030 target.

Because this portfolio follows the same logic as the Gas Conversion 2026/2029 Portfolio, Siemens PTI observes an identical capacity build out by the end of 2050. The main difference observed between the two gas conversion portfolios, is the timing of the solar and storage builds.

Exhibit 18 shows the detailed portfolio build-out of the Gas Conversion 2036/2040 Portfolio for the 2020-2030 timeframe, as well as a high-level view on the capacity changes for 2030-2050.

Exhibit 18: Gas Conversion 2036/2040 Portfolio Build-Out (2020-2050)

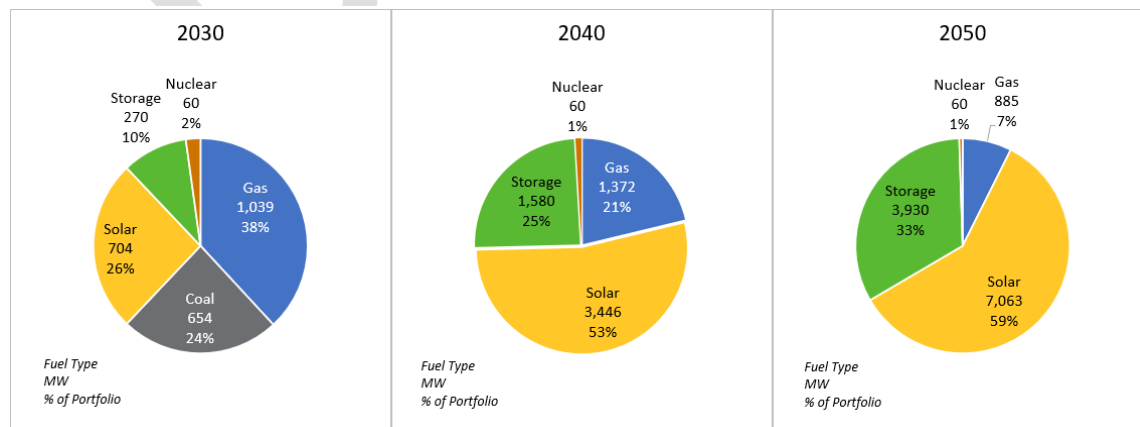


Source: Siemens PTI

Shown in Exhibit 19, this portfolio maintains a diverse portfolio in 2030 because the coal units are not converted. Most of the capacity in 2040 consists of solar and storage and a greater amount of these resources are installed compared to the Gas Conversion 2026/2029 Portfolio. To meet the 2050 100% Net Zero CO₂ target, this portfolio retires the Stanton A and B units by 2050. By 2050, the technology mix is identical to the Gas Conversion 2026/2029 Portfolio.

The installed capacity per resources is: 7,335 MW solar, 3,390 MW storage, and 693 MW gas-fired. The retirements within this portfolio are: 108 MW solar (PPAs and contracts), 880 MW gas-fired (Stanton A PPA and OUC's share of Stanton A and B), and 801 MW coal (OUC's portion of CD McIntosh and Stanton 1 and 2).

Exhibit 19: Gas Conversion 2036/2040 Portfolio Installed Capacity

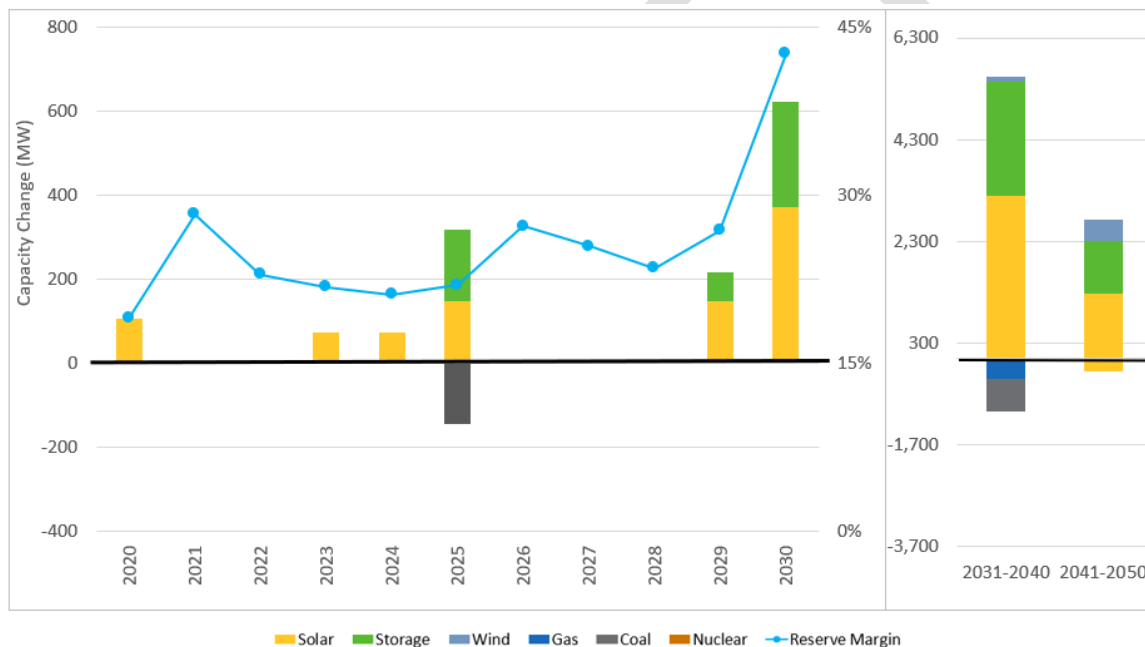


Source: Siemens PTI

2.3.8 Wind-by-Wire

The Wind-by-Wire Portfolio retires the Stanton 1 and Stanton 2 coal units by 2036 and 2040. However, this portfolio allows for replacing the fossil units with solar and storage, as well as the potential for wind-by-wire from the SERC region. The addition of wind capacity provides a resource with the ability to generate electricity when solar energy is unavailable. By adding the wind resource, less solar is required, and the reserve margin is reduced significantly compared to the Net Zero CO₂ by 2050 Portfolio. This portfolio shows the benefits of decreasing the reliance on solar and storage to back-fill the loss of fossil fuel capacity. Exhibit 20 shows a detailed portfolio build-out for the 2020-2030 time frame, as well as a high level overview of capacity changes in 2030-2050 for the Wind-by-Wire Portfolio.

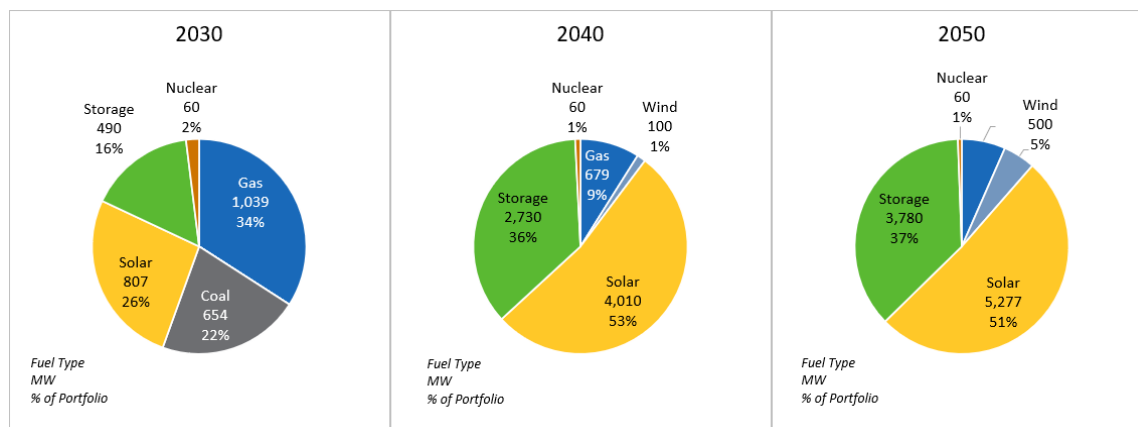
Exhibit 20: Wind-by-Wire Portfolio Build-Out (2020-2050)



Source: Siemens PTI

Since the coal units are retired in 2036 and 2040, this portfolio observes a balanced resource diversity in 2030, shown in Exhibit 21. By 2040, the coal units are retired and most of the capacity installed is solar and battery storage. Additionally, 100 MW of wind capacity is brought in from the SERC region to partially replace the capacity lost from the coal unit retirements. By 2050, 500 MW of wind capacity is brought in from the SERC region to improve the resource diversity of this portfolio. The installed capacity per resource over the forecast horizon is: 5,398 MW solar, 3,780 MW storage, and 500 MW wind. The retirements within this portfolio are: 108 MW solar (PPAs and contracts), 360 MW gas-fired (Stanton A PPA), and 801 MW coal (OUC's portion of CD McIntosh and Stanton 1 and 2).

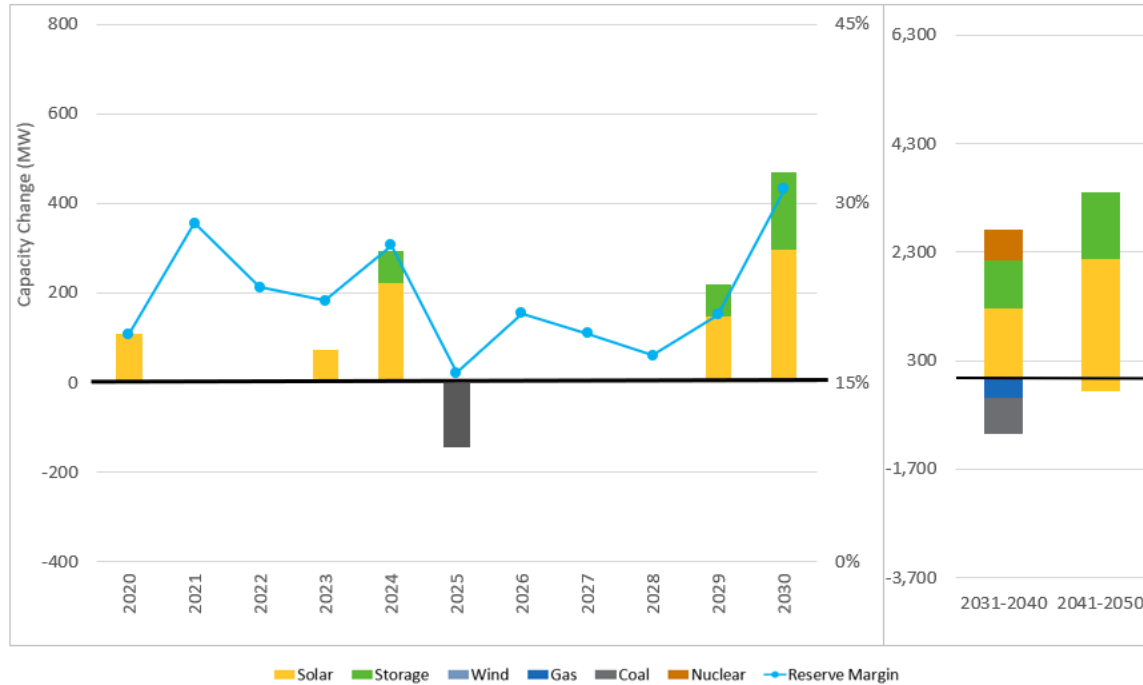
Exhibit 21: Wind-by-Wire Portfolio Installed Capacity



Source: Siemens PTI

2.3.9 Modular Nuclear

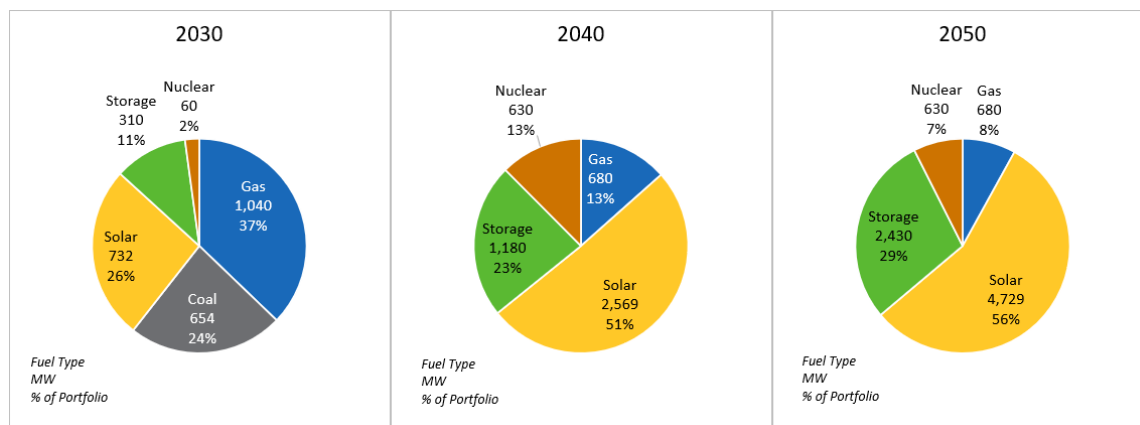
The Modular Nuclear Portfolio retires the Stanton 1 and Stanton 2 coal units by 2036 and 2040. However, this portfolio allows for replacing the fossil units with solar and storage, as well as adding a small modular nuclear reactor (SMR) (for more details about SMR, see Section 5.2.6). Specifically, a 570 MW SMR unit is installed in 2036, essentially replacing the capacity lost from the retirement of the Stanton 1 and 2 coal units. Adding this dispatchable non-CO₂ emitting resource significantly decreases the solar and storage capacity required to serve OUC's load while still meeting the Net Zero CO₂ targets. Furthermore, this results in the Modular Nuclear Portfolio requiring the least amount of solar and storage builds, out of all Candidate Portfolios. Exhibit 22 shows a detailed portfolio build-out for the whole forecast horizon.

Exhibit 22: Modular Nuclear Portfolio Build-Out (2020-2050)

Source: Siemens PTI

Shown in Exhibit 23, this portfolio has a very similar capacity build out compared to some of the other Candidate Portfolios and maintains a well-balanced resource diversity, using coal, gas, solar, storage, and nuclear in 2030. By 2040, the Stanton 1 and 2 coal units are retired and replaced by the SMR reactor. Although the coal units are retired, the resource diversity in this portfolio remains fairly balanced, with solar making up half the capacity installed while storage, nuclear, and gas-fired capacity evenly splitting up the other half of installed capacity. By 2050, a little more than half of the capacity installed is solar, but the technology resource diversity remains more balanced compared to some of the other Candidate Portfolios. The installed capacity per resource over the forecast horizon is: 5,398 MW solar, 3,780 MW storage, and 500 MW wind. The retirements within this portfolio are: 108 MW solar (PPAs and contracts), 360 MW gas-fired (Stanton A PPA), and 801 MW coal (OUC's portion of CD McIntosh and Stanton 1 and 2).

Exhibit 23: Modular Nuclear Portfolio Installed Capacity



Source: Siemens PTI

2.4 Attributes and Metrics

As previously mentioned, the key Attributes considered in this EIRP are Reliability, Affordability, Sustainability, and Resiliency. Since these Attributes are somewhat competitive in nature, it is important to establish different metrics to measure the performance across these Attributes to properly analyze the performance of each portfolio on these Attributes. The metrics established for analyzing these Attributes are further described below.

2.4.1 Reliability

The Advisory Council determined that Reliability is the most important Attribute and weighted highest across the four Attributes. Consequently, each Candidate Portfolio was designed to be self-sufficient and able to serve all of OUC's load throughout the forecast period without relying on purchases from neighboring utilities *under expected conditions*. To distinguish the degree of Reliability between each Candidate Portfolio, two metrics are used for the Reliability Attribute.

Cloud Cover Analysis

Siemens PTI developed an analysis to determine the first year the portfolio could have insufficient energy during a period of very high cloud cover. Specifically, the cloud cover analysis degraded the solar output by 70%. This analysis evaluates the total generating capacity in each hour of the test period to determine if a shortage of capacity exists in any hour with solar output reduced by 70%. The first year of the forecast period where there is insufficient energy in any hour to meet demand is identified.

Technology Diversity 2050

The second metric established for the Reliability Attribute is the technology diversity at the end of the forecast. This metric was chosen because, in general, a system is expected to be more reliable if it has a greater number of generating technologies.

2.4.2 Affordability

The Advisory Council deemed the Affordability Attribute to be the second most important Attribute. For the Affordability Attribute, there are two metrics considered: the mean present value of portfolio costs and the uncertainty of those costs. Two periods are considered for each of these metrics. The first ten years, and the entire forecast period.

Present Value of Costs

The present value is the value of future portfolio costs discounted to 2020 based on a 6.3% discount rate, which is a weighted average between OUC's debt and equity percentages. This considers the time value of money; the generally accepted financial theory that near-term cash flows have greater value than future cash flows.

Uncertainty of Costs

The second metric for the Affordability Attribute is the uncertainty around the present value of costs. Since the stochastic analysis (further discussed in Section 7) provides a broad range of market outcomes, cost uncertainty can be measured as the standard deviation of costs over that range. The standard deviation measures the amount of dispersion of costs over that range over the forecast period.

2.4.3 Sustainability

The Sustainability Attribute was voted as the third most important by the Advisory Council. Metrics associate with the Sustainability Attribute calculate the probability of meeting Net Zero CO₂ targets as well as the clean energy percentage in 2050.

Probability of Meeting Net Zero CO₂ Targets

Through the stochastic analysis, Siemens PTI measured the likelihood that each Candidate Portfolio would achieve the Net Zero CO₂ targets. The portfolios with the highest probability of meeting the target in 2030, 2040 and 2050 score the best across these metrics.

Clean Energy Generation in 2050

This metric is calculated as a percentage of clean generation compared to the overall generation within the portfolio in 2050. Clean energy is defined as either a renewable resource (solar or wind), nuclear energy, or generation coming from landfill gas.

2.4.4 Resiliency

Metrics for the Resiliency Attribute measure the amount of unserved energy during the highest two-week load period in August of 2025, 2035, and 2045, during stressed conditions. The low probability, high outcome events that were used to test each Candidate Portfolio's Resiliency are described below.

East Coast Hurricane Scenario

This scenario is developed to represent how OUC is affected when a major hurricane hits the East coast of Florida. In this scenario, the hurricane causes multiple fossil-fuel powered plants to shut down to prevent catastrophically damage as well as a decrease in solar output. The effect of the hurricane scenario on the OUC plants is shown in

Exhibit 24. The red in the table on the left means that all OUC plants in that technology category are taken offline according to the percentages described in the table on the right. The black color in the table to the left means that there is no technology available in the portfolio during that year. The green color means that the technology in this year is not affected by the hurricane scenario. Additionally, the following powerplants are taken offline in areas outside of OUC: Sanford, Cape Canaveral, St. Lucie.

Exhibit 24: East Coast Hurricane Methodology⁹

OUC Units Only		Calibration	Net Zero CO ₂ by 2050	100% Renewable by 2050	Coal Retirement 2022/2026	Gas Conversion 2026/2029	Gas Conversion 2036/2040	Wind-by-Wire	Modular Nuclear	OUC Optimized Portfolio	Technology	1 st Week	2 nd Week
Gas	2025										Gas	100% offline	50% offline
	2035										Conv.	50% offline	25% offline
	2045			●*							Nuclear	100% offline	50% offline
Conv.	2025										Coal	50% offline	25% offline
	2035										Wind	n/a	n/a
	2045										Solar	75% offline	50% offline
Nuclear	2025										Storage	n/a	n/a
	2035												
	2045												
Coal	2025												
	2035												
	2045												
Wind	2025												
	2035												
	2045												

Source: Siemens PTI

West Coast Hurricane

This scenario is similar to the East Coast Hurricane scenario since it observes a hurricane that hits the West Coast of the Florida peninsula. Since OUC is located closer to the East

⁹ The black dot in the table to the right indicates that in the 100% Renewable by 2050 retires a Stanton gas-fired unit by 2044 so it already has less gas capacity around in 2045 compared to the other portfolios.

side of Florida, this scenario has less of an impact on the OUC plants. Because of this, all the colors in the table on the left in

Exhibit 25 are green, meaning that the plants within that technology remain operating as they would under normal conditions. There is an assumption made about the effect the hurricane has on solar output and is reduced according to the table on the right. However, there are more plants affected in the rest of Florida. The Florida plants affected by this hurricane scenario are Hines Energy Complex, Bayside, Intercession, Anclote, P L Bartow, Larsen, Cane Island, Manatee, Tiger Bay, Big Bend.

Exhibit 25: West Coast Hurricane Methodology

OUC Units Only		Calibration	Net Zero CO ₂ by 2050	100% Renewable by 2050	Coal Retirement 2022/2026	Gas Conversion 2026/2029	Gas Conversion 2036/2040	Wind-by-Wire	Modular Nuclear	OUC Optimized Portfolio
Gas	2025									
	2035									
	2045									
Conv.	2025									
	2035									
	2045									
Nuclear	2025									
	2035									
	2045									
Coal	2025									
	2035									
	2045									
Wind	2025									
	2035									
	2045									

Source: Siemens PTI

Technology	1 st Week	2 nd Week
Gas	n/a	n/a
Conv.	n/a	n/a
Nuclear	n/a	n/a
Coal	n/a	n/a
Technology	1 st Week	2 nd Week
Gas	n/a	n/a
Conv.	n/a	n/a
Nuclear	n/a	n/a
Coal	n/a	n/a
Wind	n/a	n/a
Solar	75% offline	50% offline
Storage	n/a	n/a

Gas Pipeline Disruption

This disruption scenario calculates the impact on OUC if a major gas pipeline is shut down, preventing natural gas from being delivered to gas plants throughout the Florida peninsula. Since this disruption scenario only affects the gas-fired plants, the only technologies affected in the OUC territory, presented in red in the table on the right in

Exhibit 26 are the Stanton A and B combined-cycles, the Indian River A, B, C, D gas peakers, and the Stanton 1 and 2 gas conversions. The offline schedule during the two-week period is described in the table on the left. Furthermore, the gas-fired power plants affected in the Florida peninsula are: Shady Hills, Bayside, P L Bartow, Vandolah, Polk, Richard J Midulla, Osprey, Cane Island, Manatee, Hardee, Hines Energy Complex, Larsen, Intercession, Big Bend, Anclote, Higgins, Treasure Coast.

DRAFT

Exhibit 26: Gas Pipeline Disruption Methodology

OUC Units Only		Calibration	Net Zero CO ₂ by 2050	100% Renewable by 2050	Coal Retirement 2022/2026	Gas Conversion 2026/2029	Gas Conversion 2036/2040	Wind-by-Wire	Modular Nuclear	OUC Optimized Portfolio	Technology	1 st Week	2 nd Week
Gas	2025										Gas	100% offline	50% offline
	2035										Conv.	100% offline	50% offline
	2045			●*							Nuclear	n/a	n/a
Conv.	2025										Coal	n/a	n/a
	2035										Wind	n/a	n/a
	2045										Solar	n/a	n/a
Nuclear	2025										Storage	n/a	n/a
	2035												
	2045												
Coal	2025												
	2035												
	2045												
Wind	2025												
	2035												
	2045												

Source: Siemens PTI

3. Load Forecast

OUC develops a base load forecast annually for its service territory. Included in this OUC forecast are assumptions for current economic projections, energy efficiency (EE), technology advancement, and codes and standards changes resulting in an OUC base net energy for load forecast. The latest OUC load forecast was used as a starting point for this EIRP. Presented here is an EIRP net load forecast through 2050 which is the OUC gross load forecast refined for energy efficiency, distributed solar generation (DG), and electric vehicles (EV), collectively load modifiers. These refined load modifiers are further described below. Siemens PTI also developed a stochastic load forecast around the refined net load forecast.¹⁰

3.1 Load Forecasting Methodology

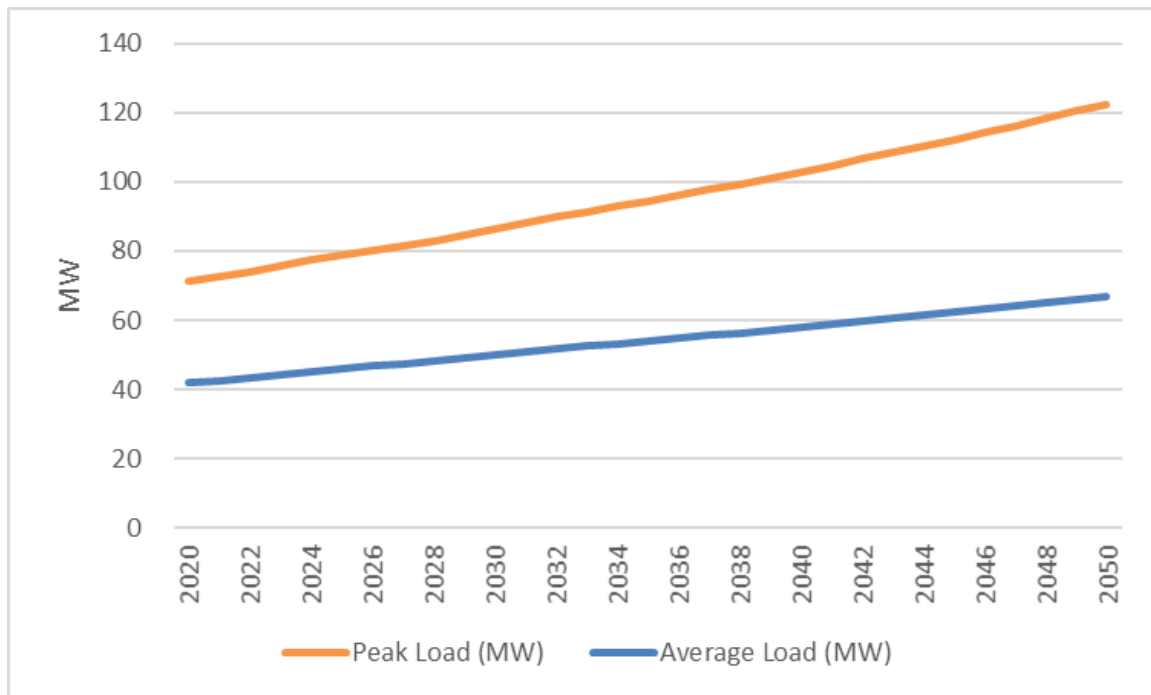
The net load forecast was received from OUC for the 2020 to 2035 study period. Beyond 2035, Siemens PTI extrapolated OUC load to 2050. Net load modifiers from the original load forecast were deducted, or added to, the net load forecast to calculate a base load forecast. Siemens PTI developed average and peak load forecasts for each of these load variables as explained below.

3.1.1 Energy Efficiency Impact

Energy efficiency refers to using technology that requires less energy to perform the same function. It includes the improvements in federal and state codes and standards that reduce energy consumption. In the EIRP analysis to measure Affordability and Sustainability for each portfolio, Siemens PTI reviewed all of OUC's energy efficiency plans and concluded that 0.5% incremental reduction per year is a reasonable expectation for energy efficiency load reduction. This 0.5% reduction per year exceeds the requirements of the Florida Public Service Commission (FPSC)¹¹. In this EIRP analysis, Siemens PTI has included achieving the 0.5% load reduction in the base load forecast throughout 2050. Additionally, by using a broad range of potential future demand over the forecast horizon (2020 – 2050), Siemens PTI allowed for a high degree of potential energy efficiency penetration.

¹⁰ Load forecast is based on information available as of Q1 2019.

¹¹ FPSC's goal is approximately 0.1% of sales through 2024.

Exhibit 27: Annual Average and Peak Load EE Reduction Estimates

Source: Siemens PTI

3.1.2 Distributed Generation (DG) Impact

Distributed generation, primarily rooftop solar, is treated in Siemens PTI's analysis as a decrement to energy consumption. Siemens PTI's expected value assumptions on rooftop solar penetration were based on an independent distributed solar adoption study from the National Renewable Energy Laboratory (NREL). Peak impact is assumed to be half of the adoption nameplate capacity.

3.1.3 Electric Vehicle (EV) Impact

Siemens PTI forecasted the net energy for load and peak load impacts of increased electric vehicle adoption within OUC's service territory through the forecast period. To estimate the potential for EV adoption in OUC's territory, Siemens PTI applied a proprietary electric vehicle forecasting approach, which employs Siemens PTI's market view, a leading Light Duty Vehicle (LDV) adoption tool, and Siemens PTI's proprietary analytical models to project commercial vehicle adoption and load calculations.

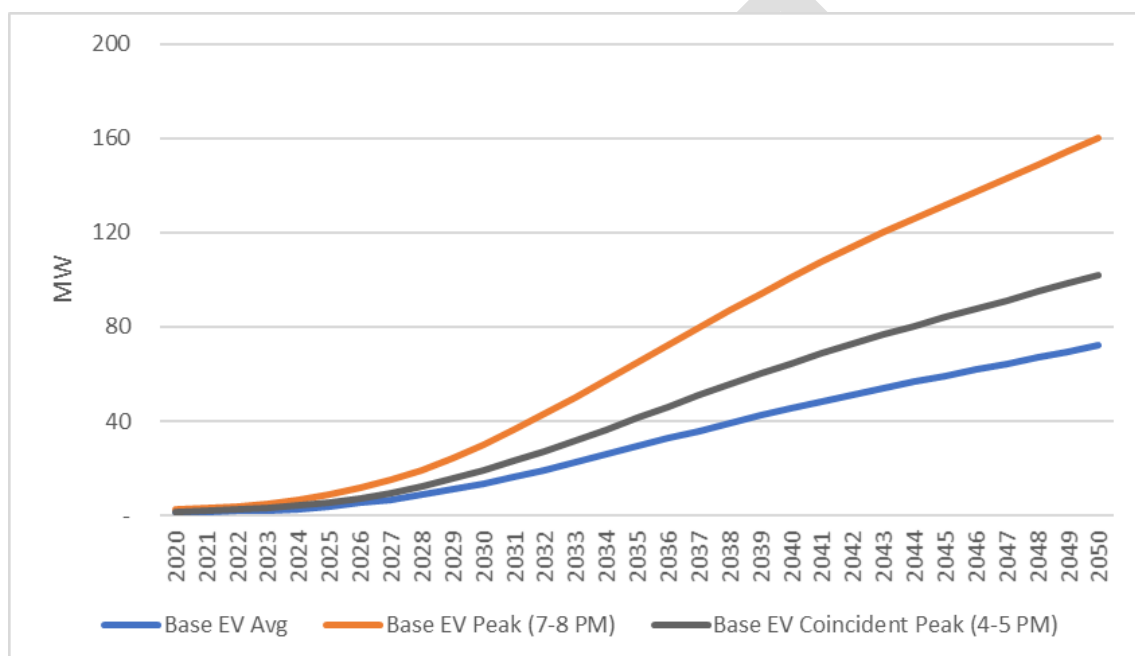
The Siemens PTI's expected LDV adoption forecast leverages proprietary inputs and adjustments to the latest version of the best-in-class customer choice model (MA³T Model¹²) developed by Oak Ridge National Labs (ORNL). This model generates forecasts for both battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs) by state. Siemens PTI segmented the Florida forecast derived from this model into OUC's LDV portion using OUC's residential customer count. The commercial vehicle base

¹² <https://www.ornl.gov/content/ma3t-model>

forecast was derived from the Department of Energy's 2019 Annual Energy Outlook EV adoption forecast, which we applied to the commercial vehicles operating in OUC's service territory.

As illustrated in Exhibit 28, average load and peak load impacts from electric vehicle charging are very small in 2020, but rise gradually over the period of the analysis. Electric vehicle charging activity usually peaks at 7-8 PM, which does not currently coincide with the summer peak hour of the OUC system at 4-5 PM. Therefore, the charging impact on the system's coincident peak is lower than the maximum charging impact. The charging impact on average load is lower than the peak.

Exhibit 28: Electric Vehicle Average and Peak Load Impact



Source: Siemens PTI

3.1.4 Demand Response

Demand Response includes programs that provide incentives for specific customer classes to reduce energy consumption during high demand period. Siemens PTI reviewed several studies, including the market potential study from Nexant from April 2019, sponsored by the seven electric utilities (FEECA Utilities¹³) subject to Florida Energy Efficiency and Conservation Act, which assessed Demand Response (DR) potential based on an analysis of mass market direct load control programs.

These studies include residential, small commercial and industrial (C&I), as well as analysis of DR programs for large C&I customers. The large C&I programs assessment

¹³ FEECA Utilities include Florida Power & Light Company (FPL), Duke Energy Florida, Inc. (DEF), Tampa Electric Company (TECO), Gulf Power Company (Gulf), Florida Public Utilities Company (FPUC), Orlando Utilities Commission (OUC) and JEA.

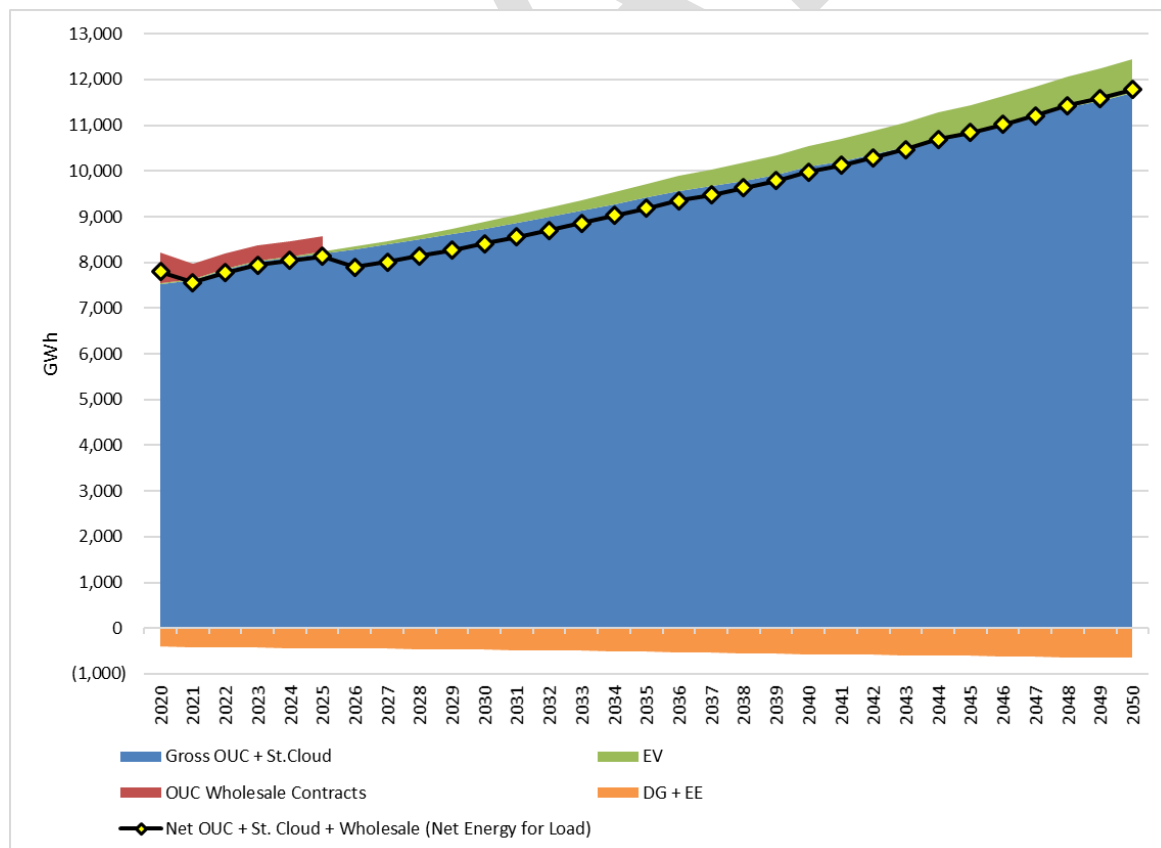
used publicly available data on mature DR programs to derive estimate of price responsiveness to program incentives and market techniques. The analysis is focused on potential for demand reduction through air conditioning, central heating, ventilation, water heating, and pool pump load control. These were chosen in part because of their large contribution to peak period system load.

Siemens PTI concluded that demand response penetration and cost would not result in a meaningful reduction in demand based on the current state of demand response programs and customer usage profiles. However, as is the case with energy efficiency and other load modifiers, Siemens PTI incorporated a broad range of energy demand levels to test the portfolios. This approach allowed for the potential for a much greater penetration of demand response and other load modifiers.

3.2 Long-Term Net Energy and Demand Forecast

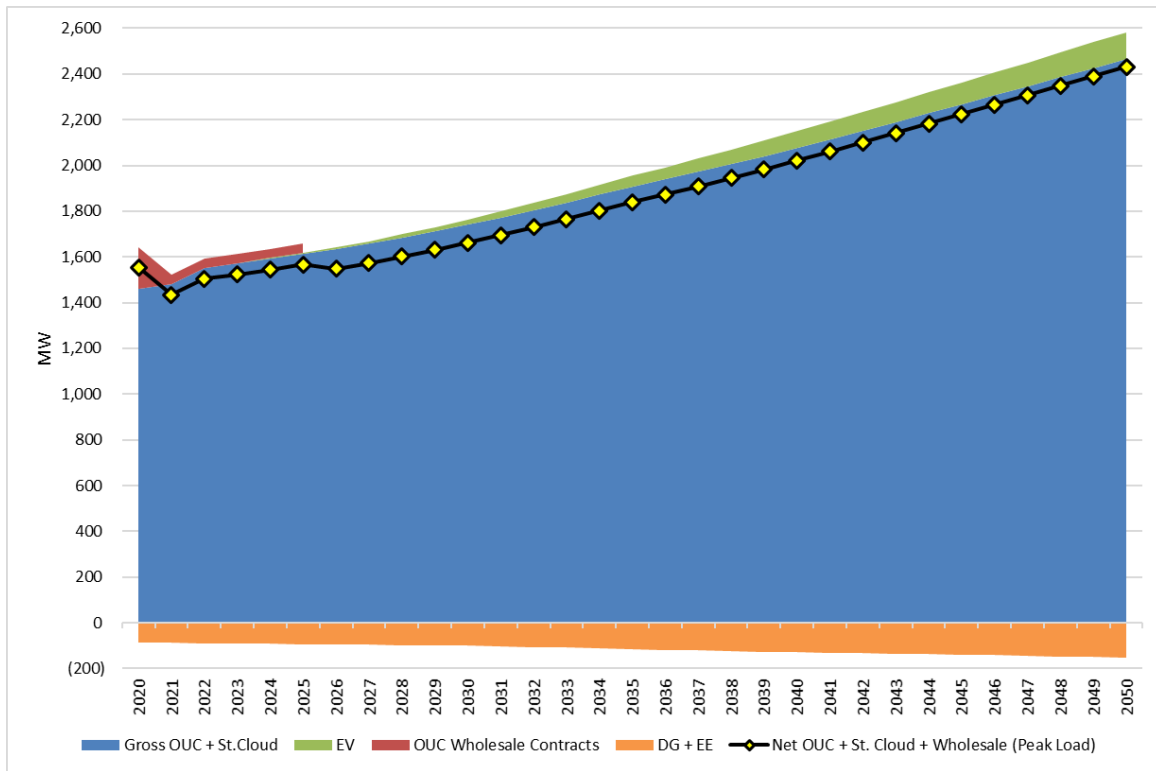
The long-term net energy base forecast estimates are presented below in Exhibit 29 and peak load in Exhibit 30. This net energy forecast is the gross system energy forecast after accounting for separate forecasts of all load modifier impacts. The forecast includes an overall increase in energy consumption over the 2020-2050 period. The net annual average growth rate is about 1.6% for net energy for load and peak load.

Exhibit 29: Forecasted Net Energy Estimates (GWh)



Source: Siemens PTI

Exhibit 30: Forecasted Net Peak Load (MW)



Source: Siemens PTI

4. Environmental Considerations

This EIRP analysis serves as a means for OUC to determine how to meet all of OUC's load over the 31-year forecast horizon. However, an additional motive for this EIRP analysis was to align with the City of Orlando's target of 100% renewable energy by 2050. To do this, OUC established the goal of Net Zero Carbon by 2050. To provide a consistent path toward achieving this goal, OUC also established some interim Net Zero CO₂ goals. In 2030, OUC aims to reduce CO₂ emission by 50% compared to 2005 levels and by 2040 the reduction is aimed to be 75% reduced compared to 2005 levels. This section will outline some of the underlying environmental considerations implemented in this EIRP analysis.

4.1 CO₂ Pricing

No comprehensive national regulation of CO₂ emissions currently exists in the U.S. in spite of efforts to enact policies covering CO₂ emissions from major sources. This included efforts by the U.S. Congress to pass a national cap and trade regime, the EPA's regulation of greenhouse gas emissions from new and existing power generators, and more recently, proposals in Congress for CO₂ taxes and comprehensive clean energy targets.

Action to limit CO₂ emissions has increased recently with states taking the lead in defining low- and no-CO₂ generation requirements. Currently, Florida does not have a state policy covering CO₂ emissions from power generation. To account for the uncertainty of potential federal CO₂ legislation, an expected price on CO₂ emissions from fossil generators is assumed (Exhibit 31). This outlook includes a national CO₂ price to become effective in 2025 and rising each year thereafter, covering emissions from electric generating units in the U.S.

Exhibit 31: Expected Value CO₂ Price Projections (2019\$/ton CO₂)

Year	2020	2025	2030	2035	2040	2045	2050
CO ₂ Price	\$0	\$6	\$11	\$16	\$30	\$41	\$45

Source: Siemens PTI

Candidate Portfolios were designed to meet 2050 CO₂ limitations and then tested for compliance as part of the Sustainability Attribute. Specifically, each portfolio was structured to meet the Net Zero CO₂ targets under expected conditions with OUC modeled as an isolated system. The costs of CO₂ did not serve as an economic driver during the development of the portfolios. There was no price for CO₂ assumed during the development of Candidate Portfolios, but CO₂ costs were used to measure the performance of the Candidate Portfolios.

As presented in later sections of this report, a range of possible future CO₂ costs were included in the study and are contained in the Affordability Attribute metric for each portfolio. The

range of CO₂ prices used in the analysis allows for the high degree of uncertainty in potential federal climate change regulations and legislation.

4.2 Electric Vehicles used for CO₂ Offsets

To assist with meeting Net Zero CO₂ targets, electricity producers are assumed to have available CO₂ offsets. The Environmental Protection Agency defines a CO₂ offset as “a specific activity or set of activities intended to reduce GHG emissions, increase the storage of CO₂, or enhance GHG removals from the atmosphere”¹⁴. These offsets can be used for both direct and indirect emissions from an electricity producer’s operations.

There are many ways in which electricity producers can use CO₂ offsets but for the purpose of this analysis the only offset considered is increased electric vehicle adaptation. The idea is that by increasing the number of electric vehicles on the road and replacing internal combustion vehicles, the CO₂ emissions avoided from the use of electric vehicles can offset the CO₂ emissions originating from electricity production. This allows for CO₂ emissions above the original emission target to allow for more flexibility on fossil-fuel generation. This flexibility provides the potential to reduce the costs by reducing the required resource capacity build-out to meet OUC’s, while maintain the ability to meet the emission reduction targets.

¹⁴ For a detailed explanation of offsets, please refer to https://www.epa.gov/sites/production/files/2018-03/documents/gpp_guide_rec_offset.pdf

5. Resource Options

This section documents the methodology Siemens PTI applied to develop the cost and performance assumptions for all new-build generation and energy storage technologies for OUC, as well as assumptions on existing unit optimization (i.e., coal-to-natural gas conversions). These assumptions are used to develop the portfolios, for measuring performance regarding the four key Attributes, and are summarized by resource type (new generation, conversion, storage).

5.1 New Generation and Energy Storage Resources

Siemens PTI maintains a technology cost and performance database that includes all applicable studies, projects, and announcements from over fifty public and confidential client sources. All sources in the database are maintained to be within three years of the current year to sustain up-to-date assumptions. Key public sources include annual reports such as the NREL Annual Technology Baseline (ATB), the EIA Annual Energy Outlook (AEO), the Lazard Levelized Cost of Energy, and the Lazard Levelized Cost of Storage. In addition, key subscription sources such as ThermoFlow, S&P Global, Energy Velocity, and Greentech Media are included.

Siemens PTI screens each source for equipment type, model, project scope, and location to develop qualified samples. These qualified samples are then modified using variables including location adjustments, inflation adjustments and owner's interest rate to develop comparable national samples. Siemens PTI then uses statistical analysis from the comparable national samples and expert opinion to determine likely cost ranges for each technology.

The technology database provides the foundation for our technology cost and performance forecasts. To develop longer term cost projections, Siemens PTI considers several factors, including the recent and expected rates of technological improvements for existing technologies and new technologies that are under development. By varying assumptions (i.e. productivity, learning curves, technology obsolescence, cost escalations etc.), Siemens PTI develops a distribution of values for each technology over time, which we apply to define high and low values for each of the technologies.

Other technologies that are not currently commercially available such as hydrogen, fuel cells and tidal energy are not included in the study. OUC will continue to monitor these technologies and consider them in future EIRPs.

5.2 Assumptions

For this analysis, generation options for the portfolios including advanced combined cycle gas turbine (CCGT), conventional CCGT with duct firing, simple cycle advanced frame combustion turbine (CT), simple cycle aero derivative CT, single-axis tracking solar PV (either self-build or PPA), wind-by-wire (with firm transmission rights from SERC), lithium-ion battery storage, onshore wind (for new-build resources in the SERC market), and nuclear small modular reactor

(SMR), are explained in more detail in the following section. The underlying detailed assumptions are included in Appendix A.

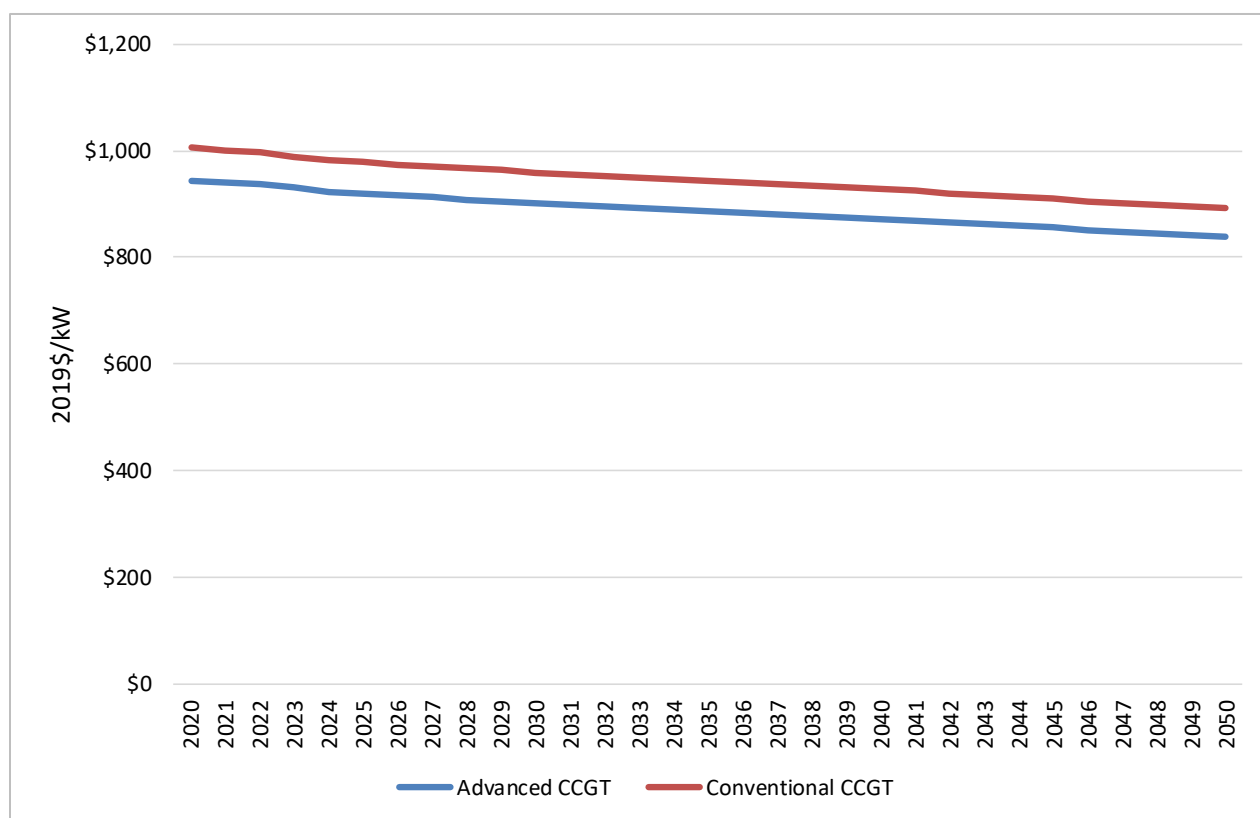
5.2.1 Combined Cycle Gas Turbine

Combined cycle gas turbines (CCGTs) provide a reliable source of capacity and energy for relatively low plant capital investment. Relatively fast ramp rates and the ability to cycle daily allow CCGTs to integrate with the variable nature of renewable generation.

Advanced CCGTs can achieve operating efficiencies above 62%, compared to conventional generation technologies (including simple cycle CTs) that range from 30 to 44%. Generally, CCGTs are good replacement options for less efficient, higher-emitting fossil fuel resources. Favorable capital costs, operational flexibility, lower CO₂ emissions, and high plant efficiencies have allowed CCGTs to expand their role in power generation, serving as either baseload or intermediate, load-following generators.

Advanced CCGTs in a 2x1 configuration (950 MWs) generally offer the lowest cost of generation and in large markets, are often selected for their competitive costs. While these units are large, they represent a small portion of generation in a large market, so the impacts on Reliability of a forced outage are manageable. However, the Reliability impacts of a forced outage for this unit operating in the FMPP pool would be very challenging. OUC's peak load is expected to reach more than 2,250 MW and such a unit would represent 42% of that peak demand. As a result, Siemens PTI considered smaller 1x1 CCGT configurations including one at 605 MW and another at 385 MW. Siemens PTI optimized the 1x1 CCGT by adding duct firing (i.e. adding burners in the heat recovery steam generator [HRSG] to produce more steam). If a CCGT was selected as part of a long-term capacity expansion plan, the duct firing portion would increase the unit capacity Reliability support at a lower capital cost and better heat rate than a simple cycle gas turbine.

Exhibit 32: Combined Cycle Capital Cost Forecast, 2019\$/kW



Source: Siemens PTI

5.2.2 Simple Cycle Combustion Turbine

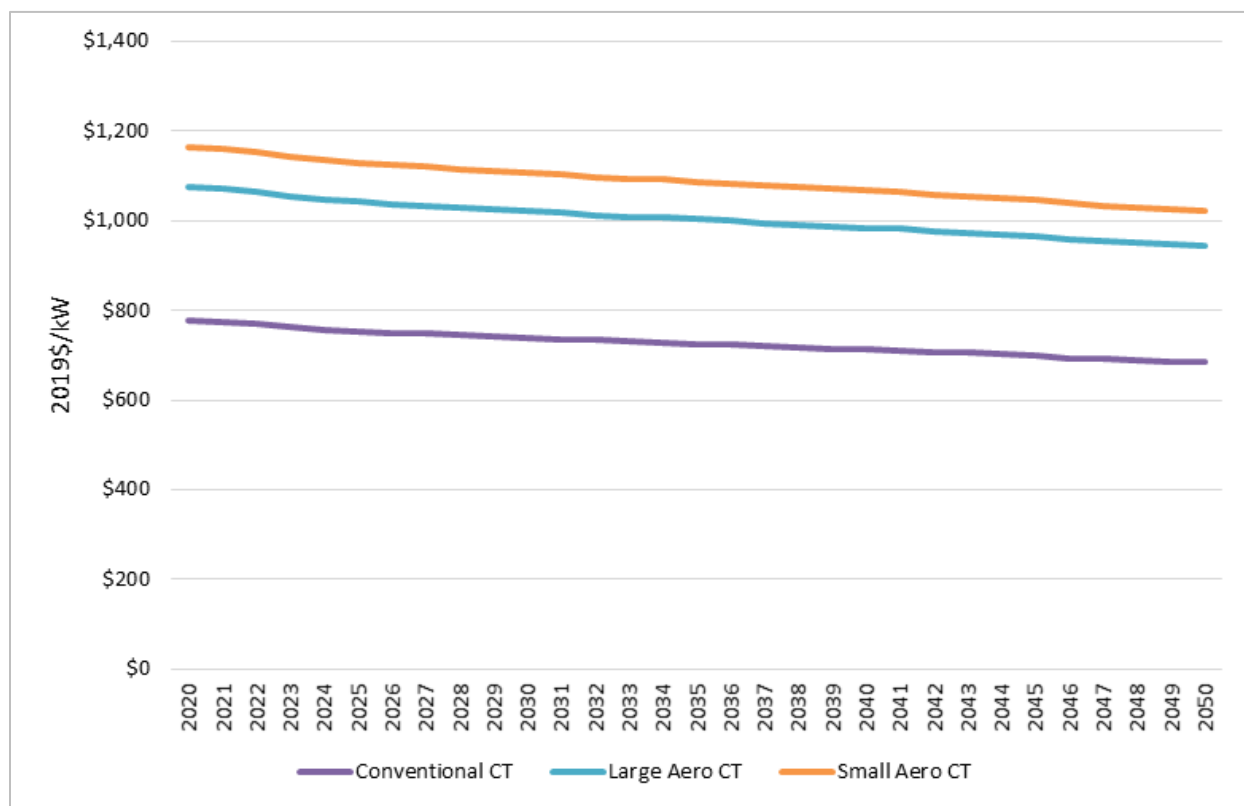
The high operating costs and low efficiency of simple cycle combustion turbines (CT) (around 40%) typically keep annual capacity factors below 10% and limit CTs primary use to load peaking purposes. However, CTs start quickly and ramp up and down quickly, and play a key role in grid stability, providing reserve capacity and ancillary services. The responsiveness of CTs make them viable candidates to manage intermittent resources such as renewables on a broad scale. Historically, frame CTs were used as peaking resources because of their low operating costs and economies of scale, and aero derivative CTs were also used for peaking service when smaller capacities were a better fit. Newer frame CT models offer higher capacities (300 to 400 MW) and increased efficiency (heat rates of 8,000 to 8,500 Btu/kWh) than earlier models. Aero derivative CTs are available in relatively small capacities with heat rates between 8,000 to 10,500 Btu/kWh, albeit with higher unit costs.

An influx of intermittent energy resources and lower load growth, as well as the need for more flexible resources has increased interest in aero derivative CT technologies to provide faster ramping capabilities. Newer models provide faster start up, higher ramp rates, and integration with other technologies, particularly battery energy storage.

Siemens PTI compared its simple cycle combustion turbine capital cost assumptions to both NREL ATB and EIA AEO similar technologies, as it does with most technologies, and determined

prices to be in broad alignment. It is important to note that NREL does not disclose the size or type (frame vs. aero) of their combustion turbine assumptions in the ATB, so a direct comparison can be difficult. For reference, Siemens PTI presents our forecast for conventional frame (7FA technology) and advanced frame below.

Exhibit 33: Simple Cycle CT Capital Cost Forecast, 2019\$/kW



Source: Siemens PTI

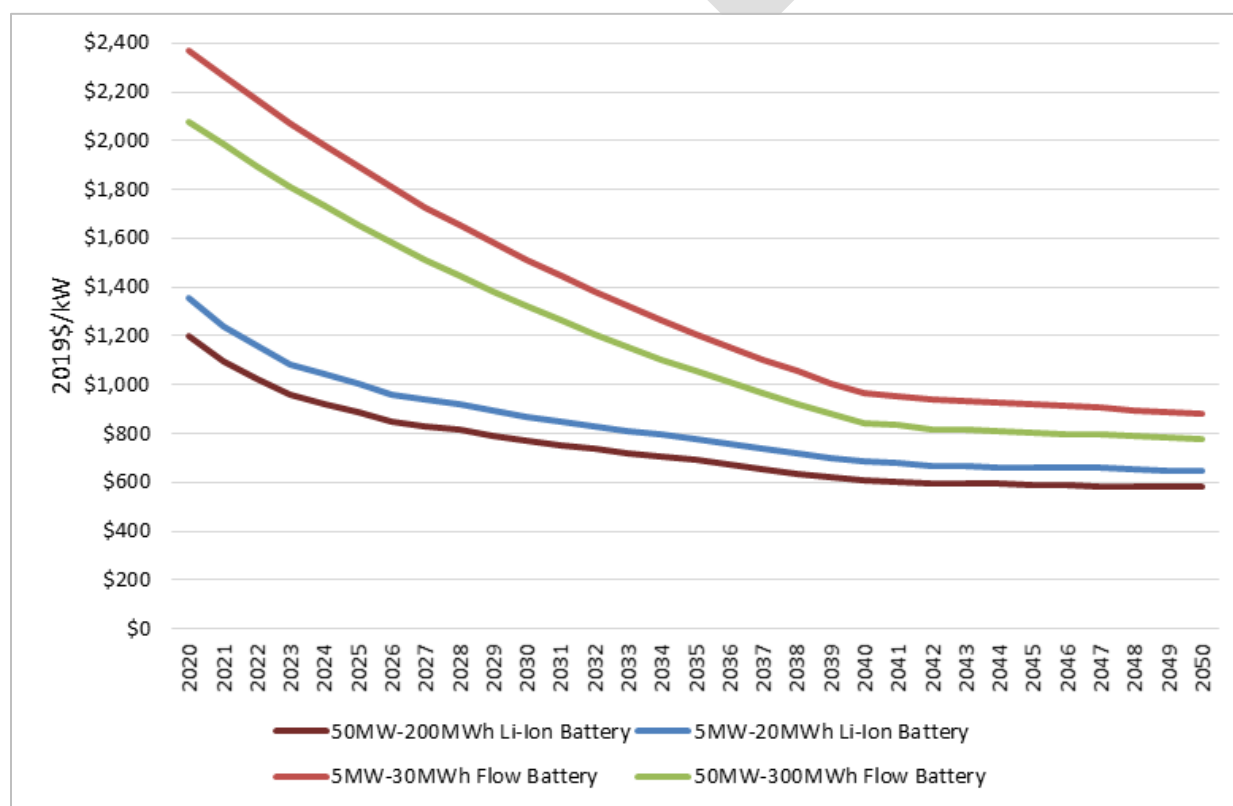
5.2.3 Battery Storage

In recent years, battery energy storage has become more important as a utility-scale option to integrate non-dispatchable resources onto the energy grid. Lithium-ion (Li-ion) batteries are the most common type of storage used at the utility scale and can target location-specific applications unsuitable to pumped hydro or compressed air energy storage. Other storage technologies beginning to be considered for broad use include various flow battery chemistries, thermal storage (either high or low temperature), hydrogen storage, and other fuels created from hydrogen including ammonia and synthetic methane. Li-ion battery costs are declining as suppliers increase production and as the technology matures, making them a popular choice for current energy storage needs. Manufacturing capacity is expected to grow to meet strong energy storage demand from mobile devices, medical devices, and electric vehicles. Currently, there are no significant supply constraints observed but there are concerns over the availability of lithium at current prices.

The battery storage sector has experienced strong growth in recent years. Between 2011 and 2018 there were 810 MW of power capacity from large-scale battery storage added leaving a total of 869 MW battery storage power capacity operational by the end of 2018¹⁵. Most of existing U.S. power capacity has been installed by independent power producers (IPP) in the PJM Interconnection (PJM). Regulated utilities in the California Independent System Operator (CAISO) territory have procured storage capacity as well. The United States observed a new record for annual power capacity additions in 2018 when it saw 222 MW of large-scale battery storage installed.

Li-ion batteries have accounted for 94% of all new energy storage capacity in the U.S. since 2012, growing at an average rate of 55% per year. Most of the installed Li-ion capacity provides frequency regulation, but recent projects in the U.S. have targeted alternative applications including peaking capacity, renewable integration (energy arbitrage), peak shaving, shifting, smoothing, firming, and other use cases. Exhibit 34 presents Siemens PTI's battery storage capital costs.

Exhibit 34: Battery Storage Capital Cost Forecast, 2019\$/kW



Source: Siemens PTI

An important consideration for battery storage is that there are efficiency losses from storing the energy and dispatching it later. Each time energy is stored in the battery, 85%-90% of it

¹⁵ U.S. EIA, Battery Storage in the United States: An Update on Market Trends, July 2020: https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf

will be able to be dispatched with the remaining percentage lost in the process. The efficiency losses increase over the time that the battery is in operation.

A key challenge of battery storage technology is capacity degradation. With every battery cycle (i.e. charging and discharging the battery fully), the ability of the battery to retain charge is diminished. After 10 years the capacity of a battery storage project may decline by 15 to 20%. For an owner wishing to maintain the capacity of a battery system over time, battery capacity must be augmented with replacement capacity under the following circumstances: (1) if the particular unit charges or discharges to a level less than its rated energy capacity (kWh) per cycle; (2) if the battery chemistry does not have the cycle-life needed to support the entire operating life of the use case; or (3) if the energy rating (kWh) of the battery chemistry degrades due to usage and can no longer support the intended application.

Siemens PTI expects that OUC would elect to maintain the capacity of any battery system installed and would need to account for the augmentation costs. Siemens PTI assumed augmentation of the battery packs every seven years, with battery packs comprising approximately 40% of the cost of the total battery system. In total, the battery augmentation cost is about 13% of the total battery system cost. Each battery storage system's capacity is replaced at the end of its operational life of 20 years (also its book life), keeping the system capacity the same but at the current year replacement cost.

5.2.4 Solar Photovoltaics (PV)

Solar PV generation has been expanding as a form of renewable generation in recent years, with total U.S. installed capacity reaching 81.4 GW through Q1 2020.¹⁶ Single-axis tracking solar PV systems offer higher capacity factors and require less land for nearly the same unit cost as fixed-tilt systems. As a result, tracking solar installations now account for more than 50% of utility-scale solar PV in the U.S. and are most common in the southwest.

Renewable energy incentives have played a critical role in supporting the development of solar PV, either in the form of Renewable Portfolio Standards (RPS), feed-in tariffs, or tax credits. The Investment Tax Credit (ITC) is set to decline to 10% of capital investment in 2022, remaining available post-2021. Developers can "safe harbor" solar equipment for up to four years to qualify for the ITC, past the deadline.¹⁷

Siemens PTI's single-axis tracking solar technology forecast accounts for the increasing application of bifacial solar cells. While monofacial cells dominate the market today, bifacial cells are expected to comprise most solar cells sold by 2030. While bifacial cells cost slightly more than monofacial cells, they can deliver small but meaningful generation gains over monofacial cells, so Siemens PTI's forecast accounts for a phasing in of bifacial technology. Exhibit 35 shows Siemens PTI's forecast for solar PV.

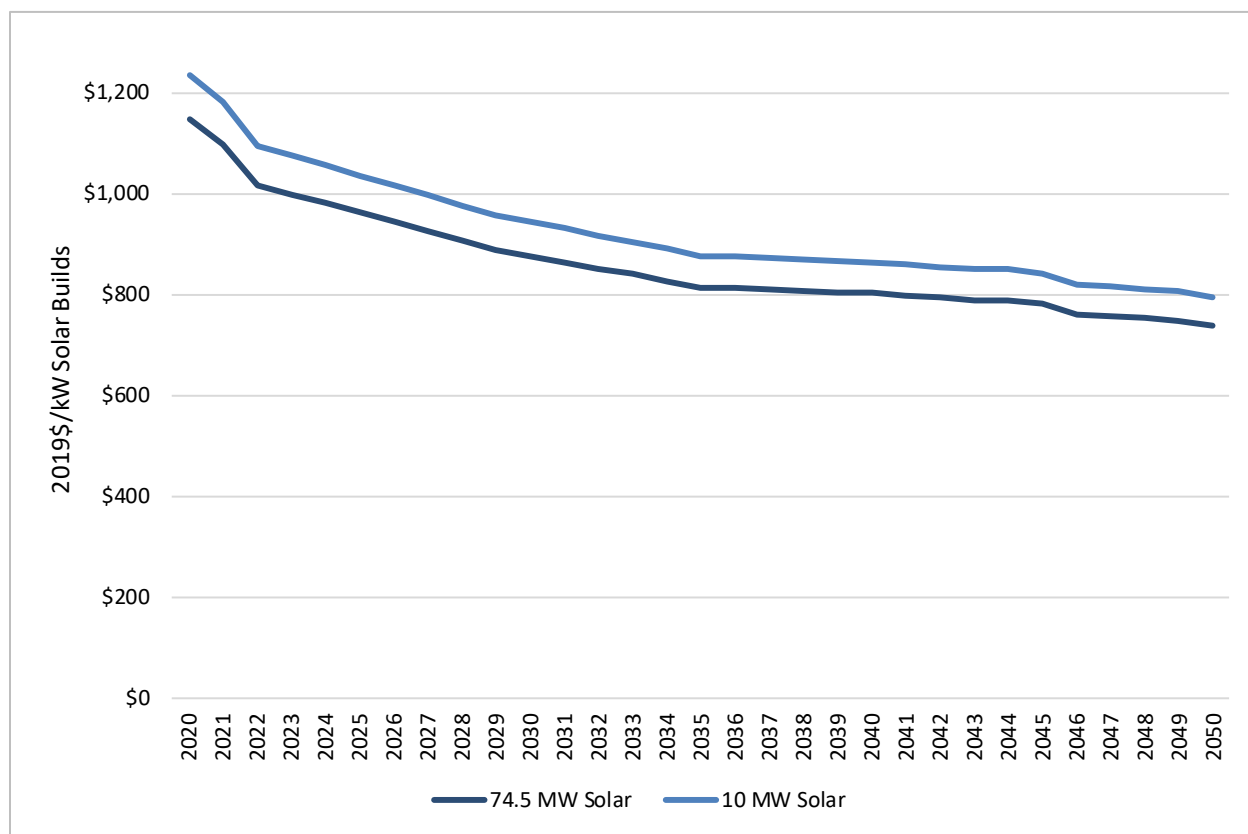
OUC considered both generic solar builds (which could be self-build, developer turn-key, or some other commercial arrangement) and solar PPA purchases. The solar PPA purchase price

¹⁶ SEIA U.S. Solar Market Insight: Q1 2020

¹⁷ Siemens assumes two years of safe harboring in our calculations.

is benchmarked to recent offerings seen in the marketplace and conversations with solar developers. There are several moving parts to solar prices, including trade tariffs, the sunset of ITC, land costs (see the following section), wheeling costs etc. These solar PPAs are limited based on geographical diversity of OUC's service territory.

Exhibit 35: Single-Axis Tracking Solar PV (2019\$/kW)



Source: Siemens PTI

Land Consideration

One of the constraints associated with utility-scale solar PV development that should not be ignored is land availability and geographical diversity. Siemens PTI worked with OUC to identify local land considerations for utility-scale PV build in this EIRP. Greater geographical diversity of solar energy will be required to minimize the risk of cloud cover and other extreme weather events. The prospective land for solar PV is typically limited to agriculture and/or large commercial and industrial parcels that are generally flat, not prone to flooding, and relatively affordable. Current solar PV technology requires approximately 5 acres of land for every MW of capacity, i.e. a typical-for-Florida 74.5 MW PV project would require 373 acres of land. Further, solar developers try to select sites that are co-located next to existing transmission rights-of-way to minimize interconnection costs. Solar PV development in Central Florida will be hampered by the limited availability of attractive land and the likely need to acquire multiple conjoined parcels for larger capacity plants. Siemens PTI estimates that the largest portfolio solar PV buildout of 10,000 MW of solar PV capacity by 2050 would require 50,000

acres of land or, for scale and context, approximately 69% of the land area of the City of Orlando. The cost of land was also reviewed in collaboration with OUC for solar PV development in the Central Florida region. Considering the limited availability of suitable land, the cost of land is expected to be higher than the national average.

5.2.5 Onshore Wind and Wind-by-Wire

Wind generation is one of the largest source of CO₂-free electric generation in the United States, accounting for 7.3% of power produced in 2019¹⁸ generated from 98,000 MW of installed wind capacity. Technology improvements coupled with lowered production costs have resulted in declining capital and operating costs, and improved performance resulting in increased unit energy output. In general, wind turbines are taller with larger wind-swept areas which allows them to produce more energy across a wider range of wind speeds, which drives up average capacity factors.¹⁹ Further, the federal Production Tax Credit (PTC) has lowered recent prices for wind power. However, the PTC is scheduled to phase out by 2020, which could affect near-term Affordability for new wind resources. Developers can “safe harbor” wind turbine equipment for up to four years to qualify for the PTC past the deadline.

Siemens PTI allowed for onshore wind developed for the SERC region, with costs beginning at \$1,542/kW (2019\$) in 2020 and ending at \$1,102/kW in 2050 (also in 2019\$), as well as the wind-by-wire option for OUC. In the wind-by-wire option, the wind energy is assumed to come from the Midcontinent Independent System Operator, with the corresponding wind generation profile of that region. The wind-by-wire energy transactions would incur multiple wheeling charges going through 3 or more systems in order to deliver the energy to Orlando. The wind energy is benchmarked to recent market prices.

5.2.6 Small Modular Reactor (Nuclear)

Small modular reactor (SMR) technology was initially developed for naval/shipping purposes and is being adapted for utility scale generation. It has not yet demonstrated commercial operation in the United States, though a test is being conducted in Idaho. SMR modules range in size from 10 to 300 MW (compared to roughly 900 to 1,200 MW for conventional nuclear reactors), and modules can be scaled to meet loads. Some SMRs, by virtue of their smaller size and other operational features, can offer greater capability to conduct load following operations than larger nuclear power plants. SMRs have appeal as potential future CO₂-free reliable non-intermittent resources to complement renewable resources.

Much of the key equipment components for SMRs can be manufactured off-site in controlled factory environments, reducing plant construction time by an expected 40% or more. They also provide potential improvements in safety from their underground containment designs and passive cooling systems. However, underground installations could make maintenance more challenging during a malfunction. NuScale Power LLC is aiming to put an SMR into commercial operation in Idaho, comprised of a dozen 50 MW reactors. It is the only company

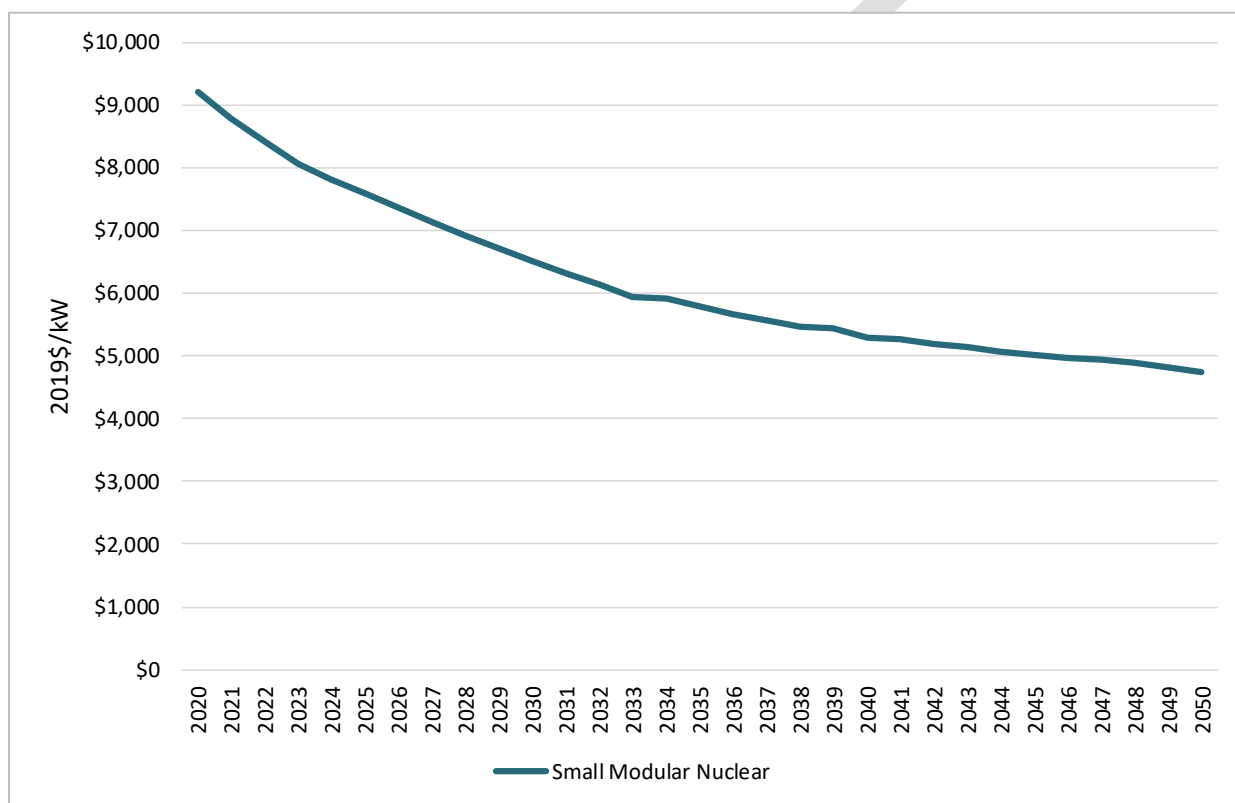
¹⁸ <https://www.eia.gov/tools/faqs/faq.php?id=427&t=3>

¹⁹ Siemens PTI assumes wind generation can be built in the SERC region, but is not an option for the FRCC market.

with an SMR design certification recently approved by the U.S. Nuclear Regulatory Commission (NRC). The NRC is also reviewing two SMR pre-applications from BWXT mPower, Inc. and SMR Inventec, LLC.

For this EIRP, an SMR was modeled at a capacity of 570 MW, which captures the economics of scale that would come with a larger SMR build but lower unit cost after incorporating the base costs that come with one module or 10 modules. The capital costs of SMRs are shown in Exhibit 36.

Exhibit 36: Small Modular Reactor (Nuclear) All-In Capital Cost, 2019\$/kW



Source: Siemens PTI

6. Fuel Forecast

For the development of new supply options, several natural gas thermal units, including combined cycle gas turbines (CCGTs), combustion turbines (CTs), and conversion units were offered for the long-term capacity expansion optimization process used as part of the development of Candidate Portfolios. Natural gas price projections were also used to evaluate the costs to operate conversion units and existing gas-fired power plants. For the EIRP, Siemens PTI used gas price projections from PIRA.

6.1 U.S. Natural Gas Market Outlook

The U.S. natural gas market outlook is expected to see low prices at the benchmark natural gas commodity price at the Henry Hub market point in the short-term to 2021, despite increasing liquefied natural gas (LNG) demand and with higher storage refill requirements coming out of the 2018-19 and 2019-20 winters. Low prices are primarily due to excess production particularly with the ongoing natural gas production increases out of the Permian Basin and the Marcellus Shale. The main drivers of Henry Hub pricing in the short-term are:

1. The drop in natural gas demand due to shelter-in-place responses to the COVID-19 pandemic, counterbalanced by the decline in associated gas production due to low oil prices stemming from an oversupply in global crude oil markets.
2. LNG export demand, which is expected to grow from 4.5 billion cubic feet per day (Bcf/d) in 2019 to 9-10 Bcf/d by 2021 from online or under construction projects, out of a total LNG export capacity of 10.6 Bcf/d. Furthermore, there were three Gulf Coast LNG projects reaching a go-forward Final Investment Decision in 2019, which are expected to add an additional 4 Bcf/d of LNG export capacity in the early- to mid-2020s, for a total of 14.6 Bcf/d by 2024.
3. U.S. production growth, most of which is coming from the Marcellus Shale and Permian Basin, albeit to a lesser extent in the latter with a decline in oil prices (and thus associated gas production).
4. Over 43 Bcf/d of U.S. pipeline projects under construction or expected to become operational through 2021 (15.5 Bcf/d is Marcellus takeaway capacity and 8.6 Bcf/d is Permian takeaway capacity).

The 14.6 Bcf/d of LNG export capacity expected by 2024 is mostly under “take-or-pay” contracts, meaning demand for LNG feedstock gas will be baseload with liquefaction capacity expected to run at an 85% capacity factor or greater. LNG export demand is expected to put modest upward pressure on prices, despite low Asian LNG prices in early 2020. However, we expect that the downward price pressure from supply/production growth and pipelines will largely moderate any such increase in prices.

Generally, a trend has emerged of increased gas usage in the power sector at the expense of coal burn. With natural gas prices still relatively cheap compared to historical levels and coal

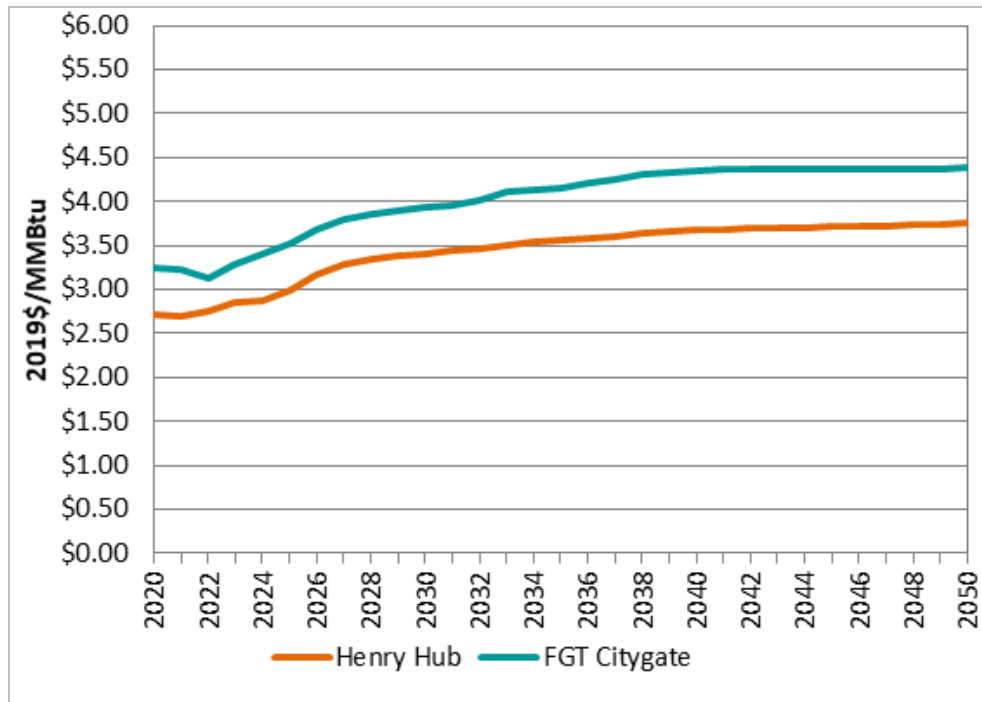
facing other economic and regulatory pressures, there has been some switching to gas-fired units from coal-fired units in the dispatch order in certain power regions, particularly during shoulder-season months. Utilities in regions where gas transportation costs are relatively low and coal transportation costs are high, for example the SERC region, have announced the shutdown of certain coal units in favor of increasing utilization at intermediate gas units. Annual electricity generation from coal declined 31% in the past decade (2009-2018) from 1,756 Terrawatt-hours (TWh) to 1,204 TWh, while generation from natural gas increased 43% from 921 TWh to 1,319 TWh, with natural gas surpassing coal beginning in 2016.

Major uncertainties on the demand side include the power sector response to new environmental regulations and rapidly declining renewables costs and battery storage costs that can displace gas-fired generation. While a CO₂ regime is not likely to advance in the current U.S. government administration, the finalized Affordable Clean Energy (ACE) rule has been promulgated and is expected to lead to heat rate improvements for coal plants >25 MW that will in turn lead to greater dispatch of coal units. Nevertheless, utilities and other generators are beginning to plan for the rising probability of a CO₂-constrained future.

On the supply side, shale gas accounted for over 70% of U.S. gas production in 2018, up from 17% in 2008. During this time, unconventional gas production (primarily shale gas) has changed the perception of gas markets and has been the primary driver of Henry Hub pricing, causing prices to drop from the 2008 records that topped \$13/MMBtu. The cost of production in 2019 ranges widely, from core Marcellus Shale play acreage able to generate breakeven returns at only \$0.80/MMBtu compared to higher-cost conventional or non-core shale that might require prices of \$4/MMBtu or more to break even. Additionally, U.S. gas production is influenced to a relatively substantial degree by oil prices. When oil prices are high, incentivizing producers to drill for oil and natural gas liquids, a significant amount of associated gas can be produced as a by-product. Associated gas now accounts for 20% of total U.S. production, with notable recent growth in associated gas in areas such as the Permian Basin in West Texas.

In addition, the nature of drilling in shale plays is that, while initial production can be strong, the production curve declines very rapidly. A sustained or growing level of production requires ongoing drilling programs. This has resulted in U.S. supply becoming more responsive to market conditions, with shale wells acting as virtual storage to adapt quickly to changes in the market. It also means that a decline in oil prices, as occurred in early 2020, can lead to a decline in associated gas production. Producers typically hedge a significant portion of their forward production, but a sustained decline in oil prices will result in less associated gas production growth out of regions such as the Permian Basin. Exhibit 37 shows increasing real prices over time as declining associated gas production is coupled with rising marginal costs of production and extraction.

Exhibit 37: Annual Henry Hub Natural Gas Forecast (2019\$/MMBtu)



Source: Siemens PTI and PIRA

The Stochastic section of this report presents Siemens PTI's view on possible ranges of future prices for natural gas under different views of regulations (e.g. fracking), markets (e.g. exports) and technology advance²⁰.

6.2 Natural Gas Forecast Methodology

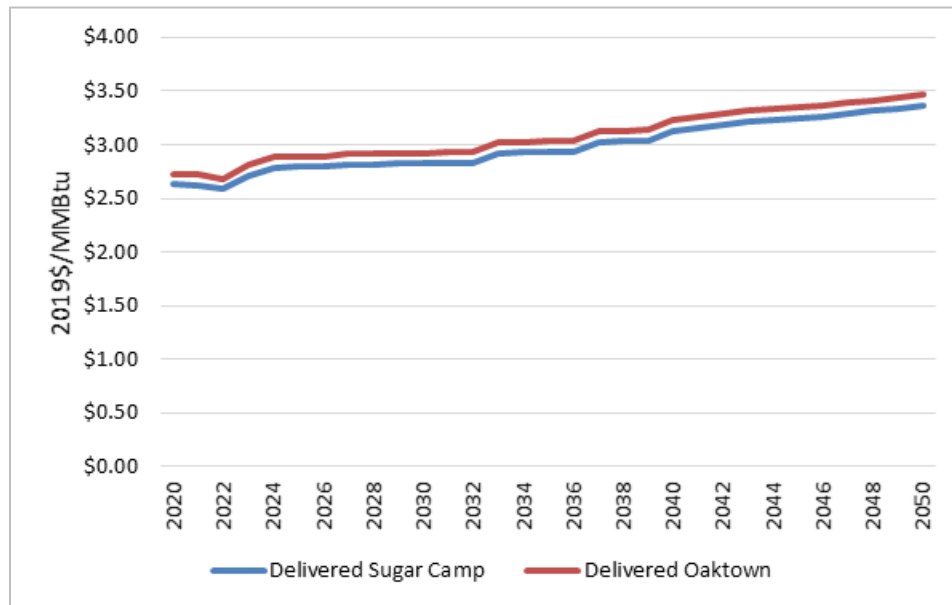
The Gas Pipeline Competition Model (GPCM) was used to develop long-term price forecasts by incorporating the fundamental drivers of supply, demand, and infrastructure described in the prior section. In the short-term, natural gas forwards were averaged and used explicitly for the first 18 months of the forecast, after historical prices. In the subsequent 18 months, the forecast is blended away from forwards toward the fundamental GPCM forecast, after which the forecast is purely fundamentals-based. This provides a view of natural gas prices and basis to Henry Hub delivered to liquid market trading points throughout the United States. The price forecast does not include delivery from the market trading hub to each plant gate, as not all these transportation costs align with the published tariffs nor can it be certain which hub is indexed in each plant's supply contract.

²⁰ The natural gas commodity price forecast used in this EIRP is based on information available as of Q1 2019 from PIRA.

6.3 Coal Price Forecast

Siemens PTI used Energy Ventures Analysis' coal price outlook for this EIRP analysis. This forecast for delivered OUC coal prices from two specific mines in the Illinois Basin is provided below for reference.

Exhibit 38: OUC Delivered Coal Price Outlook (2019\$/MMBtu)



Source: Energy Ventures Analysis

7. Stochastic Analysis

7.1 Introduction

Probabilistic modeling (also known as stochastic analysis or risk analysis) incorporates several market variables and probability distributions into the analysis, allowing for the evaluation of a portfolio's performance over a wide range of market conditions. Quantitative data is extracted from the results and is the foundation for some of the metrics in the Balanced Scorecard.

Probabilistic modeling begins with the development of 200 sets of future pathways for coal prices, natural gas prices, CO₂ prices, peak and average load (at the OUC, FMPP, FRCC, and SERC levels), and capital costs for a range of technologies. These 200 sets of future pathways are based on the forecasts of the expected value of these variables, described in Sections 3, 4, 5, and 6. These stochastic variables are initially forecasted for use over the study period, typically 1,000 to 3,000 times. A stratified sampling of the simulations is used, which then allows the sample set to be reduced to 200 iterations, or individual simulations, while still allowing for a representative sample of the universe of potential outcomes. These inputs allow for the testing of each portfolio's performance across a wide range of market conditions.

All Candidate Portfolios were subjected to each of the 200 iterations or simulations using the production cost model AURORAxmp in dispatch mode where the OUC portfolios are fixed but other FRCC and SERC members can make their own build and retirement decisions.

The stochastic modeling of each portfolio was developed by Siemens PTI using the AURORAxmp® dispatch model. There were several steps to this process:

- The first step was to develop the input distributions for each of the major market and regulatory drivers, including average and peak load growth and shape, natural gas prices, coal prices, CO₂ prices, and technology capital costs. This was done by considering volatility of each factor in the short-term, medium-term, and long-term.
- The second step was to run a probabilistic model (Monte Carlo) which simulated 200 possible future states over the 30-year study planning period.
- In the third step, each Candidate Portfolio was then run through simulated dispatch for the 200 possible future states using the AURORA production cost model. AURORA dispatches the Candidate Portfolio for each sampled hour over the planning horizon. For this risk analysis procedure, AURORA assumes that each Candidate Portfolio is constant but allows for builds and retirements to occur throughout the region based on economic criteria. OUC generation, costs, emissions, revenues, etc. are tracked for each iteration over time.
- Next, values for key metrics associated with the Attributes (Affordability, Sustainability) are tracked across all 200 iterations and presented as a distribution with a mean and other percentile (5th, 25th, 50th, 75th, and 95th).
- These measures are used as the basis for evaluation in the stochastic analysis.

7.2 Use of Stochastic Analysis

The stochastic analysis includes the probabilistic modeling conducted to inform the objective analytical considerations in the selection of the Leading Portfolio. Many other factors were considered besides the stochastic analysis. Nevertheless, a key part of designing the Leading Portfolio was based on how well each portfolio scored on multiple metrics and Attributes across 200 energy market simulations representing different, but internally consistent and plausible, market conditions. The selection process consisted of several comparisons illustrating each Candidate Portfolio's performance measured against competing objectives. The goal is to create the right balance between satisfying the competing objectives. The Leading Portfolio delivered the best balance of performance across all competing metrics when viewed across the full range of 200 simulations, while also maintaining Reliability and providing resource diversity/system flexibility. This procedure is used and presented in the sections below where each portfolio is assessed.

7.3 Stochastic Distributions

To perform the probabilistic modeling, a set of probability distributions was required for each of the key market driver variables (fuel, emissions, load, and capital costs). 200 future paths for each stochastic variable were developed using statistical methods. The following sections describe the methodologies for developing these stochastic variables, with additional detail explained in Appendix B: .

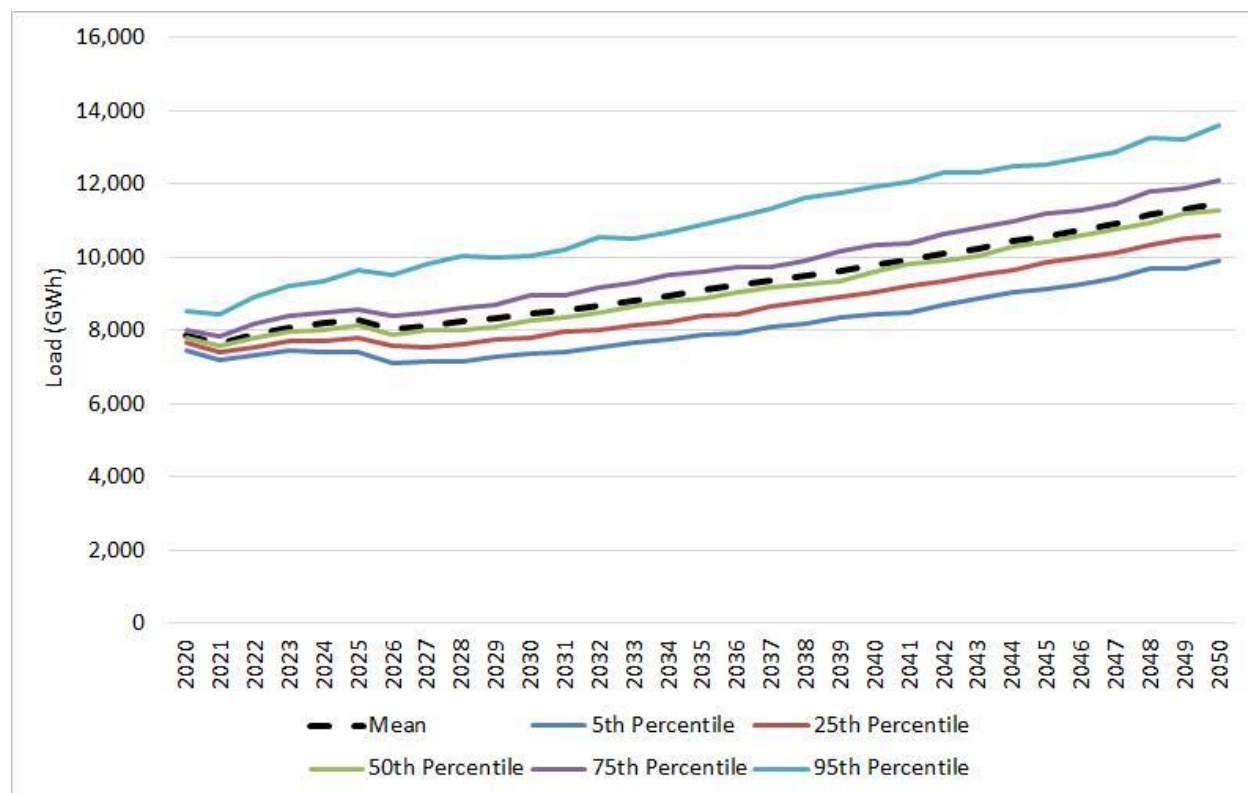
7.3.1 Load Distributions

To account for electricity demand variability and uncertainty that derives from economic growth, weather, energy efficiency, distributed generation and demand side management measures, Siemens PTI developed a range of stochastic inputs around the energy demand expectations for the OUC service area and the neighboring markets including FMPP, FRCC, and SERC. The base long-term load forecast was provided by OUC with some extrapolation to 2050. For the broader FRCC and SERC markets, Siemens PTI forecasted long-term energy demand using a two-step process that captures both the impact of historical load drivers such as economic growth and variability of weather and the potential impacts of energy efficiency, demand response, distributed generation and electric vehicles.

Siemens PTI benchmarked the market-wide energy demand projections against FRCC- and SERC-sponsored load forecasting studies that are conducted by independent consultants, institutions, and market monitors to ensure consistency. Exhibit 39 shows Siemens PTI's stochastic range for energy demand and includes a wide range of potential energy efficiency, demand response, distributed generation and electric vehicle adoption. The stochastic distributions are the net result of 200 random simulations for the base net load forecasts. Siemens PTI calculated the distributions for the 5th and 95th percentiles (approximately two standard deviations), quartiles (25th, 50th, and 75th) percentiles, and the average (mean) of the annual distributions over time. Siemens PTI's Stochastics Methodology is further explained in Appendix B: .

As shown in Exhibit 39, the overall distribution shows a higher level of future load growth exceeding the expected value.

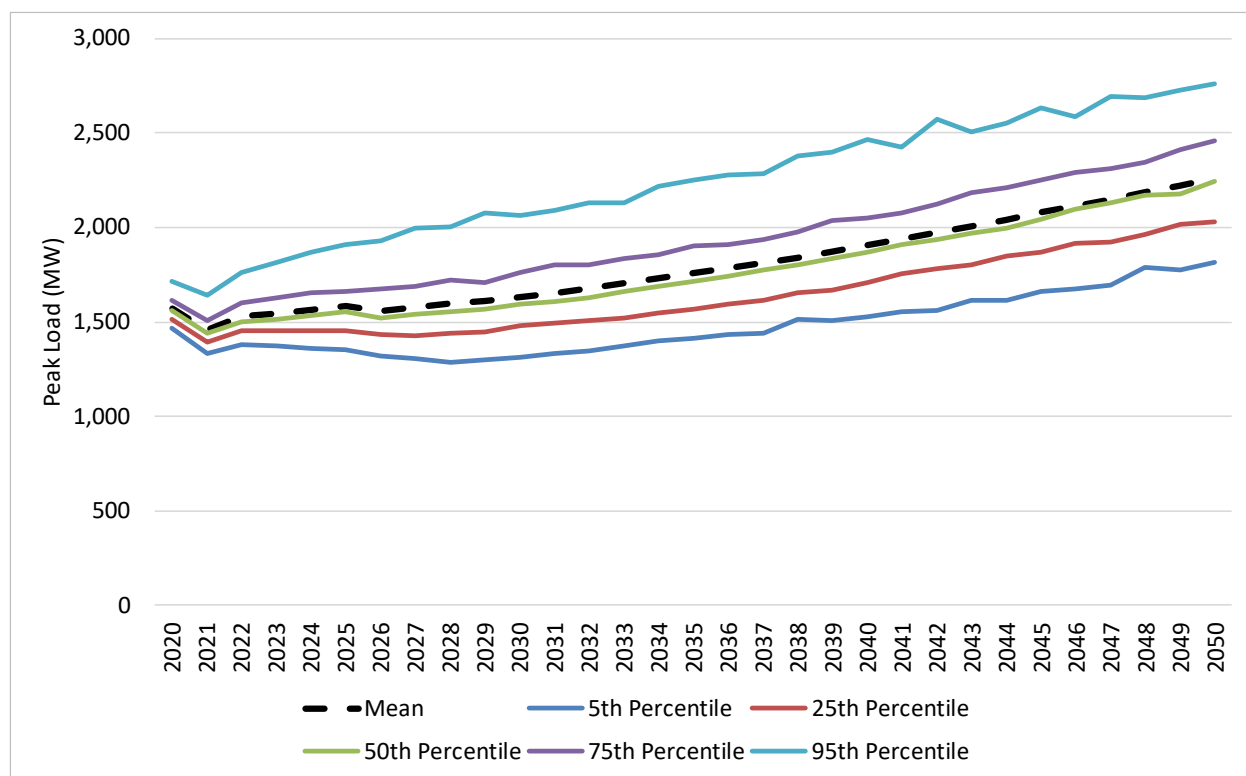
Exhibit 39: Forecasted Net Energy Load (GWh) Distribution²¹



Source: Siemens PTI

Similarly, as shown in Exhibit 40, the stochastic distribution also shows a higher potential that peak load will exceed the mean or expected value over time. Both the forecast of total energy demand and the forecast for peak energy demand allow for a wide range of energy efficiency, demand response, distributed generation and electric vehicle adoption, all of which could reduce or increase the energy that would need to be generated and distributed by OUC. Energy efficiency, demand response, and distributed generation assist with reducing the energy required to meet load. Together, these resources have the potential to reduce the load by 6% in 2050 under base load forecast. Similarly, electric vehicles increase the net energy for load by 5% in 2050. Through the stochastic analysis the net energy required for load vary by a much wider range throughout the study period. For example, the 95th percentile is 18% higher than the base forecast, and the 5th percentile is 14% lower than the base forecast by 2050, which represents a wide range of potential load modifier penetration.

²¹ Reductions in load in 2021 and 2026 are a result of the expiration of wholesale sale commitments.

Exhibit 40: Forecasted Peak Load (MW) Distribution²²

Source: Siemens PTI

7.3.2 Natural Gas Price Distributions

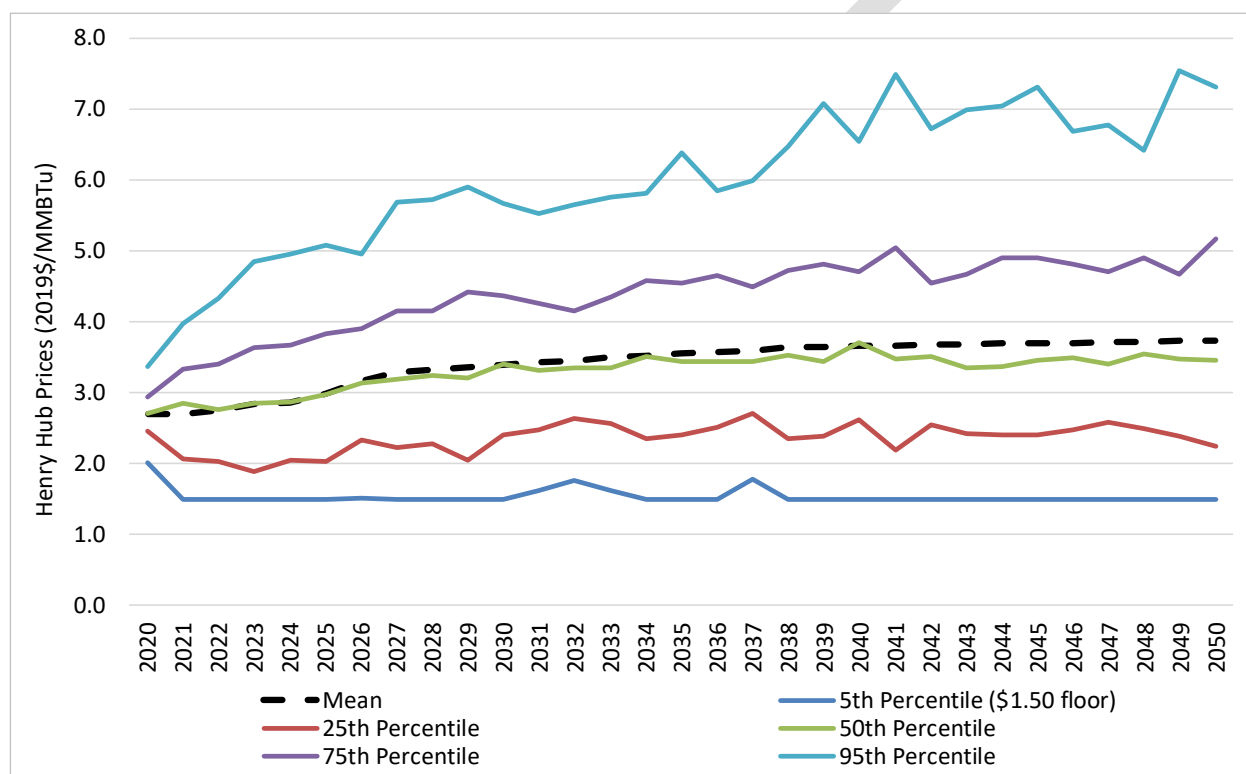
Siemens PTI developed natural gas price stochastic distributions for the benchmark natural gas commodity price at the Henry Hub market point. These stochastic distributions are first based on the expected value forecast of PIRA Energy Group's²³ view of natural gas prices with probability bands developed based on a combination of historical volatility and mean reversion parameters as well as a forward view of expected volatility. For the period 2020-2022, volatility calculated from the past three years of price data is used. For 2023-2025, volatility calculated from the past five years is used. For 2026-2050, volatility calculated from the past 10 years is used. This allows gas price volatility and uncertainty to be low in the short-term, moderate in the medium-term and higher in the long-term in alignment with observed historical volatility.

²² Reductions in load in 2021 and 2026 are a result of the expiration of wholesale sale commitments.

²³ PIRA Energy Group was acquired by S&P Global Platts in 2016. It is a nationally recognized energy forecasting organization.

The 95th percentile probability bands are driven by increased gas demand (e.g., coal unit retirements) and potential fracking regulations that raise the cost of producing gas. Prices in the 5th percentile are driven by significant renewable development that keeps gas plant utilization relatively low as well as few to no new environmental regulation around power plant emissions. Exhibit 41 shows the stochastic distributions for the fuel inputs. The natural gas price stochastic inputs represent the possible outcomes for Henry Hub commodity prices. Siemens PTI then layers the natural gas price basis on top of the Henry Hub prices to provide the delivered gas price to the OUC and FRCC gas-fired power plants.

Exhibit 41: Natural Gas (Henry Hub) Price Distribution (2019\$/MMBtu)

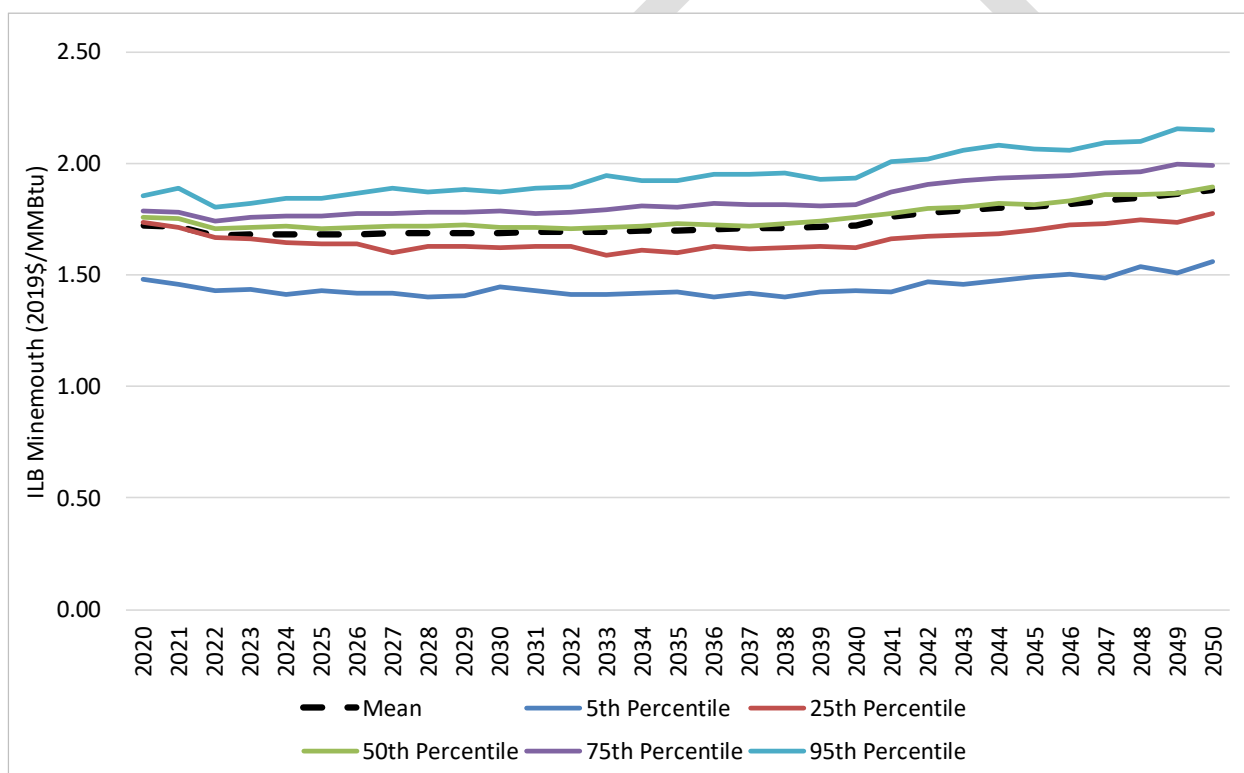


Source: Siemens PTI

7.3.3 Coal Price Distributions

Siemens PTI developed coal price stochastic distributions for the Central Appalachian (CAPP), Northern Appalachian (NAPP), Illinois (ILB) and Powder River (PRB) basins. These stochastic distributions are first based on an Energy Ventures Analysis²⁴ expected view of coal prices with probability bands then developed based on a combination of historical volatility and mean reversion parameters. It should be noted that most coal contracts in the U.S. are bilateral and only approximately 20% are traded on the New York Market (NYMEX) Exchange. The historical data set that is used to calculate the parameters is comprised of the weekly traded data reported in NYMEX. The coal commodity price stochastic variations shown in Exhibit 42 are based on ILB Minemouth prices, applicable to OUC's coal plants. Siemens PTI adds individual transportation adders to represent the delivered coal prices to OUC and FRCC coal-fired power plants.

Exhibit 42: ILB Minemouth Coal Price Distribution (2019\$/MMBtu)



Source: Siemens PTI

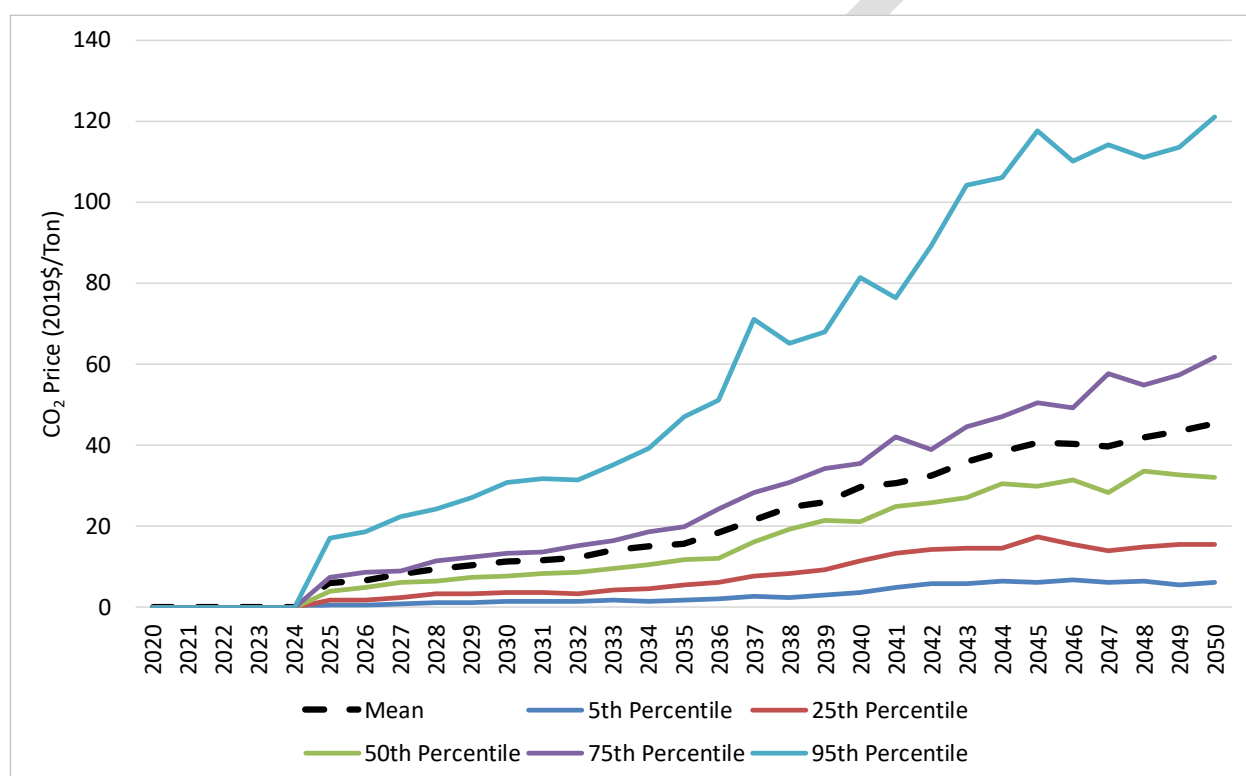
7.3.4 Emission Price Distributions

Siemens PTI developed uncertainty distributions around CO₂ compliance costs, which were used to capture the inherent risk associated with regulatory compliance requirements. The technique to develop CO₂ costs distributions, unlike the previous variables, is based on projections largely derived from expert judgment, as there are no national historical data sets

²⁴ Energy Ventures Analysis is an independent nationally recognized energy forecasting organization.

(only regional markets in California and the northeast) to estimate the parameters for developing CO₂ costs distributions. The expected value (mean of the distribution) reflects a view that some type of legislation will likely occur in the mid-2020s. Previous studies of a proposed trading mechanism as well as analysis on the requirements to meet the Paris Agreement showed prices rising to about \$30/short ton by 2040. The bottom end of the distribution assumes little future regulation, while the top end reflects the inclusion of social cost of CO₂ emissions. The portfolios are designed without considering CO₂ prices and are only exposed to the costs associated with emissions through the stochastic analysis.

Exhibit 43: CO₂ Price Distribution (2019\$/short ton)



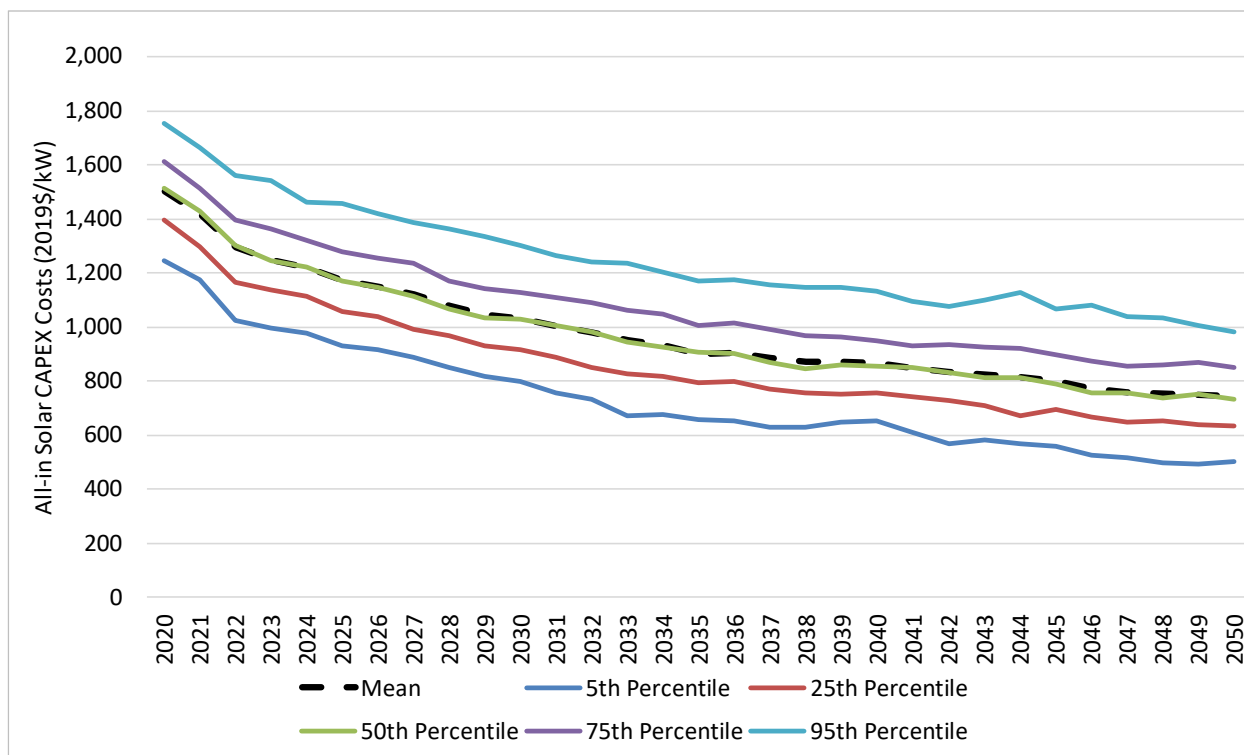
Source: Siemens PTI

7.3.5 Capital Cost Distributions

Siemens PTI developed the uncertainty distributions for the cost of new entry units by technology type, which were used for determining the economic new builds in FRCC and SERC based on market signals. These technologies included gas peaking units, gas combined cycle units, solar, wind, and Li-on battery storage resources. The methodology of developing the capital cost distributions is a two-step process: (1) a parametric distribution based on a deterministic Base Case view of future all-in capital costs, historical costs, and volatilities, and a sampling of results to develop probability bands around the Calibration Portfolio outlook; and (2) a quantum distribution that captures the additional uncertainty with each technology that factors in learning curve effects, improvements in technology over time, and other uncertain events such as leaps in technological innovation. Additional detail on the stochastics

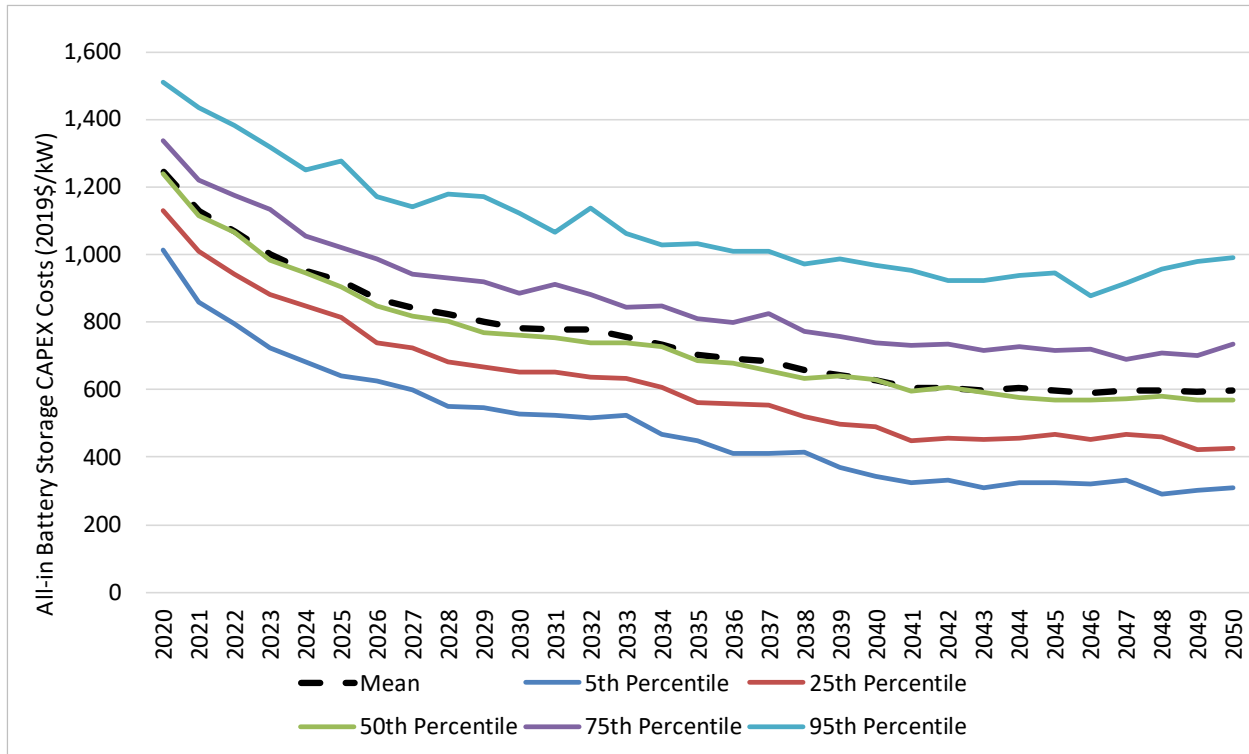
methodology is provided in Appendix B: Stochastics. Exhibit 44 to Exhibit 47 shows stochastic variations related to the all-in capital costs for various technologies. The stochastic variations in these costs are only implemented for capacity additions built by other utilities, thus have little impact on costs shown for the portfolios analyzed in this EIRP. Regional multipliers are applied to the costs for use in this analysis.

Exhibit 44: 74.5 MW Solar Capital Costs Distribution (2019\$/kW)



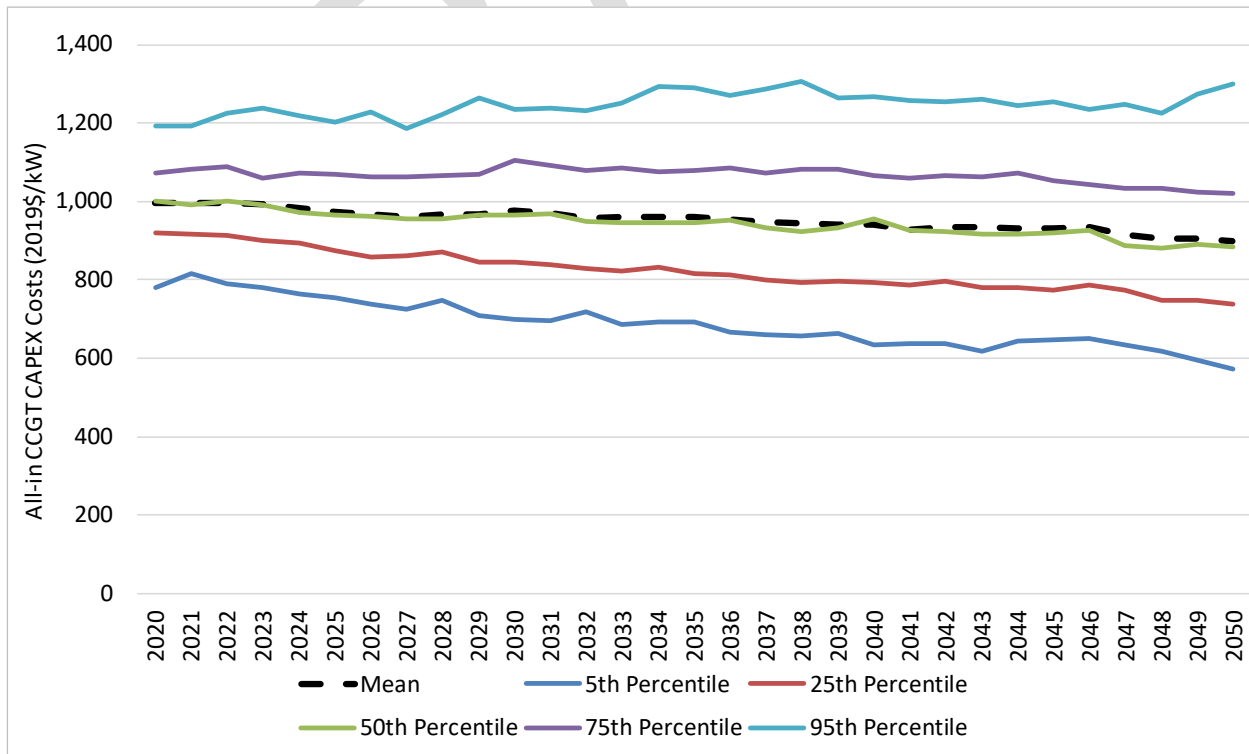
Source: Siemens PTI

Exhibit 45: 50 MW Lithium-Ion 4-hour Battery Storage Capital Costs Distribution (2019\$/kW)

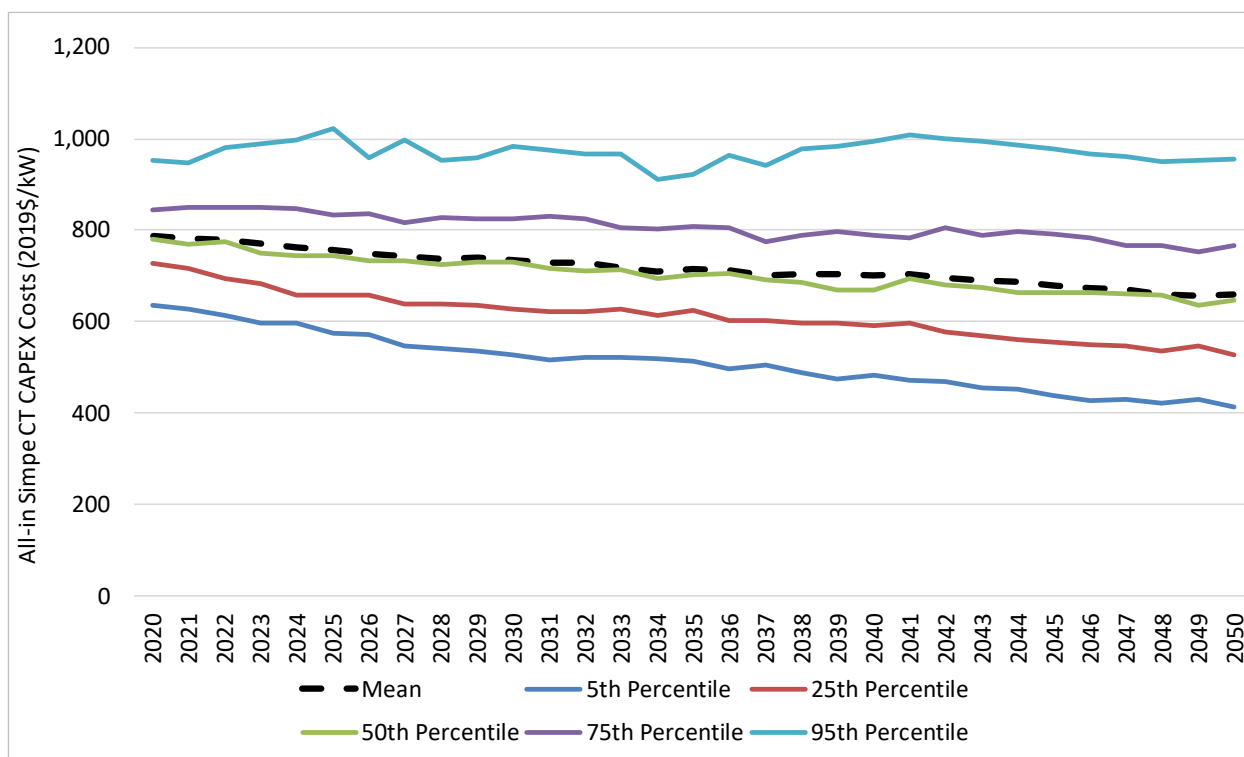


Source: Siemens PTI

Exhibit 46: Advanced 2x1 Combined Cycle Capital Costs Distribution (2019\$/kW)



Source: Siemens PTI

Exhibit 47: Advanced Simple Cycle Frame CT Capital Costs Distribution (2019\$/kW)

Source: Siemens PTI

7.3.6 Cross-Commodity Correlations

Siemens PTI captured the cross-commodity correlations in the stochastic process. This is a unique stochastic process for natural gas, coal, and CO₂ prices. The feedback effects are based on statistical relationships between coal and natural gas switching and the variable cost of coal and natural gas generators. Siemens PTI conducted a fundamental analysis to define the relationship between natural gas and coal dispatch costs and demand. The dispatch costs of natural gas and coal were calculated from the natural gas and coal stochastics and CO₂ stochastics, along with generic assumptions for variable operation and maintenance costs. Where the gas-coal dispatch differential changes significantly enough to affect demand, natural gas demand from the previous year was adjusted to reflect the corresponding change in demand. A natural gas price delta was then calculated based on the defined natural gas demand. This natural gas price delta was then added to the natural gas stochastic path developed from historic volatility to calculate an integrated set of CO₂ and natural gas stochastic price forecasts.

8. Analysis Results and Comparisons

Siemens PTI conducted an extensive analysis of the options available to OUC for fulfilling its energy demand through 2050. The analysis included conventional and renewable energy generation, and battery storage systems both in OUC's service territory and more generally in the broader FRCC and SERC footprints, as well as a level of energy efficiency commensurate with OUC's current suite of demand side management measures. Additionally, the analysis accounts for electric vehicle load and incorporates a detailed study of distributed solar generation conducted independently of this EIRP by the National Renewable Energy Laboratory (NREL). Lastly, this analysis limited purchases and sales to historical numbers to provide an accurate representation of the bilateral energy marketplace in Florida.

The overall analysis considers a multitude of metrics across all the Attributes mentioned in Section 2.4. The results of the analysis based on all of these metrics can be observed in Exhibit 56. The colors represent the performance of each portfolio on each metric. A predominance of green is favorable, and a predominance of red is unfavorable. The analysis concluded that the Modular Nuclear, Gas Conversion 2026/2029, Gas Conversion 2036/2040 Portfolios perform the best out of all Candidate Portfolios. Each Attribute and associated metrics are explained in more detail in the next section.

8.1 Reliability

Through public and stakeholder engagement, it was determined that the Reliability metric is the most important and is weighted at 35% in the final balanced scorecard roll-up. From a Reliability perspective, all Candidate Portfolios were designed to meet or exceed the minimum reserve margin required by the Florida Public Service Commission. The combination of the Unforced Generation Capacity (UCAP) + Capacity Import Limit (CIL) must be more than 115% of the annual peak demand. Additionally, each portfolio is designed to be self-sufficient under expected conditions. In other words, each portfolio can supply all OUC's energy demand throughout the entire forecast horizon, without having to rely on imports from surrounding utilities under expected supply and demand conditions. Exhibit 48 shows how each portfolio performed on the Reliability metrics.

Next, as discussed previously, two metrics comprise the Reliability Attribute. The first metric is the first year occurrence of unserved energy determined through Siemens PTI's Cloud Cover analysis. The second metric is the technology diversity of each portfolio by the end of the forecast (2050). Each of these metrics are weighted equally for the ranking. The results across these metrics are discussed in further detail below.

Exhibit 48: Reliability Attribute Metrics and Results

Metrics	Units	Calibration Portfolio	Net Zero CO ₂ by 2050	100% Renewable by 2050	Gas Conversion 2026/2029	Gas Conversion 2036/2040	Coal Retirement 2022/2026	Wind-by-Wire	Modular Nuclear
1st Year Cloud Cover U-E	First Year	Never	2036	2040	2050	2050	2027	2036	Never
2050 Technology Diversity	Tech Count	5	4	2	4	4	4	5	4

Source: Siemens PTI

Cloud Cover Analysis

The cloud cover analysis observes the first year in which there is unserved energy due to a 70% reduction in solar output from cloud cover during the highest demand week, occurring in August. As Exhibit **48** shows, the Calibration Portfolio and Modular Nuclear Portfolio never incur unserved energy under this condition. For the Calibration Portfolio this is due to heavy reliance on fossil-fuel powered plants, which are unaffected by the cloud cover. The Modular Nuclear Portfolio includes a 570MW nuclear powered unit, a generation source not impacted by cloud cover. It also contains sufficient energy storage to provide flexibility for the energy in the OUC system. Both the Gas Conversion 2026/2029 Portfolio and Gas Conversion 2036/2040 Portfolio perform well in the cloud cover analysis. The first year of unserved energy occurs in 2050, which is when these portfolios retire the Stanton A and B units to meet the 2050 Net Zero CO₂ target.

2050 Technology Diversity

This metric observes the number of different types of technology within the portfolio in 2050. The technology types include coal-fired plants, natural gas-fired plants, solar, wind, nuclear, and storage. The Calibration Portfolio and Wind-by-Wire Portfolio achieve the highest technology diversity. The Calibration Portfolio has the following technologies in 2050: natural gas-fired plant, nuclear, coal-fired plant, solar, and storage. The Wind-by-Wire Portfolio has the following technologies in 2050: natural gas-fired plant, nuclear, solar, storage, and wind.

8.2 Affordability

The second most important Attribute is Affordability and is weighted at 24% in the final balanced scorecard. The Affordability of the portfolios is important because it ultimately determines the costs for OUC to serve all load. There are many cost components that feed into the metrics shown in Exhibit 49, including fuel costs, fixed operating and maintenance costs, variable operating and maintenance costs, emission costs, and sales and purchases. Since costs occurring early in the forecast have higher value in terms of time value, the metrics weigh 2020-2030 costs at 50%, 2020-2050 costs at 10%, 2020-2030 uncertainty at 30%, and 2020-2050 uncertainty at 10%. Costs and uncertainty as shown in Exhibit 49 are measured in millions of dollars and standard deviation in millions of dollars, respectively.

Exhibit 49: Affordability Attribute Metrics and Results

Metrics	Units	Calibration Portfolio	Net Zero CO ₂ by 2050	100% Renewable by 2050	Gas Conversion 2026/2029	Gas Conversion 2036/2040	Coal Retirement 2022/2026	Wind-by-Wire	Modular Nuclear
Cost 2020-2030	PV 2020 \$M	\$3,108	\$3,137	\$3,354	\$3,497	\$3,127	\$3,762	\$3,167	\$3,142
Cost 2020-2050	PV 2020 \$M	\$7,319	\$9,257	\$10,078	\$8,596	\$8,585	\$11,180	\$8,877	\$9,098
Uncertainty 2020-2030	Std Dev Cost	\$342	\$435	\$392	\$333	\$459	\$302	\$416	\$353
Uncertainty 2020-2050	Std Dev Cost	\$1,119	\$942	\$929	\$625	\$1,042	\$549	\$835	\$705

Source: Siemens PTI

Present Value of Cost 2020-2030

This metric calculates the present value of costs over the 2020-2030 time horizon. As Exhibit 49 shows, the portfolio that performs best on this metric is the Calibration Portfolio since it does not aim to meet any of the Net Zero CO₂ targets. Out of the Candidate Portfolios, the Gas Conversion 2036/2040 Portfolio performs the best, with Net Zero CO₂ by 2050 and the Modular Nuclear Portfolio coming in close second and third, respectively. The Coal Retirement 2022/2026 Portfolio performs worst in this metric because the retired coal units need to be replaced with solar and battery storage early in the forecast. The capital investments associated with adding this capacity drives up the portfolio costs significantly.

Present Value of Costs 2020-2050

This metric calculates the present value of costs over the full forecast horizon. Exhibit 49 shows that the Calibration Portfolio performs best in this metric for the same reasons described above. The Candidate Portfolios that perform best in this metric are the Gas Conversion portfolios. They can take advantage of the existing infrastructure at the Stanton Energy Center and convert coal to a natural gas-fired plant at a fraction of the costs of an entirely new combined cycle gas turbine plant. Additionally, converting the coal units significantly reduces the investment costs in solar and storage capacity. Again, the Coal Retirement 2022/2026 Portfolio performs worst in this metric due to the early coal retirement.

Present Value of Uncertainty 2020-2030

This metric calculates the present value of standard deviation of portfolio costs. The portfolio that performs best in this metric is the Coal Retirement 2022/2025 Portfolio because it retires a significant portion of its fossil-fuel fired capacity early in the forecast. Therefore, it is less exposed to uncertainty around fuel prices as well as emission prices. The Gas Conversion 2026/2029 Portfolio also performs well in this metric because it is less exposed to volatility around the emission prices by converting the heavy emitting coal units to gas units.

Present Value of Uncertainty 2020-2050

Similar to the Uncertainty 2020-2030 metric, this metric calculates the present value of standard deviation of the portfolio costs, but over the full forecast horizon. Again, the Coal Retirement 2022/2026 Portfolio performs best in this metric and the Gas

Conversion 2026/2029 Portfolio comes in second for the same reasons described before. However, the Calibration Portfolio performs worst in this category because it becomes highly exposed to the increasing volatility of gas and CO₂ prices, which means more upside risk late in the study horizon (shown in Exhibit 49).

8.3 Sustainability

Sustainability is the third most important Attribute and is weighted at 22% in the final balanced scorecard, similar to Affordability. The metrics for this Attribute measure the probabilities of meeting the 2030, 2040, and 2050 Net Zero CO₂ targets, as well as the percentage of clean energy generated in the portfolio in 2050. All of these metrics are weighted equally at 25%. Exhibit 50 shows how each portfolio performs across different metrics for this Attribute.

Exhibit 50: Sustainability Attribute Metrics and Results

Metrics	Units	Calibration Portfolio	Net Zero CO ₂ by 2050	100% Renewable by 2050	Gas Conversion 2026/2029	Gas Conversion 2036/2040	Coal Retirement 2022/2026	Wind-by-Wire	Modular Nuclear
Probability of Reduction Target 2030	Probability	5%	5%	25%	95%	5%	95%	5%	5%
Probability of Reduction Target 2040	Probability	5%	95%	75%	95%	50%	95%	95%	95%
Probability of Reduction Target 2050	Probability	5%	95%	95%	95%	95%	95%	95%	95%
Clean Energy Gen in 2050	%	15%	92%	100%	98%	97%	93%	87%	93%

Source: Siemens PTI

Probability of Reduction Targets

The probability of meeting reduction targets can be broken into three different metrics: Probability of meeting 2030 reduction target, 2040 reduction target, and 2050 reduction target. As Exhibit 50 shows, the only two portfolios that have a 95% probability of meeting the 2030 reduction target under varying market conditions are the Gas Conversion 2026/2029 Portfolio and Coal Retirement 2022/2026 Portfolio. All other portfolios have lower chances of meeting the 2030 goal because they retire the Stanton 1 and 2 coal units after 2030. Therefore, converting or retiring the coal plants are crucial in meeting the 2030 goal under varying market conditions.

As for the probability of meeting the 2040 reduction target, more portfolios are able to achieve 95% probability because of the retirements of the Stanton 1 and 2 coal units. The only portfolios that do not have a 95% probability of meeting this target are the Calibration Portfolio and Gas Conversion 2036/2040 Portfolio.

Again, the Calibration Portfolio only has a below 5% probability of meeting the 2050 reduction target because it keeps all fossil units. All Candidate Portfolios have a 95% probability of meeting the 2050 emission reduction target because each portfolio has retired the Stanton 1 and 2 coal units before 2050.

Clean Energy Generation 2050

As Exhibit 50 shows, all of the Candidate Portfolios perform very well in this metric. As long as a portfolio achieves above 90% clean energy generation, it is ranked the best. Any portfolio with less than 90% clean energy generation are ranked lower accordingly.

8.4 Resiliency

The last Attribute is Resiliency and it has a relative weight of 19%. This Attribute is ranked lowest, nevertheless, it is very important for the portfolios to withstand the unusual events that disrupt the electricity system within the Florida service area. The metrics based on the scenarios are weighted equally. Each metric measures the total amount of unserved energy over the two-week period with the highest demand (occurring in August) and sums the unserved energy occurring in 2025, 2035, and 2045 to provide the total amount of unserved energy in the portfolio. Exhibit 51 shows how each portfolio performs across the assumed scenarios and U-E stands for unserved energy.

Exhibit 51: Resiliency Attribute Metrics and Results

Metrics	Units	Calibration Portfolio	Net Zero CO ₂ by 2050	100% Renewable by 2050	Gas Conversion 2026/2029	Gas Conversion 2036/2040	Coal Retirement 2022/2026	Wind-by-Wire	Modular Nuclear
East FL Hurricane U-E 2025, 2035, 2045	MWh	510,259	449,274	416,852	416,456	454,814	517,701	473,178	513,767
West FL Hurricane U-E 2025, 2035, 2045	MWh	76,294	128,278	269,945	126,960	105,418	196,911	155,009	65,021
Gas Disruption U-E 2025, 2035, 2045	MWh	288,065	79,910	96,197	225,334	137,031	150,882	131,381	114,699

Source: Siemens PTI

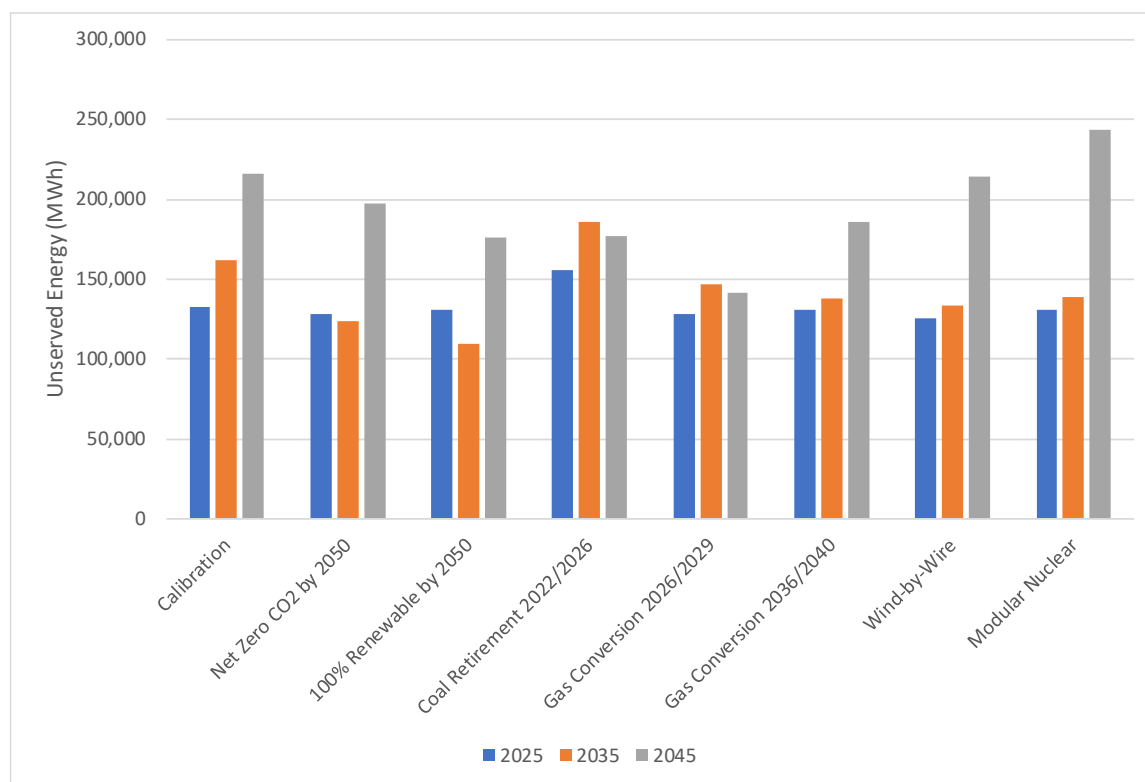
East Coast Hurricane

This scenario calculates the unserved energy associated with a major hurricane on the east coast of Florida. As Exhibit 51 shows, this disruption scenario results in the highest amount of unserved energy due to the location of Orlando within the Florida peninsula. The portfolio that performs worst in this scenario is the Coal Retirement 2022/2026 Portfolio. Exhibit 52 shows the Coal Retirement 2022/2026 Portfolio incurs consistently high unserved energy in each year of the analysis. The reason is that the Coal Retirement 2022/2026 Portfolio heavily relies on solar and storage early in the forecast and solar output is reduced by 75% in the first week and 50% in the second week (Section 2.4.4) in the scenario. The second worst performing portfolio is Modular Nuclear Portfolio because it heavily relies on the nuclear unit in 2045 and its output is reduced by 100% in the first week and 50% in the second week of the disruption scenario.

The portfolios that perform best in this scenario are the 100% Renewable by 2050 and the Gas Conversion 2026/2029 Portfolio. The 100% Renewable by 2050 Portfolio performs better because it retires both Stanton 1 and 2 coal plant by 2040, which is later than all other portfolios, and because it has more solar and storage capacity to meet the 100% renewable target. The Gas Conversion 2026/2029 performs better

compared to the Gas Conversion 2036/2040 Portfolio since in 2045 it has more solar capacity.

Exhibit 52: East Coast Hurricane Detailed Results



Source: Siemens PTI

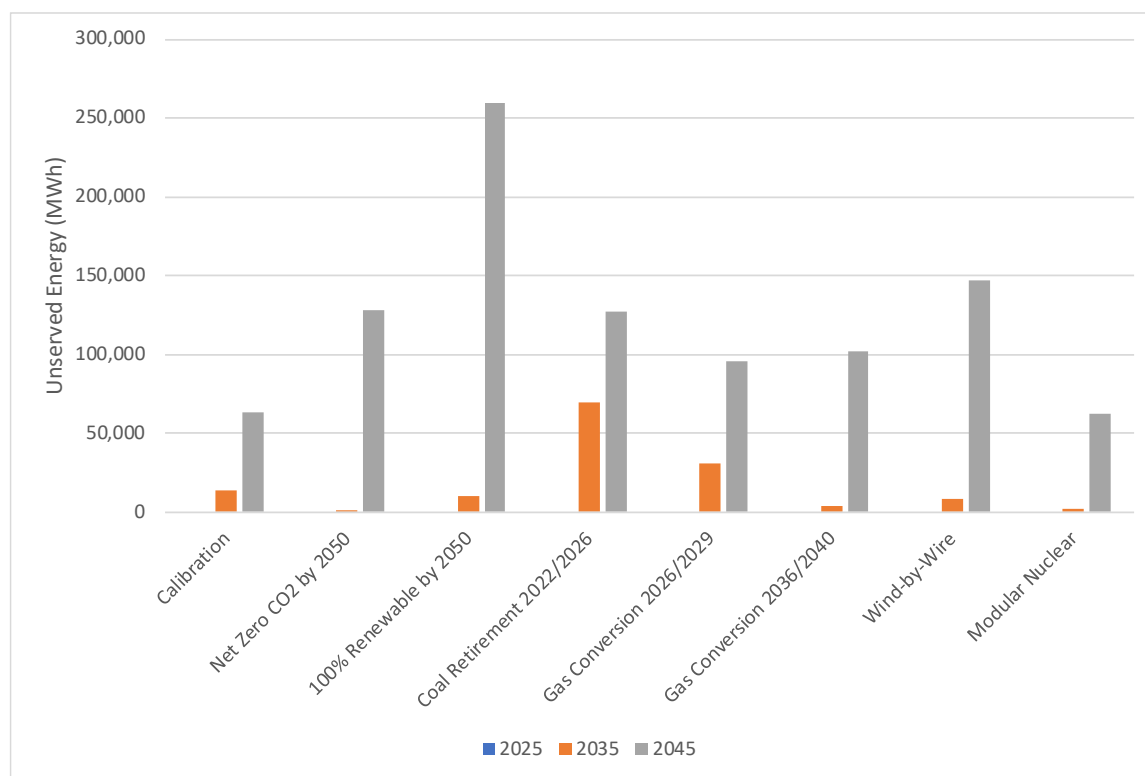
West Coast Hurricane

This scenario quantifies unserved energy as a result from a major hurricane occurring in the Gulf of Mexico. Because of Orlando's location within the Florida peninsula, this scenario has less of an impact on the Orlando service area. As shown in Section 2.4.4, the only resource affected by a west coast hurricane is assumed to be solar. As Exhibit 51 shows, the portfolios that perform best in this scenario are the Calibration Portfolio and Modular Nuclear Portfolios. Since the Calibration Portfolio and Modular Nuclear Portfolio have less solar capacity in 2035, less unserved energy is observed in this year. In 2045, the Calibration Portfolio maintains a lot of dispatchable generation through the added natural gas-fired combined cycle and peaker capacity. The Modular Nuclear Portfolio has 570MW of nuclear capacity in this year and the portfolio can rely on the steady output of this plant.

The two portfolios that perform worst in this hurricane scenario are the 100% Renewable by 2050 Portfolio and Coal Retirement 2022/2026 Portfolio. This is due to the heavy reliance on solar energy in these portfolios, which is the only technology affected by this hurricane scenario. 2045 shows the most impact for the 100% Renewable by 2050 Portfolio because the Stanton A unit is retired, which means that

this portfolio has much less dispatchable capacity that can make up for the loss of solar output.

Exhibit 53: West Coast Hurricane Detailed Results



Source: Siemens PTI

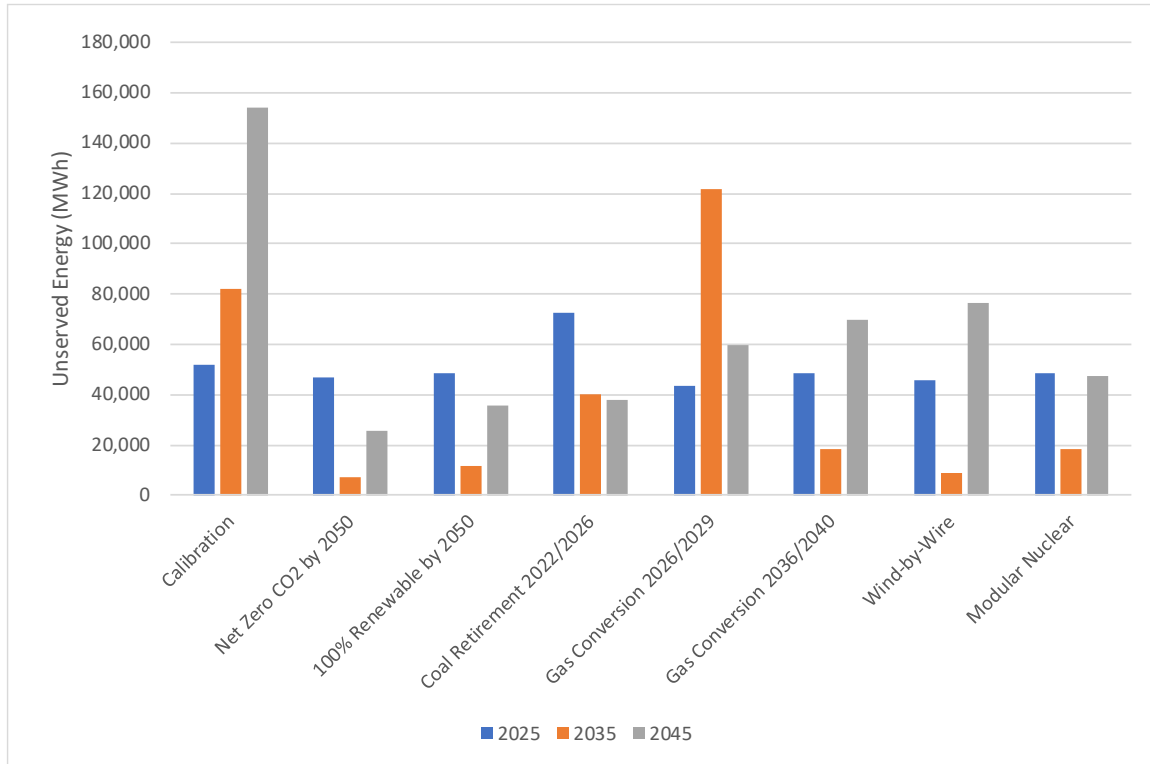
Gas Pipeline Disruption

The last scenario analyzed for the Resiliency Attribute is a large gas pipeline disruption in the Florida peninsula. As the name suggest, this scenario only affects natural gas-fired plant output (100% in the first week, 50% in the second week) by significantly reducing the amount of natural gas that can be delivered to various gas plants throughout the FRCC and OUC service areas. As Exhibit 54 shows, most portfolios perform comparably in 2025. However, the Coal Retirement 2022/2026 Portfolio has slightly more unserved energy in 2025 because of a Stanton coal unit retiring in 2022. Overall, the portfolios that perform worst in this scenario are the Calibration and Gas Conversion 2026/2029 Portfolio since these portfolios rely heavily on gas capacity through most of the forecast. The Gas Conversion 2026/2029 Portfolio has the most unserved energy in 2035 due to the reasons described above. The Calibration Portfolio has the most unserved energy in 2045 because of large amount of gas capacity installed in this year.

The portfolios that perform best in this metric are the Net Zero CO₂ by 2050 Portfolio and 100% Renewable by 2050 Portfolio. In 2025 these portfolios perform similar to the other Candidate Portfolios. However, these portfolios excel in 2035 and 2045. In 2035,

these portfolios maintain both Stanton coal units, providing sufficient reliable and dispatchable capacity, similar to some other Candidate Portfolios. In 2045, after the retirement of the Stanton coal units, these portfolios have a significant amount of solar and battery storage capacity to assist with the loss in gas capacity in this year.

Exhibit 54: Gas Pipeline Disruption Detailed Results



Source: Siemens PTI

8.5 Findings and Recommendations

This EIRP report is designed to provide OUC with the information needed to consider the tradeoffs associated with the different Candidate Portfolios. By comparing all Candidate Portfolios, this study was able to establish some key findings.

Exhibit 55: EIRP Key Findings

1. Although attainable, developing a high renewable portfolio that meets all of OUC's load under expected conditions without relying on purchases can significantly increase costs.
2. Retiring or converting the Stanton coal units early in the forecast is essential to achieving a high probability of meeting the Net Zero CO₂ target and interim targets under varying conditions.
3. Converting the Stanton coal units instead of retiring them greatly reduces the need for solar and storage capacity, while still significantly reducing emissions.
4. Converting the Stanton coal units enables OUC to bridge technology advances and take advantage of technology improvements as well as reductions in costs of these technologies. Additionally, potential stranded costs are avoided, and the converted units can use existing transmission infrastructure at the Stanton Energy Center.
5. Maintaining a highly diverse portfolio assists with better performance on the key Attributes of Reliability, Affordability, and Resiliency.

Source: Siemens PTI

After rolling up the scores across the different metrics and weighting the Attribute as previously described, the resulting final balanced scorecard is presented in Exhibit 56. As described in Section 8.3, the only Candidate Portfolios that have a 95% probability of meeting all Net Zero CO₂ targets are the Gas Conversion 2026/2029 Portfolio and Coal Retirement 2022/2026 Portfolio. Out of these two portfolios, the Gas Conversion 2026/2029 Portfolio is the best performing portfolio with a weighted score of 3.0.

Exhibit 56: Final Balanced Scorecard

Attributes	Weight	Net Zero CO ₂ by 2050	100% Renewable by 2050	Gas Conversion 2026/2029	Gas Conversion 2036/2040	Coal Retirement 2022/2026	Wind-by-Wire	Modular Nuclear
Reliability	35	3.5	3.0	2.0	2.0	4.0	3.0	1.5
Affordability	24	5.2	6.2	5.1	4.7	5.8	5.5	4.4
Sustainability	22	1.5	1.5	1.0	2.0	1.0	1.8	1.5
Resiliency	19	3.0	4.3	4.3	4.0	8.0	5.0	4.0
Total	100	3.4	3.7	3.0	3.0	4.5	3.7	2.7

Source: Siemens PTI

After considering the key findings and the balanced scorecard, this EIRP established the recommended refinements to the Leading Portfolio as described in the following section to determine the Optimized Portfolio.

9. OUC's Optimized Portfolio

9.1 Introduction

After conducting the development and analysis of the original Candidate Portfolios, OUC and Siemens PTI identified the Gas Conversion 2026/2029 Portfolio as the Leading Portfolio as it was the best performing portfolio that maintained a 95% probability of meeting all Net Zero CO₂ targets throughout the forecast. Therefore, the Gas Conversion 2026/2029 Portfolio was used as a starting point and further refined to develop the recommended Optimized Portfolio.

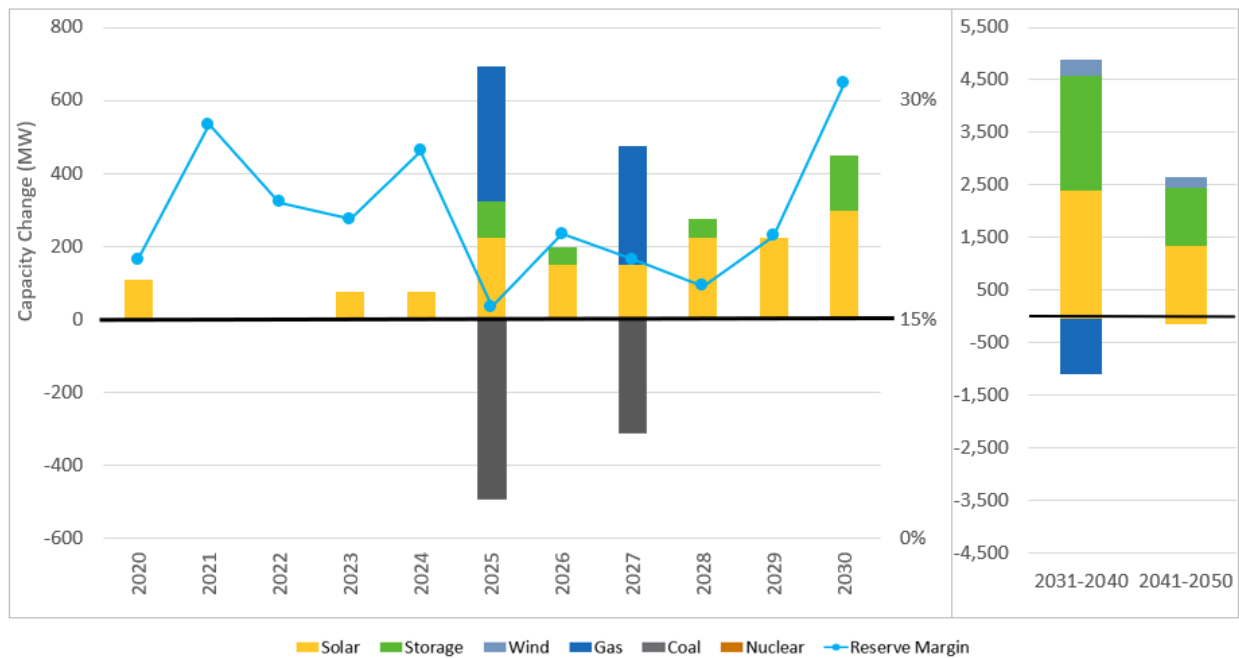
9.2 Optimized Portfolio Advantages

The Optimized Portfolio provides the following advantages over the Leading Portfolio:

1. The Optimized Portfolio converts the Stanton coal units earlier – starting no later than 2025 and completed no later than 2027 compared to 2026 and 2029 for the Leading Portfolio. The converted gas units are planned to be retired by 2040.
2. The Optimized Portfolio reduces emissions by approximately 7.6 million tons over the forecast period compared to the Leading Portfolio under expected conditions.
3. Adding wind capacity late in the forecast period increases resource diversity, likely improving both Reliability and Resiliency compared to the Leading Portfolio.
4. The Optimized Portfolio incorporates a higher level of storage in the near-term, facilitating a potential higher level of Reliability.
5. The Optimized Portfolio avoids some operations costs, improving Affordability. It bridges technology advances while keeping the overall portfolio cost down.

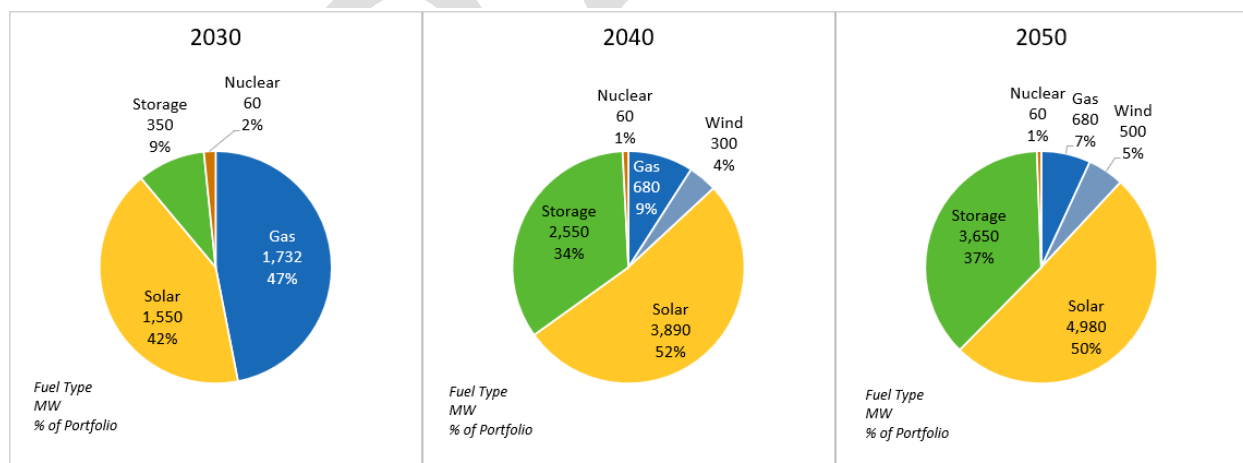
These revisions made to the Leading Portfolio results in the portfolio illustrated in Exhibit 57 with the resource mix by technology shown in Exhibit 58.

Exhibit 57: Optimized Portfolio Build-Out (2020-2050)



Source: Siemens PTI

Exhibit 58: Optimized Portfolio Installed Capacity



Source: Siemens PTI

A brief description of the enhancements to the Optimized Portfolio within the context of the Attributes follows.

9.2.1 Reliability

The Optimized Portfolio contains more technology diversity than the Leading Portfolio. This includes the natural gas conversions, solar, storage, wind, and nuclear. The increase in technologies in this portfolio is expected to contribute to its Reliability.

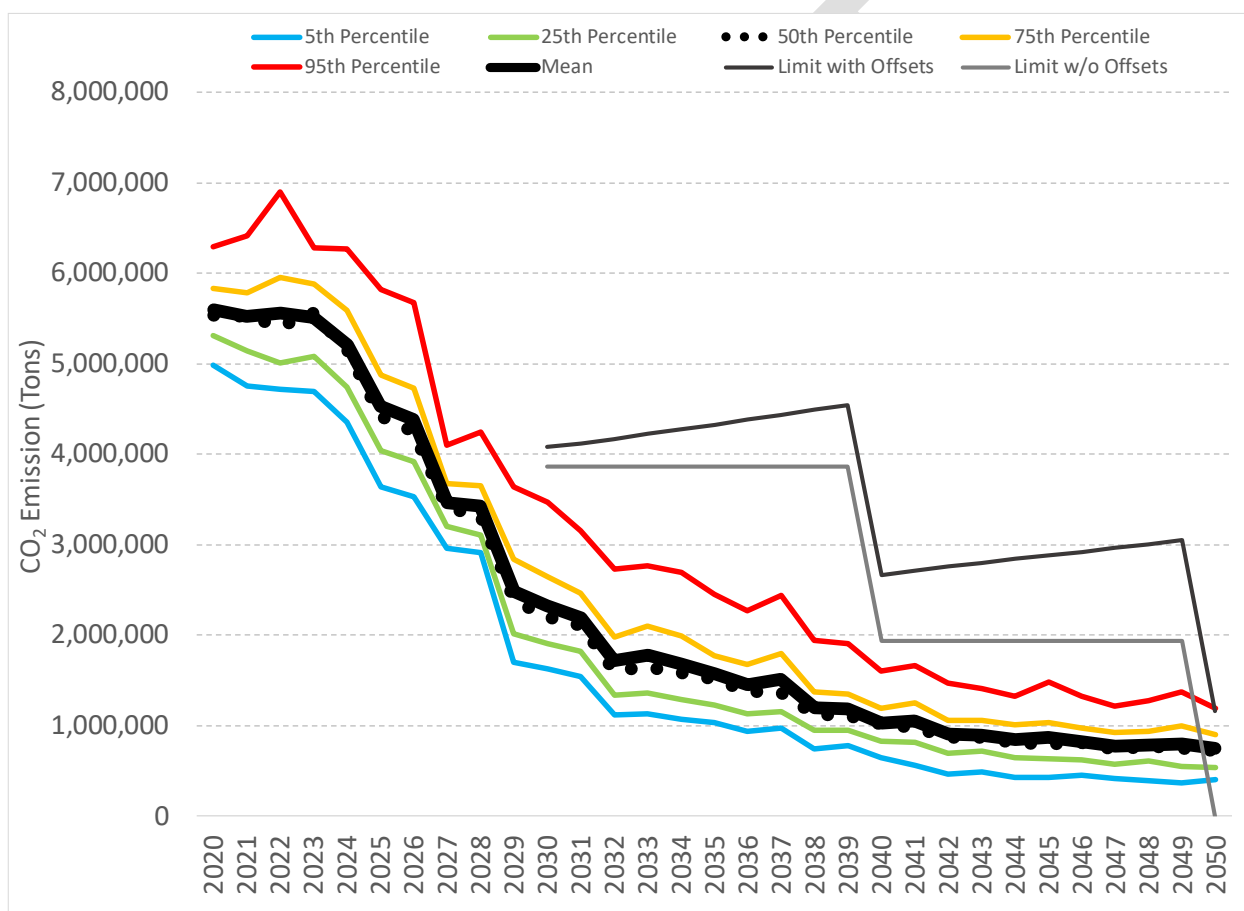
9.2.2. Affordability

The Optimized Portfolio bridges technology advances while keeping the overall portfolio cost down. Potential stranded costs are avoided by not spending resources for the construction of *new* natural gas-fired capacity and taking advantage of existing transmission infrastructure at the Stanton Energy Center. Gas conversion capital costs are 5 to 10% of the cost of a new Combined Cycle gas plant. This allows for the retirement of the converted natural gas-fired units by 2040 without the risk of stranded costs.

9.2.2 Sustainability

The Optimized Portfolio introduces some changes to the Leading Portfolio to increase Sustainability. By converting the Stanton coal units earlier, it avoids the high CO₂ emissions from burning coal. Additionally, retiring the gas conversion units further reduces CO₂ emissions. The Optimized Portfolio reduces CO₂ emissions by approximately 7.6 million tons over the entire forecast compared to the Leading Portfolio. To put this into perspective, this is the equivalent of the annual emissions of approximately 1.7 million passenger cars.²⁵

Exhibit 59: Optimized Portfolio CO₂ Emissions Stochastic Distributions



Source: Siemens PTI

Exhibit 59 illustrates the impact of retiring fossil fuel capacity on CO₂ emissions within the portfolio. CO₂ emissions are reduced when the coal units are converted to natural gas starting no later than 2025 and completed no later than 2027, after the Stanton A PPA ends in 2032, and upon the retirement of the conversion units.

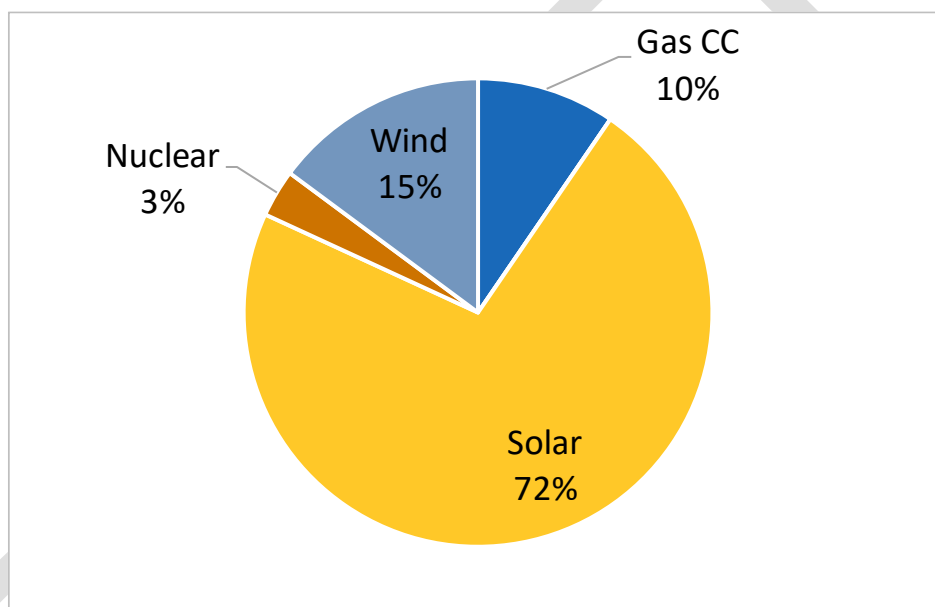
As Exhibit 59 shows, the Optimized Portfolio maintains a 95% probability of meeting all Net Zero CO₂ target throughout the forecast period. The 2030 and 2040 interim targets are

²⁵ This is based on data from EPA that calculates an annual average CO₂ emission of 4.6 metric tons for one passenger vehicle.

expected to be met without the need for offsets through EV adaptation. In 2050, the offsets are required because the Optimized Portfolio maintains the Indian River gas peaker units and the Stanton A and B combined cycles to maintain dispatchable capacity to ensure Reliability.

The second metric within the Sustainability Attribute is the amount of clean generation in the portfolio in 2050 on an expected basis. Exhibit 60 shows the energy generation by technology in 2050 for the Optimized Portfolio. Solar generation makes up almost three-quarters of the generation in 2050. The other clean generation technologies (Nuclear and Wind) contribute another 18% of the clean generation. This provides a total of 90% non-emitting energy generation in 2050 for the Optimized Portfolio. The only fossil fuel fired capacity generating energy in 2050 is OUC's portion of the Stanton A and B combined cycle units. The Indian River peaker units are still operating but are generating a negligible amount of energy in 2050.

Exhibit 60: Percentage of Total Energy Generation (MWh) by Technology (2050)



Source: Siemens PTI

9.2.3 Resiliency

The addition of wind generation reduces the solar and storage required to achieve energy sufficiency. Energy from wind resources is generally available at different times of day from solar resources important for Reliability and Resiliency.

Once the gas conversion units are retired and replaced with wind capacity, the portfolio is more resilient. The Optimized Portfolio has a high technology diversity, including the gas conversion and wind capacity in the latter part of the forecast, minimizing the impact of the hurricane.

10. Challenges and Opportunities

This EIRP presents a way forward for OUC to meet its load while significantly reducing its CO₂ emissions. However, since the state of the market will change over the next few years, it is important to consider both the challenges and opportunities that the Optimized Portfolio may present across the different Attributes described in this analysis. The following challenges and opportunities can be considered in future EIRP analyses conducted for OUC.

10.1 Reliability

Reserve margin focused on capacity will become less relevant and *energy* sufficiency more relevant as intermittent resources become more prevalent in the resource mix. Solar intermittency challenges are more acute in Florida than other areas of the country that allow large areas to pool resources to take advantage of load and resource diversity.

10.2 Affordability

To ensure energy sufficiency from solar and storage during high demand periods, OUC will have an energy surplus during lower demand periods. Managing this energy surplus may provide benefits that help to contain costs while maintaining reliability and other important Attributes.

Increased solar capacity increases remote generation as compared to local generation, with implications for transmission wheeling cost, interconnection cost and potentially local jobs.

10.3 Sustainability

Unlike other parts of the country, solar energy is the only renewable resource currently economically viable at scale in Florida. Wind energy could be made available by mid-2030s and OUC will continue to monitor its availability. OUC will continue to evaluate and monitor emerging clean resources such as hydrogen, offshore wind and small modular nuclear technologies.

10.4 Resiliency

OUC will have greater reliance on transmission infrastructure. Greater geographical diversity of renewable energy will be required to minimize the risk of extreme weather. Generation diversity will need to remain part of the OUC strategy.

Appendix A: Technology Cost and Performance Assumptions

This summary includes national capital cost forecasts from Siemens PTI by technology class.²⁶ All capital cost assumptions are considered to be “all-in” overnight capital costs which include EPC costs (Engineering, Procurement, and Construction), developer costs (i.e. land acquisition, permitting, legal, etc.), and financing interest during construction. However, these capital costs only include onsite costs up to the point of interconnection.²⁷

Estimates of unit cost are provided in

²⁶ Regional capital cost forecasts for FRCC and SERC are developed by applying regional multipliers from the EIA AEO to the Siemens national capital cost forecasts.

²⁷ Siemens “all-in” capital costs do not include additional transmission/interconnection costs past the busbar as these costs are highly variable and dependent on project specific details.

- Exhibit 61. According to the American Association of Cost Engineers (AACE), this is a Class 4 estimate appropriate for a study with an expected accuracy range on the low side: -15% to -30%, and on the high side: +20% to +50%. Given the modularity and experience building most generation technologies, Siemens PTI believes the cost estimates we provide are closer to Class 3 estimates and within a tighter range of accuracy than AACE defines.
- The estimates are for typical units of a class (i.e. Advanced class CT = G, H, J, or HA CT models depending upon the vendor), the unit models presented are typical for the class, and do not necessarily represent the specific models used as a basis for the estimate. Specific units may be chosen during a procurement process when vendors provide both unit performance and cost guarantees.
- Performance (e.g. heat rates) are based on International Organization for Standardization (ISO) conditions. ISO Conditions means the reference temperature, humidity and pressure conditions established by the International Standards Organization. ISO Conditions means 59 degrees Fahrenheit and 60% relative humidity. Only in extreme cases (i.e. high elevations or exceptional temperatures) does Siemens PTI adjust performance estimates to locational specificity, which does not apply in Florida, though adjustments are made for local cost conditions.
- Provided estimates are “inside-the-fence” estimates and account for all EPC and owners costs, including interest during construction, insurance and taxes. They do not include the cost of fuel, water, or waste pipelines, rail, or transmission upgrades since the exact location of the study plant is unknown. A cost of interconnection was not included but a cost for fuel transport was included.
- Technology cost and performance estimates are based on a combination of public and private sources which provide a range of potential inputs. No single budgetary estimate source will exactly represent the performance of a given unit when constructed. Vendors will assess site conditions during a procurement process and develop a specific offer which guarantees both performance and cost.
- Vendors operate in a highly competitive market and they continually improve unit performance and cost. As a result, a given turbine model (i.e. F-class) will perform better two to three years from now than today, while still being termed “F-class.” Thus, the studies and tools used to develop the performance and cost estimates may not represent the exact characteristics of a new unit purchased today, though the difference will be small, and the characteristics will remain within the bounds provided. Even vendor websites often lag in presenting their latest performance.
- Even within a given equipment model, customers have choices which influence performance and cost, and those choices are not always apparent. They may select wet or dry cooling, add evaporative cooling, require on-site gas compression, or add a range of duct firing capability, for example. This is one key reason Siemens PTI does not use project announcements in establishing technology cost and performance estimates. Announcements typically lack a clearly delineated supply scope and condition definition.

Siemens PTI capital cost forecasts are assumed for the year of commercial operation. Development timelines are considered for building new generation or storage, and interest during construction is included in the all-in capital cost estimation. Siemens PTI applied a weighted average cost of capital (WACC) of 6.3%, as provided by OUC, for plants OUC would finance.

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Exhibit 61: Siemens PTI New Resource Technology Cost and Financial Assumptions

Technology	Fuel	Constructi on Time (Yrs)	Winter Capacity (MW)		Average Heat Rate (Btu/kWh), HHV	VOM (2019\$/ MWh)	FOM (2019\$/ kW-yr)	Range of Capital Cost (2019\$/kW)	Book Life
Advanced 1x1 CCGT, Fired	Nat. Gas.	3	605		6,800	\$1.50	\$15.60	\$945-838	30
Conventional 1x1 CCGT, Fired	Nat. Gas.	3	385		7,000	\$2.00	\$17.50	\$1005-892	30
Simple Cycle Conventional Frame 7FA CT	Nat. Gas.	2	225		8,900	\$4.50	\$12.50	\$777-683	30
Simple Cycle Large Aero CT	Nat. Gas.	2	100		9,000	\$5.50	\$15.60	\$1074-944	30
Simple Cycle Small Aero CT	Nat. Gas.	2	50		9,000	\$5.50	\$15.60	\$1163- 1023	30
Landfill Gas	RNG	2	5		11,575	\$12.50	\$17.50	\$2578- 2267	40
Utility Solar PV - Tracking (Large)	Sun	1	74.5		N/A	\$0.00	20.80	\$1148-738	20
Utility Solar PV - Tracking (Small)	Sun	1	10		N/A	\$0.00	20.80	\$1236-795	20
Wind-by-Wire	Wind	2	100		N/A	\$49.48	0	N/A	N/A
Lithium Ion Batteries (4 hrs.)	Elec. Grid	1	50 MW	200 MWh	N/A	\$1.00	\$32.80	\$1201-580	20
Lithium Ion Batteries (4 hrs.)	Elec. Grid	1	5MW	20MWh	N/A	\$1.00	\$32.80	\$1357-647	20
Flow Batteries (6 hrs.)	Elec. Grid	1	50MW	300MWh	N/A	\$3.00	\$28.10	\$2075-781	20
Flow Batteries (6 hrs.)	Elec. Grid	1	5MW	30MWh	N/A	\$3.00	\$28.10	\$2370-883	20
Solar + 4 hr Storage	Sun/Ele c. Grid	1	50MW+	50MWh	N/A	\$1.00	\$26.00	\$1273-671	20
Nuclear SMR	Uranium	7	570		N/A	\$15.00	\$167.8 0	\$9215- 4734	40

Source: Siemens PTI

Appendix B: Stochastics

In order to perform the stochastic analysis, a set of probability distributions are required for key market driver variables. These include probabilistic distributions for demand growth (load), fuel costs (natural gas and coal), environmental compliance costs (CO₂), and capital costs.

B.1 Load Stochastics

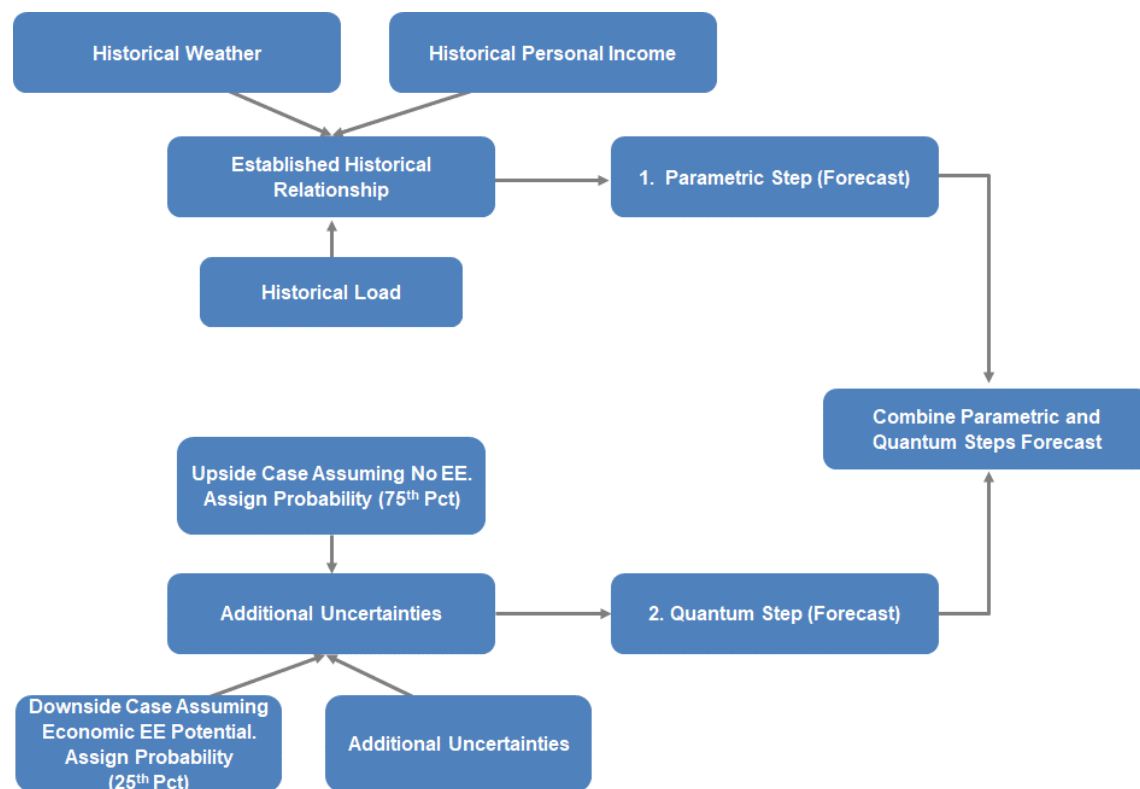
To account for variations in electricity demand stemming from economic growth, weather, and energy efficiency and demand side management measures, Siemens PTI developed stochastics around the load growth expectations for the OUC control area and the neighboring ISO zones. While values in the 95th percentile are driven by strong economic growth, values in the 5th percentile are driven by economic stagnation as well as energy efficiency and demand-side management implementation.

Siemens PTI's long-term load forecasting process is a two-step process that captures both the impact of historical load drivers such as economic growth and variability of weather (parametric step) and the possible disruptive impacts of energy efficiency penetration (quantum step) in constructing the average and peak demand outlook.

Finally, Siemens PTI benchmarked the projections against FRCC-sponsored load forecasting studies that are conducted by independent consultants and institutions and then released into the public domain. The process to benchmark the load to FRCC's forecasts is undertaken during the quantum step, which is described below.

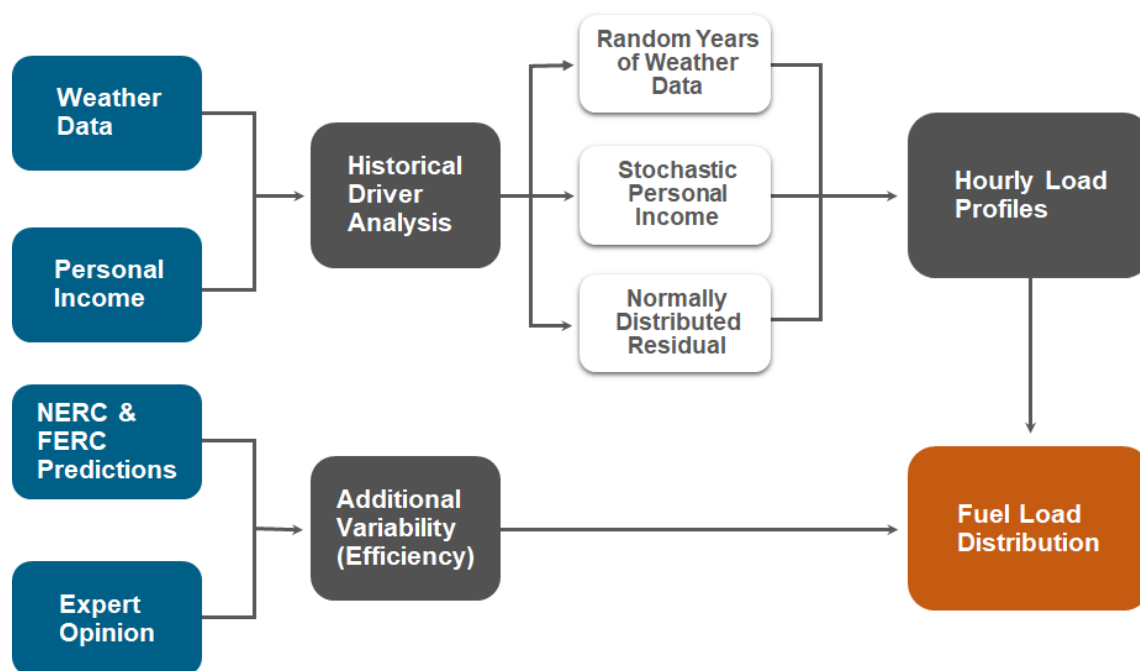
B.1.1 Load Forecast Process

The process for developing stochastic distributions for OUC and surrounding FRCC and SERC zones loads begins with a deterministic estimation of load uncertainties, followed by parametric and quantum forecasts for the FRCC and SERC zones.

Exhibit 62: Process for Developing Stochastic Distribution

To address demand uncertainty in modeling and capture the risk associated with demand growth, Siemens PTI produced a distribution of monthly average and peak loads using the methodology described below and summarized in the following flow chart.

Exhibit 63: Flow Chart to Address Load Uncertainty



Source: Siemens PTI

With respect to the historical driver analysis, we find that historical monthly weather data and personal income have explained changes in monthly average and peak load well. This relationship forms the basis for Siemens PTI's load uncertainty analysis. The basic premise of the model is that load can be expressed as a function of heating degree days, cooling degree days, humidity, and personal income.

$$\text{Load}_t = \alpha + \beta_1 * \text{HDD}_t + \beta_2 * \text{CDD}_t + \beta_3 * \text{HUM}_t + \beta_4 * \text{PI}_t + \xi_t$$

Where the independent variables are:

- HDD (Heating Degree Days): 65 - Average daily temperature in degrees Fahrenheit or zero (HDD is never negative)
- CDD (Cooling Degree Days): Average daily temperature -65 in degrees Fahrenheit or zero. (CDD is never negative)
- HUM (Humidity): Average daily percent humidity
- PI: Personal Income
- ξ : A normally distributed variable with mean 0 and constant variance
- α : A constant derived from the regression analysis
- β_n : Coefficients derived from the regression analysis
- t : Month of the year

A stepwise regression then calibrates this model for the historic net peak and average OUC load data. The stochastic distributions of the load were then computed by running 200 iterations on the independent variables as the randomly generated input parameters and applied to the equation and the calibrated model coefficients above.

B.1.2 FRCC and SERC Forecast Load Uncertainty

The subsequent load stochastics propagation for the surrounding FRCC and SERC zones is conducted in a two-step process: a parametric step and a quantum step.

The parametric step separately employs the same econometric specification for the FRCC and SERC Balancing Authorities based on the historical relationships between average and peak load, and key driver variables, including temperature data (HDD, CDD, and humidity) and an economic factor variable (personal income for the geographical area). Siemens PTI uses the historical personal income drift rates and volatility and a sampling from 17 years of historical data for each region or balancing authority to assess the distribution of overall load growth conditions for each year of the forecast. The base average and peak demand forecasts are based on the average of the peak and average demand forecasts.

Siemens PTI benchmarks its outlook against the latest FRCC-sponsored load forecasting study, which shows the CAGR for the next 10 year study period. To produce load stochastics, Siemens PTI propagates three independent random paths: weather data, personal income, and a residual. Weather data includes heating and cooling degree days and humidity. To produce reasonable weather data projections, Siemens PTI samples actual yearly paths from history. On average, we use about 17 years of historical data to perform the weather projections for the forward study period. Personal income is assumed to follow Geometric Brownian Motion. This means that there exists a normal distribution with constant mean and variance that describes how the return on personal income will behave at any time. Historical personal income data produces a best estimate for the relevant monthly mean and variance of this process going forward. Finally, to account for unexplained variation in the observed data, Siemens PTI adds a normally distributed residual with mean zero and standard deviation equal to the root mean squared error of the previously mentioned stepwise regression.

B.2 Gas Stochastics

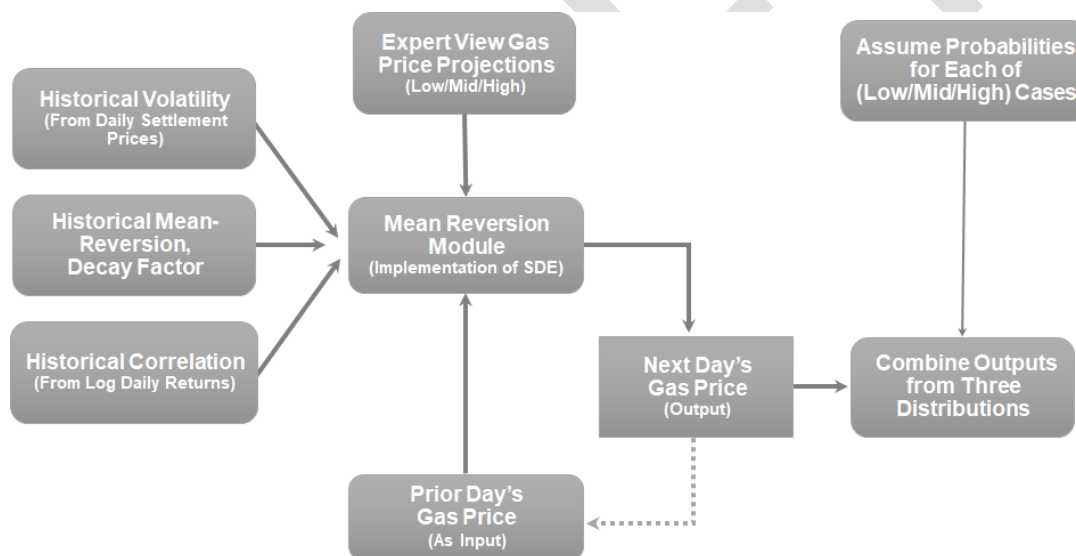
Siemens PTI develops natural gas stochastic distributions for Henry Hub and other basis points. These stochastic distributions are based on a reference case view of natural gas prices with probability bands developed based on a combination of historical volatility and mean reversion parameters as well as a forward view of expected volatility.

Siemens PTI has developed stochastics around the price at the Henry Hub (and other gas basis point as needed) based on historical volatility, current market forwards, and a long-term term fundamental view that considers the expected supply-demand balance. The 95th percentile probability bands are driven by increased gas demand (most likely due to coal retirements) and fracking regulations that raise the cost of producing gas. Prices in the 5th percentile are driven by significant renewable development that keeps gas plant utilization down as well as little to no environmental legislation around power plant emissions.

The steps involved in the development of gas stochastics are:

- As the first step, Siemens PTI develops the long-term fundamental forecast of Henry hub and several other gas basis points prices (using the GPCM model). The probability distributions are developed around this fundamental forecast.
- From historical data sets, the volatility parameter is calculated using the daily settled prices. Volatilities for different historical time periods are calculated (such as past 10-years, past 5 years, recent 2.5 years etc.)
- The daily gas prices are modeled as a single-factor continuous mean-reverting process. The mean reversion parameter is also calculated from the historical daily settled prices.
- For more than one gas basis point prices, the appropriate correlations are also calculated from the historical data.
- The entire process to develop the gas stochastics is described in the exhibit below.

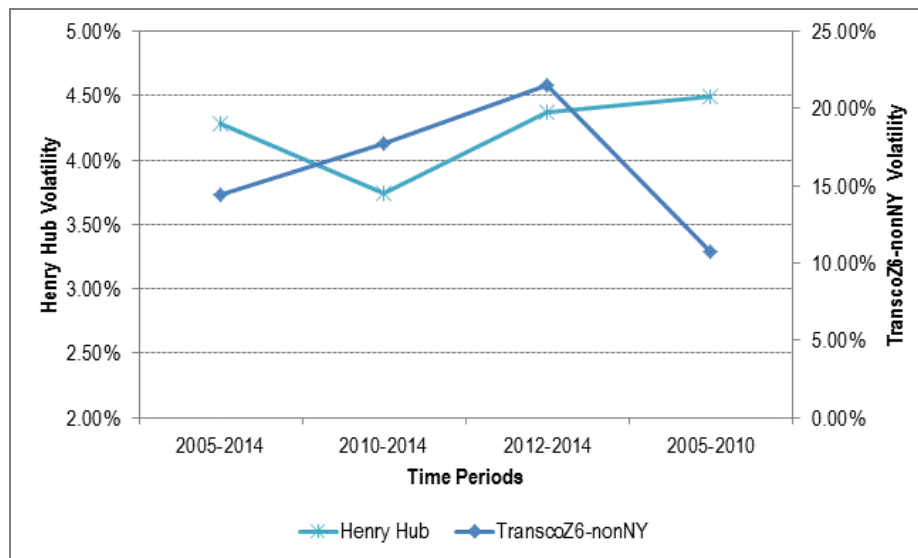
Exhibit 64: Gas Stochastics Development Process



Source: Siemens PTI

- The volatilities tend to vary for different time periods. In order to capture this for the forecast time period, different volatility values from different historical time periods are considered. For example, for the first 3 forecast years, volatility calculated from the past 30 months price data will be used. For years 4-8, volatility calculated from the past 5 years will be used. Beyond that time period, the past 10-year historical volatility will be used.
- For example, Exhibit 65 below shows the volatilities for Henry hub and a gas point in the Northeast (for illustration), for different historical time periods.

Exhibit 65: Henry Hub and TranscoZ6-nonNY Volatility



Source: Siemens

The long-term fundamental forecast for each month in the forecast time period will be treated as the mean-reverting level in this process.

B.3 Coal Stochastics

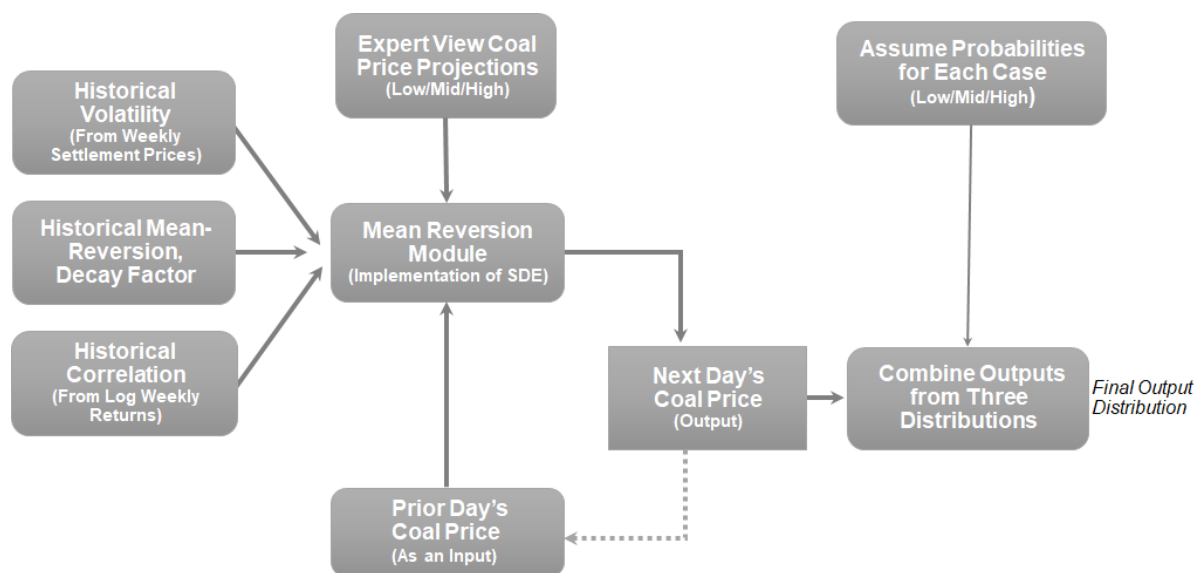
Siemens PTI develops coal price stochastic distributions for CAPP, NAPP, ILB and PRB basins.

These stochastic distributions are based on a reference case view of coal prices with probability bands developed based on a combination of historical volatility and mean reversion parameters.

It is to be noted that majority of coal contracts in the U.S. are bilateral and only about 20% are traded in NYMEX. The historical data set which is used to calculate the parameters comprise of the traded data reported in NYMEX, which is weekly.

The methodology involved in the distribution of stochastic coal prices is exactly similar to natural gas stochastics.

Exhibit 66: Process for Coal Price Stochastic



Source: Siemens

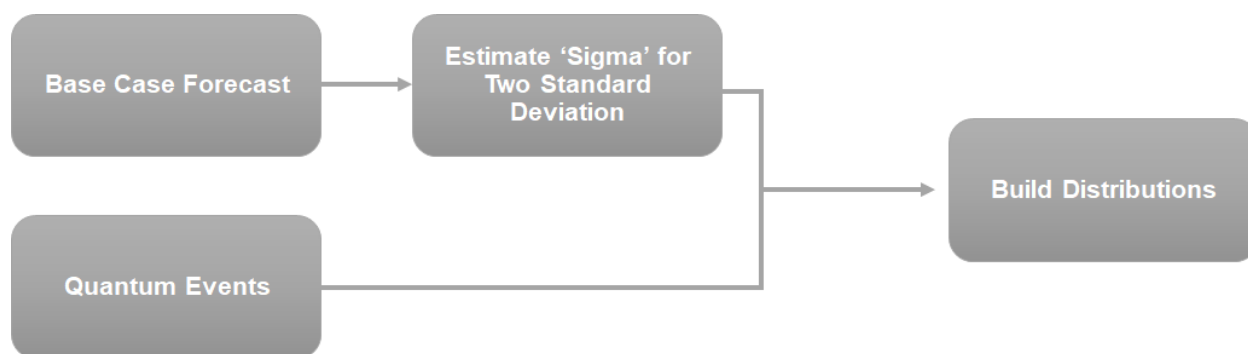
The steps involved in the development of coal basin price stochastics are:

- As the first step, Siemens PTI develops the long-term fundamental forecast of each of the coal basins. The probability distributions are developed around these fundamental forecasts.
- From historical data sets, the volatility parameter is calculated using the weekly prices. Volatilities for different historical time periods are calculated (such as past 10-years, past 5 years, recent 2.5 years etc.)
- The coal prices are modeled as a single-factor continuous mean-reverting process. The mean reversion parameter is also calculated from the historical prices.
- For the four coal basin prices, the appropriate correlations are calculated from the historical data.

B.4 CO₂ Stochastics

Siemens PTI develops uncertainty distributions around CO₂ compliance costs, which will be used in the power dispatch modeling to capture the inherent risk associated with regulatory compliance requirements.

The technique to develop CO₂ costs distributions, unlike the previous variables, is based on the “expert-opinion” based projections. There are no historical data sets to estimate the parameters for developing CO₂ costs distributions. The views of the internal subject matter experts (Siemens PTI’s) are taken into consideration. The exhibit below shows the high-level methodology for developing stochastic distributions when the historical data is not available.

Exhibit 67: Technique to Develop CO₂ Costs Distributions

Source: Siemens PTI

Given below are the steps involved in this process:

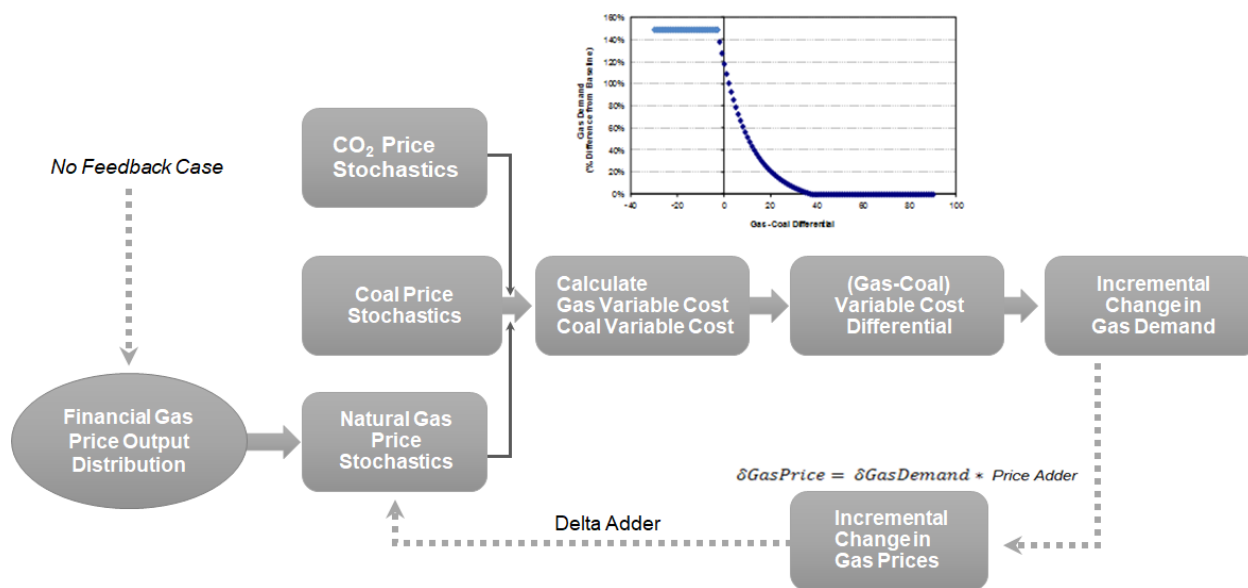
- Siemens PTI's environmental team develops a reference case (base case) forecast, and an associated high and low case. In addition to the high and low cases, the probability values for the high and low cases are also developed.
- These three cases are treated as 16th, 50th and 84th percentiles. Using these percentiles and statistical techniques (tools), the standard deviation values are calculated.
- The reference case is treated as the mid-case (median).
- Using the standard deviation values and a sampling from an underlying standard normal distribution (which has a mean zero and variance one), the probability bands are constructed around the reference projections. This underlying distribution captures the "quantum" events that can happen in the market.
- The distributions are then adjusted to incorporate probabilities such as "the probability of a CO₂ program not taking effect", "greater chance of a nation-wide CO₂ regime starting in, say 2022" etc.
- Separate distributions are developed for national CO₂ costs, California CO₂ costs and RGGI prices, which are then applied to the respective states.

B.5 Gas-Coal-CO₂ prices feedback (Cross-Commodity Correlations)

Siemens PTI has implemented a distinct process to capture the cross-commodity correlations into the stochastic processes. This is a separate process which is implemented after modeling the gas, coal and CO₂ processes discussed above.

The exhibit below describes the coal and CO₂ feedback to gas prices. At a high level, the feedback effects are based on statistical relationships between coal and gas switching and the variable cost of coal and gas generators.

Exhibit 68: Cross Commodity Correlations



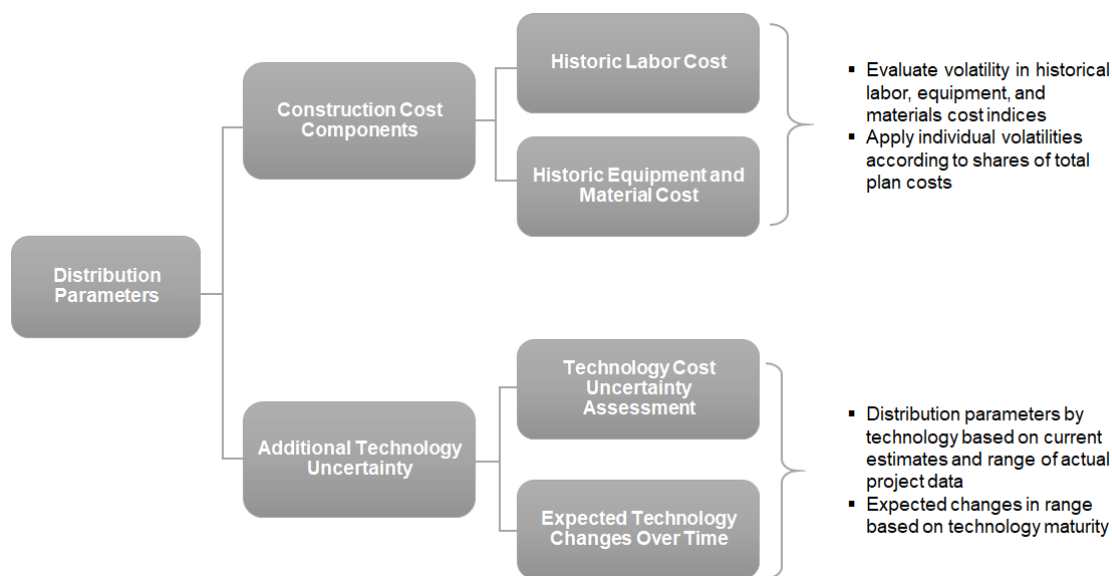
Source: Siemens PTI

- Siemens PTI has performed some fundamental analyses to define the relationship between gas-coal dispatch cost and demand; incremental gas demand curve as a function of the gas-coal differential was calibrated.
- For each iteration, the dispatch cost of gas and coal is calculated from the fuel stochastics and CO2 stochastics, along with generic assumptions for VOM.
- If the gas-coal dispatch differential changes significantly enough to affect demand, gas demand from previous year is adjusted to reflect the corresponding change in demand.
 - Adjustment can happen in both directions
- A gas price delta is then calculated based on the defined gas demand – price relationship developed.
- This gas price delta is added to the gas stochastic path developed from historic volatility to calculate an integrated CO2 and natural gas stochastic price.

B.6 Capital Cost Stochastics

Siemens PTI develops the uncertainty distributions for the cost of new entry units by technology types, which will be used in the AURORA dispatch model for determining the economic new builds based on market signals. The exhibit below describes the methodology at a high level.

Exhibit 69: Capital Costs Stochastics Methodology



Source: Siemens PTL

The methodology of develop the capital cost distributions is a two-step process:

B.7 Step 1: Parametric Distribution:

Siemens PTI's subject matter experts provide a reference case forecast of \$/KW all-in capital costs for different technology types. Along with it, high and low case forecasts are also developed.

The plant costs are broken down by Equipment, Materials, Labor & Others. Historical data (from Handy-Whitman Index) is used to estimate mean price changes and volatilities in these cost categories.

Suitable weights are allocated to each of these 4 categories. The weighted average of the historical mean and volatilities are then estimated.

Using the mean and volatility values, and sampling from an underlying standard normal distribution (which has a mean zero and variance one), the probability bands are constructed around the reference forecast.

B.8 Step 2: Quantum Distribution:

This step captures the additional uncertainty associated with each technology. It also factors-in the learning curve effects, improvements in technology over time and other “uncertain” events. The expert-opinion based high and low cases are treated as 1 standard deviation from the mean. With this assumption, the variance values are calculated.

To come with probability distributions, a log-normal distribution is assumed. This distribution is combined with the parametric distribution obtained in the previous step, to come up with the final set of distributions

DRAFT

Appendix C: Terms and Definitions

Advisory Council

The OUC EIRP Advisory Council is 12-member volunteer group – nominated by elected City and County Commissioners from Orange and Osceola counties and the Cities of Orlando and St. Cloud – who represent a cross-section of our community. The role of the Advisory Council – as advisors, educators and a connection point to the communities they represent – is to serve as a voice for all stakeholder groups. These groups include residential customers, fixed income groups, community partners, environmental groups, OUC program participants, and Orange and Osceola County residents.

Affordability

An electric system's ability to produce and deliver energy at an affordable cost with minimal price fluctuations.

Siemens PTI uses metrics related to the portfolio costs of generation and transmission, including fixed cost recovery, and the uncertainty of portfolio costs to measure each Candidate Portfolio for this Attribute.

Attributes

A quality or characteristic of a portfolio. For the purpose of the EIRP, the four Attributes (Affordability, Reliability, Resiliency, Sustainability) are the primary objectives used to evaluate the performance of all Candidate Portfolios.

Calibration Portfolio

This portfolio serves as a business-as-usual (BAU) outlook of expected market conditions and expected load. The Calibration Portfolio also serves as a benchmark to measure the performance of other portfolios relative to a baseline.

Candidate Portfolios

For the purpose of the EIRP, Candidate Portfolios are developed to be tested against the four Attributes for potential selection as OUC's resource strategy.

CO₂ Offsets to Meet Net Zero CO₂ Goals

CO₂ offsets were calculated from the use of electric vehicles to potentially offset any CO₂ emissions from electricity generation. The electric vehicles forecast is consistent with OUC's 2025 strategic plan. Although other types of offsets are available such as market purchases of credit and reforestation, no other offsets are used for the purpose of this EIRP.

Conditions

Conditions represent external scenarios that influence and affect the financial, technical and operational environments in which future generation resources should be considered including technology advancements and regulatory changes.

Demand (Peak Demand)

The rate of electricity consumption over any instance. It is typically measured in kilowatts (kW) or megawatts (MW).

Deterministic Modeling

A deterministic model is one where variables are uniquely determined by parameters in the model²⁸. In other words, the analysis or simulation is conducted with one set of inputs and one set of outputs. A deterministic model does not capture the uncertainty inherent in forecasts.

Dispatchable Generation

Dispatchable generation refers to a type of generation that can be controlled to balance real-time electricity supply and demand. Most conventional power sources such as coal or natural gas power plants are dispatchable in order to meet the always changing electricity demands of the population. In contrast, many renewable energy sources are intermittent and non-dispatchable, such as wind power or solar power which can only generate electricity while their primary resource is available²⁹.

Energy

Energy is defined as the electricity consumption by consumers over a period of time. It is typically measured in kilowatt-hours (kWh) or megawatt-hours (MWh).

Battery Energy Storage Systems

While battery energy storage cannot generate electricity, energy can be stored and later reconverted to electricity on demand. For the purpose of the EIRP, battery energy storage systems store energy from solar arrays or the electric grid and provide energy to consumers when needed. Battery energy storage systems can be used to improve the dispatchability of solar or wind energy systems.

Net Zero CO₂

Net Zero CO₂ refers to a condition of zero CO₂ emissions from electric generation net of any recognized offsets such as avoided CO₂ emissions from electric vehicles.

²⁸ Renard, Philippe, et al. "Stochastic versus Deterministic Approaches." *Environmental Modelling*, 2013, pp. 133–149., doi:10.1002/9781118351475.ch8.

²⁹ https://energyeducation.ca/encyclopedia/Dispatchable_source_of_electricity#cite_note-2

Pathways

Methodologies and/or strategies to achieve the EIRP objective to reach the Net Zero CO₂ goal by 2050. Pathways are used to develop Candidate Portfolios. Examples of pathways used in the EIRP are:

- *Net Zero CO₂ by 2050* – Both CO₂-free and CO₂-generating resources are used.
- *100% Renewable Energy by 2050 w/ Intermediate Targets* – Meets the City of Orlando's target of 100% renewable energy by 2050 with intermediate benchmarks for OUC of 50% Renewable Energy Generation by 2030 and 75% Renewable Energy Generation by 2040.
- *100% Renewable Energy by 2050 w/ Intermediate Targets including Nuclear* – Same as Pathway 2 but with Nuclear and Biomass included as potential resources.
- *100% Net Zero CO₂ by 2050 (OUC+FL)* – Same as Pathway 1 but with all Florida Utilities required to offset their CO₂.
- *Stanton Plant Retirement (Stanton Phase-Out)* – Follows the first unaffiliated Synapse report (circa 2018) that posits the retirement of the Stanton 1 coal unit and the Stanton 2 coal unit with only renewable energy and storage capacity allowed to backfill.

Reliability

An electric system's ability to effectively produce and deliver the energy required by customers with minimal interruptions and consistent quality while maintaining compliance.

Each portfolio is designed to meet or exceed the Reliability requirement of 100% energy sufficiency as an islanded system under expected deterministic conditions. All portfolios meet this minimum threshold. Siemens PTI uses unserved energy and technological diversity as metrics to measure the Reliability of Candidate Portfolios.

Resiliency

An electric system's ability to adapt to uncontrollable events – such as weather extremes (hurricanes, major storms, heat waves, cloud cover, other extreme weather events) – maintain physical and cyber security, and quickly bounce back following an interruption.

Siemens PTI uses scenario analysis simulating system shocks such as hurricanes and gas pipeline disruptions and metrics related to unserved energy to measure each portfolio for this Attribute.

Stochastic Modeling

A stochastic model attempts to capture the uncertainty inherent in forecasts. Whereas a deterministic model has one set of inputs and one set of outputs for each variable, a stochastic model may have a range of inputs and outputs for each variable. For the purpose of the EIRP, Siemens PTI uses a stochastic modeling approach that simulates a broad range of market conditions, capturing the uncertainty in electricity demand, fuel prices, emissions prices, and the capital costs for generating technologies.

Sustainability

An electric system's ability to produce energy in a way that proactively reduces pollution and impacts on the surrounding ecosystem.

For the purpose of the EIRP, Sustainability is synonymous with environment stewardship through the use of "clean" generating technologies.

Synapse Study (August 1, 2018)

A third-party study provided by the First Fifty Coalition that details how the Stanton coal plant could be closed in a short time frame. Synapse proposes to retire one Stanton Coal unit at the end of 2020 and a second Stanton coal unit as soon as possible thereafter. The Synapse report was revised in June 2020.

Appendix D: Existing Unit Specifications and Model Topography

Capacity Holder	Plant Name	Summer Capacity (MW)	Winter Capacity (MW)	Entity Share of Capacity (%)	Summer Capacity by Entity Share (MW)	Winter Capacity by Entity Share (MW)	Minimum Capacity (%)	Entity Share Minimum Capacity (MW)	Fuel Type	COD	End Date	Heat Rate	Minimum Up Time (Hours)	Minimum Down Time (Hours)	Ramp Up Rate (MW/Hour)	Ramp Down Rate (MW/Hour)	Average Forced Outage	Average Maintenance Rate (%)	Emission Rates lbs/MMBtu (CO ₂)	Emission Rates lbs/MMBtu (SO _x)	Emission Rates lbs/MMBtu (NO _x)	Resource Location (for modeling)
OUC Assets	Stanton 1	441.0	441.0	68.5%	302.1	302.1	25%	75.4	Coal	Jul-87	n/a	9,806	168	60	120	120	7.7%	9.6%	202	0.1200	0.2500	OUC GEN
	Stanton 1 (effective May 1, 2020)	453.0	453.0	68.5%	310.3	310.3	24%	75.4	Coal	Jul-87	n/a	9,200	168	60	120	120	7.7%	9.6%	202	0.1200	0.2500	OUC GEN
	Stanton 2	453.0	453.0	75.0%	339.8	339.8	24%	82.5	Coal	Jun-96	n/a	9,184	168	60	120	120	7.7%	9.6%	202	0.1100	0.1400	OUC GEN
	Stanton 2 (effective Dec 1, 2020)	463.0	463.0	75.0%	347.3	347.3	24%	82.5	Coal	Jun-96	n/a	9,050	168	60	120	120	7.7%	9.6%	202	0.1100	0.1400	OUC GEN
	Stanton A Owned (1x1)	230.0	235.0	80%	184.0	188.0	66%	124.0	Natural Gas	Oct-03	n/a	7000 / 8000	40	8	360	360	4.6%	7.0%	119	0.0000	0.0180	OUC GEN
	Stanton A PPA (2x1)	332.8	340.0	80%	266.2	272.0	54%	148.0	Natural Gas	Oct-03	12/31/2031	6800 / 7500	8	8	720	720	4.6%	7.0%	119	0.0000	0.0180	OUC GEN
	Stanton A PPA (DF)	107.6	110.0	80%	86.0	88.0	36%	32.0	Natural Gas	Oct-03	12/31/2031	12,000	2	1	120	120	4.6%	7.0%	119	0.0000	0.0180	OUC GEN
	Stanton B CC + PA	271.1	285.0	100%	271.1	285.0	53%	150.0	Natural Gas	Feb-10	n/a	7,400	36	8	360	360	4.6%	7.0%	119	0.0000	0.0050	OUC GEN
	Stanton B Duct-Burner	39.9	42.0	100%	39.9	42.0	0%	0.0	Natural Gas	Feb-10	n/a	9,350	n/a	n/a	30	30	4.6%	7.0%	119	0.0000	0.0050	OUC GEN
	Indian River A	30.2	35.0	48.8%	14.7	17.1	63%	10.7	Natural Gas	Jun-89	n/a	13,200	1	1	300	300	11.2%	3.9%	119	0.0000	0.1300	OUC GEN
	Indian River B	30.2	35.0	48.8%	14.7	17.1	63%	10.7	Natural Gas	Jul-89	n/a	13,200	1	1	300	300	11.2%	3.9%	119	0.0000	0.1000	OUC GEN
	Indian River C	103.2	110.0	79%	81.5	86.9	32%	27.7	Natural Gas	Aug-92	n/a	12,400	1	1	600	600	7.6%	3.9%	119	0.0000	0.0720	OUC GEN
	Indian River D	103.2	110.0	79%	81.5	86.9	32%	27.7	Natural Gas	Oct-92	n/a	12,400	1	1	600	600	7.6%	3.9%	119	0.0000	0.0650	OUC GEN
	St Lucie	60.0	62.0	100%	60.0	62.0	100%	60.0	Nuclear	Jun-83	n/a	10,500	n/a	n/a	n/a	n/a	3.8%	8.3%	n/a	n/a	n/a	OUC GEN
	C. D. McIntosh Jr. 3	352.1	360.0	40%	140.8	144.0	50%	72.0	Coal	Sep-82	12/1/2024	10,163	168	60	180	180	7.9%	9.6%	205	0.0520	0.0540	OUC GEN
	Florida Municipal Solar PV1-3	223.5	0.0	48%	54.0	0.0	n/a	n/a	Solar	Jun-20	6/30/2050	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	OUC GEN
	Invernergy Kissimmee	74.5	0.0	100%	37.3	0.0	n/a	n/a	Solar	Dec-22	12/31/2042	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	OUC GEN
	Invernergy Sabal Palm	74.5	0.0	100%	37.3	0.0	n/a	n/a	Solar	Dec-23	12/31/2043	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	OUC GEN
	Stanton Solar Farm	6.0	0.0	100%	3.0	0.0	n/a	n/a	Solar	n/a	8/31/2030	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	OUC GEN
	Stanton Solar PPA (Ksionek)	8.9	0.0	100%	4.5	0.0	n/a	n/a	Solar	n/a	8/31/2037	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	OUC GEN

Capacity Holder	Plant Name	Summer Capacity (MW)	Winter Capacity (MW)	Entity Share of Capacity (%)	Summer Capacity by Entity Share (MW)	Winter Capacity by Entity Share (MW)	Minimum Capacity (%)	Entity Share Minimum Capacity (MW)	Fuel Type	COD	End Date	Heat Rate	Minimum Up Time (Hours)	Minimum Down Time (Hours)	Ramp Up Rate (MW/Hour)	Ramp Down Rate (MW/Hour)	Average Forced Outage	Average Maintenance Rate (%)	Emission Rates lbs/MMBtu (CO ₂)	Emission Rates lbs/MMBtu (SO _x)	Emission Rates lbs/MMBtu (NO _x)	Resource Location (for modeling)
	Landfill Gas (CBI @ Drury)	9.0	9.0	100%	9.0	9.0	n/a	n/a	LFG	n/a	10/31/2035	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	OUC GEN
	Landfill Gas PPA (Broward)	6.0	6.0	100%	6.0	6.0	n/a	n/a	LFG	n/a	3/31/2036	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	OUC GEN
	Landfill Gas PPA (Charlotte)	2.6	2.6	100%	2.6	2.6	n/a	n/a	LFG	n/a	9/30/2031	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	OUC GEN
Non-OUC FMPA Assets	Cane Island 1 - CT	35.0	38.0	100%	35.0	38.0	30%	0.0	Natural Gas	n/a	n/a	9,000	6	4	308	308	4.6%	7.0%	119	0.0000	0.0247	FMPA KUA GEN
	Cane Island 2 - CC	109.0	113.0	100%	109.0	113.0	30%	33.9	Natural Gas	1995	n/a	7,910	6	4	151	151	4.6%	7.0%	119	0.0000	0.0247	FMPA KUA GEN
	Cane Island 3 - CC	240.0	250.0	100%	240.0	250.0	30%	75.0	Natural Gas	2002	n/a	7,400	6	4	335	335	4.6%	7.0%	119	0.0000	0.0247	FMPA KUA GEN
	Cane Island 4 - CC	300.0	310.0	100%	300.0	310.0	30%	93.0	Natural Gas	2011	n/a	7,400	6	4	415	415	4.6%	7.0%	119	0.0000	0.0247	FMPA KUA GEN
	St Lucie	9.0	9.0	100%	9.0	9.0	90%	8.1	Nuclear	n/a	n/a	10,500	n/a	n/a	n/a	n/a	3.8%	8.3%	n/a	n/a	n/a	FMPA KUA GEN
	Indian River A	30.2	35.0	51.2%	15.4	17.9	63%	11.3	Natural Gas	Jun-89	n/a	13,200	1	1	300	300	11.2%	3.9%	119	0.0000	0.1300	OUC GEN
	Indian River B	30.2	35.0	51.2%	15.4	17.9	63%	11.3	Natural Gas	n/a	n/a	13,200	1	1	300	300	11.2%	3.9%	119	0.0000	0.1000	OUC GEN
	Indian River C	103.2	110.0	21%	21.7	23.1	32%	35.0	Natural Gas	n/a	n/a	12,400	1	1	600	600	7.6%	3.9%	119	0.0000	0.0720	OUC GEN
	Indian River D	103.2	110.0	21%	21.7	23.1	32%	35.0	Natural Gas	n/a	n/a	12,400	1	1	600	600	7.6%	3.9%	119	0.0000	0.0650	OUC GEN
	Larsen 2	10.0	14.0	100%	10.0	14.0	30%	4.2	Natural Gas	n/a	n/a	15,500	6	4	114	114	4.6%	7.0%	119	0.0000	0.0247	LAKELAND GEN
	Larsen 3	9.0	13.0	100%	9.0	13.0	30%	3.9	Natural Gas	n/a	n/a	15,500	0	0	105	105	21.4%	3.9%	119	0.0000	0.0112	LAKELAND GEN
	Larsen 8	105.0	124.0	100%	105.0	124.0	30%	37.2	Natural Gas	n/a	n/a	9,000	0	0	166	166	21.4%	3.9%	119	0.0000	0.0112	LAKELAND GEN
	C. D. McIntosh Jr. 3	352.1	360.0	60%	211.2	216.0	50%	108.0	Coal	n/a	12/1/2024	10,163	168	60	180	180	7.9%	9.6%	205	0.0520	0.0540	LAKELAND GEN
	C. D. McIntosh Jr. 5	338.0	354.0	100%	338.0	354.0	30%	106.2	Natural Gas	n/a	n/a	7,400	6	4	474	474	4.6%	7.0%	119	0.0000	0.0247	LAKELAND GEN
	LAK MAC GT2	115.0	125.0	100%	115.0	125.0	30%	37.5	Natural Gas	Apr-20	n/a	11,700	4	8	670	670	2.5%	3.9%	119	0.0000	0.0112	LAKELAND GEN
	McIntosh Diesels	5.0	5.0	100%	5.0	5.0	0%	0.0	Diesel	n/a	n/a	10,696	0	0	27	27	4.0%	3.8%	162	0.6505	0.0327	LAKELAND GEN
	McIntosh GT1	16.0	19.0	100%	16.0	19.0	45%	8.6	Natural Gas	n/a	n/a	15,000	6	4	102	102	8.1%	3.9%	119	0.0000	0.0112	LAKELAND GEN
	Winston Diesels	50.0	50.0	100%	50.0	50.0	0%	0.0	Diesel	n/a	n/a	9,000	0	0	268	268	4.0%	3.8%	162	0.6505	0.0327	LAKELAND GEN
	Oleander 5	157.0	157.0	100%	157.0	157.0	30%	47.1	Natural Gas	n/a	n/a	11,500	0	0	841	841	7.9%	9.6%	119	0.0000	0.0112	FMPA EAST GEN
	St Lucie 2	48.0	50.0	100%	48.0	50.0	100%	48.0	Nuclear	n/a	n/a	10,500	n/a	n/a	n/a	n/a	3.8%	8.3%	n/a	n/a	n/a	FMPA EAST GEN
	Stanton 1	441.0	441.0	31.5%	112.0	112.0	31%	34.7	Coal	Jul-87	n/a	9,806	168	60	120	120	7.7%	9.6%	202	0.1200	0.2500	FMPA EAST GEN + FMPA WEST GEN
	Stanton 1 (effective May 1, 2020)	453.0	453.0	31.5%	112.0	112.0	31%	34.7	Coal	Jul-87	n/a	9,806	168	60	120	120	7.7%	9.6%	202	0.1200	0.2500	FMPA EAST GEN + FMPA WEST GEN
	Stanton 2	453.0	453.0	25.0%	102.0	102.0	27%	27.5	Coal	Jun-96	n/a	9,184	168	60	120	120	7.7%	9.6%	202	0.1100	0.1400	FMPA EAST GEN + FMPA WEST GEN

Capacity Holder	Plant Name	Summer Capacity (MW)	Winter Capacity (MW)	Entity Share of Capacity (%)	Summer Capacity by Entity Share (MW)	Winter Capacity by Entity Share (MW)	Minimum Capacity (%)	Entity Share Minimum Capacity (MW)	Fuel Type	COD	End Date	Heat Rate	Minimum Up Time (Hours)	Minimum Down Time (Hours)	Ramp Up Rate (MW/Hour)	Ramp Down Rate (MW/Hour)	Average Forced Outage	Average Maintenance Rate (%)	Emission Rates lbs/MMBtu (CO ₂)	Emission Rates lbs/MMBtu (SO _x)	Emission Rates lbs/MMBtu (NO _x)	Resource Location (for modeling)
	Stanton 2 (effective Dec 1, 2020)	463.0	463.0	25.0%	102.0	102.0	27%	27.5	Coal	Jun-96	n/a	9,184	168	60	120	120	7.7%	9.6%	202	0.1100	0.1400	FMPA EAST GEN + FMPA WEST GEN
	Stanton A (1x1) FMPA-Owned	230.0	235.0	20%	46.0	47.0	66%	31.0	Natural Gas	n/a	n/a	7,400	8	8	720	720	4.6%	7.0%	119	0.0000	0.0180	FMPA EAST GEN
	Stanton A (2x1) FMPA-PPA	332.8	340.0	20%	66.6	68.0	54%	37.0	Natural Gas	n/a	n/a	7,400	8	8	720	720	4.6%	7.0%	119	0.0000	0.0180	FMPA EAST GEN
	Stanton A (DF) FMPA-PPA	107.6	110.0	20%	21.5	22.0	36%	8.0	Natural Gas	n/a	n/a	7,400	8	8	720	720	4.6%	7.0%	119	0.0000	0.0180	FMPA EAST GEN
	Florida Municipal Solar PV1-3	223.5	0.0	52%	58.1	0.0	n/a	n/a	Solar	Jun-20	6/30/2050	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	FMPA EAST GEN
	Stock Island CT 1	19.0	19.0	100%	19.0	19.0	0%	0.0	Diesel	n/a	n/a	10,607	0	0	154	154	4.0%	3.8%	162	0.6505	0.0327	FMPA EAST GEN
	Stock Island CT 2	16.0	16.0	100%	16.0	16.0	0%	0.0	Diesel	n/a	n/a	10,000	0	0	130	130	4.0%	3.8%	162	0.6505	0.0327	FMPA EAST GEN
	Stock Island CT 3	14.0	14.0	100%	14.0	14.0	0%	0.0	Diesel	n/a	n/a	10,000	0	0	114	114	4.0%	3.8%	162	0.6505	0.0327	FMPA EAST GEN
	Stock Island CT 4	46.0	46.0	100%	46.0	46.0	0%	0.0	Diesel	n/a	n/a	9,119	0	0	246	246	4.0%	3.8%	162	0.6505	0.0327	FMPA EAST GEN
	Stock Island EP2	2.0	2.0	100%	2.0	2.0	0%	0.0	Diesel	n/a	n/a	10,607	0	0	11	11	4.0%	3.8%	162	0.6505	0.0327	FMPA EAST GEN
	Stock Island MSDs + EP2	18.0	18.0	100%	18.0	18.0	0%	0.0	Diesel	n/a	n/a	10,000	0	0	86	86	4.0%	3.8%	162	0.6505	0.0327	FMPA EAST GEN
	Treasure Coast Energy Center	300.0	310.0	100%	300.0	310.0	30%	93.0	Natural Gas	n/a	n/a	7,600	6	4	415	415	4.6%	7.0%	119	0.0000	0.0247	FMPA EAST GEN
	Tom Smith CC	30.0	30.0	100%	30.0	30.0	48%	14.4	Natural Gas	n/a	12/31/2025	10,244	5	6	40	40	4.6%	7.0%	119	0.0000	0.0247	LAKE WORTH GEN
	Tom Smith GT	27.0	27.0	100%	27.0	27.0	0%	0.0	Diesel	n/a	12/31/2025	12,460	0	0	145	145	4.0%	3.8%	162	0.6505	0.0327	LAKE WORTH GEN
	Tom Smith 3	27.0	27.0	100%	27.0	27.0	27%	7.3	Natural Gas	n/a	12/31/2025	12,537	6	6	36	36	13.1%	3.9%	119	0.0000	0.0247	LAKE WORTH GEN
	St. Lucie 2	20.0	20.0	100%	20.0	20.0	100%	20	Nuclear	n/a	12/31/2025	10,500	n/a	n/a	n/a	n/a	3.80%	8.30%				LAKE WORTH GEN

Appendix E: List of Abbreviations

Abbreviation	Definition
AACE	American Association of Cost Engineers
ACE	Affordable Clean Energy
AEO	Annual Energy Outlook
ATB	Annual Technology Baseline
BAU	Business-As-Usual
BEV	Battery Electric Vehicles
CAISO	California Independent System Operator
CAPP	Central Appalachian
CCGT	Combined cycle gas turbines
CDD	Cooling Degree Days
CIL	Capacity Import Limit
CT	Cycle Combustion Turbines
DEF	Duke Energy Florida
DG	Distributed Solar Generation
DR	Demand Response
EE	energy efficiency
EIA	U.S. Energy Information Administration
EIRP	Electric Integrated Resource Plan
EPA	Environmental Protection Agency
EV	Electric Vehicle
FEECA	Florida Energy Efficiency and Conservation Act
FMPA	Florida Municipal Power Agency
FMPP	Florida Municipal Power Pool
FPL	Florida Power and Light
FPSC	Florida Public Service Commission
FRCC	Florida Reliability Coordinating Council
GHG	Green House Gas
GPCM	Gas Pipeline Competition Model
HDD	Heating Degree Days
HRSG	Heat Recovery
HUM	Humidity
ILB	Illinois Basin
IPP	independent power producers
ISO	Independent System Operator (Organization for Standardization)
ITC	Investment Tax Credit

Abbreviation	Definition
LDV	Light Duty Vehicle
LNG	Liquefied Natural Gas
NAPP	Northern Appalachian
NERC	North American Electric Reliability Corporation
NRC	U.S. Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
ORNL	Oak Ridge National Labs
PHEV	Plug-In Hybrid Electric Vehicles
PJM	PJM Interconnection
PPA	Power Purchase Agreement
PRB	Powder River Basin
PV	Photovoltaic
RPS	Renewable Portfolio Standards
SERC	SERC Reliability Corporation
SMR	Small Modular Reactor
TECO	Tampa Electric Company
UCAP	Unforced Generation Capacity
WACC	Weighted Average Cost of Capital

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)
Emergency Order: Orlando Utilities Commission
Regarding the Stanton Energy Center

Order No. 202-26-42

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

EXHIBIT 9

DOE 4.8.26 LETTER



Department of Energy
Washington, DC 20585

April 8, 2026

Mr. Clint P. Bullock
General Manager and Chief Executive Officer
Orlando Utilities Commission
100 W. Anderson St.
Orlando, FL 32801

Re: Information Request for Stanton Energy Center

Mr. Bullock:

The U.S. Department of Energy (DOE) is responsible for ensuring the adequacy, reliability, and security of energy supplies throughout the United States. This mission includes oversight of energy production, transmission, and distribution infrastructure; coordination with federal, state, and regional entities; and the collection of information necessary to identify and address risks to the national energy supply. DOE carries out this work to protect the public interest and support the long-term resilience of the Nation's energy systems.

The Trump Administration and Secretary Wright have prioritized ensuring reliable electric supplies. Key sectors in the modern economy of our great Nation depend on reliable electricity, including hospitals and emergency services, transportation, communications, and industrial production. President Trump has emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."¹ Disruptions to electric supply, even of short duration, can have serious and cascading consequences for public safety, economic activity, and national security. Therefore, DOE seeks to understand the capacity, condition, and operational status of electric supplies across the country, including the potential retirement of existing generation resources, to ensure that the Nation's electric

¹ Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), <https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid>.



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Washington, DC 20585

grid will meet the current and projected demand for manufacturing, re-industrialization, and technological innovation, among other needs.

DOE requests that you complete and return the questions attached as Exhibit 1 within 14 calendar days. You may designate information as confidential, where appropriate, and DOE will handle any such information in accordance with applicable laws and regulations. Please ensure that responses are accurate and complete. If you have any questions, you may reach out to the Office of Cybersecurity, Energy Security, and Emergency Response (CESER) at askCR@hq.doe.gov.

DOE appreciates your attention to this important request, which supports the reliability and security of the bulk power system.

Sincerely,

A handwritten signature in blue ink, appearing to read "Alex Fitzsimmons", is positioned below the word "Sincerely,".

Alex Fitzsimmons
Under Secretary of Energy (Acting)
Director, Office of Cybersecurity, Energy Security & Emergency Response



Department of Energy
Washington, DC 20585

Exhibit 1

1. Please identify the full legal name of the generating facility, its physical address, the Facility ID Number, and also the owner and operator names.
2. Please identify the Generator/Unit Information for each unit at the facility, including the Generator/Unit Name, the types of fuel it uses, whether it is dual fuel, its nameplate capacity in MW and its operating status. For example, an acceptable response would be Unit 1, coal, not dual fuel, 125MW, down for periodic maintenance.
3. Please explain how the unit is currently used (e.g. peaking, baseload, backup), its planned retirement date (if applicable), whether retirement has been previously accelerated or delayed, the reasons for the planned retirement, and the relevant local, state, or federal laws related to retirement.
4. If you were at some previous point considering a retirement or sale of the facility and are now considering delaying retirement or sale of the unit please describe the circumstances.
5. If you are considering a retirement or sales of the unit, please identify and explain with detail and particularity:
 - a. If the facility is not in an ISO/RTO market how is a loss of generation from the planned retirement expected to be replaced?
 - b. Are there any relevant local, state, or federal laws regarding generation from the type of facility at issue?
 - c. Is it possible for the facility to operate on a going forward basis without conflicting with federal, state, or local laws? If so, for how long and under



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what operating conditions?

- d. Would continued operation of the facility/units planned for retirement result in significantly increased costs for consumers? If yes, how? Would these costs be offset by increased reliability?
6. If you are considering a conversion to natural gas, please identify the planned conversion date and general timeline, explain whether the conversion will result in units maintaining or increasing nameplate capacity and/or an increase in capacity factor, and whether there will be a result in cost savings for customers.
7. If you are considering a conversion to natural gas, please explain with detail and particularity the actions being taken to minimize the length of outage for the conversion (e.g. use of existing turbines), explain whether external factors (e.g. laws, company policy) are driving the conversion, and any other relevant information.
8. Please explain with detail and particularity:
 - a. Are there any major operating limitations for any units at the facility;
 - b. Are there any safety considerations with continued operations; and
 - c. Are there any workforce, fuel availability, contractual, or permitting complications at issue?
9. Regarding each generating facility footprint, please identify and explain with detail and particularity:
 - a. The Balancing Authority;



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- b. The Reliability Coordinator;
 - c. The name of the state utility regulatory commission and its relevant regulatory authority as it relates to the facility; and
 - d. Any other relevant parties.
10. If the facility is not in an ISR/RTO market, please explain with detail and particularity, how energy and capacity, as applicable, from the facility is purchased. Are there any unique requirements/laws that affect the sale of energy and/or capacity from the facility?

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)
Emergency Order: Orlando Utilities Commission
Regarding the Stanton Energy Center

Order No. 202-26-42

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

EXHIBIT 10

YOUTUBE, GOVERNOR DESANTIS SIGNS LAW TO PROTECT
FLORIDIANS FROM SUBSIDIZING DATA CENTERS



secretary Alex Kelly, of course our president