2023-2024 GRU Integrated Resource Plan (IRP) Modeling Assumptions and Considerations

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1.0 Firm Import Capacity

1.1 Transmission upgrade option
1.2 Five-year contract capacity agreement
1.3 Wheeling cost assumptions

2.0 NERC Regulatory Requirements

2.1 NERC-TPL-001-4, "(N-1)"
2.2 NERC-BAL-001-2, Area Control Error (ACE)

3.0 Utility-Scale Solar Projects

3.1 Tier I projects (275 MW (AC))
3.2 Tier II projects (+200 MW (AC), beginning 2028)
3.3 Tier III projects (+200 MW (AC) with $131m investment)
3.4 Solar contribution to summer peak
3.5 Solar contribution to winter peak

4.0 "Investment Grade" Utility-Scale Energy Storage Projects

5.0 Timeline Considerations

5.1 Tier I solar project timeline constraint
5.2 Tier II & III solar project timeline considerations
5.3 Gas turbine and/or RICE project timeline considerations
5.4 Max battery contribution prior to 2023

6.0 Demand Side Management (DSM) and Energy Efficiency (EE)

7.0 Biomass Resource Option

8.0 DHR Retirement Date

9.0 CT1 and CT2 Delayed Retirement

10.0 CC1 Cycling Constraint

Introduction

GRU's 2024 Integrated Resource Plan (IRP) is being completed by The Energy Authority (TEA), of which GRU is a member. TEA is using an energy production cost modeling software package produced by Energy Exemplar named PLEXOS to evaluate available resource options and identify those that most economically meet GRU's customers demand for energy. An important aspect of software like PLEXOS is that it can compare a baseline case to multiple scenarios (where more than one input or constraint is changed) and sensitivities (where only one input or constraint is changed). Using this methodology, a generation portfolio can be tested against a variety of future possibilities, which ultimately helps to mitigate risk.

This document outlines some of the modeling parameters and considerations that were used in GRU's PLEXOS IRP models that may not be readily apparent.

1.0 Firm Import Capacity

GRU has transmission ties with Duke Energy and Florida Power & Light (FPL). Those transmission ties allow GRU to enter into power transactions with other utilities in the southeast when it is economical for GRU to do so. GRU can purchase and sell power on firm and non-firm basis. Non-firm power can be curtailed or cancelled for any reason (e.g. the unit making the power for the transaction suffers a mechanical failure), whereas firm power is considered reliable and must be backed up by the seller with other resources if the unit generating the power for the transaction is not available. Non-firm power purchases and sales are typically made hour-to-hour or on a short-term basis and are made to incrementally move a utility's own generating units output up or down, but not offline. For example, if a utility is purchasing non-firm power, it can turn its own generating unit down, but not off in the event the non-firm transaction is cancelled. Firm power purchases can be used to commit or decommit generating units, meaning that the power transacted is reliable and a utility's own generating units can usually be turned on or off based on that decision.

For the IRP's capacity analysis, only firm transactions are considered for measuring GRU's power supply adequacy. Non-firm transactions, also known as market transactions, are included to allow generating units to move up or down economically, but those transactions do not count toward power supply adequacy. Changes in transmission capacity throughout the IRP study period are detailed in the following sections.

1.1 <u>Transmission upgrade option</u>

GRU's current transmission ties allow for the import of approximately 75 MW of firm power throughout most of the year. However, during winter peak, this capacity typically drops to zero as Duke's system could become overloaded during cold weather events. Duke is in the process of upgrading its transmission system in the area. These improvements should be completed by the end of 2027, and in the summer of 2028, GRU is projected to be able to firmly import up to 200 MW of power throughout the year.

If GRU desires to import more than 200 MW in the summer of 2028 and thereafter, GRU would need to build an additional transmission line(s) to Duke, FPL, or Seminole, and rebuild its transmission line to FPL. The most economical transmission capacity increase for GRU would come from infrastructure built to strengthen connections with FPL and Duke. Under this option, GRU would need to rebuild its transmission line with FPL, build an additional transmission line to Duke's substation, and pay for upgrades within FPL's and Duke's transmission systems. The costs for these upgrades are estimated to be $131 million (2023 dollars). If PLEXOS deems it more cost-effective than for GRU to generate its own power, PLEXOS can select this investment option in 2028 (or beyond), enabling GRU to procure and import more than 200 MW of power.

1.2 Five-year contract capacity agreement

The model can select to import power in lieu of GRU generating that same power if it is more economical to do so. The cost of that firm import power is modeled as a contract with a five-year term and is based on projected market conditions. Contracts such as this are referred to as power purchase agreements (PPA). For import power considerations, these PPAs include a capacity cost, a non-fuel energy charge, and a fuel charge. The capacity charge begins at $6.50/kW-month and escalates annually at the inflation rate (GDP deflator). The non-fuel energy charge begins at $1.50/MWh and escalates annually at the inflation rate. The fuel charge is based on a 7000 BTU/kWh heat rate, combined-cycle unit and the forecasted price of delivered natural gas plus a $0.55/MMBTU firm transportation capacity adder (escalated annually).

1.3 Wheeling cost assumptions

When power is moved over other utilities transmission lines to GRU, GRU must pay "wheeling costs" to the utility that owns the transmission assets. Wheeling costs are fees set by the Florida Public Service Commission, typically expressed in $/kW-month. The model uses a beginning wheeling rate of $2.67/kW-month, and escalates this cost annually based on the inflation rate. Firm power imports with a PPA (as discussed in section 1.2) would require a multi-year transmission capacity reservation, which GRU would need to buy, regardless of how much of its purchased capacity is utilized.

2.0 NERC Regulatory Requirements

The North American Electric Reliability Corporation (NERC) is a regulatory body that enforces standards GRU must follow. For the IRP, there were two applicable standards that were used to add model considerations within PLEXOS:

(NERC-TPL-001-4) is a standard that GRU Transmission Planning personnel must follow.
(NERC-BAL-001-2) is a standard that GRU System Control personnel must follow.

2.1 NERC-TPL-001-4, "(N-1)"

According to NERC, the purpose of the NERC-TPL-001 standard is to: "Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies." Effectively, GRU must have enough generation capacity to cover the loss of its largest unit in service or active transmission import. The utility industry calls this requirement their "N minus 1" (N-1) contingency.

Between now and 12/31/2031, Deerhaven Unit #2 (DH2) is GRU's largest generation unit, and therefore its (N-1) unit. The maximum load GRU can place on DH2 is 150 MW while maintaining its ability to recover this loss of generation within ~15 minutes.

GRU is a member of the Florida Reserve Sharing Group (FRSG). Along with the other utility members of this group, each utility maintains a certain share of "spinning reserve" power that must be able to dispatch within 15 minutes to cover the loss of the state's largest generating facility. GRU's portion of this spinning reserve requirement is 38 MW. Portions of this 38 MW can be called upon as needed to maintain grid stability. These reserve calls can be in 1/8 increments. For IRP planning purposes, GRU is modeling a 4/8 reserve call, or 19 MW. This 19 MW reserve call is in addition to the (N-1) requirement of 150 MW.

Lastly, if DH2 were to trip, it requires 14 MW of power to safely shut-down the unit. To prevent damaging the unit in the event of a unit trip, 14 MW of capacity must be always available whenever DH2 is in operation.

After DH2 retires, the largest unit on GRU's system will be the Kelly combined-cycle unit #1 (CC1) at 114 MW. To safely shut-down CC1 requires 2 MW of station service. In addition, it is modeled that GRU can satisfy a 4/8 reserve call.

In summary, PLEXOS includes two "(N-1)" model considerations:

- Between now and 12/31/2031: "(N-1)" = (150 + 19 + 14) = 183 MW
- Beyond 12/31/2031: "(N-1)" = (114 + 19 + 2) = 135 MW

2.2 NERC-BAL-001-2, Area Control Error (ACE)

The NERC-BAL-001 standard aims to control interconnection frequency within defined limits. To maintain frequency within acceptable bounds, System Control operators ensure power generation matches system load with system demand. The effectiveness of GRU's system control is measured by the Area Control Error (ACE) metric, ideally kept at zero. System Control operators adjust generation on the unit with the lowest incremental heat rate to control frequency and maintain ACE near zero. Gas turbines, reciprocating internal combustion engines (RICE), and 25 MW (AC) blocks of four-hour lithium-ion batteries with fast-start capability are options for controlling ACE.

Solar farms, being intermittent, pose challenges, and a 2:1 ratio of nameplate solar capacity to fast-start capability is required for stability. For instance, adding 100 MW (AC) of solar farm capacity necessitates 50 MW (AC) of gas turbine, RICE, or battery farm capacity. This 2:1 ratio is integrated as a constraint in PLEXOS, ensuring stand-alone solar as a resource option is supported by a fast-start resource in the specified proportion.

3.0 Utility-Scale Solar Projects

To be considered as a site for a utility-scale solar facility, several key attributes are required:

1) large land area (~5-7 acres / MW (AC)) with suitable zoning and an available and willing counterparty to support the facility
2) proximity and cost-effective access of an electrical transmission facility (usually within a few miles);
3) available electrical capacity at the transmission facility; and
4) absence of impediments to successful siting (wetlands, historical, geological, etc.).

While agricultural land is the typical location for utility-scale solar, it can be unavailable for sale or long-term solar leases due to estate planning, prior commitments to agricultural or silvicultural use, or may be held for future housing or other uses.

Due to the high costs of project development, transmission access, and engineering, size drives project economics. Currently, Florida Statutes require solar facilities that are greater than or equal to 75 MW (AC) to go through the extensive Power Plant Siting Act permitting process. Thus, nearly all utility-scale projects are less than 75 MW (AC). The economic “sweet spot” for projects in Florida is currently between 50 and 75 MW (AC).

The smallest solar project considered within the IRP is 50 MW (AC), and the largest single project considered is 75 MW (AC). Due to limited available land within GRU’s service territory, GRU would eventually have to pursue projects outside of its service territory. A such, GRU considered three tiers of solar projects as outlined in the following sections.

3.1 <u>Tier I projects (up to 275 MW (AC) of solar)</u>

Tier I Projects would be connected directly to GRU’s transmission system to avoid wheeling costs and minimize transmission system congestion. GRU assessed areas within approximately three miles of its existing transmission facilities to determine the availability of potentially suitable sites and believes that there is a planning level likelihood of two additional 74.9 MW (AC) facilities and one 50 MW (AC) facility (in addition to the Sand Bluff solar project to be completed in late 2024). Due to wheeling costs, it is likely that Tier I projects could be delivered to GRU for a cost lower than projects located outside of GRU’s transmission system.

3.2 Tier II projects (+200 MW (AC))

Tier II Projects are solar facilities that are not directly connected to GRU's transmission grid. These projects would connect to another transmission provider and be wheeled into GRU's transmission system. These projects would be subject to wheeling costs, which increases their cost to GRU. Due to limited firm import capability from Duke and FPL, this capability is limited to 200 MW (AC).

Due to wheeling costs, it is likely that economic Tier I opportunities would be exhausted prior to moving on to Tier II.

3.3 Tier III projects (+200 MW (AC) with $131m investment)

Tier III projects will require an additional grid connection which will have an estimated capital cost of ~$131 million (2023 dollars) (for additional details regarding this ~$131 million cost, refer to section 1.1). Also, additional costs may be incurred depending upon transmission provider network upgrades necessitated above the cost of the transmission line.

Within the planning horizon, there would be only one Tier III project that PLEXOS could select prior to 2050 (please refer to Table 2, section 5.2). Therefore, this $131 million would be a one-time investment in our transmission system upgrades, and the model cannot consider the addition of any Tier III project without this corresponding investment in the transmission system.

3.4 Solar contribution to ummer and winter peak

Solar facility output is a function of the amount of light reaching solar photovoltaic panels. Solar facilities rarely provide output at their full rated capacity. GRU's system peaks tend to occur during summer between 5-7 pm, and in winter around 6-8 am eastern prevailing time. Based on analysis of anticipated solar output at these times, GRU estimates utility-scale solar facilities will contribute 36% of their rated output to summer peak, and 0% capacity contribution towards winter peak.

4.0 "Investment Grade" Utility-Scale Energy Storage projects

There are numerous energy storage technologies that are being tested and developed. Currently, lithium-ion battery technologies appear to be the technology of choice for many utilities, and cost estimates for two-hour and four-hour units is readily available from organizations such as Wood Mackenzie[1]. Solar developers will not finance an unproven technology. However, lithium-Ion systems are considered "investment grade" by most financial institutions.

The PLEXOS modeling being performed for GRU allows for the option to select increments of 25 MW (AC) x 4-hour battery systems via a PPA. Each PPA has a 15-year term, with the first system commencing no earlier than 2027.

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[1] U.S. Energy Storage Monitor | Wood Mackenzie

5.0 Timeline Considerations

To allow for the assimilation of new solar capacity into GRU's system, increments of no more than 75 MW (AC) are considered every four years. This four-year period allows GRU to gather system data for a year following the interconnection of a new solar facility; the commissioning and evaluation of an ACE study, and two years for the procurement, permitting, and construction phases of the subsequent solar facility. This will allow GRU to gain experience with each increment of capacity and ensure that sufficient storage and firm capacity is added to maintain compliance with NERC regulations and to mitigate potential technical risks associated with inverter-based resources.

The PLEXOS model does not permit more than one utility-scale solar project in any specific year. Outlined below are additional timeline consideration that were included in GRU's PLEXOS modeling that enables the portfolio of supply options to comply with market and project implementation considerations.

5.1 Tier I solar project timeline considerations

Tier I projects have a four-year project duration from the time the previous solar project is commissioned. The first Tier I solar implementation is the 74.9 MW (AC) Sand Bluff Solar project that is scheduled to be commissioned in January of 2025. Therefore, the timeline of subsequent utility-scale projects is modeled as follows:

Table 1 – Timeline Considerations for Tier I Utility-Scale Solar Projects

Project	Incremental MW (AC) / Cumulative MW (AC)	Earliest Commission Date:
Sand Bluff Solar	75 / 75	01/2025
Tier 1, Project #2	75 / 150	01/2029
Tier 1, Project #3	75 / 225	01/2033
Tier 1, Project #4	50 / 275	01/2037

5.2 Tier II & III solar project timeline considerations

Tier II and Tier III projects have a three-year project duration from the time the previous solar project is commissioned. Therefore, the timeline of subsequent utility-scale projects is modeled as follows:

Table 2 – Timeline Considerations for Tier II and Tier III Utility-Scale Solar Projects

Projects	Incremental MW (AC) / Cumulative MW (AC)	Earliest Commission Date:
Tier II, Project #1	75 / 350	01/2040
Tier II, Project #2	75 / 425	01/2043
Tier II, Project #3	50 / 475	01/2046

Tier III, Project #1	75 / 550	01/2049

*Note, the Tier III project shown in the bottom of Table 2 would require upgrades to GRU's transmission system for GRU to have the required import capacity.

5.3 <u>Gas turbine and/or RICE project timeline considerations</u>

A typical project execution period for a project involving the addition of a new gas turbine and/or RICE engine is about three years. Therefore, PLEXOS is not allowed to add one of these resource prior to 2027.

5.4 <u>Max battery contribution prior to 2033</u>

The following model considerations were applied: initially, battery additions are capped at 50 MW (AC) from 2027-2029, with the limit rising to 100 MW (AC) from 2030-2032. By 2033, the limit is expanded to 1000 MW (AC) (effectively removing any restrictions).

6.0 Demand Side Management (DSM) and Energy Efficiency (EE)

The IRP includes a sensitivity analysis on the impacts of implementing a suite of DSM programs, with the primary focus for GRU being able to shift customer load off of peak times and into non-peak times. The DSM sensitivity models a 5% summer peak and 5% annual energy reduction. This aggressive sensitivity considered a 0.5% annual peak and energy reduction, requiring 10 years (01/2025 - 12/2034) for a cumulative 5% reduction.

The sensitivity study results compare the net present value (NPV) to the base case, offering insights into potential savings that could be allocated to a DSM program. If the savings are substantial, further evaluation is needed to determine if the costs, risks, and rate impacts of implementing and maintaining a suite of DSM programs outweigh the potential benefits.

7.0 Biomass Resource Option

Early in the IRP process, GRU contracted BioResource Management, Inc. (BRM) to determine fuel availability within a 120-mile radius of Gainesville. The specific type of fuel that was studied is Urban Waste Wood (UWW). Byproducts from the forestry industry were not included in the scope of the study. Based on a reasonable capture rate for the quantity of UWW that could be acquired, the PLEXOS model may select a 30 MW biomass facility.

8.0 DHR Retirement Date

DHR is slated for retirement by the close of 2043, but the PLEXOS model permits flexibility with this date. By 2043, the unit will have operated for around 30 years. This flexibility acknowledges that there is limited experience with similar biomass-fueled units, though other Rankin-cycle boilers over 50 years old are still in use. The unit's lifespan relies on diligent inspections, maintenance, and potential partial rebuilds or equipment replacements approaching December 2043.

Therefore, PLEXOS may elect to extend DHR's retirement date to the end of the planning horizon (end of 2050) if it is economical to do so.

9.0 CT1 and CT2 Delayed Retirement

GRU currently operates two "peaker" gas turbines (CT1 and CT2) set for retirement in 12/2026. Despite having low run hours and being in good mechanical condition, these gas turbine package units will eventually become unsupportable, primarily due to the unavailability of spare parts.

The PLEXOS model may select to delay the retirement date of these units by up to five years. The one-time cost of needed repairs and upgrades to is estimated to be about $2 million (in 2023 dollars) per turbine.

10.0 CC1 Cycling Constraint

Anytime a generating unit with a boiler is started and stopped, there is thermal wear-and-tear placed on the system components. As these thermal generation units with a boiler are not particularly "flexible", system control operators always attempt to minimize the number of cycles on these types of units, such as CC1. As GRU adds utility-scale solar to its system, the PLEXOS model may elect to increase cycling of CC1. To prevent excessive cycling of this unit, the PLEXOS model has a cap on the number of allowable cycles on CC1 (one per week).