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PNNL-35070

SCUC-DER Integration Report

Integrating Distributed Energy Resources (DER) Using Advanced Unit Commitment Models and DER Aggregation Methodologies

October 2023

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U.S. DEPARTMENT OF ENERGY

Prepared for the U.S. Department of Energy
under Contract DE-AC05-76RL01830

PACIFIC NORTHWEST NATIONAL LABORATORY
operated by
BATTELLE
for the
UNITED STATES DEPARTMENT OF ENERGY
under Contract DE-AC05-76RL01830

Printed in the United States of America

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Abstract

Distributed energy resources (DERs) are continuing to grow due to regulatory, policy, and market shifts, and it needs to be ensured that small DERs are given a level playing field with traditional resources. Legacy market processes such as unit-commitment problems were designed for a power grid consisting largely of centralized power plants. In contrast, DERs consist of many small devices with distinct operating characteristics that may or may not be connected at the transmission interconnection points, limiting their visibility to the independent system operators (ISOs) who operate wholesale electricity markets. This report details the development and initial results from a simulation platform that integrates state-of-the-art security-constrained unit commitment software, detailed feeder models, and a DER aggregator model to quantify potential DER integration issues. Quantitative results to date illustrate potential infeasible scheduling solutions from SCUC when the DERA includes aggregations of energy-limited energy storage resources. Likewise, if aggregations are not penalized for dispatch deviations, they may have incentives to deviate from the SCUC-determined resource schedules. Assumptions about the amount of aggregated demand response resources (DRRs) and the ability of DERAs to follow profit incentives have an important impact – DRRs have significant flexibility and can typically feasibly meet their SCUC schedule, but on the other hand, their profit incentives can cause unscheduled increases in load before and after DRR dispatch. Computation time results on the SCUC solver and simulation platform only show a modest increase in SCUC solution time as the number of DERAs is increased, but results to date only reflect the RTS-GMLC test system; results may show more significant solver slowdown in larger transmission systems. The largest contribution to simulation time is attributed to the DERA offer generation method, which is suggested for future improvements.

Summary

This report details the first year of development and analysis for the "Integrating Distributed Energy Resources (DER) Using Advanced Unit Commitment Models and DER Aggregation Methodologies" project, funded by the Advanced Grid Modeling program in the Department of Energy (DOE) Office of Electricity. To date, the project has developed a simulation platform, which is located in a private repository located at https://gitlab.pnnl.gov/scuc-der/der-offer-models. The platform integrates three key models:

- **Security-Constrained Unit Commitment (SCUC)** is the fundamental schedule optimization problem that is solved in market clearing software. The SCUC model in this project is implemented in EGRET and then simulates day-ahead and real-time market operations using the Prescient software package.

- **DER aggregations (DERAs)** are modeled by a custom optimization model implemented in Python with the Pyomo optimization package. The DERA model includes resource types for demand response resources (DRRs), battery storage, and solar PV. The demand response model utilizes a Cobb-Douglass utility function to capture the economic value of load. The battery storage model uses a standard energy storage model that considers roundtrip efficiency and state-of-charge management. The solar PV model includes time-varying minimum and maximum output.

- **Distribution feeders** are modeled in GridLab-D and currently model the IEEE-123 node test feeder. A separate feeder model is created for each transmission node where a DERA is placed. Communication is established between the feeder model and the DERA models via HELICS, a co-simulation tool. Detailed results from these models are still undergoing verification and debugging, but when completed, they will allow the platform to evaluate how distribution system losses, voltage limits, and utility actions may affect DERA dispatch and transmission power flows.

Initial quantitative results are based on the RTS-GMLC system. The following quantitative results are reported:

- With 5 MW of total DERA capacity added, simulation scenarios showed that the average dispatch deviation was around 2% of total DERA capacity and the maximum aggregate deviation was around 20-27% of the total DERA capacity when the DERA models are configured to follow the dispatch schedule as closely as possible.

- When the DERA models are configured to maximize profits, the average aggregate dispatch deviations range from 30-115% of total DERA capacity, and maximum aggregate deviations range from 95-350% of total DERA capacity.

- Modeling results showed that DERA's are better able to meet their schedules when more DRR is included in the aggregation, and there are no dispatch deviations when the DERA is 100% DRRs.

- DRR-based aggregations nonetheless may deviate from SCUC schedules to maximize profit. In such cases, the largest deviations are found in the hours immediately before and after the peak period. This is behavior is based on a Cobb-Douglass utility function

that assumes increases in load value in the periods before and after demand response is dispatched.

Further, the report investigates computational performance of the current simulation platform. The longest runtime so far is a simulation of a 25 DERAs over the course of one day, which took 456 seconds to complete. The majority of this time occurred in the DERA offer generation model. Solver issues within this model may have also contributed to several failed simulation runs. Improving the robustness and computational performance of this model is a priority for future development.

Lastly, the report offers several proposed modeling enhancements to pursue for the duration of the project:

- Additional debugging and verification of feeder communication via HELICS and ex-post power flow calculations.
- SCUC improvements to analyze reserve product awards, re-implementation of DERA offers to SCUC using Egret/Prescient's renewable offer format, and larger-scale SCUC test cases.
- Develop more detailed real-time market simulation with DERA offer updates.
- Design and implementation of an uncertainty-aware DERA resource type in Egret/Prescient.
- DER uncertainty feedback via HELICS, to allow Monte Carlo simulation of solar availability, DRR availability, "battery-backup" mode for solar+storage aggregations, utility and aggregator responses to distribution system violations.
- Test distribution topology changes and other feeder models.
- Identify and implement speedup performance improvements for the DERA offer generation model, possibly including machine learning, model-predictive control, or other strategies.
- Implement multi-node aggregation model based on distribution factor methodology developed by SIT

Acknowledgments

The authors of this report would like to thank Yousu Shen, Ali Ghassemian, Mads Almassalkhi, Yonghong Chen, Kim Sperry, and Bing Huang for their support, guidance, and valuable insights during the development of this whitepaper, and Weilun Wang, Yikui Liu, and Lei Wu for their helpful discussions and contributions to the project. This work is supported by Advanced Grid Modeling program under U.S. Department of Energy's Office of Electricity. Pacific Northwest National Laboratory (PNNL) is operated by Battelle for DOE under contract DE-AC05-76RL01830.

Acronyms and Abbreviations

AGM	Advanced Grid Modeling
CAISO	California Independent System Operator
DER	Distributed energy resources
DERA	DER Aggregation
DRR	Demand response resource
DSO	Distribution System Operator
EPRI	Electric Power Research Institute
ESIG	Energy Systems Integration Group
FERC	Federal Energy Regulatory Commission
ISO	Independent System Operator
ISO-NE	ISO New England, Inc.
MISO	Midcontinent Independent System Operator
ML	Machine learning
MPC	Model predictive control
MW	Megawatt
NYISO	New York System Operator
PV	Photovoltaic
RTO	Regional Transmission Organization
SCED	Security-constrained economic dispatch
SCUC	Security-constrained unit commitment
T&D	Transmission and distribution

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1.0 Introduction

DER penetration is continuing to grow due to regulatory, policy, and market shifts, and it needs to be ensured that small DERs are given a level playing field with traditional resources. Wholesale electricity market operators, called Independent System Operators[1] (ISOs), clear their markets by solving large-scale security-constrained unit commitment (SCUC) problems in market-clearing software. Typical ISO market designs, and consequently the unit commitment problem formulation, are designed for a power grid consisting largely of centralized power plants connected directly to the transmission system. In contrast, DERs consist of many small devices that are connected at the distribution system level, have distinct operating characteristics, and may not even be directly monitored by the ISO. In September 2020, the Federal Energy Regulatory Commission (FERC) issued Order 2222 to mandate participation of DERs in ISO markets via DER Aggregation (DERAs) that offer into the ISO as a single resource. Unlike conventional resources, DERAs may be located across multiple transmission nodes and may consist of heterogenous DER technologies. This report investigates the feasibility and possible risks associated with allowing DERA participation in ISO markets and that their participation will instead be facilitated via aggregators that offer the combined capability of multiple DERs as a single resource offer to the ISO.

DERA participation in ISO markets poses various challenges. The key challenges addressed in this report can be grouped into computational issues or operational uncertainties. Computational issues may arise if the unique characteristics of DERAs contribute to computational bottlenecks that slow down the optimization algorithms used in the ISO's market clearing software. For example, Order 2222 mandates a 100kW participation minimum for such DERAs, which is much smaller than a conventional resource. If many DERAs participate in the market at this lower threshold level, it may substantially increase the size and complexity of the SCUC problem and consequently result in slower performance or suboptimal results from the market clearing software. Similar issues have been caused by large numbers of virtual bidders participating in ISO markets and are expected to affect SCUC software with large numbers of DERAs (Chen et al., 2022).

Operational uncertainties are the result of various unique characteristics of DERAs. This whitepaper discusses three potential uncertainties:

1) **Distribution network conditions** may create uncertainty in net power withdrawals that the transmission and distribution (T&D) interface or result in curtailed DER dispatch.
2) **Multi-nodal aggregation** may result in suboptimal, inaccurate, and/or oscillatory dispatch from component DERs within a DERA.
3) **DER availability** may depend on uncertain characteristics, such as solar output or the real-time energy usage of end-use customers.

The second goal of this report is to propose modeling improvements and additional analysis to pursue over the project's next two years. We discuss modifications to the unit commitment formulation, feeder model uncertainty quantification and modeling extensions, multi-node modeling enhancements, and improvements to the DERA model.

[1] In some cases, the market operator is called a Regional Transmission Organization (RTO). This paper uses "ISO" to refer to both ISOs and RTOs interchangeably.

1.1 Background

FERC Order 2222 has spurred significant research effort into DER integration into ISO markets. Eldridge and Somani (2022) provides a broad review of potential difficulties facing broader DER integration. Based on this previous report and other research, the following key integration issues were identified for market clearing software:

- **Solution speed:** DERA resources could create a large number of small non-zero elements in the SCUC optimization software, leading to similar computational slowdowns as has been observed from virtual bidding (Chen, et al. 2016).

- **Self-commitment:** Some software challenges might be avoided if DERAs are required to self-commit or self-schedule (i.e., offer with a fixed commitment or fixed dispatch, respectively), but this option needs to be studied further since it may entail a loss to market efficiency and a restriction to DERA participation in ISO markets (Sioshansi et al., 2010).

- **Distribution system conditions:** Voltage constraints, congestion, line losses, topology changes, and maintenance may affect the ability of DERAs to provide their scheduled energy to the transmission grid, either due to changes in line losses or dispatch curtailments issued by the distribution utility (Rigoni et al., 2020).

- **Multi-node aggregations:** Order 2222 suggests the use of distribution factors to specify the proportion of a DERA's dispatch that is located at a specific transmission node. More analysis is needed to determine advantages of various methods to calculate distribution factors as well as various methods to determine acceptable aggregation nodes (EPRI, 2021).

- **Oscillatory dispatch and pricing:** Inaccurate distribution factor methodologies can cause oscillations and inefficiency in the DERA's dispatch due to feedback between distribution factor update methods and the market dispatch solution (Liu et al., 2023).

Various academic studies have proposed methods for TSO-DSO[1] coordination to improve DER integration (Trivedi et al., 2023). In principle, a DSO can facilitate better management of distribution system constraints (e.g., congestion, voltage limits) than when DERs participate directly in the wholesale market, leading to higher overall market surplus when a DSO aggregates DERs and submits offers to the TSO. However, TSO-DSO coordination schemes often require iterative communication between the two entities. For example, Gupta et al., 2022, uses a price-based coordination scheme and Bragin and Dvorkin, 2022, uses a dispatch-based scheme. Because ISOs use 5-minute intervals in the real-time market, it is unclear how much time would be available to pass information between the two market entities.

In contrast to DSO-based coordination schemes, Order 2222 requires ISOs to allow DER participation through third-party aggregators who have no direct oversight or association with distribution network operations. In this so-called "Aggregator Model" (ESIG, 2022), third-part aggregator companies are allowed to contract directly with end-use customers, and the

[1] TSO, or Transmission System Operator, can be considered synonymous with an ISO but also relates more generally to wholesale electricity markets outside the US. DSO, or Distribution System Operator, is a market-based entity, analogous to an ISO, that is proposed to improve distribution system management (see Rahimi and Mokhtari, 2014).

aggregator is then responsible for coordination between the ISO, the distribution utility, and relevant regulatory authorities. This participation model potentially simplifies DER participation since it does not require the formation of new entities to oversee distribution system operations, and, importantly, has already been implemented in the California ISO (CAISO) and New York ISO (NYISO) (Eldridge and Somani, 2022). The aggregator model could encourage broader participation of DERs since aggregations can potentially be created across multiple transmission nodes, whereas a DSO-based approach is inherently geographically limited to a single distribution grid.

However, due to the lack of comprehensive distribution system modeling at the ISO level, the aggregator participation model creates various challenges and modeling gaps. Inaccurate dispatch and unaligned incentives can occur when DERs are aggregated across multiple nodes. Wu et al. (2020) additionally show that these inaccuracies can result in significant power flow errors, even when aggregations are only allowed between similarly located transmission nodes. Multi-node aggregation can also cause oscillations in DERA dispatch and market prices (Zuo et al., 2021; Liu et al., 2023). Indeed, there is an unavoidable inconsistency created by aggregating multiple nodes within a nodal electricity market.

The central part of the ISO's market clearing process is the optimization software that solves the large-scale security-constrained unit commitment (SCUC) problem (Streiffert et al., 2005). Substantial research efforts are applied to making improvements to SCUC software, as more efficient solutions can provide significant economic benefits (Carlson et al., 2012). A recent task force of experts on SCUC algorithm design concluded that DER integration and participation of DER aggregators in ISOs will be one of the main challenges facing SCUC software in the coming years (Chen et al., 2022). Namely, DERA participation may introduce large numbers of variables into the SCUC software, resulting in increased computational complexity and slower solution time.

1.2 Contribution

This report provides progress to date of an Advanced Grid Modeling (AGM) project at PNNL. The broad goals of this project are to analyze how different SCUC formulations, DER aggregation architecture and controls, and market design policies can support increased DER participation in ISO markets. Toward those ends, our progress to date details a simulation platform that models the interactions between DER aggregators, distribution systems, and the transmission network. The platform simulates economic bidding by the aggregator, solves SCUC to determine ISO scheduling decisions, and simulates the individual DER dispatch at specific locations in the distribution system. We provide initial results from the simulation platform and discuss the next steps for additional analysis and capabilities that will be developed as the project continues.

The report is organized as follows. Section 2.0 describes the mathematical formulations used in the platform. Section **Error! Reference source not found.** provides analysis on DERA dispatch uncertainty. Section **Error! Reference source not found.** shows initial computational performance of the SCUC algorithm and simulation platform. Section 5.0 concludes the paper by proposing modeling enhancements to pursue as the project continues.

2.0 Models

A variety of modeling tools are necessary to simulate the day ahead market, DERA offer and dispatch, distribution system, and transmission power flow measurements. The team's main development is in the DER aggregation model, which is located at https://gitlab.pnnl.gov/scuc-der/der-offer-models. This section provides an overview of the model implementations and coordination scheme.

2.1 Simulation architecture

Simulation architecture refers here to the communication protocols and hierarchy of models included in the simulation platform. The architecture described below has been implemented and is functional. However, additional verification is needed to ensure that data communicated between models is appropriately mapped and scaled as intended.

The platform implements three main models: SCUC, the DER Aggregator, and the distribution system, shown in Figure 1. SCUC is implemented in Egret (Knueven, et al., 2020) and correspondingly simulated for day-ahead and real-time markets using Prescient (Prescient, 2023). The DER Aggregator model has been developed for this project and is implemented in Pyomo (Hart, et al., 2017). The distribution system model is implemented in GridLab-D (Chassin, et al., 2008). Communication between SCUC and the DER Aggregator is handled by plugin capabilities in Prescient, and communication between the distribution system model and the DER Aggregator is handled by HELICS, a co-simulation tool.

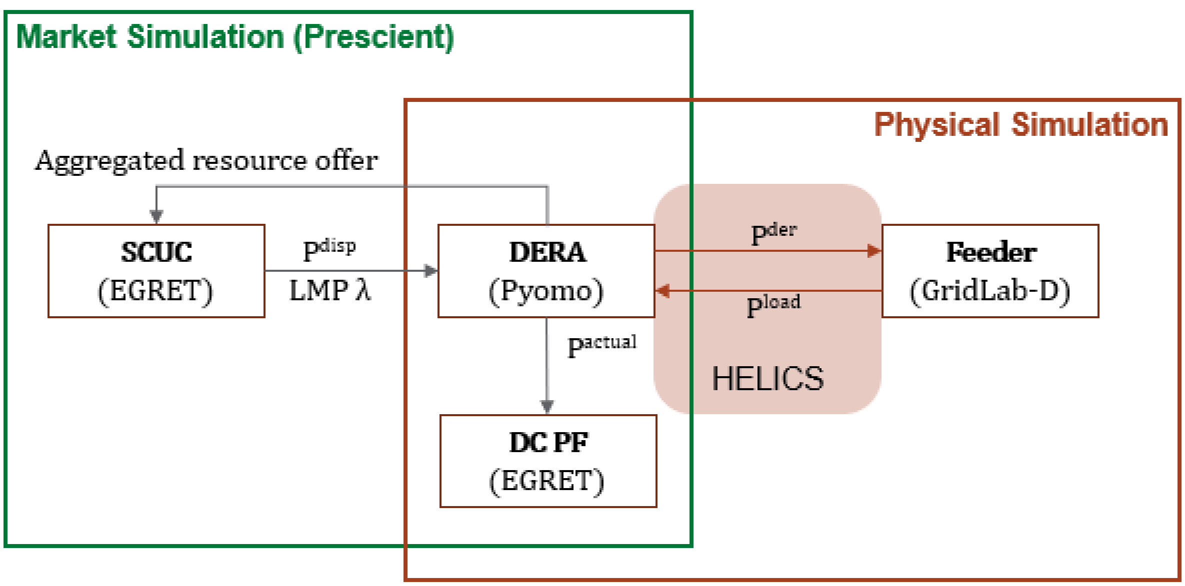

Figure 1. Simulation Architecture

Now we describe the information passing shown in Figure 1. The DERA model, implemented in Python using the Pyomo mathematical programming package, is the central module that interacts with the SCUC and feeder modules. The simulation begins by initializing a pool of DERAs, allocating those DERAs to a SCUC transmission node, and then populating the DERA with DERs located at specific locations in the feeder model.

The DERA model includes mathematical formulations for demand response, solar PV, and energy storage resource types. These formulations are briefly described in Section 2.3

Once each DERA is configured, Prescient is called to initialize a day-ahead and real-time market simulation. Plugins are configured in Prescient to allow the DERA pool to perform specific actions before and after each solve of the SCUC model, after each solve of the security-constrained economic dispatch (SCED, the real-time market scheduling problem[1]) solve, and at the conclusion of the simulation horizon. The following actions are performed:

- Before SCUC:
  - Generate DERA models.
  - Generate LMP forecast via relaxed SCUC solution.
  - Generate DERA offer curves.
  - Submit DERA offers to SCUC.
- After SCUC:
  - Update scheduled quantities and LMPs in each DERA model.
- After SCED:
  - Simulate dispatch of each DERA.
  - Publish dispatch quantities to HELICS.
- End of simulation:
  - Report model statistics.

Prescient coordinates the timing of SCUC and SCED solves throughout the day. For initial testing purposes, the SCUC model is implemented with perfect forecast accuracy, and resource offers to SCED (including DERA offers) are not updated. Prescient likewise determines LMPs for each market clearing solution.

SCUC is implemented in Egret and is called by the Prescient package to solve the day-ahead and real-time markets. Prescient manages the timing of each market run and was configured to solve one SCUC problem per day for the day-ahead market and 24 SCED problems per day, once per hour, as a placeholder for future development on the real-time market simulation. The DER Aggregator model has been developed for this project and is implemented in Pyomo. The distribution system model is implemented in GridLab-D. Communication between SCUC and the DER Aggregator is handled by plugin capabilities in Prescient, and communication between the distribution system model and the DER Aggregator is handled by HELICS, a co-simulation tool.

2.2 Security-constrained unit commitment

The basic SCUC formulation is based on Knueven, Ostrowski, and Watson (2020) and was previously described in the architecture report (Eldridge, et al. 2023). We omit the detailed formulation here but point out the salient features:

[1] Traditionally, SCUC and SCED only differ in that only SCUC considers binary unit commitment choices. State-of-the-art SCED solvers, such as the Egret implementation here, solve SCED with unit commitment for “fast-start” generators, so the distinction between the two models is less clear.

- SCUC minimizes the total cost of a production schedule, including total fuel costs, base-case transmission line violation penalties, transmission contingency line violation penalties, reserve shortfall penalties, and power balance violation penalties. The time horizon for the day-ahead market is 36 hours and consists of 1-hour intervals.
- Conventional generators are modeled with non-convex integer constraints for minimum and maximum operating limits, operating period ramping limits up and down, start-up and shut-down ramping limits, unit commitment logic, and minimum up and down time.
- Renewables are modeled with time-indexed minimum and maximum power output. The cost of renewables is assumed to be zero.
- Network constraints are included for system-wide power balance, and transmission power flow is modeled using shift-factors.
- Reserve requirements are included for each period. Reserve products include regulation up, regulation down, flexible ramp up, flexible ramp down, and spinning reserve. In the RTS-GMLC system, spinning reserve is procured zonally across three regions.

2.3 DER aggregation

The DER aggregation model was also previously formulated in the architecture report and will be omitted here. Each aggregation model contains the individual DERs that are under control of the aggregator and contains more detail than what is implemented in the SCUC model. It consists of battery, solar PV, and demand response resources:

- Batteries are modeled with constraints for state-of-charge management round-trip efficiency, and non-simultaneous charge and discharge status.
- Solar PV is modeled with time-indexed minimum and maximum power output. The cost of solar is assumed to be zero.
- Demand response is modeled with a Cobb-Douglass utility function that considers the value of energy consumption over a 24-hour period. Energy consumption in each period is reallocated into 24 energy "bundles" determined by a smoothing procedure. The bundles cause the value of energy consumption to increase in the periods adjacent to when demand response is dispatched (i.e., reflecting the value of replacing the curtailed load).

The same aggregation model is applied both to the DERA's offer generation procedure and for its dispatch simulation, described in the following sections.

2.3.1 Offer generation

DERA offer generation refers to the task of computing cost curves and/or price-quantity pairs that a DER aggregator submits to the ISO for SCUC dispatch. The aggregator considers all resources collectively and determines the cost of dispatching the DERA to a specified quantity at a specified time. Nomenclature for the algorithm is the DERA's dispatch level p_t, offer curve dispatch quantities q_{it}, baseline dispatch quantities $\bar{q}_t$, and total cost $C(\cdot, t)$ Our solution procedure is implemented as follows:

1) Solve an integer relaxation of the SCUC model to obtain a forecast of day-ahead LMPs.

2) Calculate up to 10 quantity intervals between the DERA's maximum and minimum output in each period, $q_{it} \in Q(t)$.

3) Obtain a baseline DERA schedule, $\bar{q}_t,\ t \in \mathcal{T}$, in each time period that maximizes the DERA's profit given the price forecast in step (1).

4) Begin loop over time periods, $t \in \mathcal{T}$.

5) Begin loop over quantities identified in step (2), $q_{it} \in \mathcal{Q}(t)$

6) Fix the DERA's period t dispatch, p_t, to be equal to q_{it}. Solve optimal dispatch to minimize cost and record the resulting objective function as $C(q_{it}, t)$.

7) If there are remaining quantities $q_{it} \in \mathcal{Q}(t)$, repeat step (6).

8) Once all quantities $q_{it} \in \mathcal{Q}(t)$ have been solved, fix q_t to be equal to the baseline dispatch quantity $\bar{q}_t$.

9) If there are remaining time periods $t \in \mathcal{T}$, repeat step (5).

10) The collection of $C(q_{it}, t)$ values is the resource's cost curve offer over the time period $t \in \mathcal{T}$. The cost curve can be split into marginal value bids $(Q^{\mathrm{mv}}, \lambda^{\mathrm{mv}})$ for load (negative quantities) and marginal cost offers $(Q^{\mathrm{mc}}, \lambda^{\mathrm{mc}})$ or cost curve offers $(Q^{\mathrm{cc}}, C^{cc})$ for generation (positive quantities):

$$
\begin{aligned}
Q^{\mathrm{mv}} &= \left[q_{it} - q_{i+1,t}\,; \forall t \in \mathcal{T}, q_{it} < 0\right] \\
\lambda^{\mathrm{mv}} &= \left[\frac{\left(C(q_{it}, t) - C\left(q_{i+1,t}, t\right)\right)}{q_i - q_{i+1}};\ \forall t \in \mathcal{T}, q_i < 0\right] \\
Q^{\mathrm{mc}} &= \left[q_{i+1} - q_i\,; \forall t \in \mathcal{T}, q_i \geq 0\right] \\
\lambda^{\mathrm{mv}} &= \left[\frac{\left(C\left(q_{i+1,t}, t\right) - C(q_{i+1}, t)\right)}{q_i - q_{i+1}};\ \forall t \in \mathcal{T}, q_i \geq 0\right] \\
Q^{\mathrm{cc}} &= \left[q_{it};\ q_i \geq 0, \forall t \in \mathcal{T}, q_i \geq 0\right] \\
C^{\mathrm{cc}} &= \left[C(q_{it}, t);\ q_i \geq 0, \forall t \in \mathcal{T}, q_i \geq 0\right]
\end{aligned}
$$

Each bid and offer above is also adjusted if necessary to maintain convexity, that is, the marginal value bids are monotonically non-increasing, and the marginal cost offers are monotonically non-decreasing.

2.3.2 Dispatch simulation

DERA dispatch can be simulated in two distinct modes: schedule-following and profit-following. Both modes use the same basic DERA model albeit with slight modifications. Schedule-following mode appending the objective function and constraints below to the basic DERA model:

$$\min \delta$$

$$
\begin{aligned}
\delta &\geq p_{nt} - p_{nt}^{\mathrm{sched}}, \forall t \in \mathcal{T} \\
\delta &\geq p_{nt}^{\mathrm{sched}} - p_{nt}, \forall \in \mathcal{T}
\end{aligned}
$$

In addition, the DERA dispatch model deactivates all time-indexed constraints except for the current period and all past periods (where the dispatch is fixed $p_{nt} = p_{nt}^{\text{actual}}$). The schedule-following model therefore attempts to dispatch itself as close to the SCUC schedule for the current time interval. As time progresses in the simulation, it may be impossible to meet the dispatch quantity due to lack of stored energy in a DERA's batteries, for example.

Profit-following is the second dispatch mode. The objective function is modified as follows:

$$\max \sum_{t} \left(\lambda_t p_t - C(p_t) \right)$$

The profit-following model conceptually simple – it finds the DERA dispatch level that maximizes profit given the LMP at the DERA's nodal location, λ_t. Ideally, the DERA's optimal dispatch from SCUC should be the same as its profit-maximizing dispatch, but this may not always be the case. The DERA's internal DER constraints are more complex than how the aggregation is modeled as a single resource in SCUC, so it is difficult in general to accurately portray the DERA's capabilities in an offer curve.

2.4 Distribution feeders

The distribution system is modeled in GridLab-D using the IEEE-123 bus test feeder. A single distribution feeder is used to model the host load where DERAs are located. A scaling factor is then used to scale up the individual feeder load to be equal to the load assumed in the SCUC model; in other words, we utilize a single feeder model and assume multiple, identical, parallel distribution feeders at each node. Feeders are assigned to SCUC nodes and DERs are allocated to feeder nodes as follows.

First, during initialization of each DERA, the DERA is assigned to a node in the SCUC model according to a random distribution weighted by the peak load at each SCUC node. If no other DERAs have been assigned to that SCUC node, then a new feeder model in is initialized and feeder node data is sent to the DERA model. Once the DERA and feeder are matched, scaling parameters are determined to translate the feeder load to the total load assumed in the SCUC model; by assumption, this scaling factor can be interpreted as the number of parallel feeders connected to the transmission node.

DERs are then assigned to nodes in the feeder model. Each DERA's initialization includes a target capacity for each DER type. The DERA model selects feeder nodes randomly and adds a DER at that location if doing so does not overshoot the target capacity. Demand response resources (DRRs) are allocated to load nodes in the feeder model with the added capacity equal to the load at the feeder node times a pre-determined DRR proportion (e.g., the DR capacity is 20% of the individual feeder load). Batteries and solar PV are allocated to three-phase nodes with pre-determined battery- or solar-specific capacities and attributes. Each DER will be located at a separate feeder node than any other DERs even if multiple DERAs are located at the same node.

Communication between the DERA and feeder models is handled by HELICS. The previously described DER/feeder node allocation process also configures a communication protocol that sends the dispatch quantities of individual DERs to the feeder model and the sends the modeled "actual" feeder load back to the DERA model. This updated load data is then passed to a DC power flow for the transmission network, which is solved by a power flow utility in Egret.

Recorders have also been added to the feeder models to identify power flow and voltage limit violations. Further development is needed to model possible corrective actions by a distribution operator to mitigate the violations.

3.0 Uncertainty Analysis

This section presents the status of three aspects of DERA dispatch uncertainty. First, we provide results comparing DERA dispatch under schedule-following and profit-following operational modes. Then we describe current status of the distribution feeder model and the framework being developed to expand our uncertainty analysis to include multi-nodal aggregations.

- percentage of DR sensitivity
- number of nodes sensitivity

3.1 DERA dispatch modes

A comparison of schedule-following mode and profit-following mode shows demonstrates two potential issues with DERA dispatch uncertainty. First, under schedule-following mode, we find that energy-limited DERs can cause infeasible schedules in the SCUC solution. Second, we show that this issue can become exacerbated if DERAs follow their profit incentives instead of the market schedule. We examine two sensitivities: the number of aggregations and the percentage of DRR in the aggregations.

3.1.1 Number of aggregations

To analyze how the number of DERAs effects total dispatch deviations, we created six cases, shown in Table 3.1: DERA dispatch deviation summary that vary the number of DERAs but keep the total DERA capacity approximately constant. The DERA targeted to have 50% of its capacity from DRR, 25% from solar PV, and 25% from battery storage. DERA dispatch deviations were aggregated among all DERAs and then summarized by the mean and maximum of the absolute deviations. Starting with a single 5 MW DERA located at a single node, the additional cases progressively split the DERA's capacity between additional DERAs that may be located at different nodes. The last DERA case includes 50 distinct DERAs with 0.1 MW capacity, each located at one of 26 different nodes. Cases with 10 DERAs and 50 DERAs were unable to be solved due to solver error, as noted in the table.

Table 3.1: DERA dispatch deviation summary, number of aggregations sensitivity

Case	Num DERA	DERA Nodes	DERA Capacity (MW)	Total Capacity (MW)	Deviation mean, schedule-following	Deviation max, schedule-following	Deviation mean, profit-following	Deviation max, profit-following
A	1	1	5.0	5.0	0.088	1.125	1.597	4.727
B	2	2	2.5	5.0	0.074	1.250	1.628	4.994
C	5	5	1.0	5.0	0.095	1.350	3.057	15.035
D	10	8	0.5	5.0	x	x	x	x
E	25	17	0.2	5.0	0.127	1.008	5.739	17.518
F	50	26	0.1	5.0	x	x	x	x

'x' denotes simulation did not complete due to solver errors

In schedule-following mode, DERA dispatch deviations are typically small, around 2% of the total DERA capacity. The maximum deviations are much larger than average and range from 20-27% of the total DERA capacity. This difference between average and worst case is explained by most of the DERA dispatch deviation being centered around hour 17, one of the periods with highest demand. No apparent trend was identified regarding the effect of the number of DERAs on the total deviation. Hourly profiles for the deviation errors are shown in Figure 2, below, which also shows that all deviations were in the negative direction (i.e., dispatch less than schedule).

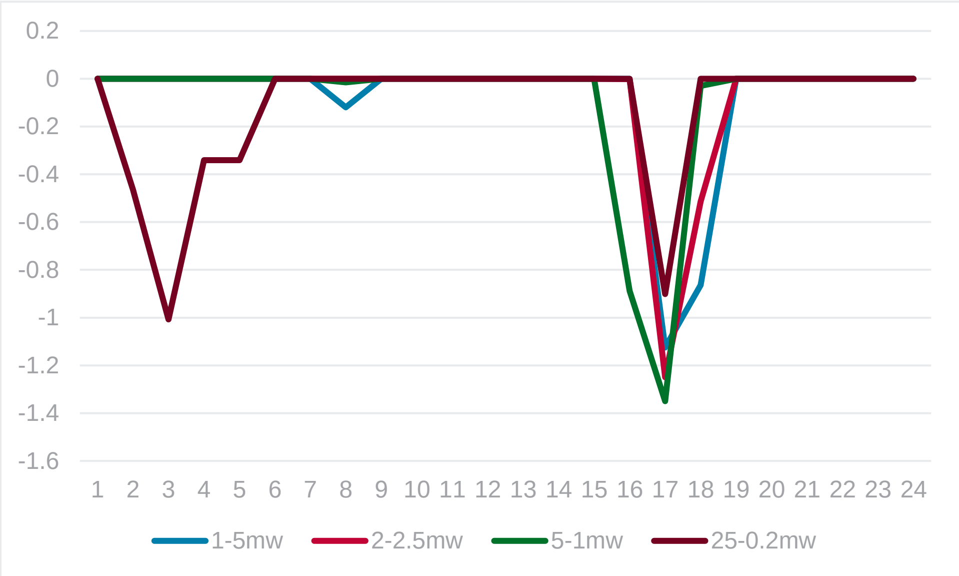

Figure 2: Schedule-following dispatch deviations, number of aggregations sensitivity

Profit-following mode, in contrast, results in significantly higher dispatch deviations. Our results show that the average profit-following deviations are close in value, or higher, than the maximum deviations found in schedule-following mode. Surprisingly, the maximum DERA deviations are close to the total capacity of the DERA in cases A and B, and the maximum deviations are over 3 times the total DERA capacity in cases C and E. These massive deviations are not modeling errors but are driven by our DRR assumptions, as we describe below.

The DRR model assumes a Cobb-Douglass utility function to calculate dispatch costs. In profit-following mode, the DERA is incentivized to maximize its dispatch in the periods with the highest prices. Apparently, this causes the DERA to dispatch its DRRs to their maximum capability in hour 16. This DRR dispatch in hour 16 causes the Cobb-Douglass function to raise the marginal value of load in all other hours, with the greatest increase occurring in the hours closest to 16, i.e., 15 and 17. Load in the hours neighboring 16 consequently increases due to the increase in load value. Hence, the Cobb-Douglass utility function illustrates an expected load behavior: the possibility of loads rebounding to compensate for lost energy consumption during DRR dispatch. The direction of change may be more informative than the absolute value of the deviations, however, since the size of the deviation may be influenced by arbitrary parameters in the Cobb-Douglass function. Calibration with actual load data may be needed.

A second key difference found in the profit-following mode is the timing of dispatch deviations. In contrast to schedule-following mode, wherein the largest deviations occurred during peak demand periods, profit-following mode has relatively smaller deviations during peak periods and much larger deviations in other periods. This may be an important tradeoff to consider, as accurate dispatch may be most important during periods when the system is most stressed. Provides the hourly deviation profiles under profit-following mode.

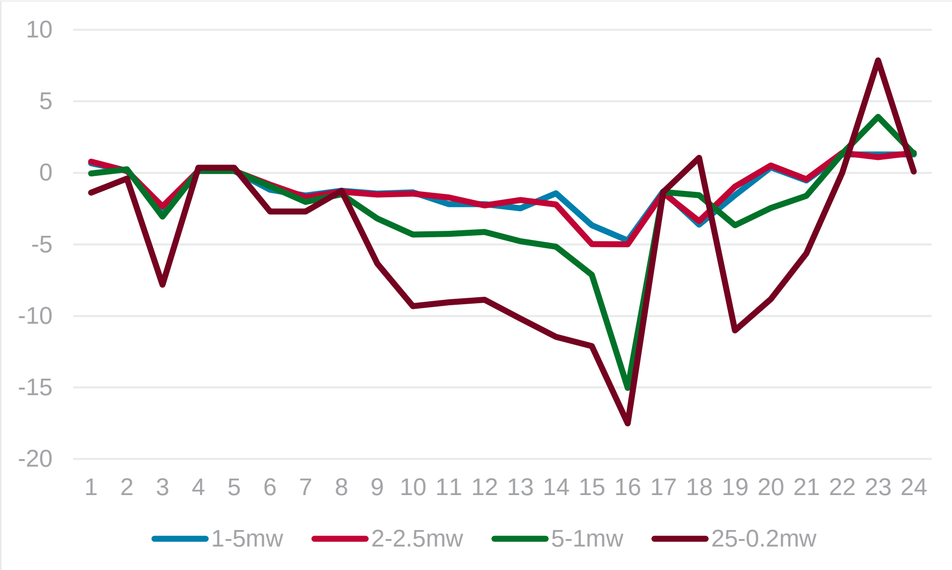

Figure 3: Profit-following dispatch deviations, number of aggregations sensitivity

Lastly, the profit-following results display an increasing trend in deviations when the number of DERAs increases and the capacity of individual DERAs decreases. This might either cause correspondingly large deviations in network power flow, or, if the DERAs are distributed, could result in offsetting power flow deviations (that is, due to counterflow between DERAs). This may be an important area to investigate with further analysis.

3.1.2 Proportion of DRR

We then performed the same analysis on six cases that varied the percentage of DRRs included in the aggregation, from 0% to 100% in 20% increments, as shown in Table 3.2. The cases each include 10 DERAs, all configured to have at least 0.5 MW of total capacity, with the prescribed percentage coming from DRR and the remaining percentage evenly split between solar PV and battery storage.

Table 3.2: DERA dispatch deviation summary, amount of DRR sensitivity

Case	Num DERA	DRR Capacity (MW)	Solar + Storage Capacity (MW)	Deviation mean, schedule-following	Deviation max, schedule-following	Deviation mean, profit-following	Deviation max, profit-following
G	10	0.0	5.0	1.177	2.700	2.467	4.995
H	10	1.0	4.0	0.175	2.174	2.6113	9.140
I	10	2.0	3.0	0.058	1.296	2.520	8.462
J	10	3.0	2.0	0.202	1.080	2.768	6.953
K	10	4.0	1.0	0.066	0.540	2.668	8.219
L	10	5.0	0.0	<0.001	<0.001	3.107	8.523

Similar to the number of DERAs analysis, the DRR analysis also shows that profit following mode results in much larger dispatch deviations than schedule-following mode. We also see that the DERAs composed of 100% DRR can be operated in schedule-following mode with essentially zero deviation. This supports a hypothesis that deviations in schedule-following mode are typically caused by reliance on energy-limited resources.

Figure 4 shows the hourly profiles of DERA dispatch deviations under the different DRR sensitivities. The addition of DRR evidently increases the ability of the DERAs to meet their scheduling obligations; the DERA with no DRR is evidently oversubscribed throughout midday, but the deviation continually decreases with each addition of DRR.

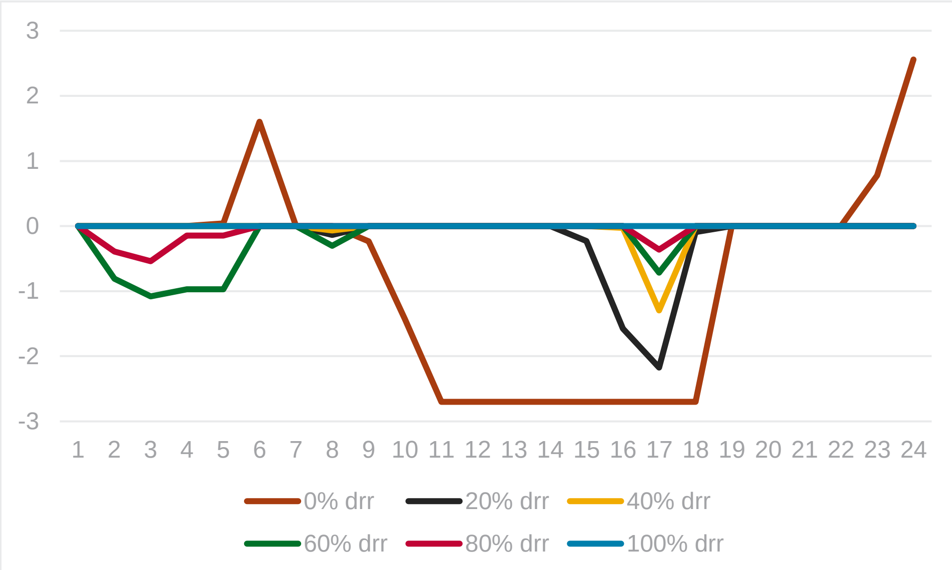

Figure 4: Schedule-following dispatch deviations, amount of DRR sensitivity

Figure 5 shows the hourly profiles when the DERAs are switched into profit-following mode. As previously mentioned, the overall level of dispatch deviations are much higher than in schedule-following mode. This is counterbalanced, however, because the profit following mode tends to result in the lowest deviations during system peaking periods, similarly to what was found in the number of DERAs analysis. This occurs because the energy-limited DERs will be held back until the highest priced periods to discharge their energy.

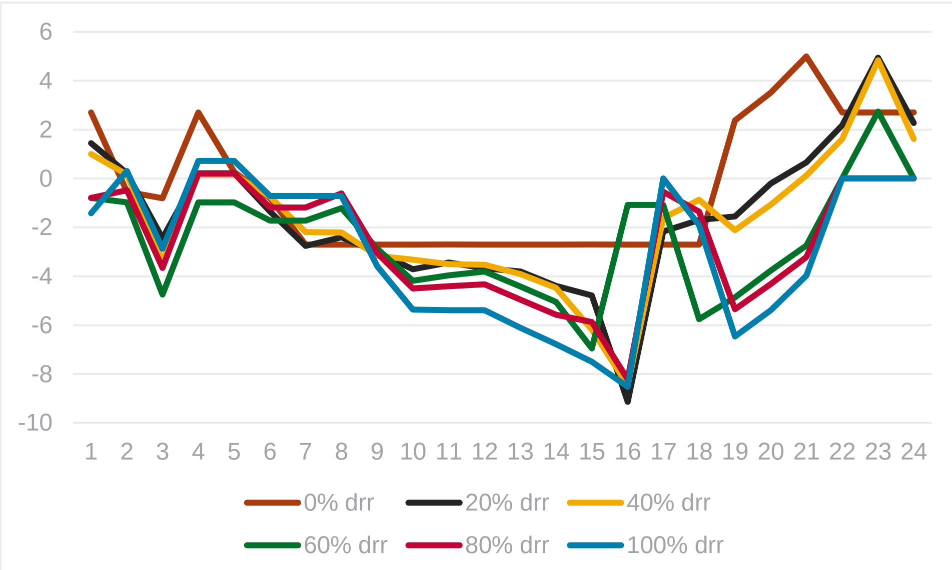

Figure 5: Profit-following dispatch deviations, amount of DRR sensitivity

Similarly, the DRR model will try to maximize DRR output in the highest priced periods, but it will then cause increases in demand in the neighboring period due to the construction of the Cobb-Douglass utility function that we assume for load. This behavior can also be seen in Figure 5: the largest deviations tend to occur just after and just before the evening peak.

3.2 Distribution feeders

Modeling of the distribution feeders will allow two key analyses. First, it will create a more accurate quantification of deviations in the expected net load at nodes that contain DERAs. Second, we can use the more accurate feeders loads to estimate the effects on power flow in the transmission system. Further verification and debugging of the feeder models still need to be completed before results can be presented, but we outline the approach below.

Deviations in expected power withdrawals may occur from three main causes. First, as explained and quantified in the previous section, the DERA itself may deviate from its scheduled dispatch. Second, dispatch from DERs may provide counter-flow in the distribution system, causing line losses to decrease and the node's net withdrawal to decrease by more than expected. DERAs may typically use a loss factor (a fixed percentage) to estimate the reduction in distribution system losses caused by the aggregated DER dispatch, but this approach is inherently inaccurate because line losses will change as a function of DER dispatch and the amount of load throughout the distribution system. Third, the net feeder load may deviate from the schedule if the distribution utility overrides DER dispatch to prevent distribution network violations, i.e., if the DERA is capable to provide its scheduled dispatch but is prevented from doing so due to distribution network limitations. We summarize these three causes below:

- DERA is unable to meet its schedule or is incentivized to deviate.
- Changes to distribution system losses due to DER dispatch.
- DERA is prevented from dispatching due to distribution utility override.

The first cause has already been discussed, and we have demonstrated quantitative results on the simulation platform. Numerical simulations to quantify effects from the second cause are nearly complete but need additional verification and debugging. The last cause has not yet been analyzed but will begin development in the next year of the project.

3.3 Multi-node aggregations

SIT has developed a methodology to calculate distribution factors for multi-node DERs. It can be difficult for SCUC software to accurately assess the on transmission flows from DERAs that connect to the transmission network at multiple interfaces since such aggregations may affect the transmission system in dynamic and state-dependent ways. Recent research proposals to avoid this issue are typically complex and/or cumbersome, so the distribution factor methodology proposed here leverages historical data and a robust model of distribution factor uncertainty to calculate dynamically-updated distribution factors than can be implemented within the time limitations of a real-time market. A draft copy is attached that describes the proposed methodology and illustrates it in a 6-bus example.

4.0 Computational Performance

This section reviews SCUC solver performance on the RTS-GMLC test case and overall simulation time. Analysis of SCUC solution times reflects a much smaller network than a full ISO-scale SCUC instance and is intended to verify and test the SCUC model implemented in EGRET. Overall simulation time results are intended to inform the feasibility of completing future scenarios within reasonable time and to identify components of the simulation time that should be targeted for speedup improvements.

4.1 SCUC solver time

Figure 6 and Figure 7 show the amount of time to construct the SCUC model and the solution time, respectively. The number of DERAs was increased from zero to 100 in increments of 2 to determine how the number of DERAs affects solver performance and was additionally performed on two separate laptops – with the same CPUs specifications but different RAM – to investigate the effect of different hardware. The results were obtained using Gurobi 9.52.

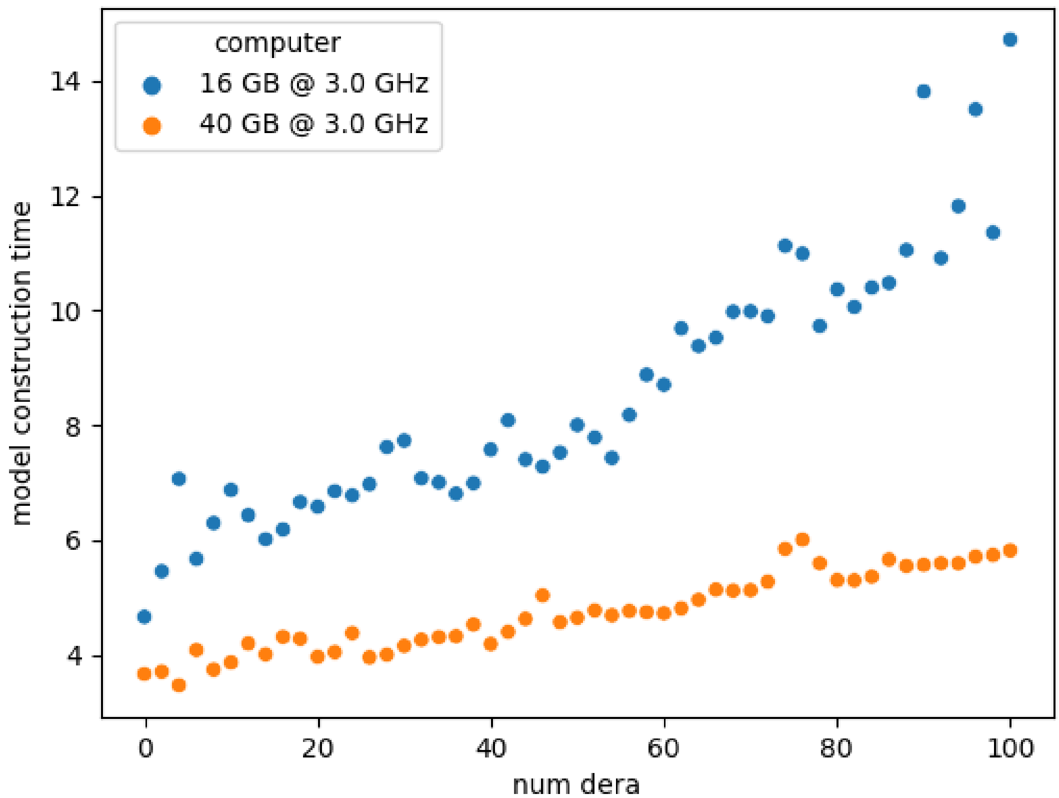

Figure 6: SCUC Construction Time vs. Number of DERA

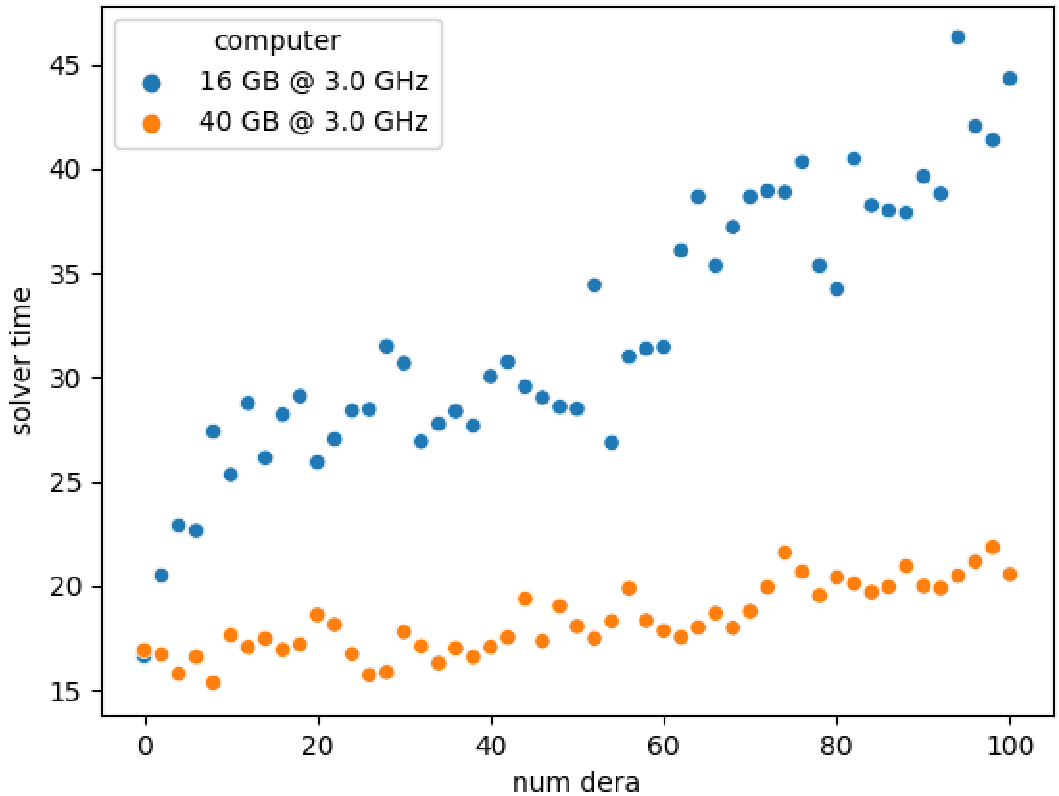

Figure 7: SCUC Solution Time vs. Number of DERA

Model solution times were generally around four times longer than the solver's construction time. Model construction and solution times appear to increase linearly with the number of DERAs. On the laptop with 16GB of RAM, the addition of 100 DERAs approximately doubled both model construction and solution time. Tests with 40 GB of RAM installed, however, showed both much faster performance than the 16 GM hardware, and also showed much lower rate of solver time increases as the number of DERAs was increased. Construction times are presently not concerning, but could become more significant in larger networks with much larger numbers of DERAs included. Cases with much larger amounts of DERAs (in the thousands) may benefit from enhanced data management or improved hardware.

The RTS-GMLC system contains 73 thermal generators, so the increase in DERAs causes the total number of thermal generators to about 135%. In comparison, model construction times approximately doubled when using 16GB hardware and by much less with the 40GB hardware. Solution times are positively correlated with the number of DERAs, but the increase in solution time is not very large. The analysis will need to be repeated on a larger ISO-scale network.

4.2 Simulation time

Total simulation time is dominated by DERA offer generation. Of the four cases shown in Table 4.1, the simulation spends approximately 5% of its time constructing the SCUC model and 10%

solving SCUC, leaving the remaining 85% split between Prescient overhead, DERA offer generation, and DERA dispatch simulation.

Table 4.1: Simulation Solver Time Statistics

Case	Num DERA	DERA Nodes	DERA Capacity (MW)	Total Capacity (MW)	Simulation Time (s)	SCUC Construction (s)	SCUC Solution (s)	Relative MIP Gap
A	1	1	5.0	5.0	136.27	5.52	12.99	1.01%
B	2	2	2.5	5.0	176.39	5.69	17.82	1.01%
C	5	5	1.0	5.0	243.31	5.36	18.93	0.94%
D	10	8	0.5	5.0	x	x	x	x
E	25	17	0.2	5.0	456.47	9.09	22.85	0.98%
F	50	26	0.1	5.0	x	x	x	x

‘x’ denotes simulation did not complete due to solver errors

Although we do not have supporting statistics, the largest portion of these additional computational tasks most likely comes from the DERA offer generation methods. The DERA offer generation method requires solving up to 11 DERA dispatch models in each of the 24 dispatch hours, plus one solution to determine the DERA’s baseline dispatch, resulting in 264 model solves. Additional model solves are also sometimes required if one of the offer quantities is found to be infeasible, in which case the offer quantity is reduced (or increased, if negative) to a value closer to zero until a feasible offer quantity is found. This feasibility step often doubles the total time required by the offer generation method.

5.0 Proposed Modeling Enhancements

Experience developing the simulation platform has led to robust discussions about possible improvements to implement during the remainder of the project. The following sections describe what we believe are the highest priority issues.

5.1 Additional debugging and verification

The simulation platform includes many communication paths between the feeder models, HELICS, the DERA models, and Egret/Prescient. The values sent and received through HELICS remain to be validated, which in turn will allow the platform to assess changes in feeder loads more accurately. The platform has also implemented communication protocol to feed these updated load values into a DC power flow implemented in Egret, but, similarly, this data needs to be validated to ensure correct mapping and scaling has been implemented correctly.

5.2 SCUC improvements

The simulation platform currently uses an "off-the-shelf" SCUC model implemented in Egret/Prescient and only analyzes the physical dispatch schedules that come out of the model. Now that the SCUC software is functional, more considerations can be made for how to make better use the SCUC model's capabilities. Two lower-hanging goals should be to analyze how ancillary services awards are allocated to DERAs. Much of DER revenue is expected to come from ancillary services products, so it is important to model this aspect of their market participation. Another short-term goal should be to add the ability to offer DERAs into the market using the renewable generator resource model instead of as a traditional generator. This alternative resource model contains all of the essential features of a DERA offer but may considerably reduce the computational complexity of the SCUC model, especially once larger test cases are attempted.

Additional SCUC improvements may take more effort to complete but will improve the quality of results. First, it should be prioritized to source larger-scale SCUC problem data. Ideally, we would like to include an ISO-scale SCUC problem, as this would add more computational strain on the SCUC software and would have more potential to show significant computational slowdowns due to DERA participation.

Second, it may be worth pursuing a new "DERA" type of resource model to include in SCUC – a resource model that considers the range of uncertainties in DERA dispatch values. The team has discussed whether this could take the form of a robust programming problem, where the resource model would be formulated such that dispatch uncertainties to not negatively impact transmission limits. A more detailed formulation is needed before work can begin on such an addition to the SCUC model.

5.3 Feeder uncertainty and DERA response

The feeder model is currently linked to the DERA and SCUC models via the HELICS co-simulation package, but many functionalities of this set-up have not been fully applied. Additional methods can be added to modify "actual" DER dispatch values before they are sent to the feeder model via HELICS and as well to allow the DERA models to respond to dispatch uncertainties. This would allow the platform to run Monte Carlo analyses of solar and DRR availability. This functionality could also be applied to add a “battery-backup” mode for solar+storage devices.

Modeling of DER dispatch overrides, initiated by a distribution utility in response to network violations, could also be added to improve the platform’s modeling of feeder uncertainties. This task would involve implementing various control strategies in GridLab-D and an additional layer of HELICS protocols to communicate any effects from these strategies back to the DERA model.

Lastly, our analysis to date has focused on the IEEE 123-node distribution feeder. Additional feeders could be tested, such as from PNNL’s prototypical feeder library (Schneider, et al., 2008), to test if there any distribution topologies are more likely to lead to DERA integration issues. Similarly, scenarios could be developed to reconfigure the IEEE 123-node test system topology, which may simulate maintenance, outages, or other distribution system conditions that may affect the ability of DERAs to deliver their energy to the T&D interface.

5.4 DERA offer model improvements

To allow more thorough simulations that test a wider array of scenarios, one of the top priorities is to improve the robustness and computational speed of the DERA offer generation model. The model is currently implemented to compute each DERA’s offer in series. Parallelization could provide a large speedup. Another possibility is to apply model predictive control (MPC) or machine learning (ML) based methods to the generate offers. Off-the-shelf Python packages may be able to perform better than the current implementation in Pyomo. Ideally any re-design of the DER offer model should be minimized, and the search should prioritize more efficient model implementation that leverages the existing DERA model as much as possible. Improvements in this area are likely needed to before multi-day or multi-week simulations can be performed.

The multi-node distribution factor methodology developed by SIT should also be implemented and incorporated into the DERA models and the SCUC model. Because the proposed methodology relies on historical information, it will be doubly important to improve the speed and robustness of the simulation platform so that enough historical data can be generated and fed into the distribution factor method.

Lastly, the DERA model currently does not update DERA offers in the real time market. This functionality is already included in the simulation platform but is not active. This function’s implementation should be verified and possibly updated, if needed, based on other improvements to the DERA model.

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