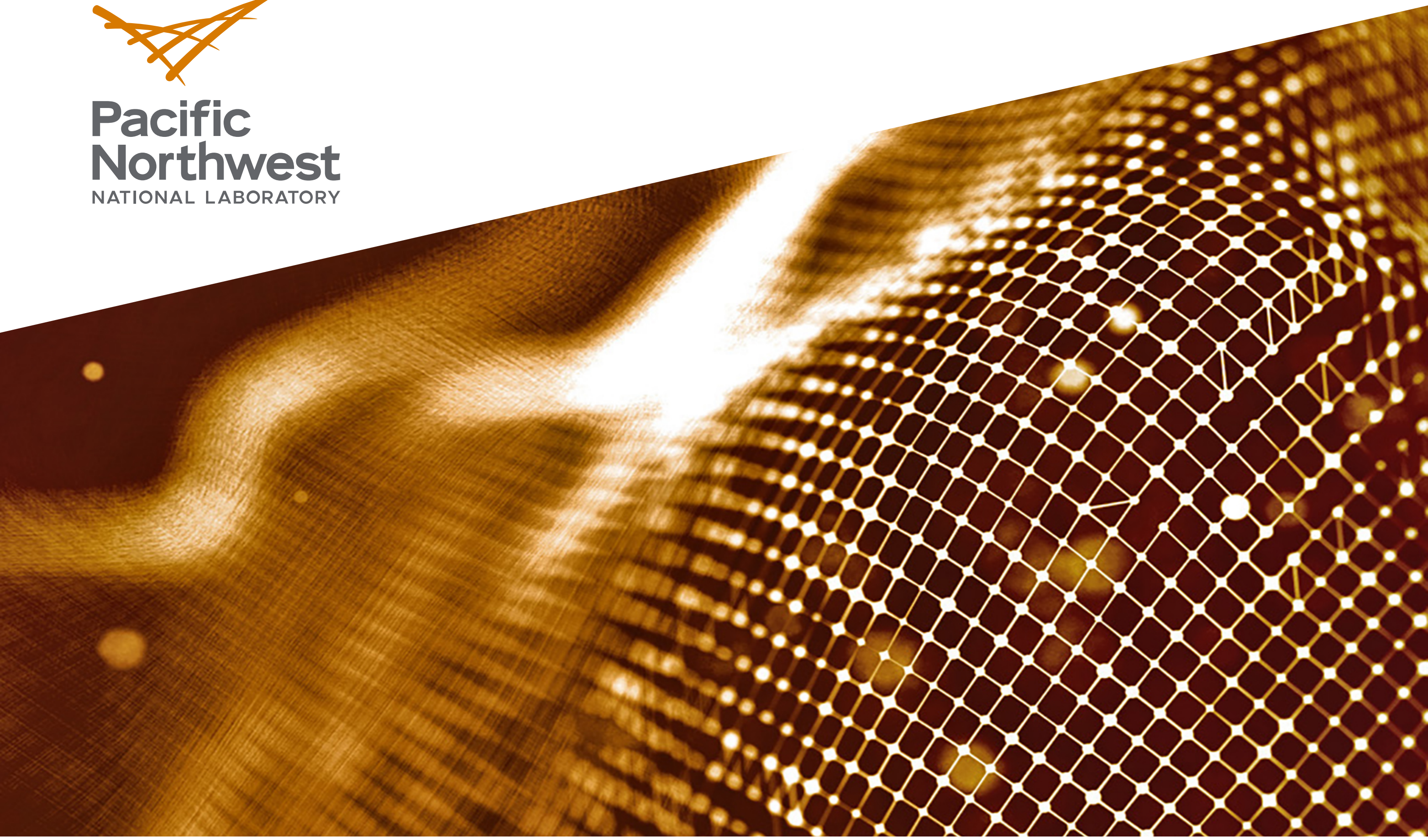

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Distribution System Operator with Transactive (DSO+T) Study: Main Report

DSO+T Study: Volume 1

January 2022

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U.S. DEPARTMENT OF ENERGY

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Abstract

The Distribution System Operator with Transactive (DSO+T) study investigates the engineering and economic performance of a transactive energy retail market coordinating a high penetration of customer-side flexible energy assets. The study seeks to answer whether such an implementation is cost effective for customers, recovers sufficient revenue for DSOs, and is equally applicable and beneficial to a range of flexible asset types, renewable generation scenarios, and market assumptions. Using a highly interdisciplinary co-simulation and valuation framework, this assessment encompasses the entire electrical delivery system from bulk system generation and transmission, through the distribution system, to the modeling of individual customer buildings and flexible assets (including heating, ventilation, and air conditioning [HVAC] units, water heaters, batteries, and electric vehicles). The study exercises a transactive energy retail market coordination scheme designed to integrate with an existing day-ahead and real-time competitive wholesale electricity market. Software decision-making agents are designed for the retail market operator as well as various price-responsive flexible assets.

The engineering and economic performance of the transactive energy scheme is studied for two separate flexible asset deployments: flexible loads (HVAC units and residential water heaters) and behind-the-meter batteries. The results of each transactive case are compared to a business-as-usual case. These cases are subject to two different renewable generation scenarios, a moderate renewable generation scenario, representative of current levels of renewable generation deployment, and a future high renewables scenario, including the increased deployment of rooftop solar photovoltaic and electric vehicles. The transactive coordination scheme is shown to produce effective and stable control and decrease peak loads 9–15%. The resulting annual demand flexibility provides net economic savings of $3.3–5.0B per year for a region the size of Texas. Detailed analysis shows that net benefits were seen for a range of distribution system operator, customer, and flexible asset types. Both participating customer (with transactive flexible assets) and nonparticipating customers (with nonflexible assets) see reductions in annual utility bills and net annual energy expenses in the range of 10–16%.

Summary

The operation of the electric grid is becoming increasingly more complex and challenging due to load growth associated with the deployment of intermittent renewable generation sources (such as wind and solar), the electrification of heating and transportation, and the occurrence of extreme weather events that increase demand and stress the reliability of supply beyond prior experience. Distributed energy resources (DERs: controllable generation, storage, and load) can offer considerable flexibility to grid operation but also present a key challenge: effectively and economically coordinating large numbers of DERs to provide grid services is nontrivial. Complications intensify when they are neither owned nor directly controlled by grid operators.

To address these challenges the Distribution System Operator with Transactive (DSO+T) study evaluated how a distribution system operator (DSO) can engage the large-scale deployment of flexible assets (such as heating ventilation air conditioning [HVAC] units, water heaters, EV chargers, and batteries) by utilizing transactive energy mechanisms. This assessment was conducted using a highly interdisciplinary co-simulation and valuation framework that encompassed the entire electrical delivery system from bulk system generation and transmission, through the distribution system, to the modeling of individual customer buildings and flexible assets. The study has three key elements: an integrated simulation model of the entire grid; the design of a practical transactive coordination and market integration framework; and an economic valuation methodology. This report (Volume 1) provides a summary of these three elements and key results. Detailed discussion of these elements and study results are provided in Volumes 2-5.

The impact on the distribution and bulk power system was modeled in a fully integrated co-simulation environment that included over 100 generators on a 200-bus transmission system that was connected via substations to distribution feeders and approximately sixty thousand individual customer buildings, as well as their associated flexible assets. The Electric Reliability Council of Texas (ERCOT) region was selected as a nationally representative system to serve as the basis of this model as it has a generation mix with significant amounts of wind, is summer peaking, is served by an independent system operator wholesale market, and is of tractable size with no synchronous interconnections. While ERCOT was selected to define the system model, the goal of the study is to develop a nationally representative regional system and associated wholesale market. Transmission line capacity constraints combined with generator operating cost and performance constraints fed the solution of a Security-Constrained Economic Dispatch and Unit Commitment optimization to calculate day-ahead and real-time wholesale market locational marginal prices for the entire region. This ensured market prices accurately factored in demand changes as a function of daily, seasonal, and geographic variations.

The transactive coordination and market integration framework was designed to integrate a transactive energy coordination scheme into existing day-ahead and real-time wholesale energy markets. Transactive agents were developed for a range of flexible assets (HVAC units, water heaters, batteries, and electrical vehicle (EV) chargers) that participate in day-ahead and real-time energy markets. The transactive agents participate in the day-ahead market by optimizing day-ahead flexibility over a 48-hour lookahead horizon and then participate in the real-time market by adjusting their day-ahead operational plan to better respond to the changes in real-time prices. The transactive energy coordination scheme, executed by a DSO retail market operator, aggregates these bids from participating customers and clears them against a forecast price-quantity supply curve using a double auction. The supply curve also includes distribution-level capacity constraints (such as substation limits) to manage local congestion. The resulting

day-ahead and real-time quantities are bid into a competitive wholesale market operated by an Independent System Operator (ISO).

To assess the economic impact of the transactive scheme on the financial performance of stakeholders the economic valuation methodology was developed based on a rigorous value activity model methodology. This analysis determined the annualized cash flow of grid operation participants (customers, DSOs, transmission system operator, generators, and ISO) at a level of granularity sufficient to understand the financial benefits and costs incurred by each party. DSO revenues were determined by applying applicable retail rate structures to customers modeled in the large-scale simulation described above. This necessitated the development of a transactive retail rate design that incorporated dynamic day-ahead and real-time retail pricing. To determine DSO costs, simulation results were also used to calculate wholesale energy purchases (including bilateral, day-ahead, and real-time energy market purchases), as well as capacity, ancillary services, transmission access, and ISO payments. Parametric models were developed to estimate the annualized costs of capital investments including substations, feeders, meters, and information technology systems. Operating costs were also estimated for labor, workspace, and operations and maintenance materials. Finally, the effect of DSO demographic attributes (e.g., rural, suburban, and urban) as well as ownership model (investor-owned, municipal, or cooperative) factored into the parametric analysis including the annualized cost of capital factors. Cash flow models and analysis methodologies were also developed for customers, generators, the independent system operator, and transmission operator.

The engineering and economic performance of the transactive energy scheme was studied for two separate flexible asset deployments: the deployment of flexible loads (HVAC units and residential water heaters) and the deployment of behind-the-meter batteries. The results of each transactive case were compared to a business-as-usual case. These cases were subject to two different renewable generation scenarios, a moderate renewable generation scenario (~15% annual renewable generation), representative of current levels of renewable generation deployment, and a future high renewables scenario (~40%), including the increased deployment of rooftop solar photovoltaic and EVs.

The transactive energy scheme was shown to produce stable and effective coordination of the flexible asset populations resulting in peak system loads decreasing 9-15% and average daily change in load decreasing 20-44%. Greater reductions were seen in cases with EVs, that were assumed to have variable charging (V1G), due to the additional flexibility they provided. This demand flexibility resulted in economic savings via reduced capacity payments, lower wholesale energy expenses, and deferrals of transmission and distribution investments. After the necessary DSO and customer investments in retail market implementation, advanced metering infrastructure, and flexible asset installation were taken into account, the net regional benefit was found to be $3.3-5.0B/year. A sensitivity analysis confirmed that these net benefits persisted for a range of market price and implementation cost assumptions.

The granularity of the analysis also allowed the impact of a DSO+T implementation to be assessed for individual DSOs and customers. This analysis showed that such an implementation has net benefits for the broad range of DSO types, customer classes, building types, and flexible asset types studied. For the moderate renewable scenario, the average participating residential customer saw reductions in their annual utility bill of 14-16%. After the customer’s annualized expense of installing and operating flexible assets was accounted for, this resulted in an 8-15% reduction in annual energy expenses. Finally, a key finding of this study is that the developed rate design allows non-participants to remain on a fixed-rate tariff and still share in the benefits of the DSO's lower overall cost basis. For the moderate renewable scenario, nonparticipating residential customers saw annual utility bill savings of 10%.

Acknowledgments

This project was supported by the Department of Energy, Office of Electricity, Advanced Grid Research and Develop Program. The authors would like to thank Chris Irwin for his support and contributions to shaping the scope and direction of the DSO+T study.

Acronyms and Abbreviations

AMES	Agent-based Modeling of Electricity Systems
AMI	advanced metering infrastructure
BAU	business as usual
CAISO	California Independent System Operator
CFS	cash flow statement
DER	distributed energy resource
DSO	distribution system operator
DSO+T	Distribution System Operator with Transactive
EIA	Energy Information Administration
ERCOT	Electric Reliability Council of Texas
EV	electric vehicle
FERC	Federal Energy Regulatory Commission
HR	high renewables
HVAC	heating, ventilation, and air conditioning
ISO	independent system operator
ISONE	Independent System Operator New England
LMP	locational marginal price
LSE	load serving entity
MR	moderate renewables
NYISO	New York Independent System Operator
PNNL	Pacific Northwest National Laboratory
PV	photovoltaic
SCED	security-constrained economic dispatch
SCUC	security-constrained unit commitment
SOC	state of charge
TESP	Transactive Energy Simulation Platform

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1.0 Introduction

Operation of the electric grid is becoming more complex and challenging due to the deployment of intermittent renewable generation sources (such as wind and solar) and the occurrence of extreme weather events that increase demand and stress the reliability of supply beyond prior experience, and the anticipated growth in loads caused by the electrification of space heating and transportation. Distributed, flexible assets—such as heating, ventilation, and air conditioning (HVAC) units, water heaters, batteries, and electric vehicles (EVs)—offer the opportunity to bring considerable amounts of new flexibility to grid operations. This is particularly useful during periods of peak load, but also during extreme events and when prices are high or fluctuations in renewable generation output must be balanced. This has the potential to improve overall system efficiency, reliability, and resilience and will be increasingly important as the power grid evolves from centralized, dispatchable forms of generation to more variable and distributed forms that are significantly more uncertain to forecast. However, harnessing the potential of such flexible assets also presents a key challenge: how do we effectively and economically coordinate the vast number of these assets to provide grid services, especially when they are neither owned nor directly controlled by grid operators.

1.1 Motivation for Distribution System Operators and Transactive Energy

These growing challenges and opportunities have identified the need for a distribution system operator (DSO) that coordinates the planning and operation of the distribution system in a way similar to how an independent system operator (ISO) or regional transmission operator coordinates the planning and operation of the transmission system. A DSO is an entity that is responsible for the planning and operational functions associated with a distribution system that is modernized to accommodate and manage the operations of high levels of flexible assets while maintaining safe and reliable operation of the system (Kristov and De Martini 2014). The form of a DSO can be varied and is under debate (e.g., it may or may not be distinct from the owner of the distribution system). There is not yet a single, well-defined business model for a DSO; however, the term DSO is used to emphasize a larger role and a broader set of functionalities that provide open, fair access to the use of the electricity delivery infrastructure than found in United States distribution utility operations today. The notion represented by the term DSO is increasingly the focus of industry discussions.[1] This interest is largely driven by stakeholders with desired or actual deployment of flexible assets in various parts of the country.

In addition to establishing DSO entities, there is a need for a coordination framework to ensure that owners of flexible assets invest in and operate these assets in a way that addresses grid operational needs. Transactive energy approaches coordinate flexible assets through transparent, competitive means using real-time transactions involving prices or incentives and quantities to provide the feedback necessary to “close the loop.” i.e., to provide performance similar to closed-loop direct control of traditional generation assets only scalable to handle extremely large numbers of flexible assets with different characteristics. The basis for this, and distinction between transactive energy approaches and simple “prices-to-devices” is the

[1] Closely related to DSO, the term distribution system platform is sometimes used to refer to the set of features and functions that a DSO might use to accomplish its basic missions, including a set of planning and operational functions that also allow flexible assets to engage in grid services for the distribution system and ISO.

transactions themselves, which are used to determine the level of value that must be exchanged within a population of flexible assets to accomplish a grid objective at any given time.

The GridWise Architecture Council has been instrumental in engaging a broad community of technical and policy experts around transaction-based grid control concepts. It defines transactive energy as a general class of solutions that involve *"… a system of economic and control mechanisms that allows the dynamic balance of supply and demand across the entire electrical infrastructure using value as a key operational parameter." (*GridWise Architecture Council 2019).

Fundamental to transactive energy is the idea that approaches that use incentives, such as prices, are required to engage flexible assets at scale. Transactive energy addresses concerns about the scalability of central decision-making approaches, customer recruitment and retention, and maintaining their privacy and "free will." Recruiting and retaining a large fraction of customers in light of the desire to continually engage their flexible assets to provide valuable grid services requires 1) sufficient incentives, 2) a high level of automation, 3) an approach that honors their individual preferences and constraints, 4) a means for them to modify those preferences and constraints when and as they see fit, and 5) an avenue for them to continually evolve their investments in flexible assets. This effectively precludes approaches based on global, centralized optimization because they become overwhelmingly complex when individual preferences, constraints, and flexible asset investments must be included. Further, even expressing these preferences, constraints, and investments to a central authority like a utility raises difficult privacy issues.

Instead, transactive energy approaches are distinguished by seeking to accomplish global, multi-objective optimization consistent with and driven by local optimization by customers, embodied in agents that manage flexible assets on behalf of the customer. Here the preferences and constraints remain local, private, and immediately accessible to customers. What is exposed to the power grid is strictly related to the business of indicating how much power will be consumed or produced, at a given price (or incentive level). The wholesale marketplace then can compare the value offered by the flexible assets to the value of alternative operations using traditional bulk system assets to maximize the overall efficiency of owning and operating the power system as a whole.

Considerable research and demonstration have been carried out on transactive energy concepts as discussed in Section 1.3 This and other work has demonstrated the feasibility and benefits of transactive energy at building, campus, and community scales. However, questions remain about the economic impacts of distributed flexible assets and transactive coordination schemes to DSOs and customers when deployed at scale. In addition, there is a need to show how to integrate a transactive coordination scheme into existing wholesale markets in a way that addresses global and local objectives and constraints and ensures stable and reliable operation. This need has been heightened by the Federal Energy Regulatory Commission (FERC) Order 2222 (FERC 2020) that ensures the access rights of flexible assets residing on the distribution system to participate in wholesale markets but leaves the details of implementation to regional operators.

1.2 The Objectives and Scope of the DSO+T Study

The Distribution System Operator with Transactive (DSO+T) study seeks to simulate a large-scale deployment of flexible assets to demonstrate a feasible method for integrating transactive energy coordination into existing market operation and assess the economic benefits and costs to grid operation stakeholders. To achieve this, the study analyzes how a DSO can engage distributed flexible assets, such as responsive air conditioners, water heaters, batteries, and EVs, in the operation of the electric power system by using a coordination strategy based on transactive energy mechanisms[2]. This study aims to:

- Produce a design of a DSO transactive network capable of coordinating flexible assets deployed at scale to produce benefits at both the distribution and bulk system levels.
- Test the design and estimate the benefits of a regional deployment at scale for a range of potential future grid scenarios using the valuation (Widergren et al. 2017) and co-simulation (Huang et al. 2019) frameworks developed previously for the U.S. Department of Energy's (DOE's) Transactive Systems Program.
- Share the simulation and valuation framework with the industrial and research community as a reference implementation of transactive energy to accelerate its continued development and large-scale deployment.

The DSO+T study compares the engineering and economic performance of transactive cases with business-as-usual (BAU) cases representing today's distribution utilities with fixed-price rates for all customer classes and no participating flexible assets. In the transactive cases the study assumes the distribution utilities have evolved into regulated DSOs that reflect their operational costs in the form of local retail markets for energy (and eventually other) services. It assumes most customers have installed price-responsive flexible assets such as batteries, EVs, HVAC, and water heating systems, which interact with forecasts of day-ahead and real-time dynamic prices—meaning they bid into the retail markets that discover economically optimal and equitable day-ahead and real-time prices in a distributed fashion characteristic of transactive energy systems.

Engineering performance is measured in terms of the stable and predictable provisioning of grid services with the right quantity and location to provide value. The primary metric for economic performance in terms of costs and benefits is based on total annualized costs for owning and operating the power system. This includes the annual costs of borrowing capital to pay for the power system infrastructure and necessary flexible asset upgrades (for example smart connectivity), fuel costs, and all other operating and maintenance expenses. A related economic metric is equity, in that the presumed net benefits should be distributed among the stakeholders in proportion to the value they provide. So, the economic analysis includes individual perspectives of various stakeholders including the DSO, ISO, merchant generators, distribution and transmission system owners, participating customers, and nonparticipating customers.

This assessment was conducted using a highly integrated co-simulation and valuation framework that encompassed the entire electrical delivery system from bulk system generation and transmission, through the distribution system, to the modeling of individual customer buildings and flexible assets. The assessment framework has three key elements (as shown in Figure 1): an integrated system model, a transactive coordination and market integration framework, and an economic valuation methodology. The integrated simulation model ensures the physical behavior and constraints of the entire electrical system are modeled including

[2] This study uses the term 'flexible assets' to be inclusive of distributed energy resources (DERs) and flexible loads. While this study analyzes HVAC units, water heaters, batteries, and electric EVs, transactive energy approaches are applicable to a wide range of both in front of and behind the meter flexible assets (e.g., solar PV, commercial refrigeration, connected lighting systems, pumping systems, and distribution-sited energy storage).

generator dispatch and transmission network constraints, distribution system feeder losses, and DER operation. The transactive coordination framework defines integration of a retail marketplace into an existing competitive day-ahead and real-time wholesale marketplace. Finally, the economic valuation methodology rigorously defines and tracks the flow of value and monetary compensation between market participants. The economic analysis enables the assessment of the overall financial performance of the various transactive cases for each stakeholder.

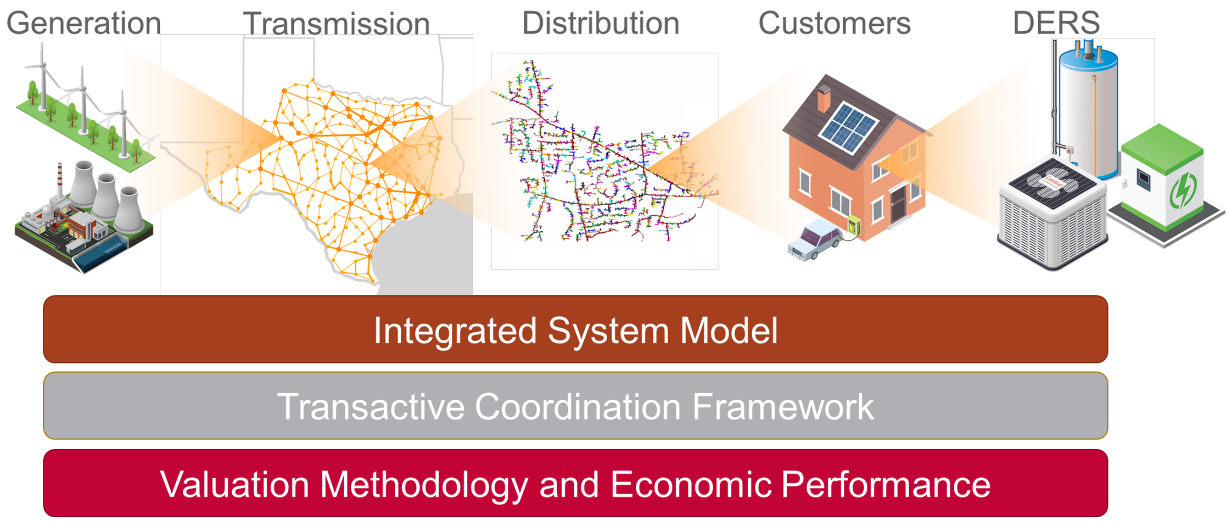


Figure 1. Overview of the DSO+T study breadth and key evaluation elements.

Ultimately the goal of the study is to determine whether the implementation of a DSO and transactive energy retail market:

- Is cost effective and beneficial for consumers
- Maintains sufficient revenue for DSOs, transmission owners, and ISOs to recover their costs
- Provides sufficient economic benefit and engineering performance for both moderate renewables (MR) and high renewables (HR) scenarios, including the additional impacts of rooftop solar photovoltaic (PV) and EVs
- Is equally applicable and beneficial to both the deployment of batteries and flexible loads
- Provides benefits that persist even with adverse future changes in market prices and implementation costs
- Provides benefits across a range of DSO types and customer classes
- Is fair and equitable to participating and nonparticipating customers, which means participating customers that provide greater flexibility receive more savings and nonparticipating customers are no worse off than under the BAU case.

1.3 Prior and Related Work

Pacific Northwest National Laboratory (PNNL) has researched transactive energy coordination since the turn of the millennium including the design, simulation, and field deployment of double auction markets for coordinating flexible assets connected to distribution circuits in Washington

State (Hammerstrom et al. 2007) and Ohio (AEP 2014). The real-time 5-minute market used in these projects was extended in the DSO+T study to include a day-ahead market to allow the resources to better prepare for forecasted weather and market conditions. This forward market also allows the DSO, as aggregator of the flexibility of these resources, to better interact with the bulk system as demonstrated by the Pacific Northwest Smart Grid Demonstration (Battelle 2015). To accomplish this, refinements were made to the responsive asset agents (e.g., HVAC units, EV chargers, and electric water heaters) and the simulation of their physical behavior. In addition, new simulation models of equipment (e.g., batteries) and buildings were developed along with their agents. The overall simulation is built on prior PNNL work including the modeling of DERs in the context of the distribution system (Fuller et al. 2012) to assess the performance and benefits of demand response of various end loads. More recently work (Mukherjee et al. 2020) bridged the transmission/distribution system divide by demonstrating the integrated simulation of DERs responding to and affecting wholesale prices. The additional report volumes (outlined in Section 1.4) have more detailed discussion of prior relevant work.

1.4 Report and Study Structure

A family of reports documents the DSO+T study. It is recommended that the reader start with the stand-alone executive summary. This main report (Volume 1) summarizes the methodology and primary results of the study. Section 2.0 details the multiple scenarios and transactive cases analyzed. Section 3.0 summarizes the integrated simulation environment including the bulk generation and transmission system as well as the distribution system and customer flexible assets. Section 4.0 details the transactive energy coordination scheme and its integration into the day-ahead and real-time energy markets. Section 5.0 presents the valuation methodology and economic metrics for the various grid stakeholders. Section 6.0 presents and discusses key results prior to a summary of lessons learned and future research directions in Section 7.0.

The additional report volumes provide substantially more detail in a parallel structure to this report[3]. For example, Volume 2 (Reeve et al. 2022a) describes the instantiation of the large, multiscale annual time-series co-simulation that is the foundation of the analysis, representing a nationally representative generation fleet, transmission system, and distribution system including retail customer building characteristics and controllable and uncontrollable loads and flexible assets. Volume 3 (Widergren et al. 2022) describes the design and integration of the wholesale and retail markets and DER control agents. Volume 4 (Pratt et al. 2022) describes the process used to assess the value of adopting the DSO+T strategy for all primary stakeholders by comparing the change in various metrics between any two cases of the study. Volume 5 (Reeve et al. 2022b) provides considerable additional detail on the results of the analysis.

[3] The study reports are located at: https://www.pnnl.gov/projects/transactive-energy/DSO+T

2.0 Analysis Scenarios

The study examines two cases of transactive flexible asset deployments in each of two different scenarios of renewables penetration. The first deployment case is based on a high participation rate of flexible customer loads (HVAC and water heating). The second is based on a presumption that customer flexible load participation is not ultimately significant and instead batteries become the flexible asset of choice. These flexible asset deployment cases are evaluated across moderate and high renewable generation scenarios. The intent is to show that transactive energy exchange mechanisms provide stable and economically effective coordination regardless of what types of flexible assets and levels of renewable generation predominate in the future.

At its most basic level, the study consists of parallel analyses of the two scenarios, each with its own BAU case that serves as its baseline. These are illustrated conceptually in Figure 2. The MR scenario looks at the combined effect of a DSO engaging a fleet of flexible assets deployed at scale and connected with a transactive network when there are moderate levels of renewables in the power system. This level of renewables generation is intended to represent what can may be achieved for the United States as a whole in the absence of federal mandates, based on 2016 levels in California or Texas (17% and 15% of energy generated, respectively). The HR scenario is similar but assumes a high level of annual renewables generation corresponding to aggressive renewables portfolio standards set by a number of states (~40% or more including substantial rooftop PV penetration). The HR scenario also assumes low-cost batteries spur a high level of penetration of EVs, with approximately 30% of households having an EV capable of variable charging rates (V1G). Note that the HR scenario does not attempt to achieve even more aggressive goals such as 80% renewables generation or conversion of gas-fueled end uses in buildings to electricity, rather it is intended to examine the relative value of a DSO+T strategy as renewable levels increase.

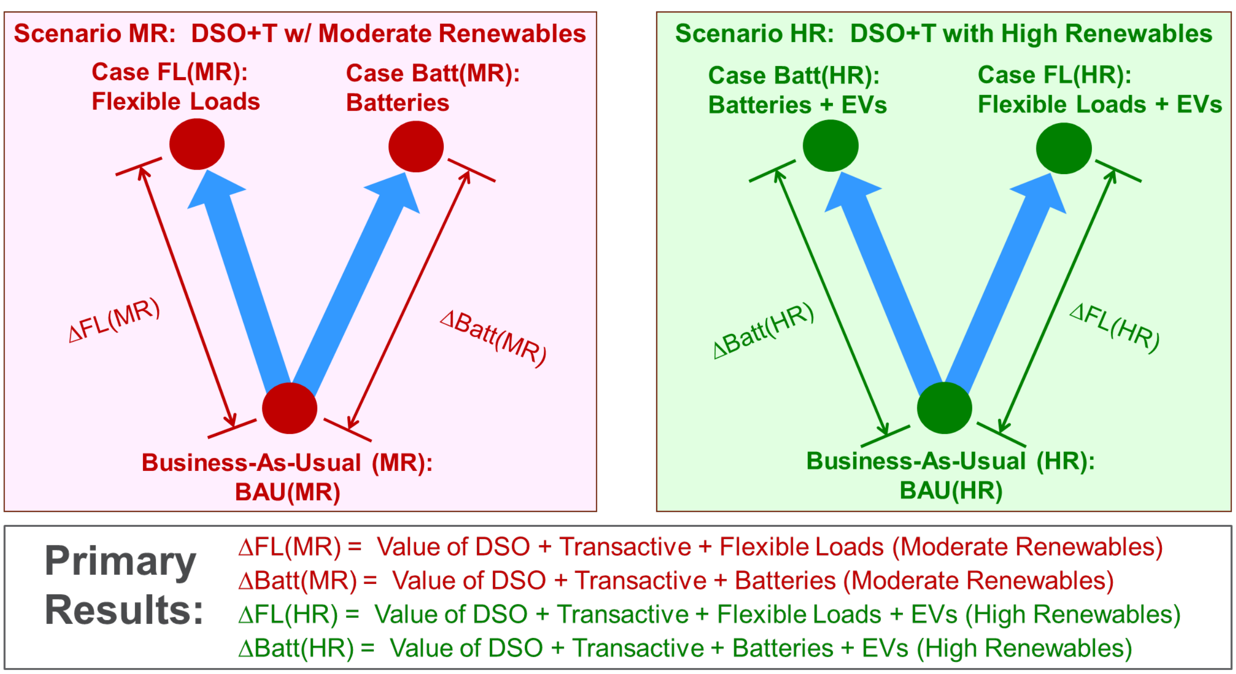


Figure 2. DSO+T study structure and basis of primary results.

Each analysis compares two transactive cases against its respective BAU case:

- The flexible load case (Case FL) assumes a high penetration of flexible loads with substantial customer participation as the primary component of the DER fleet. It also assumes that a majority of residential and commercial customers (~80%) install grid-responsive controls for primary end-use loads such as HVAC and (residential) water heating.
- The battery case (Case Batt) assumes continued breakthroughs in reducing the cost of stationary battery storage and reluctance on the part of most customers to provide flexibility from their loads will result in distributed storage dominating the DER fleet. A comparable amount of distributed battery storage will be assumed, sufficient to provide about the same approximate size resource as the fleet of flexible loads in the flexible load case. This equates to approximately 40% of residential and commercial buildings having average battery storage of 14.2 kWh each (a total capacity of 21.3 GW).

A summary of flexible asset deployment and participation rates for the various cases and scenarios are shown in Table 1. This study limits EVs deployment to only residential customers due to data and modeling constraints (discussed in Section 3.3). In addition, only residential water heaters are modeled and assumed to participate.

Table 1. Summary of flexible asset deployment and participation rates by analysis case.

Asset Deployment and Participation Rates	MRs			HRs		
	BAU	Flex	Battery	BAU	Flex	Battery
Annual renewable generation	15%	15%	15%	42%	42%	42%
Customers with HVAC	97%	97%	97%	97%	97%	97%
Faction of HVAC participating	0%	82%	0%	0%	82%	0%
Residential customers with water heaters	61%	61%	61%	61%	61%	61%
Fraction of water heaters participating	0%	77%	0%	0%	77%	0%
Residential customers with EVs	0%	0%	0%	33%	33%	33%
Fraction of EVs participating	0%	0%	0%	0%	92%	92%
Customers with batteries	0%	0%	40%	0%	0%	40%
Fraction of batteries participating	0%	0%	100%	0%	0%	100%
Customers with rooftop solar	0%	0%	0%	31%	31%	31%
Fraction of rooftop solar participating	0%	0%	0%	0%	0%	0%
Total fraction of customers participating	0%	81%	40%	0%	81%	58%

Note that the study simulates the system under 2016 conditions and, where possible, data are used from 2016 for comparisons. The BAU cases aim to represent current distribution utilities' infrastructure, operation, and cost structure. The study presumes that in the future distribution utilities have become DSOs (Kristov and De Martini 2014) and are responsible for planning and operational functions associated with distribution systems that have been modernized to accommodate and manage the operations of high levels of flexible assets while maintaining safe and reliable operation of the system. The shape that DSOs and flexibility aggregators will take is emerging in several different forms. This study defined a simplified and streamlined organization with the objectives of reliably and efficiently operating a distribution system and enabling customers' flexible assets access to the bulk electric and distribution systems' operational value streams.

Transactive energy coordination is a natural fit for translating these value streams into operational incentives for customers with responsive assets. While the organizations that ultimately aggregate DER flexibility will take different forms, the simplified DSO design used for the study supports the primary goal of linking bulk-level and distribution-level value streams with DER flexibility to enable an overall coordination framework that seeks optimal behavior from marketplace participants. The study examines two potential configurations of DSOs:

- A bundled DSO that, like today's distribution utilities, is a single entity, but with regulatory incentives to use flexible assets as an integrated part of distribution system planning and operations.
- An unbundled DSO in which regulators are presumed to have required that planning, operations, and retail functions of today's distribution utility be disaggregated into three distinct entities: 1) a distribution operator that owns and operates the distribution infrastructure; 2) a nonprofit market operator that aggregates and coordinates the use of flexible customer assets in day-to-day operations and in the distribution operator's planning processes; and 3) a load serving entity (LSE) that operates the retail interface to customers and purchases wholesale energy services on their behalf.[4]

The study makes a fundamental assumption that the adoption and deployment the DSO+T strategy occurred in the past and has reached steady state. Therefore, the initial period of rapid penetration of flexible assets is over and DSOs confidently take them into account when constructing new substations or upgrades. They have also learned to monitor peak demand closely (on at least an annual basis) to assess whether an upgrade to a constrained element of grid infrastructure has finally become more cost effective for ratepayers than continuing to rely on response from the flexible assets. This is needed because the incentives required by customers gradually (but predictably) escalate as the grid elicits increasing amounts of response from their assets and eventually a traditional capacity upgrade may become the lowest cost option.

Finally, it is important to note that this study has developed a transactive retail market that can be integrated into current competitive wholesale markets common in many regions across the United States. Therefore, we assume a wholesale market, operated by an ISO, that consists of an hourly day-ahead market (cleared once a day) and a 5-minute real-time market. As will be discussed in the following sections, we have based the definition of the physical region on Electric Reliability Council of Texas (ERCOT), given its representativeness of the nation as a whole, but are assuming the presence of a generation capacity market (similar in nature to PJM). This ensures the market design and study results are broadly applicable to common ISO market designs. The results (presented in Section 6.0) can be parsed to determine the impact of capacity market benefits versus other benefits.

[4] Note that, to simplify the discussion, this report does not continue to semantically distinguish between traditional distribution utilities in the BAU case and DSOs in a transactive case. It uses the term "DSO" when referring to either, with the context of a BAU case implying that the DSO entity being referenced is, in fact, a traditional distribution utility.

3.0 Integrated System Simulation

This section summarizes the definition and illustrative results of the integrated system simulation model. Full details of the system simulation and MR BAU performance are provided in DSO+T Volume 2: Scenario and System Definition Report (Reeve et al. 2022a).

3.1 Overview of Simulation Elements and Platform

To successfully understand the impact of load flexibility on the distribution and bulk system operation, the study simulated the fully integrated system, from generators on the transmission system to individual DERs such as HVAC units, water heaters, and batteries on the distribution system. Figure 3 shows the breath of the DSO+T simulation. The bulk generation system contains a mix of thermal generators (natural gas, coal, nuclear) as well as wind and solar resources. The bulk system generators are connected to the distribution system via an 8- or 200-bus transmission model. Forty DSOs are modeled and their distribution systems are represented by 1-2 feeders that connect a mix of residential and commercial buildings, each with a combination of end loads.

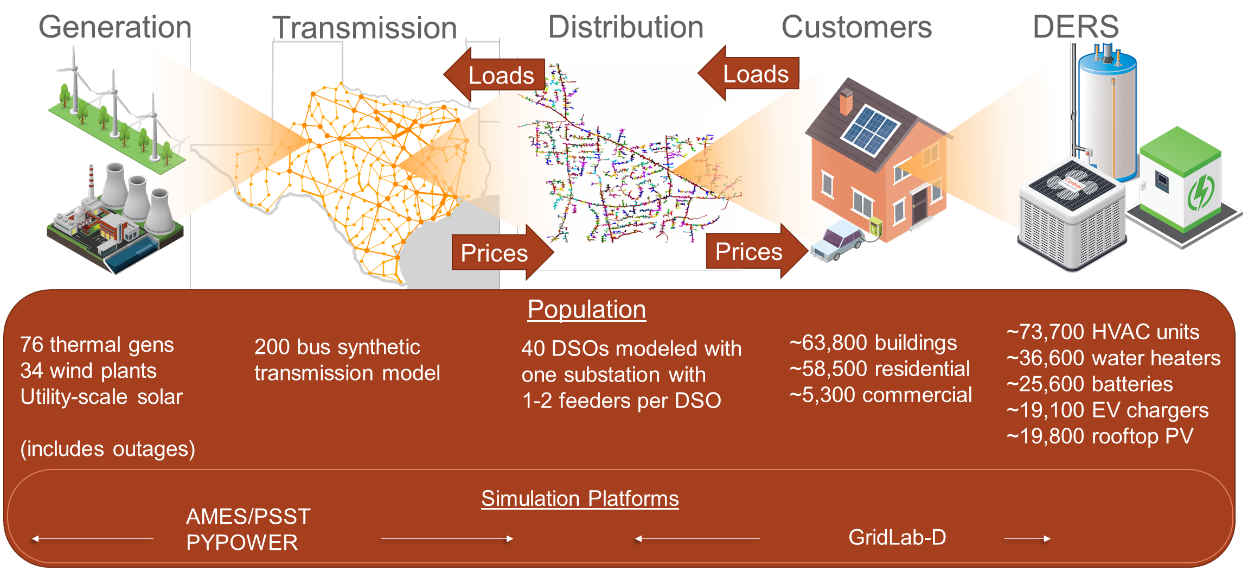


Figure 3. Overview of the 200-bus system simulation breath, scale, and modeling platforms.

Rather than use a typical research-scale model, a region of the U.S. bulk power system was chosen to ensure representative and realistic simulation behavior. After considering a number of alternatives and tradeoffs, such as size versus complexity of the modeling effort, the ERCOT region was selected as an ideal infrastructure for analysis of the bulk system for several reasons. First, it is an entire interconnection with very little power transfer capability across its boundary, eliminating considerations of major imports and exports of power. Second, ERCOT has a wholesale generation mix that is fairly representative of the United States compared to other ISO regions that were candidates for the study. As shown in Table 2, California (CAISO), New England (ISONE), and New York (NYISO) all have far less coal resources and ISONE and NYISO also have significantly more nuclear power. This shows ERCOT as more representative of the U.S. generation fleet. Furthermore, only ERCOT and CAISO have wholesale wind and solar renewable resource penetrations (15% and 17%, respectively) that approach a nominal 20% target for the MR scenario.

Table 2. Regional and U.S. generation, 2016 (fraction of wholesale energy produced).

Type of Generation	ERCOT	CAISO	ISONE	NYISO	United States
Natural gas	44%	50%	49%	44%	34%
Coal	29%	0%	2%	1%	30%
Wind	15%	7%	2%	3%	6%
Nuclear	12%	10%	31%	30%	20%
Other*	0%	34%	15%	22%	10%
Solar	0%	10%	1%	0%	1%
Non-solar	<1%	24%	14%	22%	9%
TOTAL	100%	100%	100%	100%	100%

*Includes solar, hydro, geothermal, petroleum coke, biomass, and landfill gas.

While ERCOT was selected to define the system model, the goal of the study is to develop a nationally representative model. This report compares the results of the simulation (such as loads and market prices) to ERCOT to provide insight into the representativeness of the model. Comparisons are made to other regions where possible. It is also important to remember that the performance of electricity systems changes over time. While we have chosen 2016 as the year of comparison, the performance of ERCOT in other years varies due to changes in fuel prices, load growth, climate conditions, and transmission and distribution upgrades. The goal of this simulation is to capture the essence of a fully integrated electricity delivery system. ERCOT data are used to gauge how well we have done, but the ultimate goal is to capture nationally representative behavior, not accurately model ERCOT behavior in 2016.

3.2 Co-simulation and Software Stack

Successfully simulating this fully integrated transmission and distribution system required use of a co-simulation platform to integrate and coordinate domain appropriate tools. To achieve this, the DSO+T study leveraged the Transactive Energy Simulation Platform (TESP n.d.) that enables co-simulation of the bulk grid (generation and transmission) system, distribution system, and end loads. TESP is built on top of the Hierarchical Engine for Large-scale Infrastructure Co-Simulation (HELICS) open-source framework. More details about the TESP and its usage can be found in prior trial valuation analysis and simulation efforts conducted by PNNL (Widergren et al. 2017; Huang et al. 2019).

The bulk system is modeled using a combination of Agent-based Modeling of Electricity Systems (AMES) and PYPOWER. The open-source AMES tool (AMES n.d.; Li and Tesfatsion 2009; Tesfatsion and Battula 2020), was used to simulate the wholesale market operations. Given market bids and reliability operating constraints, AMES determined the day-ahead scheduling of generators and their real-time dispatch by solving the security-constrained unit commitment (SCUC), the security-constrained economic dispatch (SCED), and calculating the locational marginal prices (LMPs) for each market cycle.

PYPOWER (2020) was used to simulate the real-time power flows in the transmission system given the modeled generators and the load managed by the DSOs. The TESP co-simulation environment uses GridLAB-D (see next subsection) to model the real-time behavior of the distribution system and customer resources (building loads, batteries, EVs, and PV) that iteratively exchange data with the PYPOWER bulk power system simulation. This overall co-simulation was executed at 15 second time steps and loads were recorded every 5 minutes. Twelve one-month runs were executed in parallel enabling analysis over an entire year.

3.3 Distribution System and End-Use Loads

The time-varying load of each DSO was determined by modeling distribution feeders, residential and commercial buildings, and their end-use loads. These elements were defined and instantiated as follows. It is assumed that each DSO is represented by a single transmission substation hosting one or more prototypical distribution feeder models (Schneider et al. 2008). The feeders were selected based on DSO type (urban, suburban, rural) and climate zone. Commercial and residential buildings were then instantiated on the feeders in proportion to the ratio of residential to commercial customers available from DOE's Energy Information Administration (DOE-EIA n.d.). Finally, industrial loads were added and, for simplicity, assumed to be an aggregated load constant for the entire year based on the low variation seen in Hale et al. (2018) and their magnitude for each DSO was based on ERCOT utility data (DOE-EIA n.d.). The electrical distribution system, buildings, and all end loads were modeled using GridLAB-D. The resulting simulated load was then multiplied by a weighting factor to represent all customers within ERCOT. For the 8-bus model, the simulation contained 11,929 buildings (11,190 residential and 739 commercial), 13,162 HVAC units, and 7,325 water heaters, representing a 1:952 scale (and hence the weighting factor) of the ERCOT system. For the 200-bus model, the simulation contained 63,729 buildings (58,453 residential and 5,273 commercial), 73,704 HVAC units, and 36,624 water heaters, representing a 1:172 scale of the ERCOT system.

The distribution of commercial and residential buildings was based on the DSO type (urban, suburban, or rural). Each building was procedurally generated with its own unique type (e.g., single family, multifamily, retail, warehouse, or office), vintage, size, and form factor. The insulation levels, thermal mass, and window and HVAC performance were based on building vintage, climate zone, and typical building practices and codes at the time. Operating and occupancy schedules and plug loads were randomized from typical values based on building type. GridLAB-D has a single-zone house model for simulating building envelope, internal gains, and HVAC performance (GridLAB-D 2017). This ensures the dynamics and thermal mass of the buildings, as well as comfort impacts, are captured in the simulation. Figure 4 shows an example of a building's HVAC thermostat setpoints and indoor air temperature resulting from modeling the HVAC operation. The result is a diverse set of buildings with different time-varying loads. Figure 5 shows an example of the variation of residential building size, resulting annual load, and load factor (the ratio of average load to peak load) for all residential buildings in the 8-bus model. More details on the building definition procedure are provided in Reeve et al. (2022a), Sections 6 and 7, and Reeve et al. (2021).

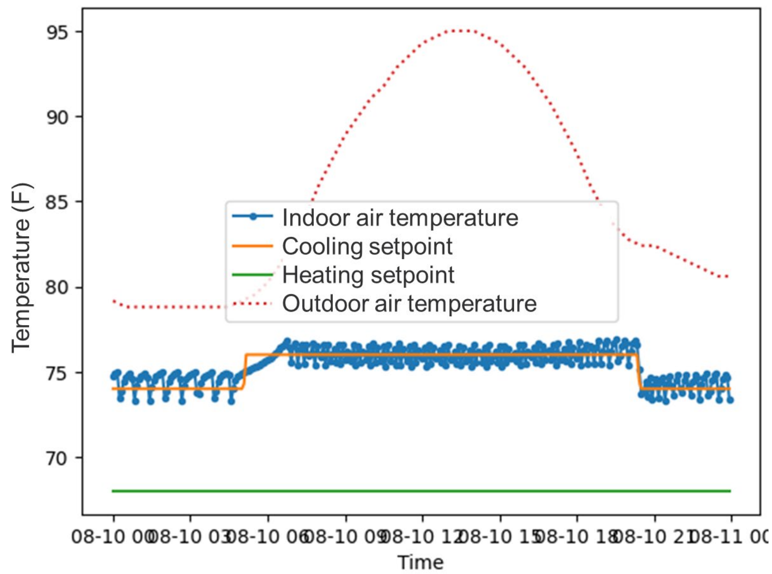


Figure 4. Example thermostat schedule and resulting simulated indoor air temperature resulting from HVAC operation for one of the tens of thousands of modeled buildings.

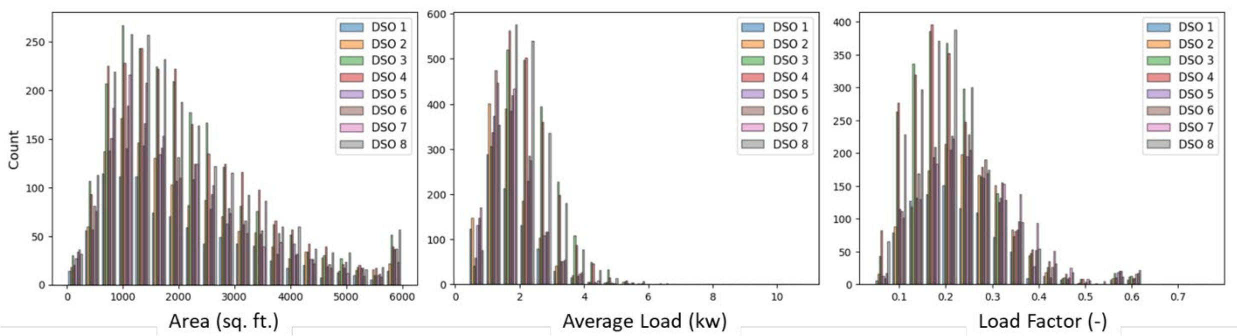
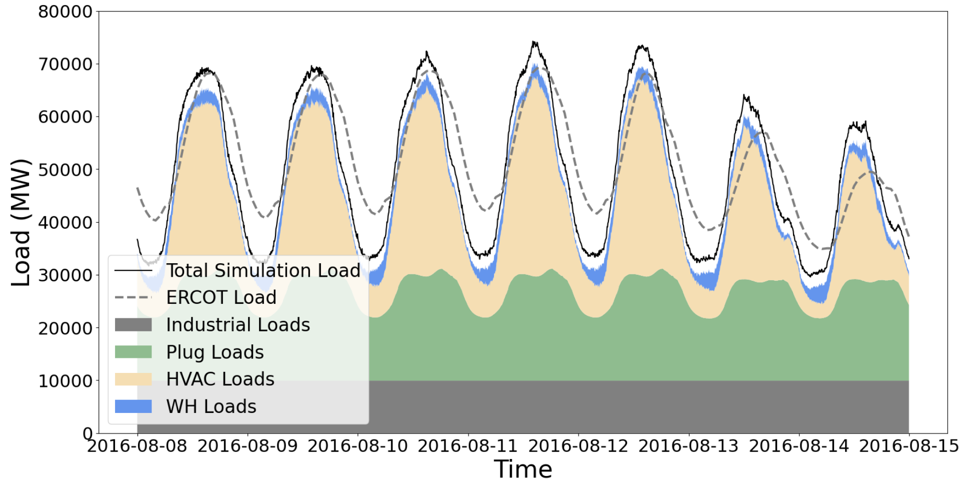


Figure 5. Residential building distributions for size (sq. ft.) and resulting average load (kWh) and load factor for the 8-bus model.

The annual simulation of 2016 was performed at 15-second time steps to capture general equipment operational dynamics and the total system load was measured every 5 minutes (the real-time market interval). The total simulated distribution load was scaled to represent the total customer count of each DSO in ERCOT. Examples of the resulting load profiles (by end use) are shown for peak and minimum system load in Figure 6. While the peak and average system load were accurately captured (within ~5% percent for the 200-bus model), the minimum total load was overpredicted by ~10%. In addition, the daily variation in load was overpredicted (on average by ~37%). As discussed in Section 3.4, this results in much larger ramping requirements for the generation fleet but not in an overprediction of daily changes in price (diurnal changes in price are under predicted). Work by Hale et al. (2018) also overpredicted the daily swing in building loads. This suggests that the use of a higher fidelity simulation tool (for example EnergyPlus) or more detailed building definition data (ComStock and ResStock databases) would be unlikely to resolve this issue. This issue may be caused by inaccurate representation of building thermal mass or occupant behaviors and schedules. Further research into the cause of this systematic overprediction is warranted.



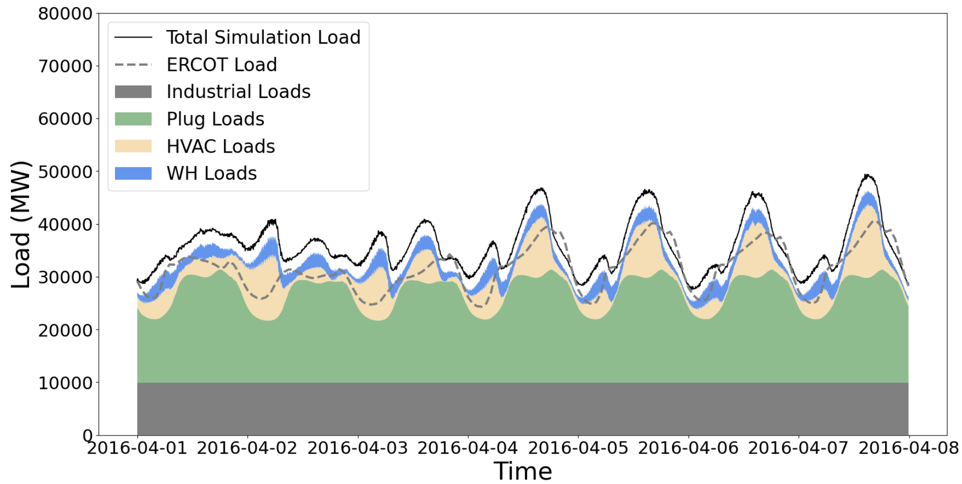


Figure 6. System load contributions by end use for peak (top) and minimum (bottom) load. Total simulation load (solid line) is shown in comparison to actual load experienced in ERCOT (dotted line).

The HR scenario assumed the deployment of EVs. Due to limitations in the simulation platform and driver behavior data, each EV was assumed to only be charged and discharged at a single building to avoid the necessity of tracking EV state of charge (SOC) across multiple buildings. For this reason, the study assumed that EVs would only be charged at residential buildings. In the HR scenario, more than 30% of residential customers were assumed to have one EV. The usage of the EV was based on publicly available survey data and the range of battery capacity. EV efficiency was based on sales data of leading EV models. For the BAU case it is assumed that EVs start charging as soon as the return home until fully charged. The transactive cases allow EVs to only vary their rate of charge (V1G operation) and not allow EVs to discharge onto the grid (V2G operation). This decision was made in part because some simulation cases also have battery DER operation that can be used to understand the potential benefits of battery discharge onto the grid (analogous to V2G operation but without the constraints that EVs need to be fully charged at a certain time and that EVs are often away from their charging station). An example of the difference in simulation results between V1G and V2G is provided in Singhal et al. (2021) and overall details of EV and battery modeling is provided in Reeve et al. (2022a), Sections 9 and 10.

3.4 Bulk Generation and Transmission System

The generation fleet for the MR scenario was made up of a combination of nuclear, natural gas, and coal thermal generators as well wind turbines. The HR scenario used the same thermal generation fleet but doubled the wind capacity and added 14.8 GW of utility-scale solar capacity on the transmission system and 21.3 GW of rooftop solar on the distribution system. Thermal plants were not retired *a priori* in the HR order to allow any economically competitive plant to be scheduled and dispatched. This does not impact the dispatch of renewables but allows the simulation to economically utilize plants as needed for reliable operation. The study results can be used to assess the savings from candidate plants for retirement in future work.

The number, location, and capacity of the bulk system generators for the MR scenario are based on the ERCOT test system (Battula et al. 2019) that used DOE-EIA data to determine the aggregate amount of generation (by fuel type) at each transmission bus. This means that each transmission bus has no more than one natural gas, nuclear, or coal generator. Each dispatchable generator represents the aggregate capacity seen in Texas for that location. A summary of the generation fleet capacity for both scenarios is show in Table 3. (A summary of resulting annual generation by fuel type is provided in Section 3.5).

Table 3. Summary of generator types, number of locations (200-bus case), and capacity for the MR and HR scenarios.

	MRs			HRs		
Generation Type	Number	Capacity (MW)	Capacity (%)	Number	Capacity (MW)	Capacity (%)
Coal	14	21,900	22%	14	21,900	15%
Natural gas combined cycle	33	40,100	41%	33	40,100	27%
Natural gas internal combustion engine	9	1,800	2%	9	1,800	1%
Natural gas steam turbine	18	13,000	13%	18	13,000	9%
Nuclear	2	5,100	5%	2	5,100	3%
Wind	34	16,300	17%	34	32,600	22%
Solar (utility scale)	-	-	-	200	14,800	10%
Solar (distributed)	-	-	-		21,300	14%
TOTAL	110	98,300	100%	310	150,600	100%

The use of thermal generators is based on solving the SCUC and SCED optimizations for both day-ahead and real-time market operations. Economic dispatch of the thermal generation fleet was based on each generator’s variable operating costs (i.e., fuel and variable operating and maintenance costs) and startup costs. The generator’s dispatch and operation were constrained by typical values of generation ramp rates and minimum compliant load levels. Planned and unplanned outages of the generation fleet were also included in the simulation.

The output of the wind generators was based on a stochastic wind power model (Chen et al. 2010) calibrated to 2016 ERCOT hourly wind generation data. The solar output was based on 2016 hourly solar radiation data. Forecast error was included in both the day-ahead renewables generation and the DSO load forecast. Unless curtailed, all renewables generation was committed and dispatched and was subtracted from the demand to create a net load at each bus. During periods of HR generation, curtailment was applied to ensure there was at least 8 GW of thermal generation requirement to ease solving the economic dispatch problem and avoid the cycling of nuclear generators. Even with such curtailment, 40% of the annual generation was sourced from renewables and the system experienced >70% renewables generation >10% of the time. Full details of the generation fleet definition are provided in Reeve et al. (2022a), Section 2.

Simulations were run on 8- and 200-bus transmission models[5]. The models are based on the ERCOT test system (Battula et al. 2019) that synthetized generic transmission network designs using population and load data. The 200-bus model (Figure 7) shows resulting transmission line utilization levels and resulting real-time market prices during the system peak load (2 p.m. August 12).

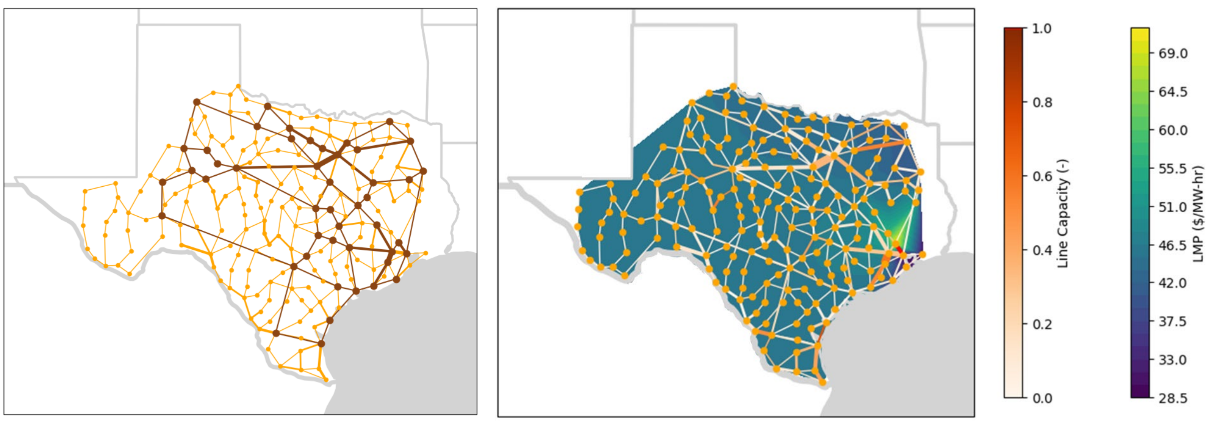


Figure 7. The 200-bus transmission network (left), with 345 kV lines shown in brown and 138 kV lines in orange. The line thickness is proportional to its MVA rating. Resulting line congestion (denoted by the line color) and geographic variation in LMPs are shown on right.

Figure 8 shows the resulting real-time generator dispatch in comparison with actual ERCOT values for the MR BAU case. The load profiles and overall generation dispatch trends, along with the resulting fuel mix, suggest that the simulation is representative. The load shape and weather-dependent changes throughout the month are well captured. As discussed in Section 3.3, the simulated diurnal swing in load was higher than actual ERCOT data, resulting in higher rates of ramping for the generator fleet. Note that since the wind generation profiles are stochastically generated and not based on 2016 data, a direct daily comparison of the wind profiles is not appropriate.

[5] The 8-bus model was used as a computationally efficient means to debug and shake-down the analysis and perform trial analysis. It also allows the impact of simulation size on study results to be assessed (discussed in Volume 5). Main study results and conclusions are based on the 200-bus results.

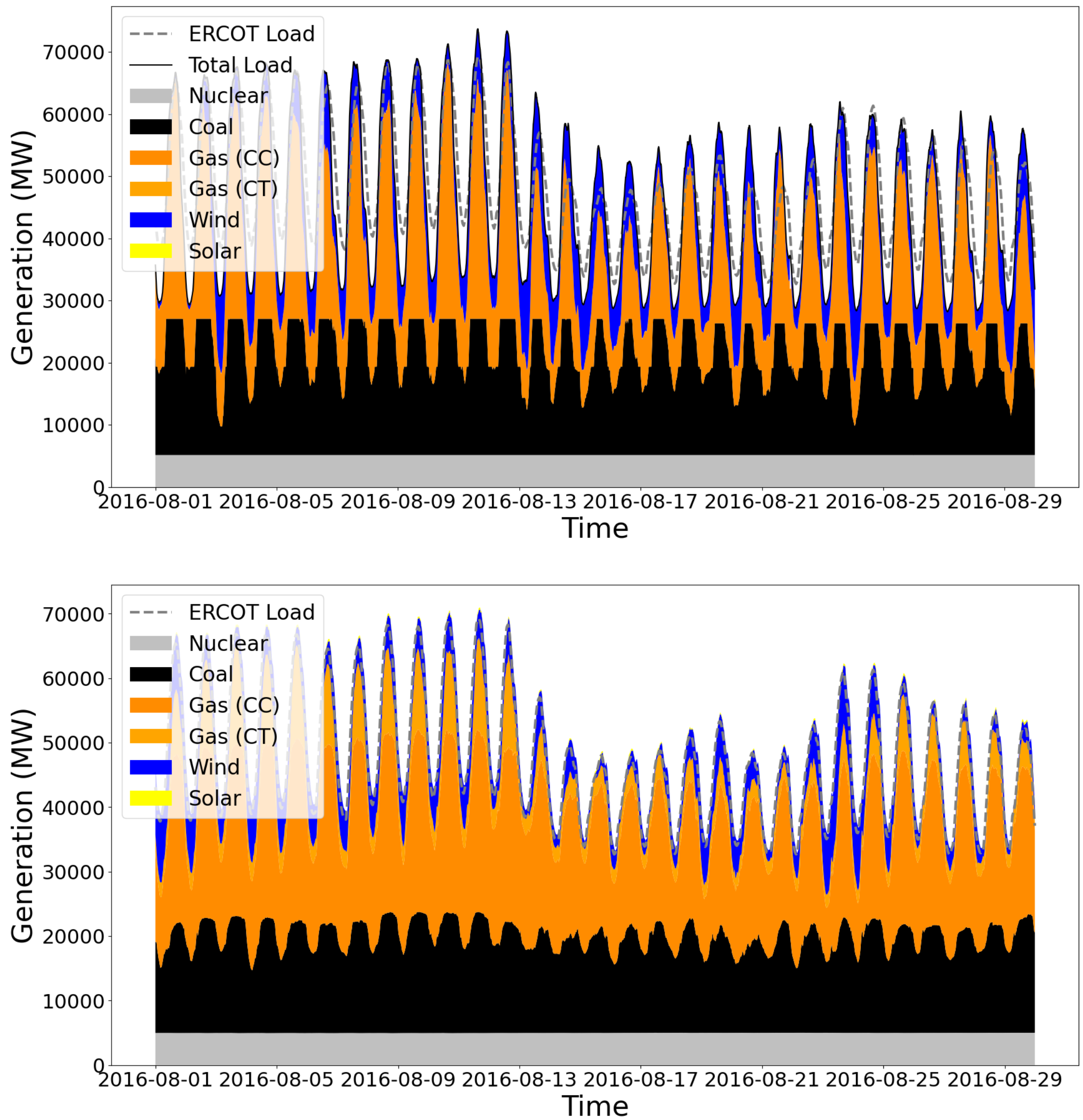


Figure 8. Comparison of AMES real-time generation dispatch for the MR scenario MR (top) versus actual ERCOT dispatch (bottom) for August 2016.

The SCUC and SCED processes also influence the calculation of the LMP at each node within the transmission system. Figure 9 shows a time history of day-ahead and real-time LMPs at a representative transmission node during the summer peak compared with 2016 ERCOT data. This illustrates that the simulation captures the overall daily trends and variation with system load. The simulation does not sufficiently capture, however, the frequency of large, rare price spikes. This could be due to the absence of scarcity price bidding in the AMES market model. This is best displayed in the price versus duration curves (Figure 10) that show how prices vary over the year including example 2016 data from PJM and 2017 data from CAISO's day-ahead market. While the simulation's average LMP prices are higher than ERCOT, they are generally representative of markets within the United States. However, the simulation does not capture the 'tails' of the price distribution seen in real market operation. For example, ERCOT and CAISO have day-ahead prices below $10/MWh approximately 5% of the time, and all three comparison markets have prices above $50/MWhr approximately 5% of the time. The end result is that the DSO+T simulation underpredicts median daily variation in day-head prices by 32-70% when compared to the three regional markets. Since this variation in day-head price drives DER bidding strategy and economic benefits, this area warrants improvement in future market modeling.

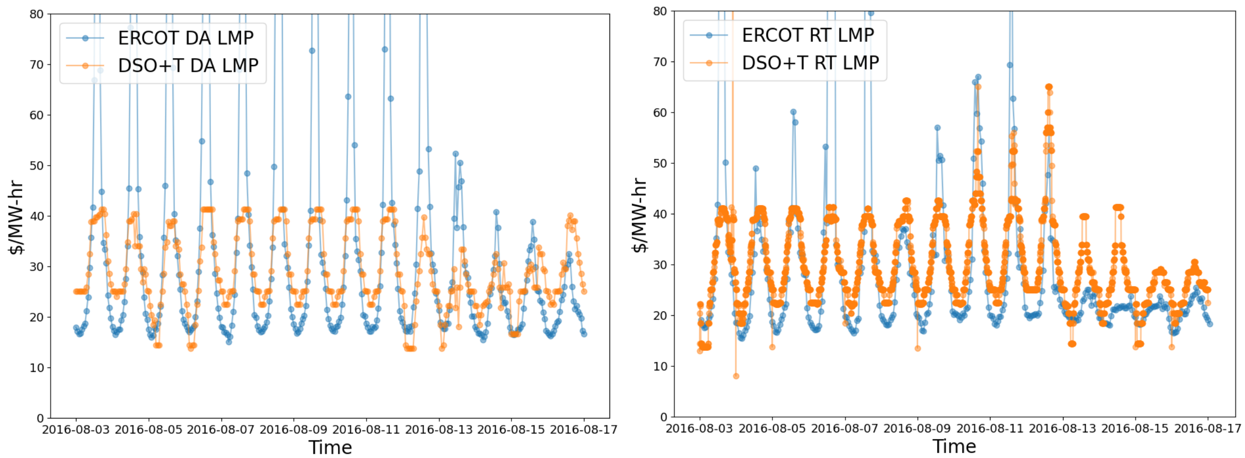


Figure 9. Comparison of DSO+T and ERCOT day-ahead (left) and real-time (right) prices in August.

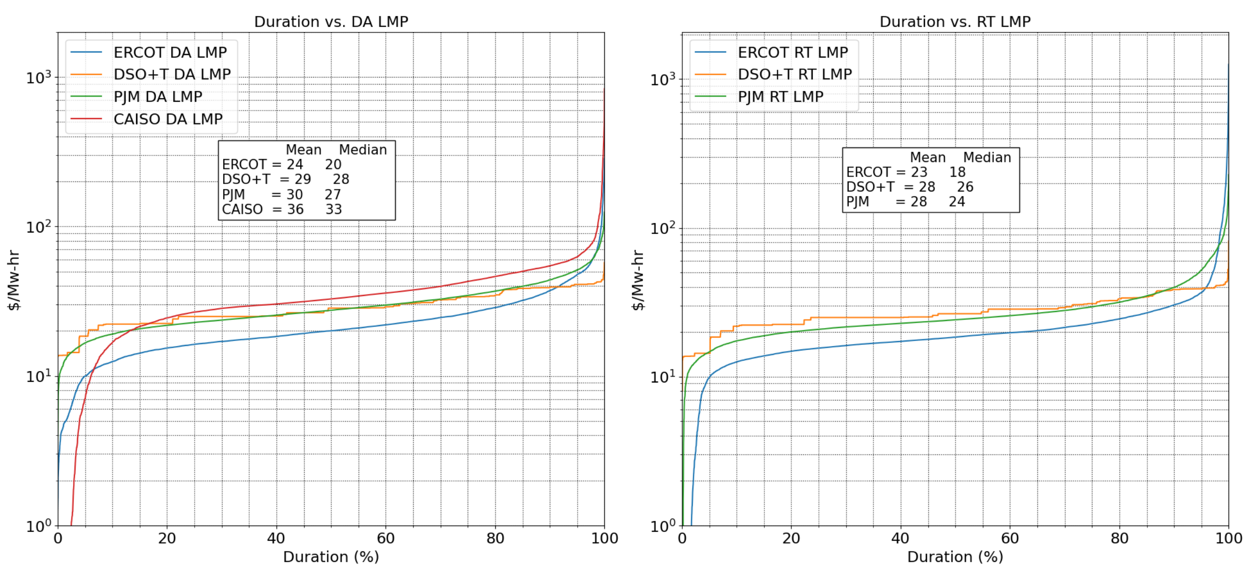


Figure 10. Annual wholesale price versus duration for day-ahead (left) and real-time (right) markets for various regions and the DSO+T simulation.

3.5 Summary of Overall System Generation and Loads

This section summarized the average annual power by generation, customer, and end-use types for both the MR and HR BAU scenarios. Since the MR scenario (Figure 11) is modeled on 2016 ERCOT data, a comparison of these values can be made to determine the overall representativeness of the generation, customer, and end-use splits.

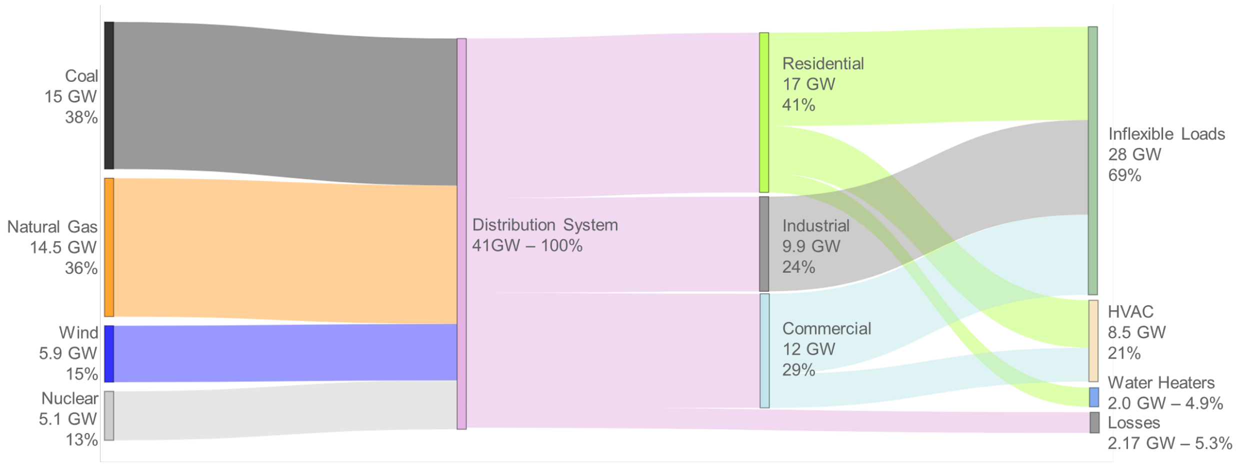


Figure 11. Annual average power by generation source, customer type, and end-use load for the MR BAU case (8-bus model).

3.5.1 Moderate Renewable Scenario

The MR BAU simulation shows (at the far left of Figure 11) that coal was dispatched at a higher rate in simulation than in 2016 ERCOT data (39% versus 29%), resulting in a decrease in natural gas utilization (36% versus 44%). Both wind and nuclear contributions were within 2 percentage points of ERCOT values. The load consumption by customer type was very close to expected values with residential loads (excluding losses) being slightly high (46% versus 43%), and commercial (29% versus 31%) and industrial loads (24% versus 26%) being commensurately lower. Finally, the contributions of specific end-use loads suitable for grid services were quantified and compared with residential and commercial building energy survey estimates (DOE-EIA 2012, 2015). HVAC accounted for 24.9% of end-use load (excluding losses) versus energy survey-based estimates of 29.6%, and residential water heating contributed 6.5% versus energy survey-based estimates of 5.2%.

3.5.2 High Renewable Scenario

The resulting average generation and end-use loads for the HR BAU case are shown in Figure 12. The introduction of solar and growth of wind resulted in renewables accounting for ~40% of total generation over the course of the year. End-use loads were unchanged except for the introduction of EVs, which constituted 5% of total average load. While we assumed that an EV is present at ~30% of residential households, the assumed usage rates did not drive significant average load increases. This was not enough to offset the presence of rooftop solar that results in a reduction of total DSO average loads of 1.6 GW (4%). However, EVs did make a significant contribution (9%) to peak loads as will be discussed in Section 6.1.

The higher penetration of renewable energy substantially changes the daily and seasonal load profile, need for dispatchable generation, and resulting wholesale prices as discussed below. This is due to the combined contribution of solar (rooftop and utility scale) and wind contributing >70% of generation over 10% of the hours of the year compared to a >25% contribution in the MR case.

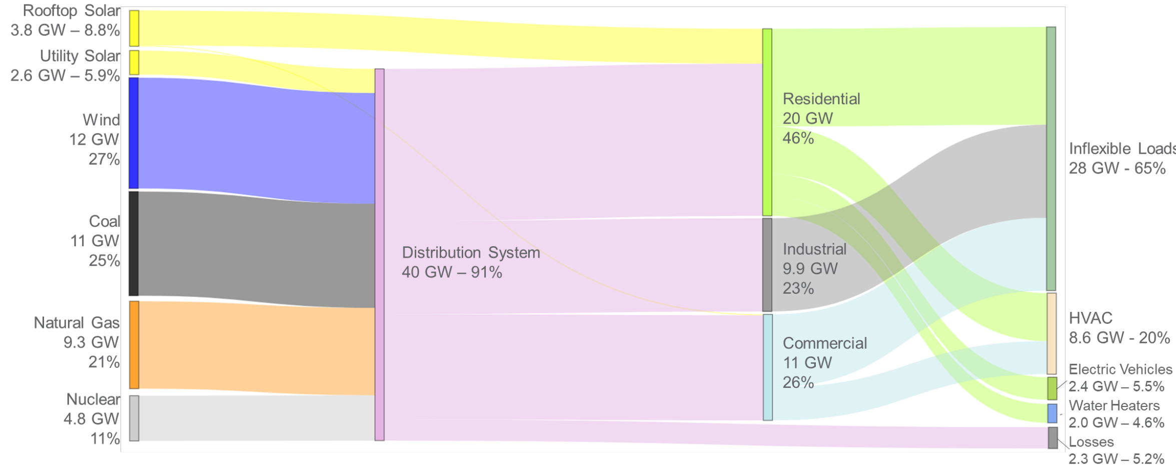


Figure 12. Annual average power by generation source, customer type, and end-use load for the HR BAU case (8-bus model).

Example load profiles are shown in Figure 13, which shows the load contributions (bottom to top) of industrial, plug, HVAC, water heater, and EVs. This load is reduced by the contribution of rooftop solar, resulting in the dashed red line. The addition of distribution system losses results in the total distribution system load (shown in the solid black line). During the summer peak generation from rooftop solar more than offsets the additional load from EVs, reducing peak load from the MR BAU case by 2.3 GW (5.6%; shown as the difference between the black and gray lines in Figure 13). Note that EVs contribute 9% of summer peak loads. This is because their load profile (dominated by afternoon and evening charging) coincides with the system peak. Furthermore, EV charging increases peak loads in the winter above the levels seen in the MR case (Figure 13, right) as EV charging occurs in the evening and night, after the sun has set, and coinciding with the nighttime peak heating load. This nighttime peak is exacerbated by significant daytime solar contributions resulting in large daily variations in distribution system net demand. The end result is that the largest variation in daily load no longer occurs during the summer peak but now occurs in January.

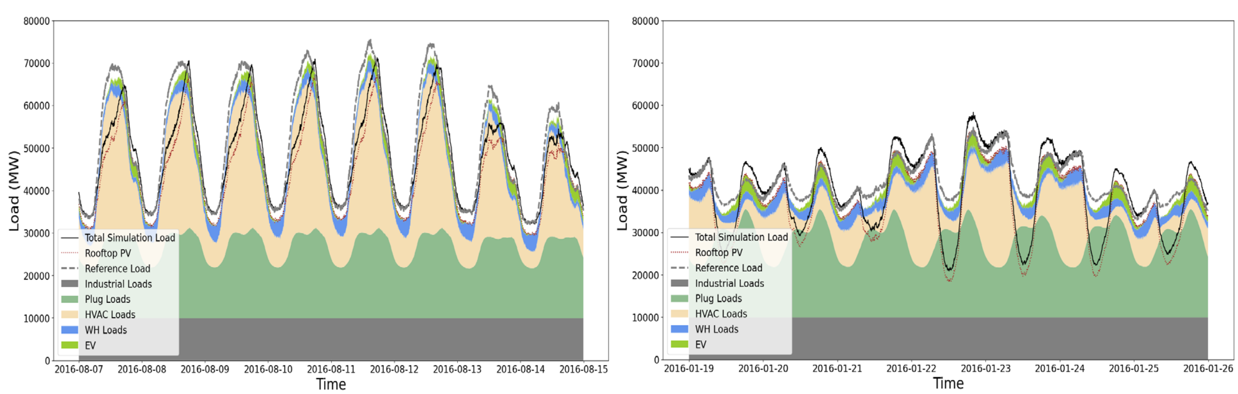


Figure 13. System load contributions by end use for peak demand (left) and maximum daily variation in load (right) for HR BAU. Total load for this scenario (solid black line) is shown in comparison to the total load for MR BAU (dotted gray line).

Figure 14 summarizes the system load for each month (top) and the daily variation in load (daily max load less the daily minimum load). This illustrates the trend seen in the HR scenario of solar and EV additions reducing the summer peak but increasing the winter peak and daily variation in winter and shoulder seasons. Overall, the average daily variation in load increased 2.5 GW (11%) between the MR and HR BAU cases. A summary of annual load statistics is provided for all cases in Section 6.1.1, Table 5.

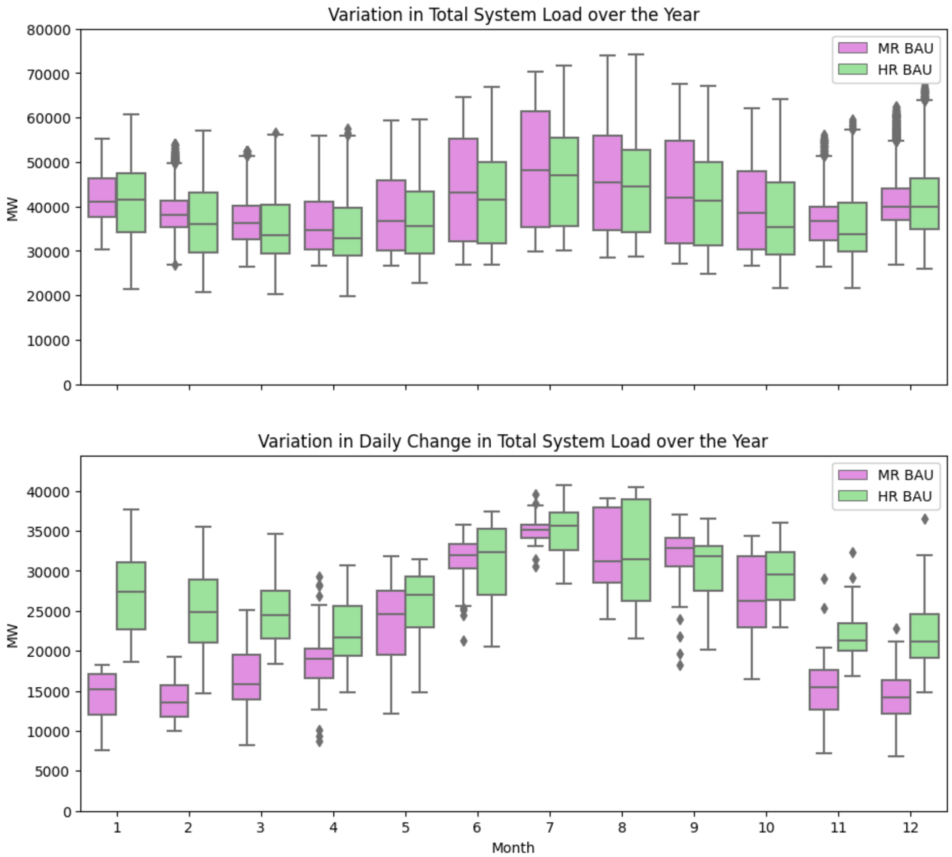


Figure 14. Monthly summary of system load (top) and daily variation in system load (bottom) for the MR and HR BAU cases.

The impact of changes in demand is compounded by additional wholesale wind and solar generation in the HR scenario. Figure 15 shows the corresponding bulk system generation dispatch. The increased contributions of wind and solar (both rooftop and utility scale) decrease the overall need for thermal generation but increase the ramping requirements. This is particularly pronounced in the winter (Figure 15, right).

Due to the simulation challenges of converging the wholesale market model at very high levels of renewables (often with very low levels of dispatchable thermal generation relative to reserve requirements), curtailment of utility-scale renewable generation was enacted to ensure there was always >8 GW of dispatchable generation[6]. The resulting impact on wholesale day-ahead market prices is shown in Figure 16. The reduced need for dispatchable generation results in an 8% decreased average price, due to the reduced need for more expensive ‘peaker’ generators, but a 12% increase in the daily variation in price due to the increased ramping and starts. A summary of annual day-ahead LMP statistics is provided for all cases in Section 6.1.2, Table 6.

[6] 8 GW was identified as the lowest value that maintained sufficient convergence of the generation scheduling and dispatch solver.

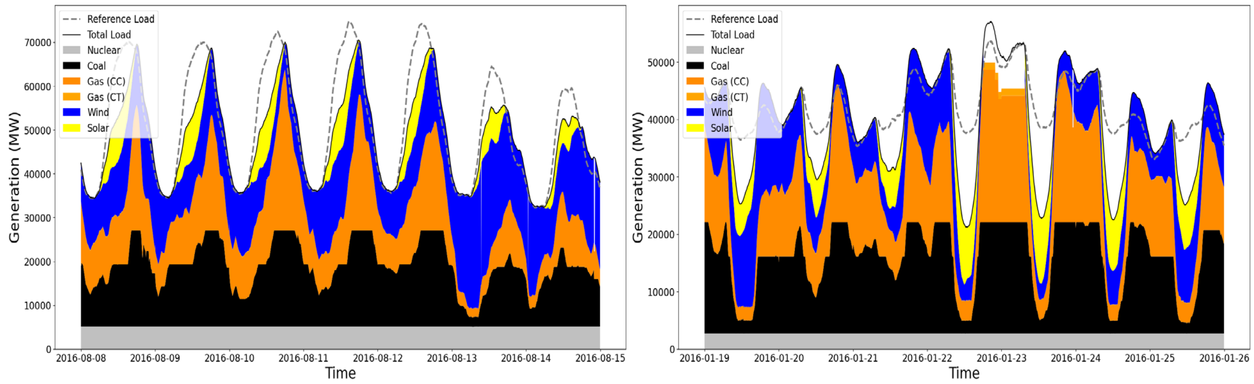


Figure 15. System generation contributions by type for peak demand (left) and maximum daily variation in load (right) for HR BAU. Total generation for this scenario (solid black line) is shown in comparison to the total generation for MR BAU (dotted gray line).

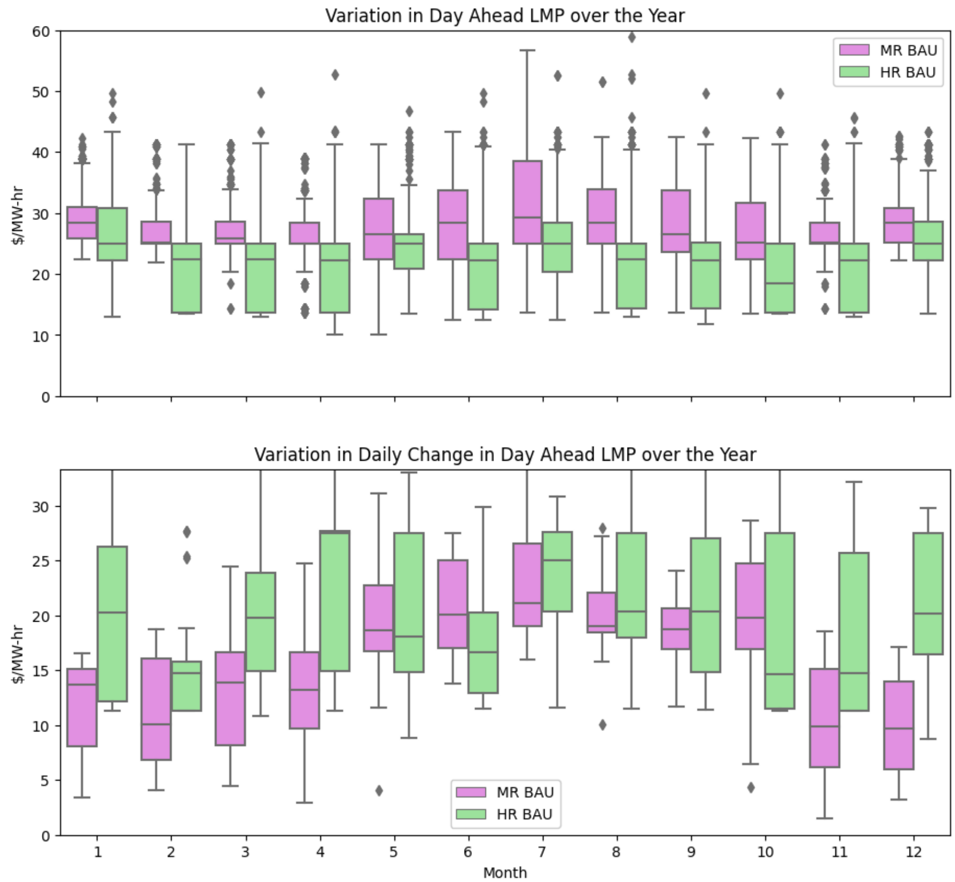


Figure 16. Monthly summary of day-ahead LMP (top) and daily variation in day-ahead LMP (bottom) for the moderate and HR BAU cases.

4.0 Transactive Coordination and Market Integration

To study the impact of large penetrations of flexible assets requires an approach to coordinating the operation of these resources in conjunction with the bulk electricity system. The DSO+T study models the DSO as an aggregator of flexible assets operated by customers in its service territory. The DSO uses a transactive energy approach to engage customer decisions in the operation of their assets. This delegative style of coordination allows customers to individually represent their priorities for energy use to meet their needs. The DSO accomplishes this by running a retail marketplace that resolves the value exchanges of customers with the dynamic prices for energy arising from a typical ISO-style wholesale market.

This section provides an overview of wholesale and retail market-based coordination design. It then delves into the design of the transactive software agents used in the retail marketplace including those operating customers' flexible assets.

4.1 Guiding Principles for Transactive Market and Rate Design

The design of the transactive retail marketplace, price signals, and rates is based on the following fundamental guiding principles.

- DSO retail markets and transactive rates should result in simpler, more transparent, and more accurate representation of actual DSO costs across customer classes.
- Customers on transactive rates should, on average, see a reduction in their electric bills in proportion to the actual value the DSO derives from their response (that is, for increasing levels of participation there are correspondingly increased levels of savings on their electricity bill).
- All transactive participating customers (within the same customer class) should have the same rate design, whether in electrically congested areas or not, to maintain equity while socializing the costs of needed distribution capacity investments across all DSO customers.
- Customers should have the option to remain on fixed rates and should pay no more on their bills than they would in the BAU case.

These principals are met while addressing the combined (sometimes conflicting) interests of fairness, simplicity, and transparency in transactive rate design. The DSO+T study uses dynamic rates and a retail market design (rather than pay-for-performance approaches) to incentivize beneficial customer responses.

4.2 Overview of Marketplace Operation

The transactive energy framework for coordinating responsive flexible assets relies on value exchanges for scheduled energy among wholesale marketplace participants in the bulk system and retail marketplace participants in the distribution system, in the form of wholesale and retail prices, respectively. The interactions between these two tiers are managed by DSOs who straddle the line between wholesale and retail markets as participants in each. A summary of the overall integrated market operation and its participants is shown in Figure 17 and Figure 18.

The BAU case also assumes a competitive wholesale marketplace but the DSO does not attempt to coordinate customers' flexible assets with time-varying prices. In the BAU case, the

DSO's entire load is non-price responsive and is bid into the wholesale market as a fixed, forecasted quantity.

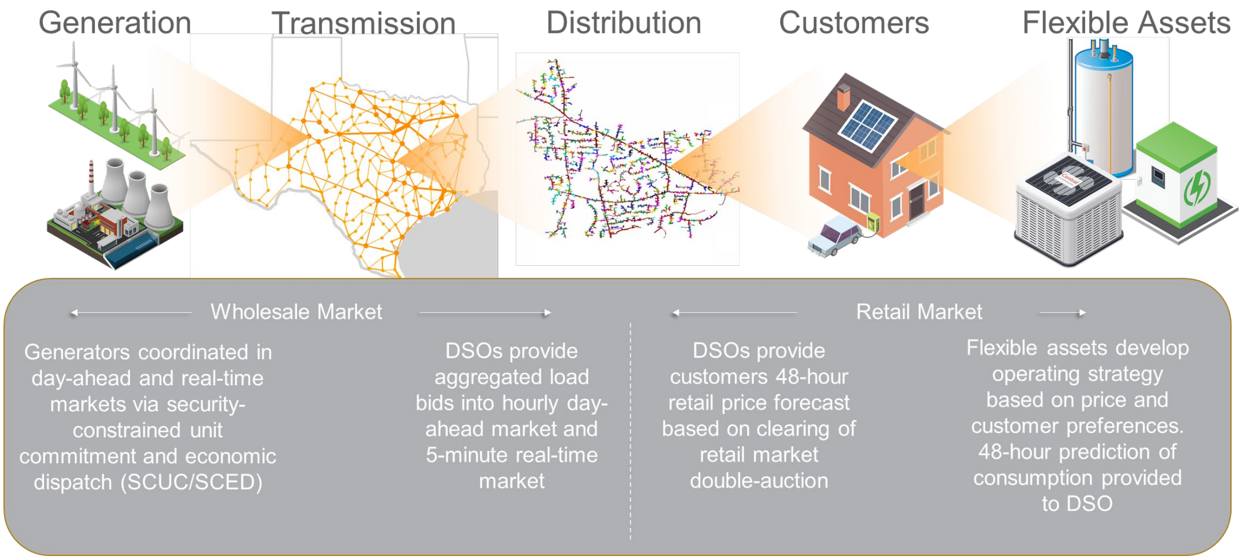


Figure 17. Summary of the wholesale and retail transactive energy markets.

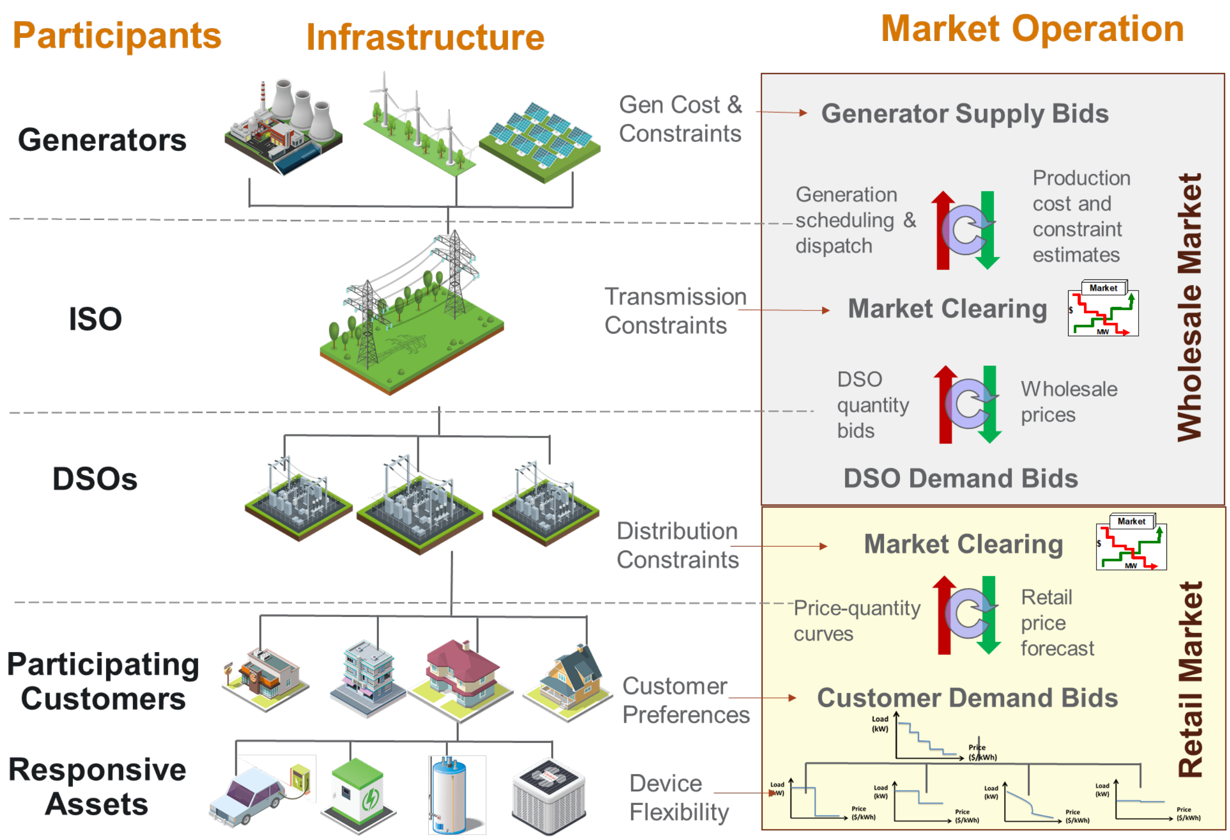


Figure 18. Overview of the wholesale and retail market coordination scheme.

For the study, the ISO operates a competitive day-ahead (24-hour) and real-time (5-minute) wholesale market. Generator owner-operators submit cost-based supply bids and DSOs submit demand quantity bids. In conjunction with this wholesale market operation, the DSOs operate a transactive retail market with participating customers. The retail market also is composed of a forward (48 hour) market and real-time (5-minute) market. The retail market is designed so the DSO can interact between the wholesale and retail marketplaces to represent the flexibility of participating customer assets.

Figure 19 shows a model of the participants and their interactions in the bulk and distribution systems. The figure depicts a third tier to describe the customer participants and their software agents that manage their flexible assets and interact with the retail marketplace in the form of retail bids for net consumption.

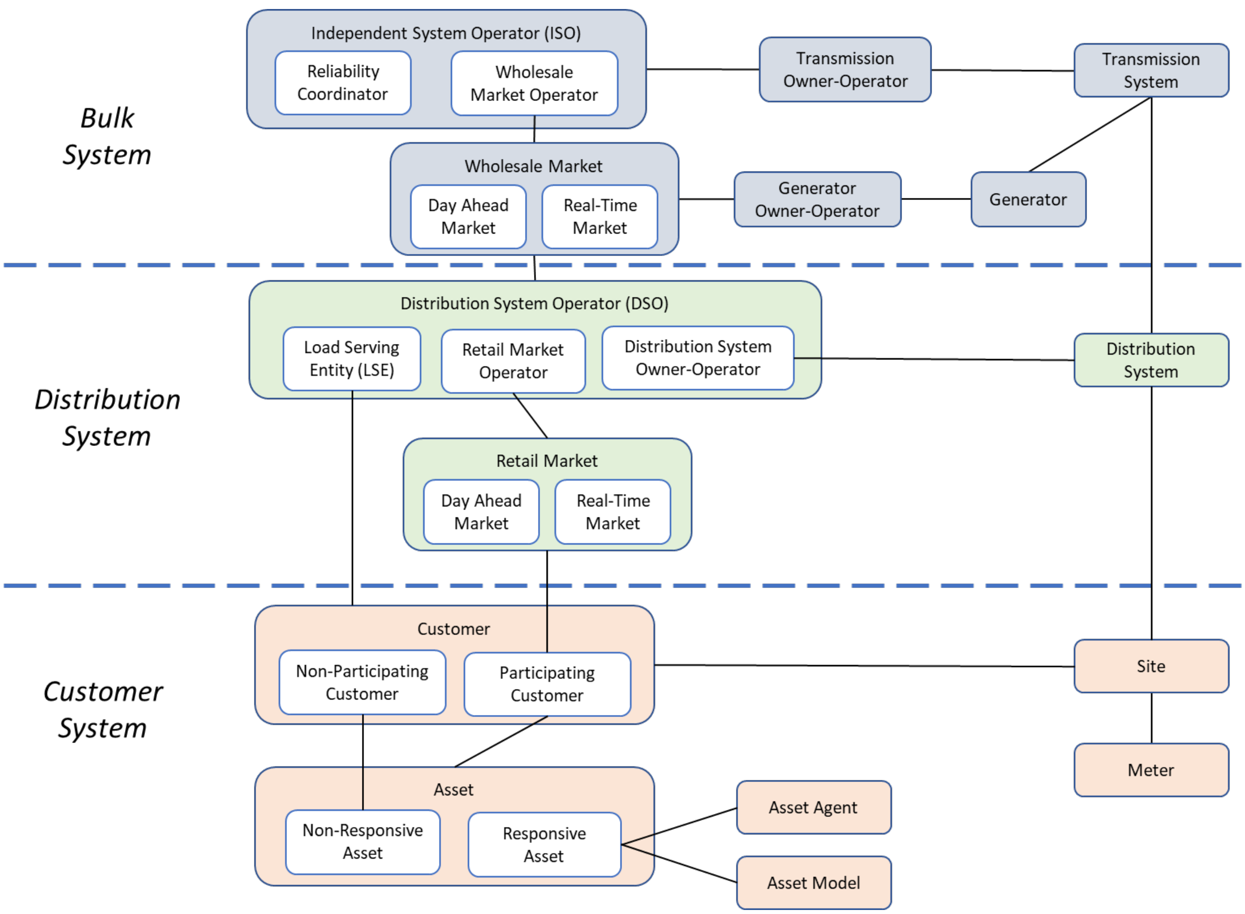


Figure 19. Overview of system marketplace with participants and assets.

Figure 20 depicts a high-level process flow of the coupled wholesale-retail marketplaces with day-ahead and real-time markets. The DSO plays a crucial role in interacting with both the wholesale and retail marketplaces and translating the value signals between them. A summary of the information flow, the timing, and the logic being executed within the market processes are presented in subsequent subsections. Full details of the wholesale market in the BAU cases and the entire wholesale and retail market structure in the transactive cases can be found in Volume 3 of the DSO+T study report (Widergren et al. 2022).

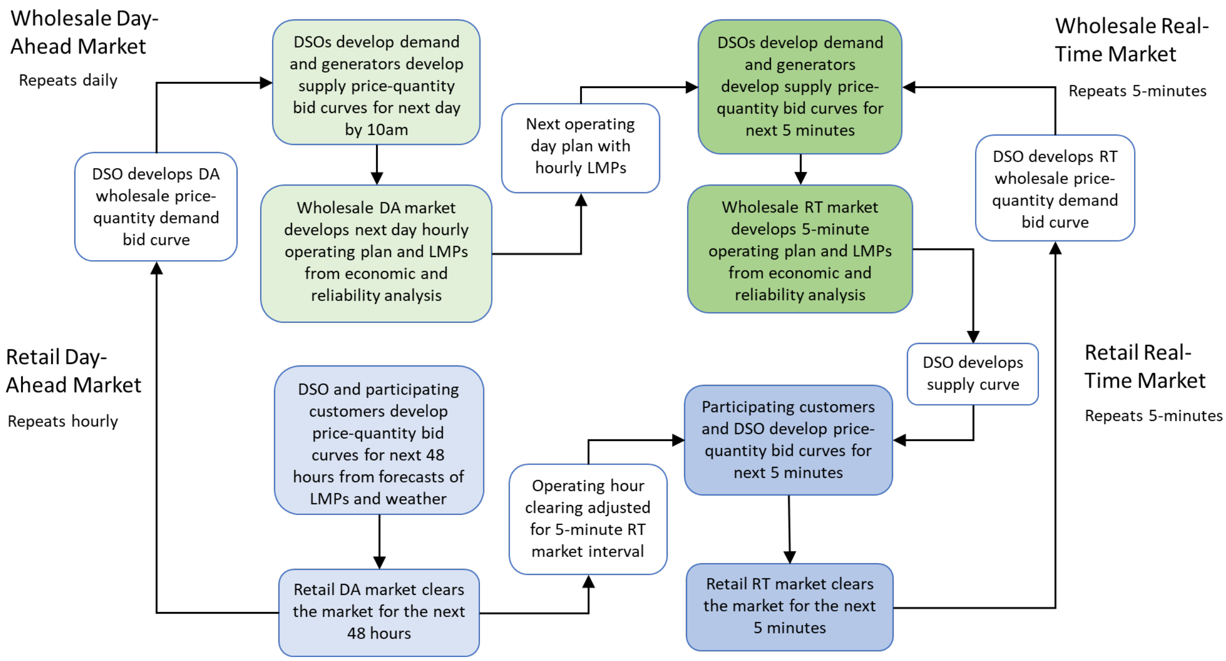


Figure 20. Overview of the coupled wholesale and retail market process

4.3 Wholesale Marketplace Design and Operation

The intent of the wholesale marketplace design is to represent the core features commonly found in ISO markets in the United States, including the Midwest (MISO), NYISO, ISONE, and the mid-Atlantic region (PJM). The characteristics include coordinated operation of day-ahead and real-time scheduled energy markets and management of transmission constraints using LMP.

The wholesale market is overseen by an ISO. The ISO acts as a reliability coordinator to manage the reliability services of the bulk system and a wholesale market operator who manages the wholesale day-ahead and real-time markets. Transmission owner-operators manage the transmission system as overseen by the ISO. Generator owner-operators manage the bulk generation fleet and interact with the wholesale markets to sell energy that is delivered through the transmission system. The study's wholesale market simulator assumes that the generators' bids accurately reflect their marginal cost of production and generation operating characteristics (such as minimum up-time/down-time constraints, ramp rates, and startup costs) to the wholesale market operator. The information is cost based and there is no competitive strategy for bidding modeled in the simulation. The complexities of competitive bidding strategies is an area for future investigation but beyond the scope of this study. DSOs represent their customers and the reliable operation of their distribution system in their interactions with the wholesale marketplace.

During operation, the wholesale day-ahead market resolves a next-day, 24-hour period (midnight to the following midnight) of scheduled energy at 10 a.m. every day. Generators present their supply bids and DSOs present their demand bids for each of these 24-hour delivery periods. While demand forecasts and demand bids may be different in today's wholesale markets, the DSO wholesale energy demand bids in the simulation are the same as their forecasted energy needs.

Given the network and generator modeling information, the wholesale market operator resolves the market while observing operational constraints. Operational constraints are enforced using a SCUC optimization algorithm and a SCED algorithm. The unit commitment ensures enough controllable generation resources are operational each hour and the economic dispatch sees that generation is dispatched to withstand operational contingency scenarios (such as line or generation outages).

The wholesale market operator computes hourly LMPs for each transmission node and power commitments for the day-ahead market. When transmission line capacity in not constrained, the result is uniform LMPs across the system. When energy transport is constrained the result is differentiated LMPs so that generators and DSOs will see differentiated prices at the transmission substation delivery point. For the study, a DSO has only one delivery point, so it only sees one LMP for each market period. Differentiated prices engage the flexibility in DSOs' customers to consume more or less to help relieve transmission congestion constraints. The hourly LMPs are then communicated back to the generator owner-operators and DSOs and used to prepare for the wholesale real-time market and operations.

In the wholesale real-time market, the same participants submit generation price-quantity bids and demand bids to correct the positions they took in the day-ahead market, based on the latest information. The real-time market runs every 5 minutes to resolve the next 5-minute delivery period based on SCED that results in nodal wholesale real-time market LMPs. Generators are dispatched according to the resulting energy schedules. Performance of each generator owner-operator and DSO is measured with respect to their real-time bids at the transmission node to which they are connected. Discrepancies between scheduled day-ahead plan and real-time actual operation are resolved at the final after-the-fact wholesale real-time LMP for each real-time delivery period.

4.4 Retail Marketplace Design and Operation

The DSO serves several roles in the operation of the retail marketplace. It acts as an LSE for its customers, a distribution system owner-operator to manage the distribution delivery infrastructure, and a retail market operator to coordinate the operation of market participating customers with price-responsive assets.

The retail market provides a market-based coordination (transactive) platform for participants through day-ahead and real-time energy markets. For both markets, participating customers prepare their scheduled energy bids in terms of their responsiveness to changes in price. While preparing their bid curves, they consider their cost-saving and amenity/comfort. Similarly, the DSO submits its supply price-quantity curve to the retail market operator. While preparing the supply bid curve, the DSO factors in the physical limits of its infrastructure (e.g., substation limits to transport energy) and the forecast wholesale electricity price. Figure 21 illustrates the process flow and timing of interactions between the retail day-ahead and real-time markets.

4.4.1 Retail Day-Ahead Market

In its role as the retail market operator, the DSO develops its wholesale day-ahead demand bid by running a transactive day-ahead retail market for participating customers and forecasting the remainder of its load from nonparticipating customers. This retail market forecasts prices 48 hours into the future, communicates this price signal to participating customers, and aggregates the resulting customer price-quantity demand bids for this forecast horizon. To achieve this, the retail day-ahead market receives a supply curve of 48 hourly delivery periods from the DSO based on a wholesale price-quantity curve forecast for its transmission node. The supply curve includes adjustments from wholesale to retail prices and incorporates the substation delivery constraint.

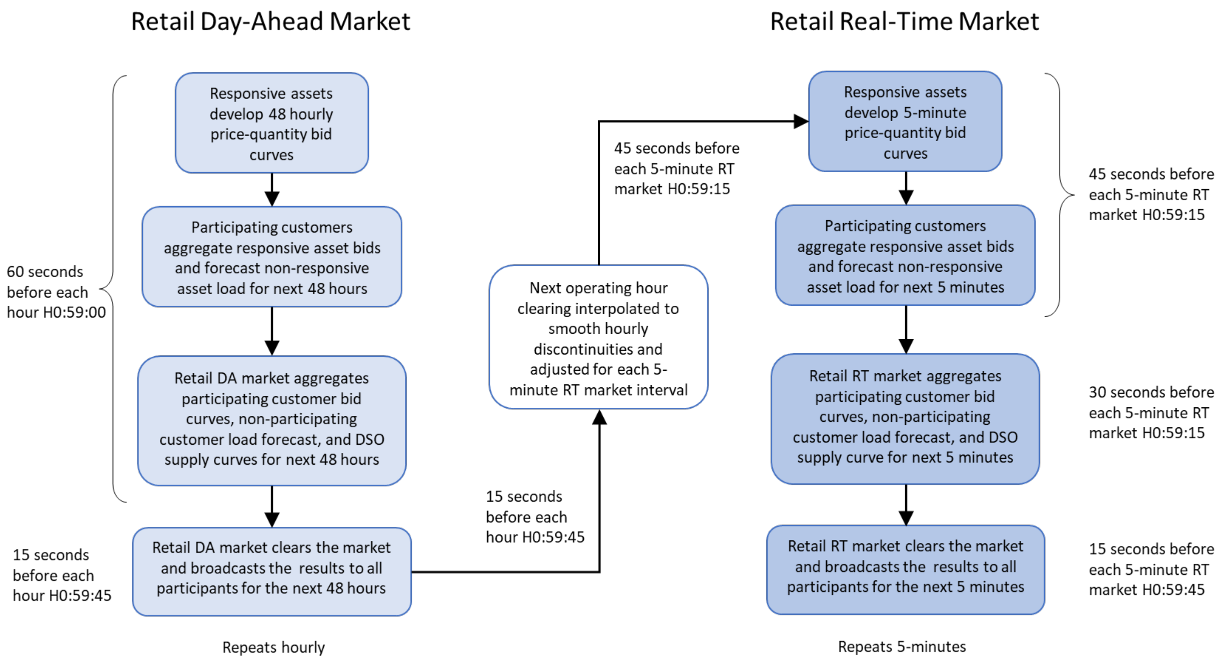


Figure 21. Retail day-ahead and real-time markets coordination. Consider hours, minutes, and seconds of time as HH:MM:SS.

The 48-hour retail market prediction horizon ensures that there are many market cycles[7] on each hourly day-ahead period before the wholesale day-ahead market closes. This allows the customer transactive agents to converge on their collective response.

Each hour, customer price-quantity bids are cleared against the retail supply curve. Updated price and cleared quantity forecasts are provided for the entire 48-hour period at the next hour. This repeats every hour to ensure the convergence of marketplace coordination and resulting quantities. At 10 a.m. each day, the DSO uses the latest retail day-ahead 48-hour lookahead market to extract the 24 hours from midnight-to-midnight corresponding to the wholesale day-ahead market period to derive its financially binding day-ahead wholesale demand bid at 10 a.m. Day-ahead customer bids are also binding for billing purposes only for the cleared day-ahead retail prices that correspond to the 10 a.m. clearing of the wholesale day-ahead market.

4.4.2 Retail Real-time Market

The retail real-time market runs every 5 minutes to resolve the next 5-minute delivery period. A price-quantity demand curve is developed by aggregating the price-quantity bid curves from each participating customer for the next 5-minute interval. This is supplemented by the forecasted demand of the nonparticipating customers for that interval. The DSO submits a supply curve bid to the retail real-time market based on the wholesale real-time market clearing (with retail adjustments) and any substation capacity limitations. The real-time market corrects

[7] 10 AM wholesale market closing implies 34 retail market cycles for next day hour 0 to 11 for hour 23

the day-ahead position taken by each participating customer while incorporating the latest market information including weather and load forecasts. Each customer's energy use for every 5-minute period is measured by an interval meter at the point where the customer's site connects with the distribution system. Bills are calculated using the fixed-rate agreement for nonparticipating customers or the dynamic rate agreement for the participating customers, which incorporated their day-ahead and real-time cleared positions. See Section 5.2.5.2 for a description of the transactive rate structure.

For simulation expediency, an LMP forecaster develops the price forecasts for each of the DSOs to use in their retail markets. To develop this forecast, the DSO+T study uses LMP results from archives of BAU case simulation data. The BAU case has the same transmission system and DSO connection structure as the transactive cases but does not include the impact of flexible customer assets. In addition, the simulation uses a separate load forecaster for all the nonparticipating customer loads. This single function develops the nonresponsive load forecasts for each DSO. Forecasting and the impacts of more accurate forecasts are an area of future study.

4.5 Transactive Retail Market Decision Making

The following describes the decision-making process and logic for the market participants interacting with the retail day-ahead and real-time markets. This represents the underpinnings of the transactive design where independent software agents make local decisions based on their objectives, state, and information exchange.

4.5.1 DSO Retail Transactive Agents

This section describes the process the DSO retail market operator takes to aggregate the customer quantity-price bids, develop demand and supply bid curves, and clear the market. A conceptual diagram of the total retail day-ahead or real-time market price-response demand curve is shown in green in Figure 22.

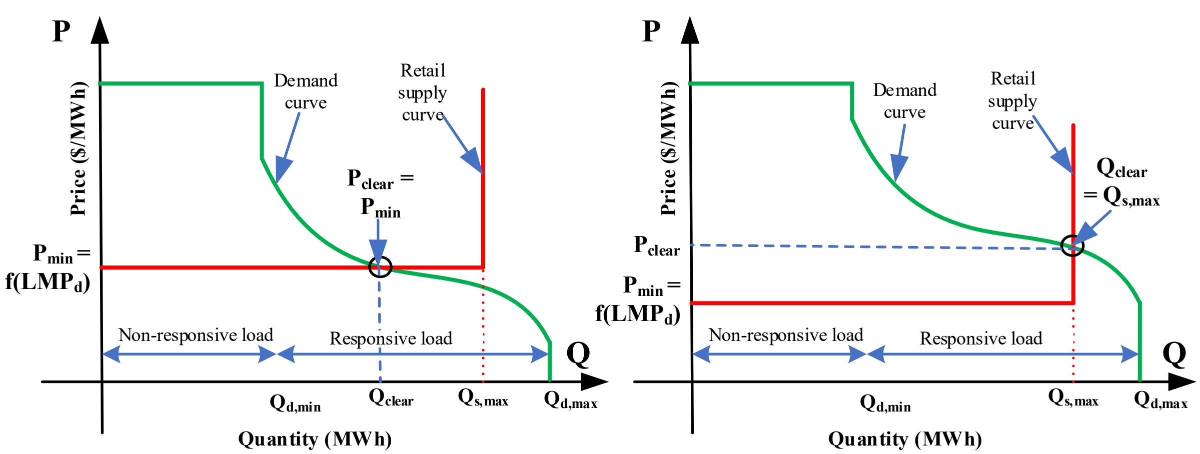


Figure 22. Market clearing for the uncongested (left) and congested (right) cases.

The demand curve includes contributions from the customers' responsive and nonresponsive assets. The sum of the forecast loads for the nonparticipating customers together with the aggregated participating customer bids represents the total price-responsive demand curve.

That is, the price-responsive portion of the curve is supplemented with the amount of nonresponsive load forecasted for that retail day-ahead or real-time market cycle.

In the general design of the market process, the retail market operator constructs the supply curve using the DSO's historical knowledge of the wholesale day-ahead and real-time markets. In addition, any distribution circuit constraints are incorporated to represent the maximum quantity for the circuit for that hour. Figure 22 shows the formation of the red supply curve, which has two parts. The horizontal red line represents (in the absence of distribution congestion) the retail expression of the forecast wholesale market clearing price for the day-ahead market hours (or the wholesale real-time price for the real-time market) as a function of quantity plus a fixed volumetric charge to cover distribution system expenses (see next paragraph). The vertical red line represents the constrained region in which the delivered quantity of energy for the market interval should not exceed the transport constraints of the power delivery system (in this case substation transformer limits). A double auction is used to clear the resulting DSO retail quantity and price signal at each of the 48 hours in the market prediction horizon, and similarly for the 5-minute real-time market.

In forming the supply curve, the DSO provides a dynamic retail price signal in the form shown below:

$$Price(t) = A * LMP(t) + D + \Delta D + DCP(t) \quad (1)$$

The wholesale LMP (forecast for the retail day-ahead market) is multiplied by a retail multiplier (*A*) that is estimated based on the typical losses seen in distribution systems. Added to this is a volumetric distribution energy price (*D*) that is estimated based on distribution costs calculated in the BAU case. Finally, the congestion pricing term (*DCP*) is determined should the retail market clear on the vertical portion of the red curve in Figure 22. The retail cleared price is then used by the customers' asset agents to 1) update their 48-hour operational plans for the next hour's retail day-ahead market, or 2) send supervisory controls to the flexible assets consistent with their retail real-time market bids. Based on the results of retail markets, the customers' bills are calculated (see Section 5.2.5.2 for a description of the retail bill calculation).

Figure 23 shows an example of the congestion pricing (clearing on the vertical red supply curve shown on the right side of Figure 22) in action managing the distribution substation transformer constraint. The DSO load quantities are shown on the left side of Figure 23. The dashed horizontal line in the left graph represents the substation distribution limit. When the predicted day-ahead quantity exceeds this limit (as is shown in the MR BAU case) the retail market would clear on the vertical portion of the red supply line. This raises the retail clearing price. On the corresponding day for the MR battery case, the battery agents respond to reduce the apparent substation load and allow the market to clear on the horizontal line.

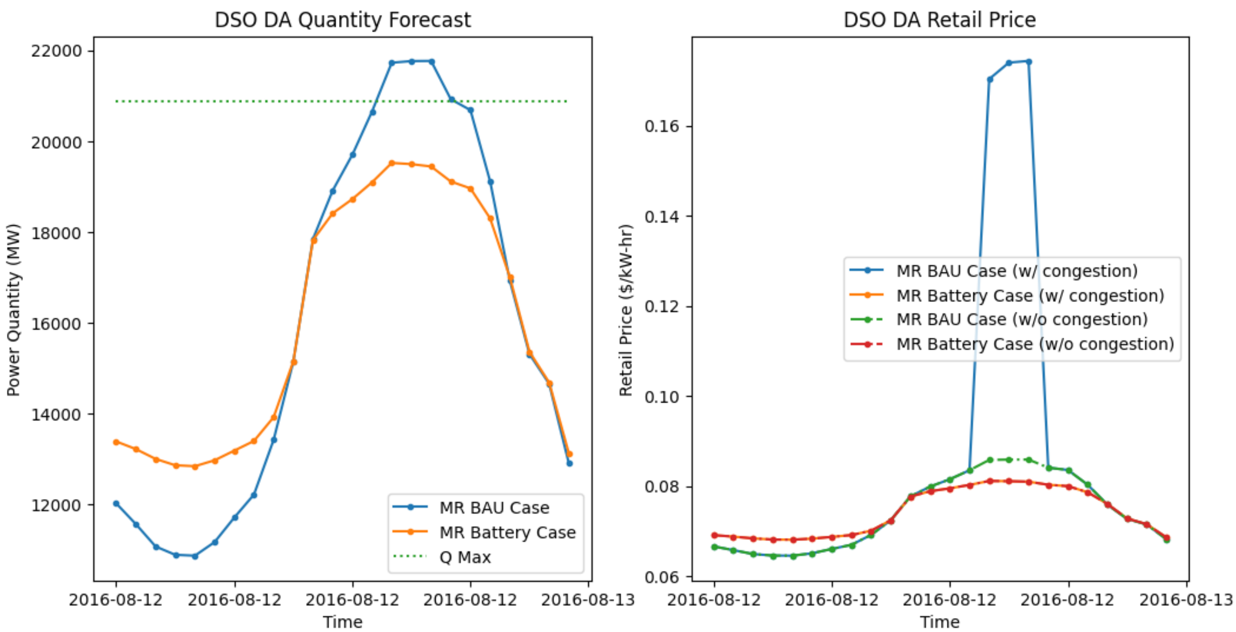


Figure 23. Examples of the day-ahead forecast quantity (left) and resulting retail price (right) for a case with and without congestion (8-bus model).

4.5.2 Participating Customer Transactive Agents

Transactive agents were developed to determine the price-responsive strategies of participating customers' assets (including HVAC units, water heaters, EVs, and batteries). This section describes the general asset agent design and provides an example of agent behavior. The common elements of each asset agent are shown in Figure 24 and include:

- **Asset model** estimates the physical behavior of the respective flexible asset based on observed sensor measurements
- **Asset scheduler** prepares an operating plan for the respective asset considering the forecast future prices and asset constraints (e.g., comfort setting preferences)
- **Asset bidding** prepares a price-quantity curve for the respective responsive asset to participate in the retail market
- **Market-control mapping** maps the real-time price into the control settings for the given asset.

The scheduler element determines an operational plan that strives to balance the tradeoff between the price of energy and the amenity (e.g., occupant comfort) received from its use over a scheduling time horizon. The customer's preference between price and amenity is expressed in the form of a slider setting, that ranges from 0 (prioritize comfort) to 1 (prioritize cost savings). The responsive asset agent acts as a supervisory control layer to the physical asset, interacting through monitoring and control signals such as setpoints or schedules. Therefore, all asset-specific closed-loop controls and associated protections remain active to protect the health of the equipment and ensure physical constraints are not violated. For instance, if an HVAC unit has not met its minimum on/off time, it will not change state (on to off or vice-versa) even if signaled to do so by a supervisory control temperature setpoint change.

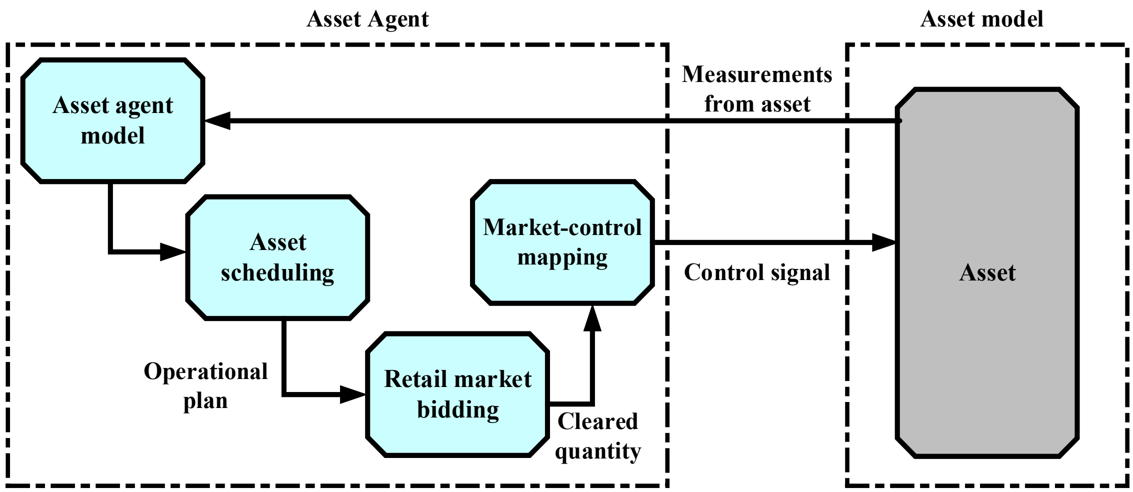


Figure 24. Overview of a responsive asset agent

Illustrations of an HVAC asset agent's performance are shown in Figure 25 and Figure 26. Figure 25 shows the performance of the asset agent model in predicting the actual HVAC energy consumption quantity (Q) within each hour for the 48-hour prediction window. The agent model of the HVAC system is a first-order representation of the dynamics of the customer's building that is modeled as a second-order model in the system simulation. The error between the agent model and simulated HVAC performance is the result of these modeling simplifications and uncertainty in the load and resulting price forecasts. These errors can be exacerbated by the discrete on/off operation of HVAC units that can result in large changes in consumption from one time interval to the next.

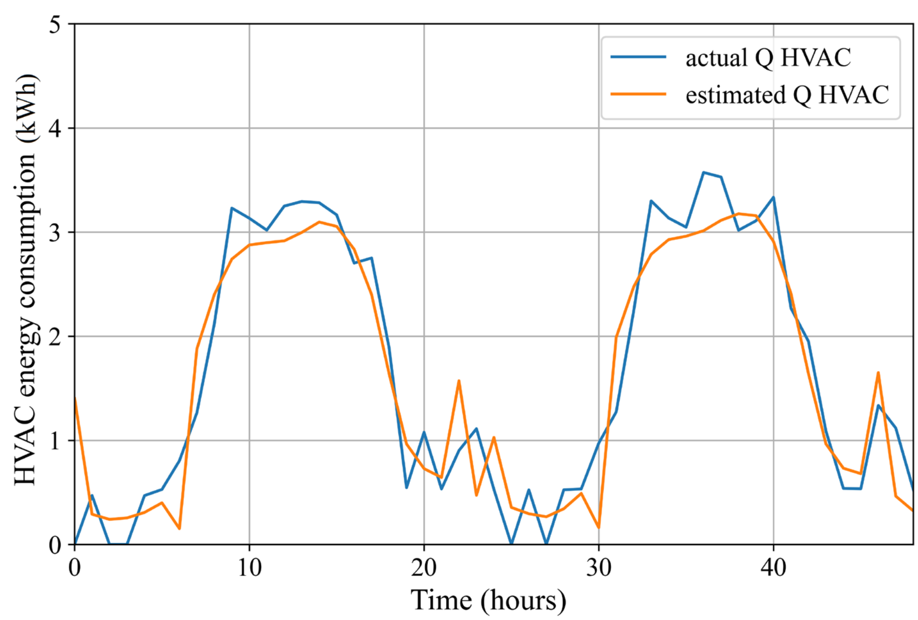


Figure 25. First-order HVAC agent asset model energy consumption comparison with actual ground-truth simulated HVAC consumption.

Figure 26 shows the resulting change in thermostat setpoint strategy (versus the baseline strategy) as a function of forecast retail prices. As expected, the asset agent lowers thermostat settings to precool the building when prices are low and increases setpoints to reduce energy consumption during periods of high prices. Full details of the general asset agent structure and specific implementations are provided in Widergren et al. (2022), Section 4.2.2.

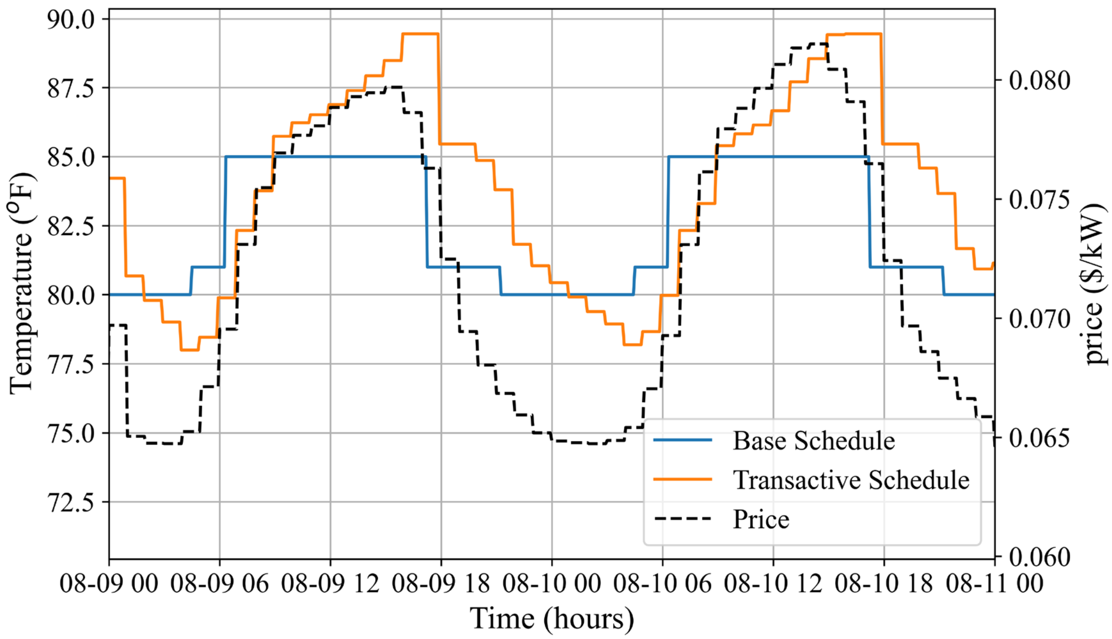


Figure 26. HVAC asset operational plan setpoint schedule compared with the original schedule.

5.0 Valuation Methodology and Economic Metrics

Many studies on the benefits of flexible assets report the marginal economic benefits and costs to the entire system, failing to distinguish which stakeholders experience what extent of net losses and gains and the fractional (percentage) reduction in their costs and in the DSO's retail customer rates. These are critical perspectives, so the valuation approach used by the study adds much greater granularity to evaluating the impact that transactive energy has on the economic values exchanged by each stakeholder. The impact is quantified in total and considerable line item detail.

5.1 Economic Stakeholders and Value Flows

This section describes the analysis methodology used for estimating the value of adopting the DSO+T strategy for all the primary stakeholders (those directly involved in managing, producing, and using electricity) by comparing the change in various metrics between any two cases of the study. These metrics are primarily the change in annual costs reflecting value exchanges among the primary stakeholders and between them and external stakeholders (those who provide products or services that enable primary stakeholders to participate). The primary stakeholders whose physical assets and economic cash flows are modeled explicitly are:

- Customers (i.e., end users of electricity)
- DSOs each consisting of a distribution owner/operator, market operator, and LSE, either bundled as a single financial entity or unbundled into three separate entities
- ISO
- Transmission owner/operator
- Generation owners/operators.

External stakeholders (e.g., fuel suppliers, equipment manufacturers, service providers) are not modeled explicitly in the study, but instead implicitly exist as sources and sinks for cash flows to or from the primary stakeholders. Examples of external sources for cash flows include equity investors, financial institutions acting as lenders, and household or business income. Examples of sinks for cash flows are vendors of equipment, materials, fuel, or services; salaries and benefits for employees of grid entities; and federal, state, and local governments (in the form of collected taxes).

The valuation metrics are computed based on simulation results for each case plus a set of (primarily economic) procedures and assumptions about the values exchanged that are used for quantifying the associated cash flows. Examples of these assumptions range from interest and discount rates and rate of return on investments, to unit costs for grid infrastructure of various sorts, to the number of utility employees and their salaries. Many of these valuation metrics are listed in Figure 27, mapped to the primary stakeholders of the DSO+T analysis (not shown is the ISO). Full documentation of the value flows and metrics and their provenance is provided in Volume 4 of the DSO+T Study Report (Pratt et al. 2022).

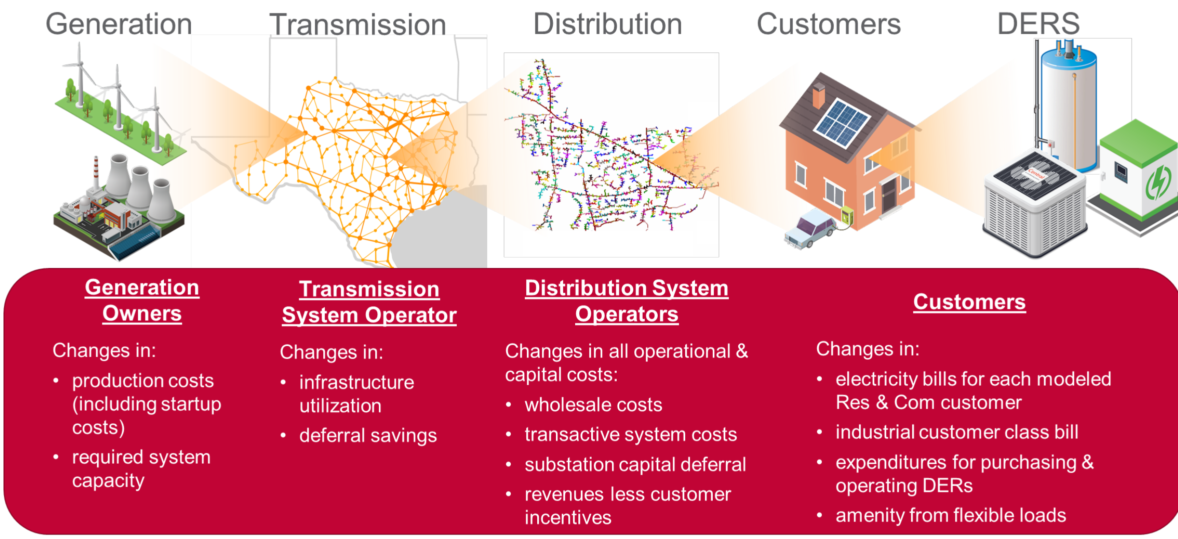


Figure 27. Primary metrics and economic values analyzed.

5.1.1 Value Activity Models

The analysis process is based on the valuation approach developed within the Transactive System Program at PNNL (Bender et al. 2021a, 2021b). It uses unified modeling language (or UML) and e3-value modeling principles to develop value activity model diagrams that enable the rigorous valuation of different cases. The e3-value modeling approach was designed for e-businesses to define how economic value is created and exchanged between actors within a system (Gordijn et al. 2001).

A key piece of information communicated within the value activity models is the allocation of value exchanges to the various actors, or stakeholders, within a system. These models allow for the analysis of each stakeholder's BAU and transactive case. In addition, the valuation methodology facilitates transparency within the calculation of the stakeholder's business case by identifying each value exchange that contributed to the calculation of the relevant metrics, which in this case is the annualized cash flows.

Figure 28 shows the high-level value flows being modeled in the DSO+T study. Stakeholders are depicted as gray rectangles, with the inner blue rectangles representing value activities. This structure for the valuation methodology is used to provide complete transparency of the values being exchanged and which parties are involved. It is also useful in assuring that costs and benefits are neither double-counted or lost. The arrows and ports that are attached to the value activities are the value exchanges associated with that given activity of the stakeholder. The dashed arrows represent the value objects being exchanged within the system, with the arrow indicating the definition of a positive cash flow. Nonmonetary values are identified with a "[NM]" and do not appear within the cash flow analysis but are shown in these models to note at a high level what tangible goods and services are involved in the exchanges. For example, generators provide electrical energy and are compensated through bilateral contracts, day-ahead and real-time market purchases, and capacity market payments. Descriptions of how these value exchanges are quantified can be found in the remainder of this section. Finally, the system boundary is indicated by the black rectangle labeled "DSO+T Analysis" and exists to separate out the primary stakeholders that are being considered within the analysis from those that are not. For example, the valuation includes the costs paid by the customer to a flexible asset vendor from the customer's perspective only, not the vendors, whereas expenses between the customer and the DSO are considered from both perspectives because both stakeholders are within the analysis boundary.

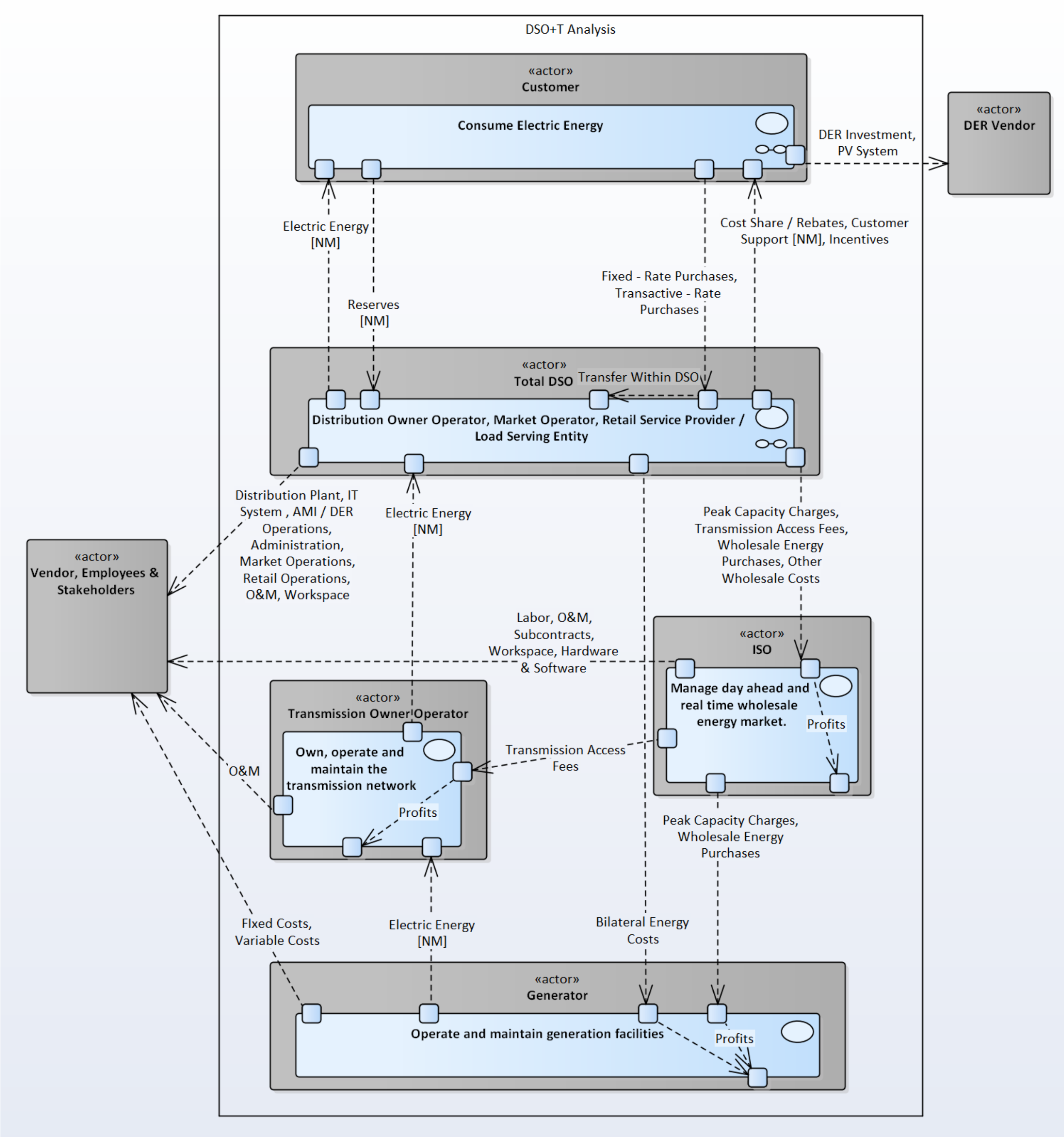


Figure 28. DSO+T system value activity model.

5.1.2 Annual Cash Flow Statements

The values shown entering and exiting the stakeholders in the value activity model define the high-level structure of the stakeholder's cash flow statement (CFS) that, once populated, reports the stakeholder's economic performance. Values flowing to a stakeholder are listed as revenues on the CFS and values flowing out are listed as expenses. The study develops estimates for a stakeholder's revenues and expenses, so that the total annual net economic outcome of a stakeholder with and without implementing the DSO+T strategy is estimated. Thus, the value exchange arrows in Figure 28 are broken into their components, providing considerable added detail This ensures that net savings in percentage terms can be estimated (beyond just net savings due to changes in the costs for individual line items that are expected to increase or decrease).

5.1.2.1 Cash Flow Statement Overview

The greatest level of detail is applied to the DSO and customer CFSs. This is because the sum of the impact of the DSO revenues, which by virtue of utility regulation are equal to the impact on the customer bills, plus customer costs for their flexible assets, represents the overall impact of adopting a DSO+T strategy (other than nonmonetary externalities). Customers pay for the entire cost of the electric power grid with their electric bills (apart from any losses suffered by unregulated investors in generation owners).

Customer electric bills are determined by retail rates that, even in the transactive cases, are set to ensure adequate DSO revenue to cover expenses and a regulated rate of return. The DSO pays for the generated electricity it consumes, its share of the transmission grid capital and operating costs, its share of ancillary service costs, and fees to support ISO expenses. The expenses for these line items cover the balance of grid costs not directly expended for capital, materials, and labor, and serve as the conduit for passing sufficient revenue from customer bills to these stakeholders.

The DSOs' regulated rate of return applies to their capital expenditures but not on their operation expenses for investor-owned DSOs. Capital investments also vary in their depreciation periods for income tax purposes. The DSO CFS is sufficiently detailed to support the design of retail rates and revenue recovery including investor rate of return. It is far more detailed than the CFSs for other grid entities. Examples of DSO CFSs are provided in Appendix A, where illustrative impacts of a transactive deployment are shown on a line item basis.

The net costs to the transmission owner and ISO are not expected to be significantly impacted by implementation of a DSO+T strategy, so their CFSs have considerably less detail. The CFSs for generation owners are also comparatively simple, since the study is only attempting to examine the net change in the revenues from various classes of generators, not whether those revenues are sufficient in sustaining the business of a particular generator.

In the transactive cases and the HR BAU case, customers also make capital investments in the power grid that are not reflected in their retail rates. Their costs for investing in flexible assets, or in rooftop solar generation, displaces a portion of the power system's capital costs and operating expenses. The costs for these investments accrue to the customer's side of the ledger, and so their CFS must include them. There are also tax implications for commercial customers and owners of rental residences that must be included. Therefore, the customer CFS includes sufficient detail to account for these impacts explicitly.

5.1.2.2 Levelized Annual Cost

The study expresses the cost of capital investments on the part of grid and customer asset owners as levelized annual costs so that infrastructure costs can be placed alongside annual operational costs in the stakeholder CFSs that are the primary basis for the valuation. The levelized annual cost of a discrete, initial capital investment over the lifetime of the investment is defined as the set of fixed (constant) payments over the lifetime period that has the same present value to the investor as the one-time initial investment, given the investor's discount rate. Those payments include the annualized values of

- principal and interest payments on any debt undertaken by the investor
- any cash down payment made by the investor
- rate of return to any equity stakeholders the investor may have in the form of stock earnings and return of principle (investor-owned utilities only)
- taxes on the revenues required to cover those costs, net of income tax deductions for depreciation and interest payments for tax paying investors in capital assets.

In Volume 4 of the DSO+T Study report (Pratt et al. 2022), Appendix A documents how levelized annual costs are computed.

5.2 Distribution System Operator Expenses and Revenues

DSOs are classified for the study as belonging to one of three types (rural, suburban, or urban) based on the predominant nature of their service territories. This distinction is important because the customer density (no./mi^2) and load density (MW/mi^2) all vary widely across these types. These, in turn, directly affect capital costs for substations, circuits, communication networks, substation automation, and automated metering infrastructure (AMI). Whether a DSO is rural, suburban, or urban influences the mix of customer and building types as well as the percentage of buildings with electric space and water heating.

The DSO type also impacts the assumed ownership model of the DSO (e.g., investor-owned, municipal, or rural cooperative). The ownership model impacts the amount and cost of financing, whether the DSO is nonprofit or can collect a regulated rate of return, and if certain expenses (such as debt financing) are tax deductible. The study assumes that DSO ownership type is highly correlated with DSO type. The 75% of DSOs serving urban areas are assumed to be investor-owned, whereas 40% serving suburban areas are assumed to be served by municipal utilities, and 75% of DSOs serving rural areas are assumed to be rural cooperatives.

5.2.1 DSO Capital Expenses

The study developed parametric models to estimate the annualized capital cost for substations, feeders, circuits, meters, and information technology systems as a function of peak system capacity and number of customers as well as assumed growth rates with and without transactive energy. A full explanation of capital cost estimates is provided in Pratt et al. (2022), Section 3.2.

5.2.1.1 Substation Costs

Capital costs for distribution infrastructure are an important component of a DSO's overall expenses. The valuation model includes estimating the impacts from the potential deferral or reduction in costs for a DSO's substation from consumers using transactive, responsive assets. Estimating annualized capital costs for a substation population requires knowledge of a DSO's existing substations and their capacities, the annual rate at which new substations are being constructed to meet load growth, and the costs of capacity in both new and existing substations.

The costs of substation capacity are based on a detailed, bottom-up cost model that itemizes costs for a variety of substation design characteristics and features. These features include the peak load served, number of the high-voltage transmission lines that serve the substation, breaker configuration, number of transformers, number and voltage of the feeders serving the load, number and rating of capacitor banks, and the low-voltage breaker configuration. The study assumes distribution voltages are 13.8 kV and urban substations are assumed to have a second transformer to increase reliability.

Load growth rates were then estimated to determine the application of the above substation cost model to existing capacity, required capacity upgrades, and investment in new substations. The study developed a model of substation capacity and the rate capacity added to serve population and load growth based on land use. The model assumes there are two distinct types of load growth:

- *Greenfield growth* reflects the construction of new substations to serve customers in rapidly developing areas, typically at suburban fringe near the suburban-rural boundary. It results in the construction of an entirely new substation.
- *Brownfield growth* for existing substations that incorporates the combined effect of the growth in number of customers and in existing per-customer loads. It is served by increasing the capacity of substations through upgrades.

The study assumes a strong correlation between the DSO type (rural, suburban, or urban) and load growth rates and substation costs as shown in Table 4. Further, a DSO's service territory is generally not purely rural, suburban, or urban in nature. The load growth model takes into account the relative proportions of these service areas for each DSO based on the assumptions about the overall load growth rates, as illustrated by the results for the example substation fleets in Table 4. Details of the load growth and substation fleet capacity models are provided in Pratt et al. (2022), Section 3.2.

5.2.1.2 Feeders, Circuits, and Meters

Unlike substations, the capacity of a DSO's distribution feeders and circuits is assumed to be unaffected by any reduction in peak load resulting from the adoption of a DSO+T strategy. This is because most of the distribution infrastructure below the substation to the customer meter – including land rights, structures, poles, towers, switches, sectionalizers, breakers, fuses, service transformers, and service drops – exists to connect customers to power. Furthermore, the increments of capacity offered by wires, cables, and service transformer sizes are large relative to the potential reduction (<10%) in peak loads from the flexible assets. No savings in feeders and circuits is attributed to the DSO+T strategy. The capacity cost for feeders and circuits to deliver power from its substations to customers during peak load periods is assumed to be $200/kVA.

Meter costs are assumed to vary by customer class and are based on a prior survey of smart metering costs. Total installed meter expenses are assumed to vary between $70 for residential customers to $1,500 for industrial customers. The cost for customer meters is also assumed to not be affected by the adoption of a DSO+T strategy.

Table 4. Peak demand growth rates, capacity costs, and exemplary substation fleets by DSO type.

DSO Type	Assumed Growth Rates			Assumed Capacity Costs		Example Substation Fleet Results				
	Brown-field	Green-field	Total	New Sub-stations	Upgraded Sub-stations	Peak Demand	Service Area Development Stage	Existing Fleet Total Capacity Factor	Existing Fleet Total Total Capacity	Existing Fleet Total Sub-stations
	(%)	(%)	(%)	($/kVA)	($/kVA)	(MW)		(%)	(MVA)	(-)
Rural	0.5%	1.0%	1.5%	$939	$362	1,200	Undeveloped	95%	74	33
							Greenfield	18%	29	1
							Fully developed	95%	1,321	59
							Total		1,425	94
Suburban	1.0%	10.0%	11.0%	$223	$109	10,000	Undeveloped	91%	28	13
							Greenfield	16%	2,708	122
							Fully developed	91%	11,746	529
							Total		14,482	663
Urban (DSO #1[a])	2.0%	1.0%	3.0%	$186	$109	25,304	Undeveloped	83%	19	9
							Greenfield	13%	835	38
							Fully developed	83%	33,897	1,525
							Total		34,751	1,572

[a] of the study's 8-bus model

5.2.1.3 Information Technology Systems

Information technology system expenses cover controls and management software as well as customer and distribution communication networks. The expenses for these systems were estimated based on a generalized model of costs as the sum of a nonlinear function of the number of customers, plus a linear function of the number of substations and a constant cost. There is little public information on software expenses. The model was fitted to sparse anecdotal costs obtained for specific (generally large) utilities and exhibit reasonable increasing costs for utilities ranging in size from the smallest to those serving a few hundred thousand customers. It is assumed that the implementation of a transactive system would result in a 25% cost adder for the billing software system to support transactive rate billing.

The cost models for the customer and distribution communication networks were based on published data. The study assumes that a transactive implementation would increase the costs of the customer AMI network by 25%. A sensitivity analysis to this assumption is also done as part of the study.

5.2.2 DSO Wholesale Market Expenses

DSO wholesale market expenses are comprised of wholesale energy purchases, capacity market payments, transmission access fees, ISO fees, and payments for ancillary services.

5.2.2.1 Wholesale Energy Purchases

The study assumes that each DSO purchases its energy through a combination of bilateral contracts and day-ahead and real-time market purchases. A substantial fraction (~55%) of the DSO's annual energy is purchased via bilateral contracts with generators, displacing some of its exposure to market prices in the markets. Bilateral energy pricing information is proprietary and protected so the valuation model includes the following estimate.

The bilateral prices are based on annual average day-ahead market prices for the three bilateral contract time blocks used (weekend days, evenings and weekend days, and nights). It is assumed that each DSO purchases the remainder of its entire forecasted load in the day-ahead market and that the DSO only pays real-time prices for any deviation between its load forecast and actual loads. The loads and market prices required to calculate these values are provided by the simulation.

5.2.2.2 Peak Capacity Expenses

While this study chose ERCOT as a representative load region, it is designed to represent conditions in the U.S. power system broadly rather than the market design of ERCOT specifically. As such, the study presumes that a capacity market is present and that the DSOs are required to reserve capacity sufficient to meet their annual peak demand in any 5-minute interval by purchasing a reservation for that capacity in an annual auction conducted by the market. The clearing price of that auction sets the capacity market price for all the DSOs. For the purposes of the study's valuation, this presumption of a capacity market also helps separate the value streams associated with shifting consumption during high-cost periods and avoiding the need for new generation.

This study does not actually simulate such an auction. Instead, it assumed a typical capacity price of $75/kW-year based on an examination of reported U.S. capacity market prices over time (Jenkins et al. 2016). It is known that this base capacity market price is under typical construction costs by roughly 30%. This is attributed to the fact that many regions in the United States have excess capacity due to rapid penetration of renewables and some of the capacity value is expressed in wholesale energy market prices (FERC 2013).

It also assumes a quantity-price sensitivity factor of 5 to determine actual prices for each case. That is, a 1% reduction in required capacity reduces the cleared capacity market price by 5%. The quantity-price sensitivity factor is included to capture the nontrivial impact that reducing the required capacity has on the cleared capacity market price (Jenkin et al. 2016; Bowring 2013).

5.2.2.3 Transmission Access Fees

The annual transmission access fees paid by DSOs are assumed to be $12.30/MWh, based on the California ISO's 2020 postage-stamp rate for high-voltage transmission access. A postage-stamp rate is so named because it is a constant regardless of the locations of the input to bulk grid by generators and output from the grid by DSOs. The impacts of transactive energy on transmission owners is assumed to be solely in changes to the annualized cost of capital and is applied as an adjustment to the BAU transmission access fees.

The study assumes a single investor-owned transmission system operator with capital expenses, operational expenses, and matching revenues. A detailed transmission capital cost model was developed and applied to the transmission system used in the simulation. The result is that the MR BAU case's transmission infrastructure represents a $16.6B capital investment, equal to about $169/kW of peak demand served. The latter is very close to the $150/kW estimated for the national transmission infrastructure by another study (Kannberg et al. 2003). The resulting annualized capital expense was subtracted from the postage-stamp rate-based transmission revenue to develop an estimate of the transmission operating costs.

5.2.2.4 Ancillary Services and ISO Fees

The costs for ancillary services (frequency regulation and spinning and non-spinning reserve) were based on average annual prices reported by the ERCOT market monitor (Potomac Economics 2017). Quantities were assumed to be 1%, 5%, and 5% of total load, respectively. The study did not analyze the value of flexible customer assets in providing ancillary services.

ISOs in the United States use a variety of fee structures to recover their annual expenses. In the study, a simple fee of $0.555/MWh is assessed on the energy supplied by the bulk power system to each DSO, based on published ERCOT's rates (ERCOT 2011).

5.2.3 DSO Other Operating Expenses

DSO costs associated with labor represent the largest portion of operational expenses after wholesale costs. To estimate these labor costs, a simple regression model of the total number of utility employees was developed based on a sample of 11 utilities spanning the range of sizes in the United States, nine of them from Texas, along with the number of customers served and other characteristics. This provided separate estimates of the number of employees strictly associated with retail operations. Estimates were then made of the number of employees by function (e.g., administration, engineering operations, retail operations) and combined with wage data from the U.S. Bureau of Labor Statistics for each job function by DSO type (rural, suburban, and urban) to estimate labor costs by CFS line item

This level of granularity allows for explicit accounting of the added labor costs of implementing a transactive retail marketplace. It is assumed this would result in a 25% increase in AMI network and billing labor and a 5% increase in cybersecurity labor. Full details of the DSO labor model are provided in Pratt et al. (2022), Section 3.3.2.1. Workspace costs were simply based on average spaces per office employee and per lineman.

Finally, the materials a DSO consumes for operations and maintenance are accounted for. The largest of these are spare parts (transformers, switches, breakers, fuses, insulators, poles, overhead wires, underground conduit, and cables, etc.). Tools and trucks used for line operations are another large component. The contributions to calculating these costs are assumed to be unchanged as a result of adopting a DSO+T strategy in the study. Therefore, the valuation model estimates the costs as a simple lumped line item equal to a cost of $0.02/kWh of electricity sold.

5.2.4 Summary of DSO Expenses

The resulting relative expenses for a typical DSO are shown in Figure 29. The overall proportions of expenses were similar for the other simulated DSOs. Wholesale energy and market costs represent over half of all DSO costs and are dominated by wholesale energy costs (29%), peak capacity charges (19%), and transmission charges (12%). Other wholesale costs, such as reserves, ancillary services, and ISO fees, account for less than 3%. Capital expenses are dominated by the distribution plant (9%) and nonmarket operations costs are dominated by operations and maintenance (24%). All other expenses account for less than 6% of the overall cost of doing business.

To determine the overall representativeness of the cost assumptions and estimating procedures discussed in this section, the overall blended average cost of electricity sold was calculated. Across all the DSOs simulated in the 200-bus model the effective average annual rate varied from 9.7–14.3 cents/kWh with an average of 11.0 cents/kWh. This is slightly higher (by 7%) than the average 2016 U.S. value of 10.3 cents/kWh, and within the cited range (7.5–17.2 cents/kWh) for the 48 contiguous United States (DOE-EIA 2020). This suggests that the overall expenses are representative of typical DSO expenses in the country.

PJM provides example breakdowns of wholesale costs (PJM 2019). The DSO+T wholesale energy costs for all DSOs in the study's 200-bus model are within 10% of PJM data for 2018 and the relative proportions are representative. For example, on average in this study DSOs spend 48% of wholesale expenses on energy purchases (versus 63% for PJM), 28% on capacity costs (versus 20%), 18% on transmission charges (versus 15%), and ~4% on other wholesale costs such as ancillary services and reserves (versus 2% for PJM).

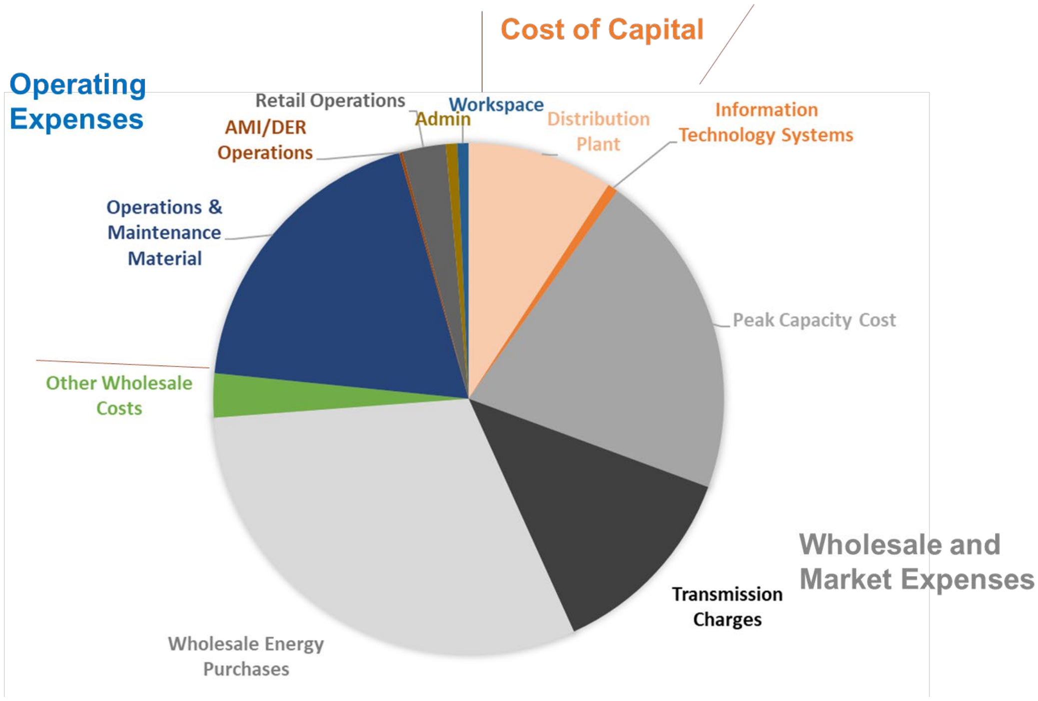


Figure 29. Typical DSO expense breakdown for the BAU case.

5.2.5 DSO Revenues

The entirety of DSO expenses is met by revenue from its customers. To evaluate the impact of transactive energy on individual customers, retail rates were designed and each customer's monthly and annual electricity consumption and resulting retail bills were calculated. Two retail rate structures were used in this study: 1) a fixed retail rate structure was applied to all customers in the BAU case as well as the nonparticipating customers in the transactive cases, and 2) a transactive rate structure was developed for customers participating in the transactive cases. The basis for these is presented in the following sections.

Finally, for simplicity, all customer rates are assumed to be net interval metering plans. This is of importance to customers with solar PV or battery systems whose output exceeds their gross demand for power for any metering interval. The resulting negative meter reading is simply integrated with the retail price and displaces some of what would otherwise have been accrued to their electric bill. Net metering over a billing cycle is a common, but not universal, rate design practice among U.S. utilities.

5.2.5.1 Fixed Retail Rate Structure

The fixed retail rate comprises three components: a charge for energy consumed, a peak demand charge, and a connection charge. The volumetric energy charge is based on a 3-tier declining-block fixed rate. The thresholds of the tiers were designed to reduce the expenses of residential homes with electric heat, and also larger commercial and industrial customers. The monthly demand charge was set to a typical value of $15/kW for non-residential customers and the monthly fixed connection charge was set to $10/month for all customers. The base volumetric rate was calculated to ensure that the total billing revenues matched the DSO expenses based on their CFS, as described above.

5.2.5.2 Transactive Rate Structure

The transactive rate structure was designed to reflect the cost basis of the DSO. Therefore, the transactive customer bill structure is reflected in four components (independent of customer class, substation constraints, or DSO):

$$Bill \quad = EnergyCost \quad + CongestCost \quad + DistribtionCost \quad + MeterCharge \qquad (2)$$

where:

EnergyCost – this is the wholesale dynamic energy cost of a customer's consumption plus distribution losses (since they do not appear in the customer metered load). This cost component is based on the wholesale market day-ahead and real-time LMPs.

CongestCost – the marginal retail congestion costs associated with peak capacity at a DSO's substation given local constraints (such as substation transformer ratings) and DSO peak-load management objectives. It is literally the difference between the retail clearing price and the wholesale energy cost (with the retail multiplier), which is nonzero only when constraints are being managed with prices.

DistributionCost – the volumetric distribution system costs, reflecting the elements in the DSO cost structure that are appropriately allocated to customers based on the relative size of their volumetric energy consumption but not the wholesale price. That is, a constant energy price term added to the customer bill over and above the retail market clearing price. Examples of such cost components include general operations and maintenance and retail labor costs.

MeterCharge – the constant (monthly) charge reflecting the constant terms of the DSO cost structure.

The revenue collected by the congestion cost surcharge from customers served by a substation is returned to those customers in its entirety in the form of a volumetric distribution charge rebate. This is done to maintain equity between customers on congested and uncongested substations while socializing needed and cost-effective distribution capacity investments across all DSO customers. This ensures that customers on congested substations do not pay more (on average) than customers on non-congested substations while still providing customers incentives to offer additional flexibility when the distribution system experiences local constraints.

The fixed-price rate for the proportion of customers who decline to adopt the transactive rate is designed to collect the same amount of revenue as if these customers were on the transactive rate design. This ensures that, on average, customers who choose not to migrate to transactive rates should pay no more on their bills than they would have if they had signed up for a transactive rate, but not participated in demand flexibility. The required revenue to be collected from nonparticipating customers is determined by the process described above. Once this revenue requirement is determined, the fixed rate is calculated for this set of customers using the BAU ratemaking described in Section 5.2.5.1.

The same rate design structure was applied to all DSOs and their customers in the simulation. A detailed treatment of the design of the transactive retail rates can be found in the Volume 4 of DSO+T report (Pratt et al. 2022), Section 4.

5.3 Customer Costs

The valuation analysis also included estimates for the annualized costs utility customers would incur to implement flexible DERs. The DER costs comprised three main elements: initial equipment cost, installation costs, and costs associated with ongoing operation and maintenance. For most flexible assets, such as HVAC thermostats, water heaters, and EV chargers, initial equipment cost also covered the incremental capability needed to participate in a transactive energy system. For example, for a residential HVAC thermostat or EV charger, the cost of equipment represents the incremental cost for a connected smart controller versus standard controls. Installation costs included labor costs, which were based on estimates of installation time and hourly labor rates, as well as installation equipment costs. Finally, ongoing operations and maintenance costs covered required annual maintenance and any degradation and depreciation caused by operation.

This analysis resulted in a marginal increase in total installed first costs associated with enabling flexible assets of $164 for residential thermostats, $318 for residential water heaters, and $254 for EV chargers (Pratt et al. 2022). Commercial HVAC control costs were assumed to be similar to that for residential thermostats scaled to the number of zones in the commercial building. All of these values represent the marginal additional cost associated with smart versions of assets capable of participating in a transactive retail marketplace. For batteries it was assumed a first cost of $83/kWh. This aggressive estimate is based on the assumption that battery prices will continue to fall and other value propositions (resiliency, self-consumption of on-site generation, deferred customer electrical system upgrades, etc.) will account for any remainder of the cost. The results section includes a sensitivity analysis to determine the impact of this and other key assumptions on the overall economic benefit.

5.4 Bulk Power System Stakeholders

5.4.1 Generator Owners

Estimates were made of the total costs and revenues of the generators in the system. Overall costs comprised annualized capital costs, variable operating costs (including startup and shutdown, fuel, and variable operations and maintenance), and fixed operating costs. This allows the impact of increased demand-side flexibility on thermal generation operating costs (including required starts) to be assessed. To ensure an overall accounting and allocation of costs, generator revenue was estimated based on multiplication of the output of the generator and the real-time LMP at the generator’s bus location as well as an allocation for capacity payments.

An assessment of the change in generator revenues resulting from changes to the wholesale dispatch caused by deploying a transactive system is not a primary objective of the study, so detailed revenue estimates were not made. Since the need for generation capacity is expected to be reduced, some generators may not be dispatched enough to cover their fixed costs. Excess capacity would presumably have been retired and some new plants not constructed. The capacity auction addresses this impact on overall system operating costs, but the effect of retirement on any given generator or class of generators is left for future studies.

5.4.2 Transmission Owner

The transmission owner's cash flow assumptions are summarized in Section 5.2.2.3 and provided in detail in by Pratt et al. (2022), Section 6.2.

5.5 Summary of Overall Economic Value Flow

The result of the valuation framework is the ability to track value flows and financial payments through the entire electricity delivery system. As an example of this, Figure 30 provides a summary of the cashflow between grid entities to help illustrate primary stakeholders, key financial interactions, and level of granularity undertaken in the value analysis for this study. Figure 30 follows Sankey diagram conventions where quantities flow from left to right, where values flowing into the left side of an entity represent revenues, and values flowing out of the right side represent expenses. Starting at the far left of Figure 30, retail customers are charged for electricity service through a range of mechanisms (energy, demand, and connection charges). These charges represent the entire revenue for the DSOs who then use it to pay for their expenses to maintain and operate the distribution system, cover transmission charges and ISO fees, and generation expenses (wholesale energy purchases, capacity, and ancillary service payments).

Finally, this cash flow is used to pay for terminal expenses, which represent the downstream boundary of this study. Such expenses include the annualized cost of capital equipment and software infrastructure investments, real estate and workspace expenses, and labor and operation costs. In addition, generation costs are broken out by fuel class (e.g., coal, nuclear, natural gas, wind, and solar) and dedicated terminal expenses to capture the startup costs and the variable fuel and operations and maintenance costs associated with generation.

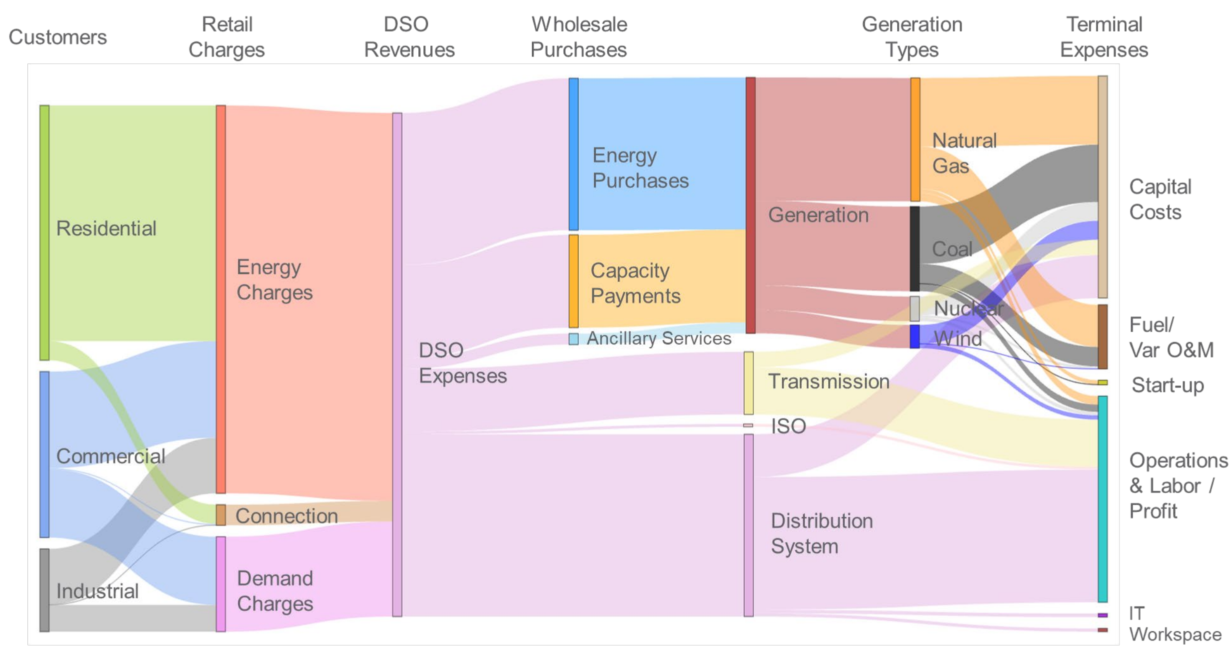


Figure 30. Summary of annualized cash flow between various stakeholders for the MR BAU case.

6.0 Results

This section provides the overall study results. It starts with a summary of the impact of transactive operation on the system-wide load profiles and resulting wholesale market prices. The resulting changes to aggregate DSO and customer annualized cash flow show the overall financial benefit of a DSO+T implementation. A sensitivity analysis is included to evaluate the robustness of these savings. Illustrative results indicate the benefits across a range of DSO types as well as customer classes. This section concludes with a discussion of the overall study results, future capability, and research needs.

6.1 System-Level Impacts

The study indicates significant changes to the system load profile and energy markets when comparing the transactive and BAU cases.

6.1.1 Demand Profile Impacts

This section provides a summary of the load profile changes resulting from the various transactive cases. The combined impact of the various DERs on total system load can be complex. To aid the following discussion Figure 31 provides a summary of typical DER behavior and their representation on load plots for the HR battery case for a peak load day in August.

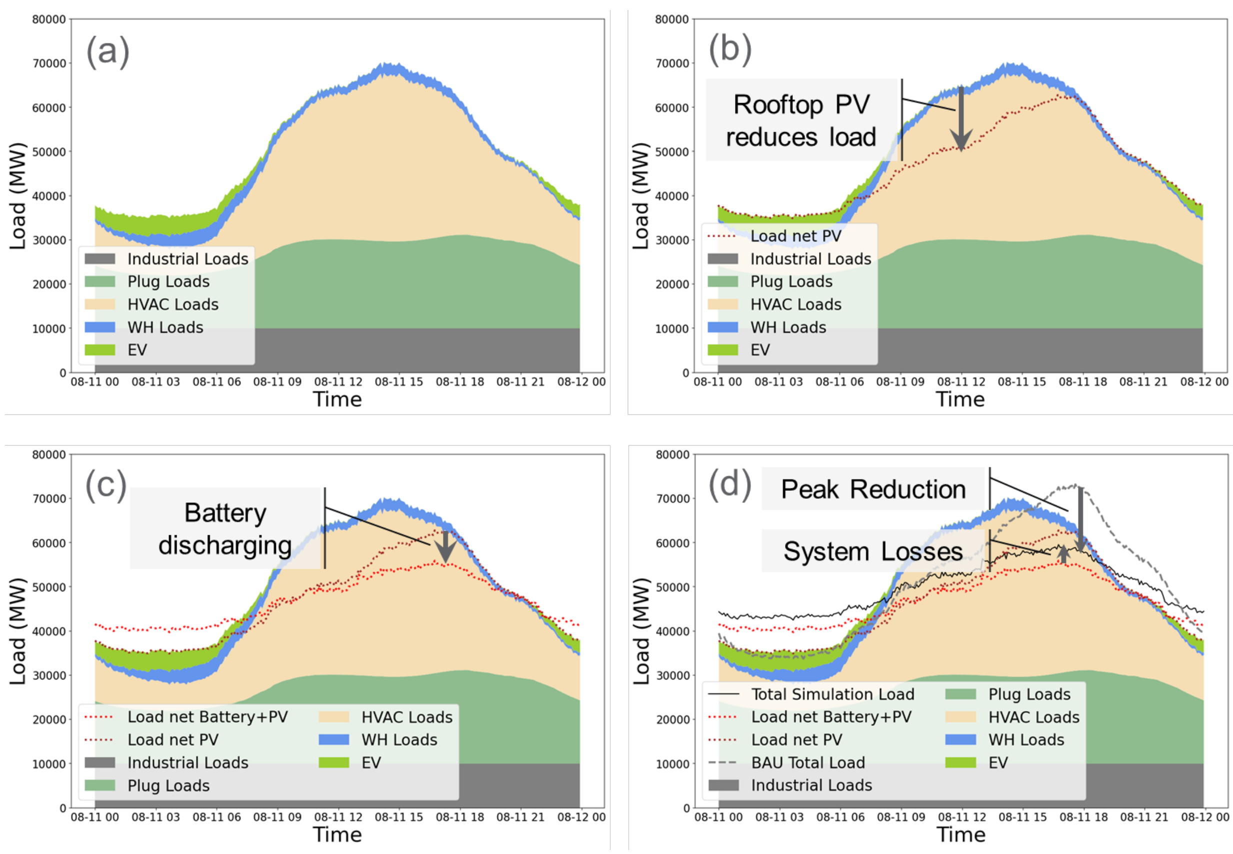


Figure 31. Load profiles plots showing stacked end-use loads (a), the reduction in peak loads due to rooftop solar (b) and battery discharging (c), and the resulting system load (d) after distribution losses are included. (Results shown for the HR battery case.)

All flexible and inflexible customer assets that are incapable of feeding power back onto the grid are shown as stacked loads in Figure 31a. This includes industrial, plug (or miscellaneous), HVAC, water heater, and EV loads. These loads are then offset in part by rooftop solar generation (Figure 31b). The load profile is further flattened by the charging and discharging of the battery fleet (shown as the difference between the brown and red dashed lines in Figure 31c). The dashed red line in Figure 31d represents the sum of all metered customer loads. The inclusion of distribution system losses results in the total distribution system load (the black line in Figure 31d). Comparing this to the BAU system load (the gray dashed line) illustrates the reduction in peak load between the two cases.

The transactive coordination of flexible assets disincentivizes consumption during periods of high prices (typically associated with high electrical demand during the afternoon and evening) and incentivizes relatively higher electrical consumption (for example, battery and EV charging, HVAC precooling, water preheating) during periods of low prices (typically during nighttime or periods with abundant renewable generation). These trends can be seen in the load profiles of Figure 32 showing the impact of the battery and flexible load operation on the daily system peak load experienced in August. For the battery case, the net result of charging and discharging (the dashed red line) decreases system peak loads by ~10% while increasing the minimum system loads and decreases the daily variation in load by ~30% for the peak day. Similar trends are seen for the flexible loads case where water heater and HVAC loads are shifted out of peak periods.

Similar load profiles for winter days are shown in Figure 33. Much smaller reductions in peak load and daily load variation are seen in this case. This is due to the much smaller overall load variation resulting in more modest changes in wholesale electricity prices (see Section 6.1.2). This in turn provides less incentive to assets to provide flexibility.

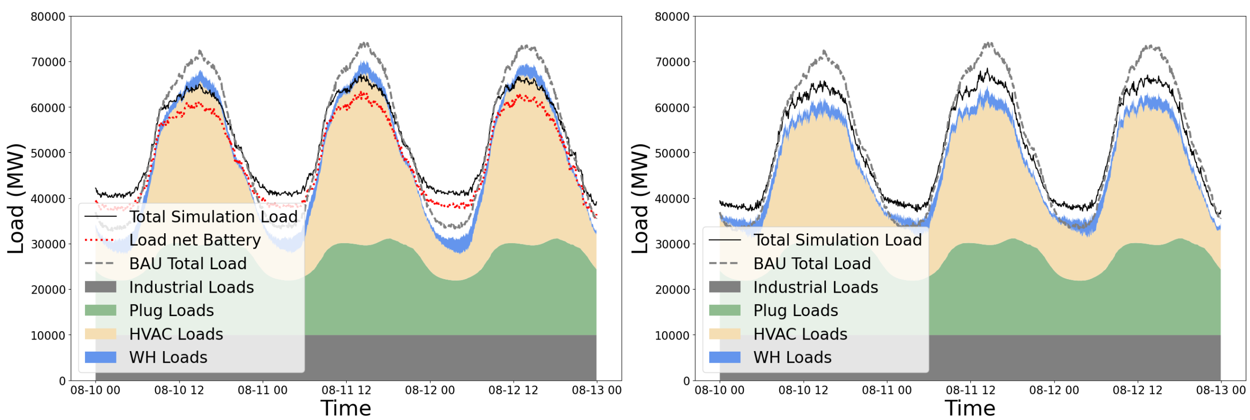


Figure 32. Peak summer load profiles for the battery case (left) and the flexible load case (right).

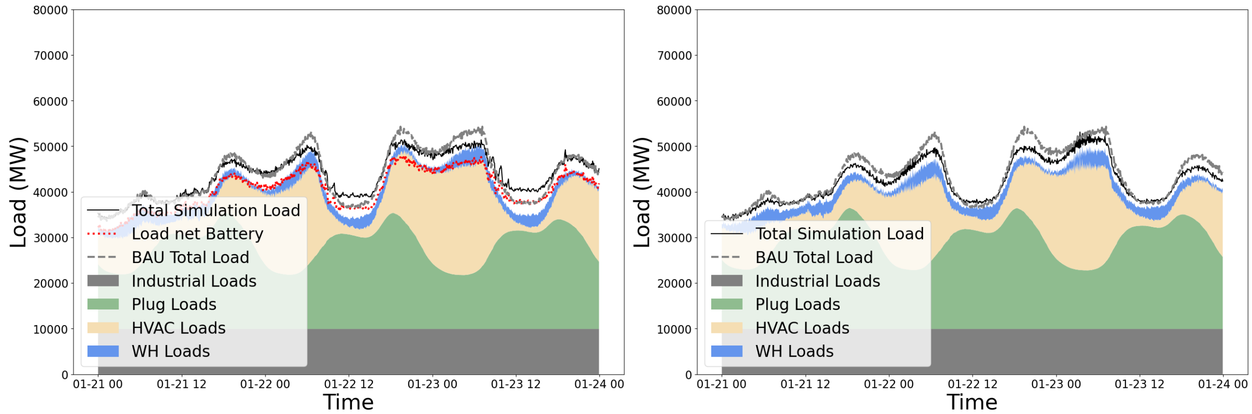


Figure 33. Winter load profiles for the battery case (left) and the flexible load case (right).

A summary of the annual variation in system loads and diurnal load change for the MR and HR scenarios are shown in Figure 34 and Figure 35, respectively, and summarized in Table 5.

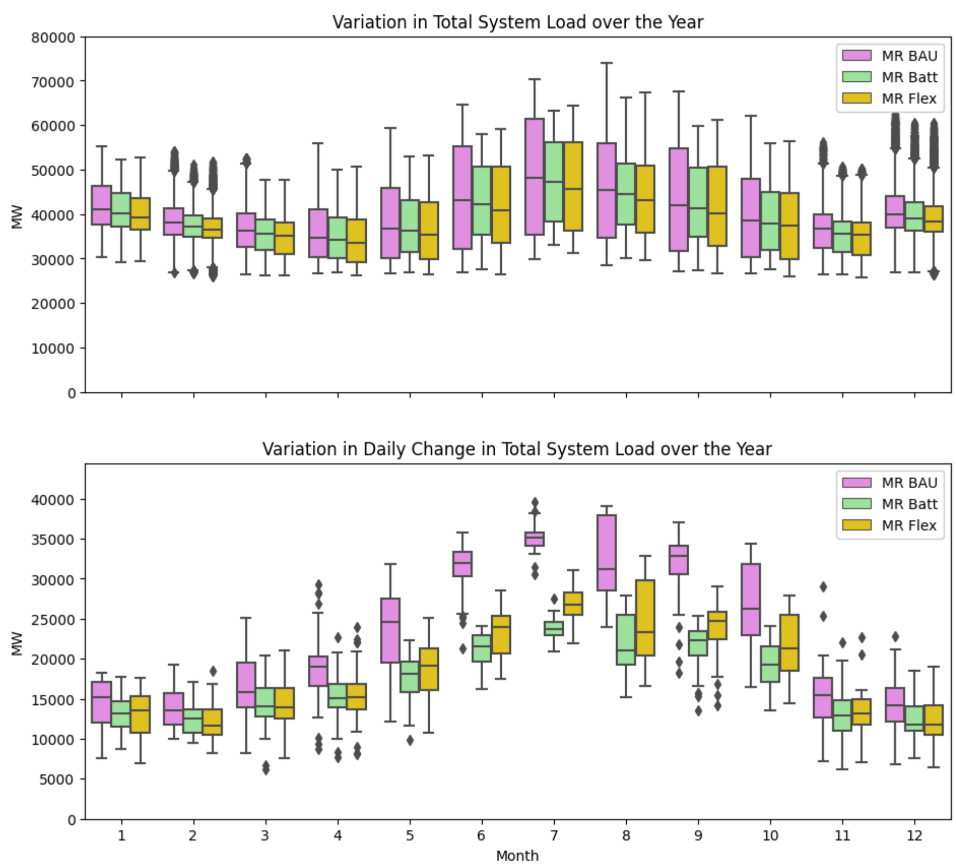


Figure 34. Monthly summary of system load (top) and daily variation in system load (bottom) for the MR scenario.

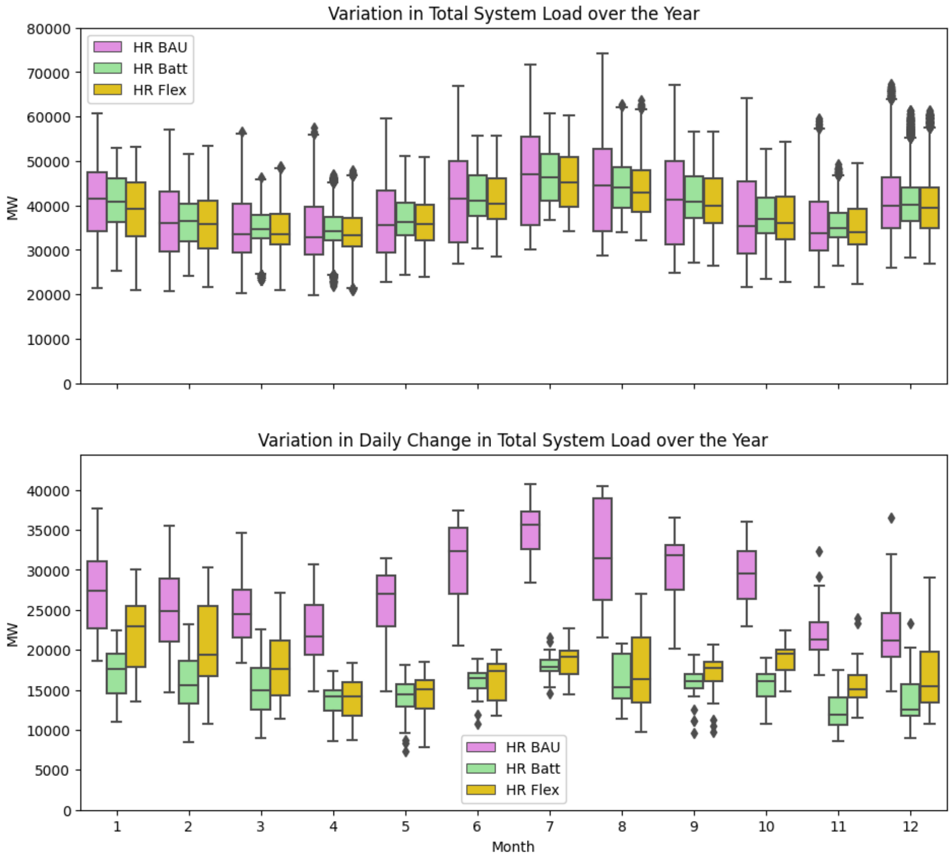


Figure 35. Monthly summary of system load (top) and daily variation in system load (bottom) for the HR scenario.

Table 5. Summary of annual average and maximum loads as well as average daily change in load for all cases.

	MR BAU	MR Battery	MR Flex	HR BAU	HR Battery	HR Flex
Average (MW)	41,000	39,900 (-2.8%)	39,100 (-4.7%)	39,400	39,400 (0.1%)	38,600 (-2.0%)
Max (MW)	73,900	66,300 (-10.3%)	67,400 (-8.8%)	74,300	62,800 (-15.5%)	63,800 (-14.2%)
Min (MW)	26,500	26,300 (-1.1%)	25,800 (-2.8%)	19,800	21,900 (10.8%)	20,900 (5.8%)
Average Daily Range (MW)	23,000	17,100 (-25.6%)	18,300 (-20.4%)	27,300	15,400 (-43.8%)	17,400 (-36.3%)

6.1.1.1 Battery Cases

The battery cases substantially reduce the system peak loads and diurnal load swing (as shown in Figure 34 and Table 5). In the MR scenario, the system maximum load is reduced approximately 10%. In the HR scenario, the peak load reduction is substantially higher (>15%). This is due to the inclusion of smart EV charging (V1G) in the HR scenario that also contributes to load reduction as shown in Figure 36. The HR BAU case experienced a peak EV charging rate of ~6 GW in the afternoon of the peak day (August 11). This is reduced to practically zero in the battery and flexible load cases, reducing peak load by 9%. The system loads are then further flattened by battery charging and discharging.

Figure 35 and Figure 37 show that for the high renewable scenario, batteries and EV provide significant load reduction in the winter, unlike in the MR scenario. This is due to increased BAU daily load variation caused by rooftop solar and EVs. Rooftop solar causes a significant reduction in net load during the middle of the day when low heating requirements already result in the minimum daily system load. In addition, the EV load coincides with the daily peak evening system load. The combined results are daily variations in load and wholesale electricity prices that are similar in magnitude to the peak summer variations seen in the MR scenario. These price variations provide sufficient incentives for batteries and EVs to provide flexibility and reduce load variation.

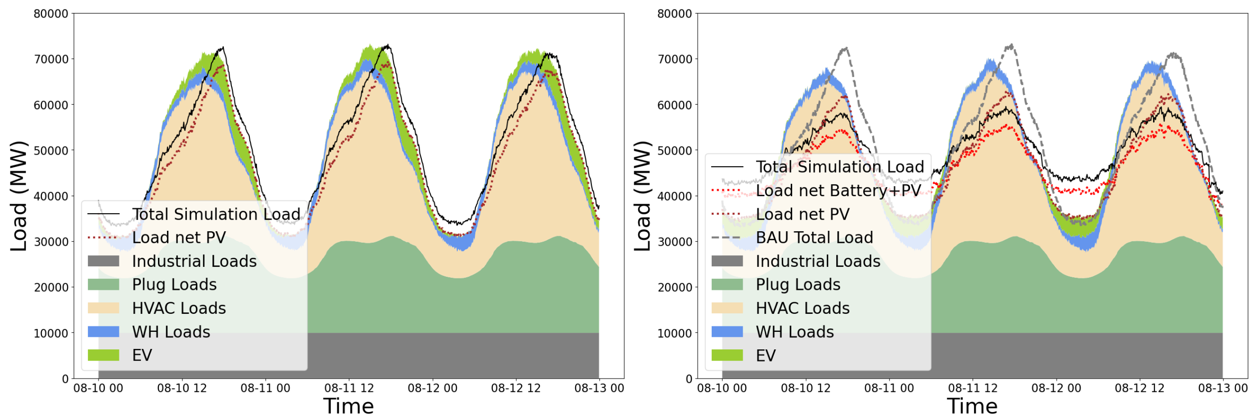


Figure 36. Comparison of BAU (left) and battery case (right) load profiles for the HR scenario showing the significant summer peak load reduction due to shifting EV charging and battery charging and discharging.

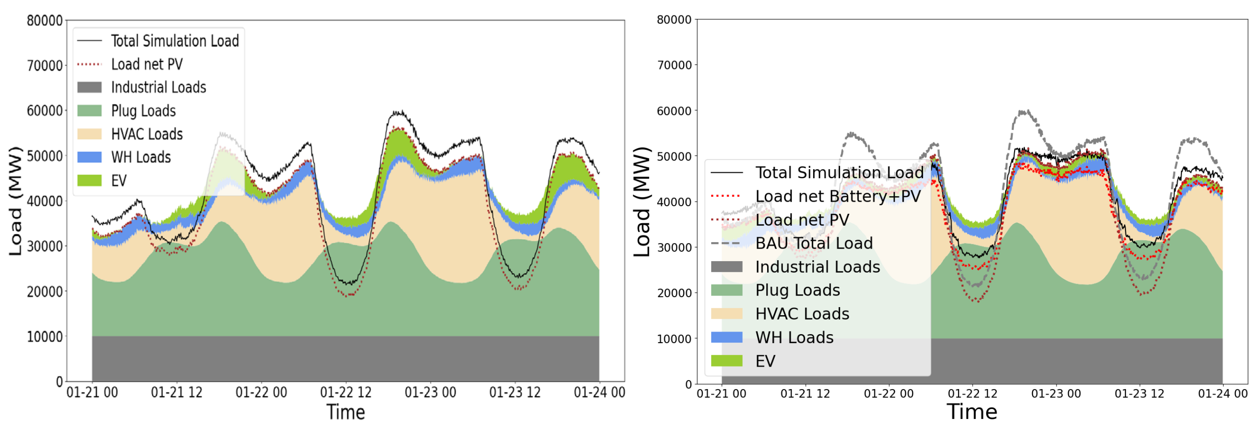


Figure 37. Comparison of BAU (left) and battery case (right) load profiles for the HR scenario showing the significant reduction in winter load variation.

Table 5 also shows that average system loads slightly decrease in the battery cases despite the slight increase in customer loads due to battery round-trip inefficiency. There are two potential reasons for this slight reduction in average load. First, the reduction in peak loads reduces distribution system loads, which are nonlinear in nature. This means that the distribution system has a higher percentage of losses when the system is operating at higher load. Second, the

DSO+T annual simulation was executed by running 12-single month simulations. Battery and EV SOC initial conditions were assumed at the start of each month, in part to ensure successful initiation of the simulation. The first three days of simulation were used to initialize performance and establish load behavior independent of initial conditions. The results from the first three days of simulation were not included in the analysis. As will be seen in Section 6.3.2 battery customers do see an annual increase in load. This suggests that the system-level reduction in load is primarily due to reductions in distribution system loses. Finally, as will be seen in Section 6.2, the majority of the economic benefit of a transactive energy implementation comes from peak load reduction, so any impact that the simulation's SOC initial conditions have on total energy purchases is assumed to be a second-order effect.

Similar, but larger reductions in average load are also seen in the flexible load case. This is due to the combination of reduced HVAC consumption due to slightly higher setpoints and moving operation to periods of colder ambient air temperatures resulting in more efficient operation as well as reduced distribution losses.

6.1.1.2 Flexible Load Cases

Flexible loads are similarly effective as batteries at reducing the peak summer loads (14.2% reduction versus 15.5%) for the high renewable scenario (Figure 38). The HR flexible load case does provide some load modification in the winter (Figure 39), however much of this is achieved by the shifting of EV load from the evening peak. While there is some flexibility provided by HVAC and WH loads, there is insufficient demand for these functions during the midday solar generation peak to allow for significant filling in of the solar 'duck' curve. Likewise, few EVs are assumed to be home during the day, limiting the amount of extra EV charging that can be achieved. Furthermore, the EVs that are available for charging during the middle of the day are assumed to charge as soon as possible under the BAU case, limiting the possibility of additional early charging of EVs under the transactive cases.

This highlights that flexible loads (EVs, HVAC, WH) are effective resources when their loads align with periods of system constraints (such as peak load). However, they are less effective during periods of time when they are unavailable or have less need and capacity of pre-charging, heating, or cooling. Figure 35 shows this trend, highlighting the ability of flexible loads to reduce system peak loads and daily variation during the summer months, but their diminished capability to reduce the daily variation in system loads during shoulder and winter seasons. This is primarily due to a diminished ability (compared to batteries) to fill the solar 'duck' curve during winter and shoulder seasons.

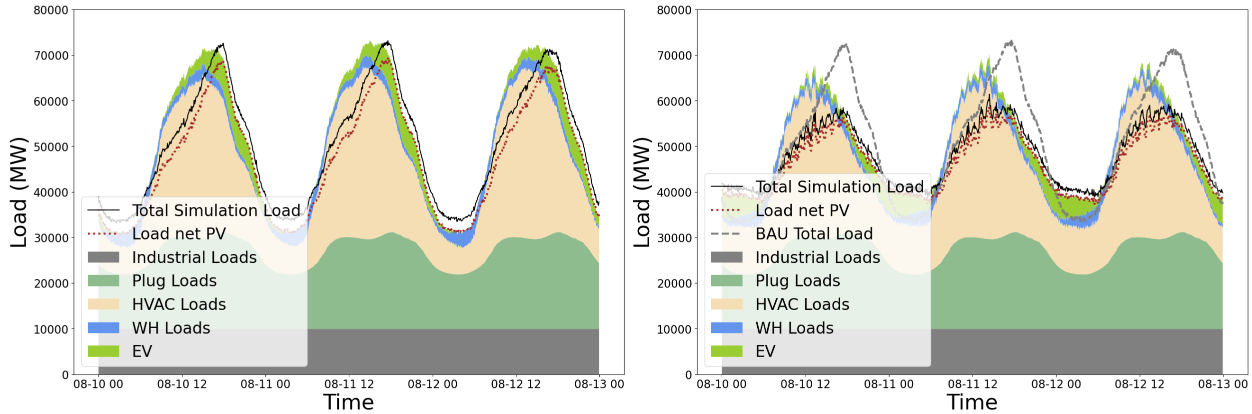


Figure 38. Comparison of BAU (left) and flexible load case (right) load profiles for the HR scenario showing the significant summer peak load reduction.

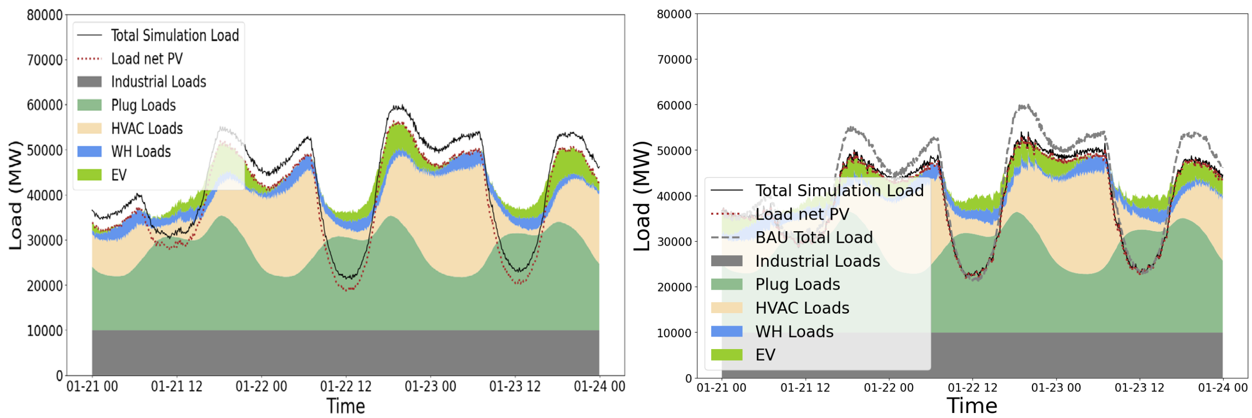


Figure 39. Comparison of BAU (left) and flexible load case (right) load profiles for the HR scenario showing the reduction in winter load variation.

6.1.2 Wholesale Energy Market Impacts

The reduction in peak system loads and diurnal load swings has a commensurate impact on the resulting wholesale energy market prices. Since DSOs purchase the majority of their energy in the day-ahead market,[1] this section will focus primarily on the changes in day-ahead LMPs. A summary of the annual variation and diurnal swings in these values for the MR and HR scenarios are shown in Figure 40 and Figure 41, respectively, and summarized in Table 6.

The MR scenario day-ahead wholesale electricity prices exhibit annual behavior that mirrors the annual load behavior. Higher prices and larger daily variation in price are seen during the peak summer months, with lower prices and variation seen in the winter and shoulder seasons (Figure 40). The transactive cases provide the greatest reduction in price variation during the summer months with smaller but still noticeable reduction in the remainder of the year. Overall, the transactive cases reduce annual average daily price variation by ~40-50%. The substantial reduction in daily load variability and price volatility has positive implications on market

[1] We are also assuming significant purchases from bilateral markets, which are indexed to day-ahead prices in this study.

operation and generator revenue sufficiency. Additional investigation into these aspects is warranted.

Table 6. Summary of annual average and average daily change in day-ahead and real-time LMPs ($/MWh) for each case.

	MR BAU	MR Battery	MR Flex	HR BAU	HR Battery	HR Flex
Day-Ahead LMP: Annual Average	29.19	28.67 (-1.8%)	27.03 (-7.4%)	23.54	25.07 (6.5%)	23.5 (-0.2%)
Day-Ahead LMP: Average Daily Range	29.21	16.59 (-43.2%)	14.72 (-49.6%)	34.61	27.66 (-20.1%)	24.11 (-30.3%)
Real-Time LMP: Annual Average	27.01	26.71 (-1.1%)	29.39 (8.8%)	39.79	24.78 (-37.7%)	31.01 (-22%)
Real-Time LMP: Average Daily Range	22.25	15.39 (-30.8%)	31.08 (39.7%)	179.48	39.77 (-77.8%)	121.7 (-32.2%)

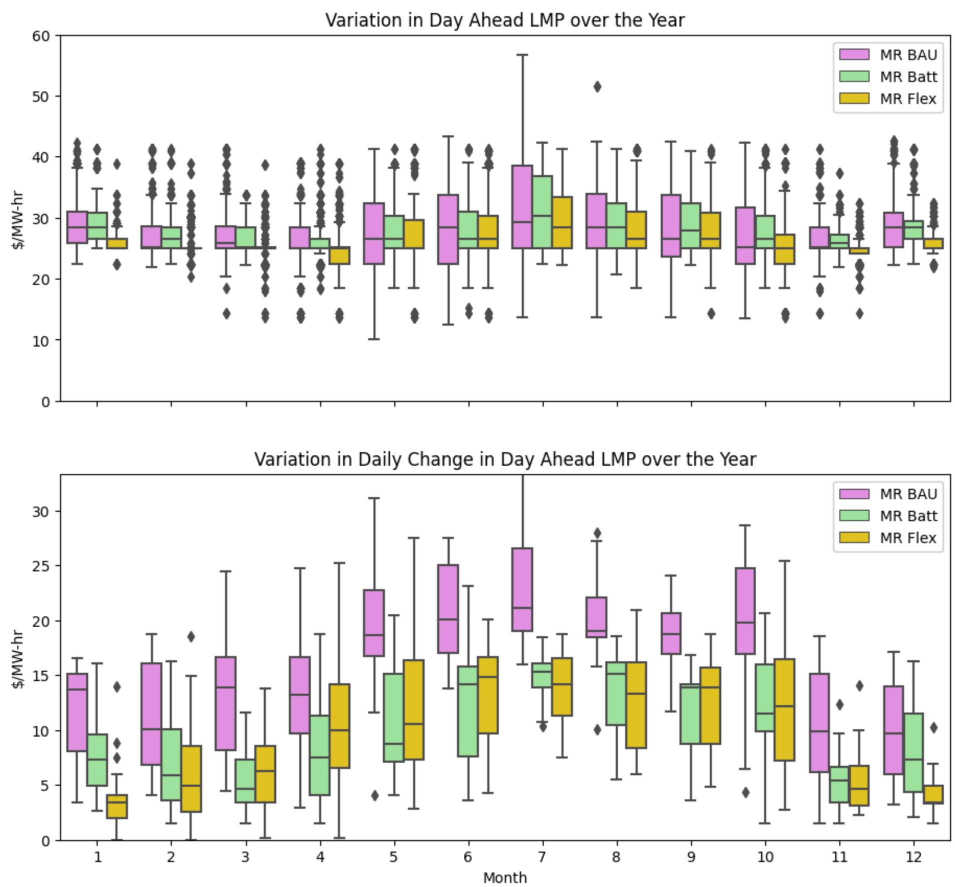


Figure 40. Monthly summary of day-ahead LMP (top) and daily variation in day-ahead LMP (bottom) for the MR scenario.

The annual price trends are less apparent for the HR scenario (Figure 41). This is due in part to increased renewable generation (particularly from solar) creating large daily load variations, and therefore price variations, throughout the year. The transactive cases do reduce annual average daily price variations ~20-30%.

While the average prices drop for most transactive cases (due to the decrease in peak loads and slight decrease in average loads) the average day-ahead price increases for the HR battery case. This is attributed to differences in load forecast accuracy between the cases, as the day-ahead price is based on the DSO's forecast day-ahead load, not the actual load. If one case has a slight forecast error bias it will result in day-ahead purchases that are higher or lower than the other cases. This is mitigated in part by the real-time market that is used to reconcile and correct the bid day-ahead quantities. That is, if a DSO overpredicts its day-ahead quantity, the excess will be sold in the real-time market and the DSO will be credited the difference. Even with the increased annual average day-ahead price, the HR battery case sees a 37% reduction in real-time prices and an overall 4.6% reduction in wholesale energy purchase expenses. This is due in part to the real-time market correction, as well as the fact that the battery operation result in the DSO purchasing more electricity during periods of lower prices and less during peak prices.

Table 6 also summarizes the average annual real-time LMP statistics for each case. The MR flexible load case is the only case that does not reduce average real-time LMPs and daily variation in LMP. This may be due to relative underprediction of the flexible loads' quantity. The HR BAU case sees substantially higher average real-time LMPs and daily variation. This may be caused by the increased variability of the higher penetration of renewable energy resulting in greater variability in the real-time market. Market operation at these high levels of renewables, as well as the role that the accuracy of flexibility estimates play in the formation of day-ahead and real-time prices warrants additional research.

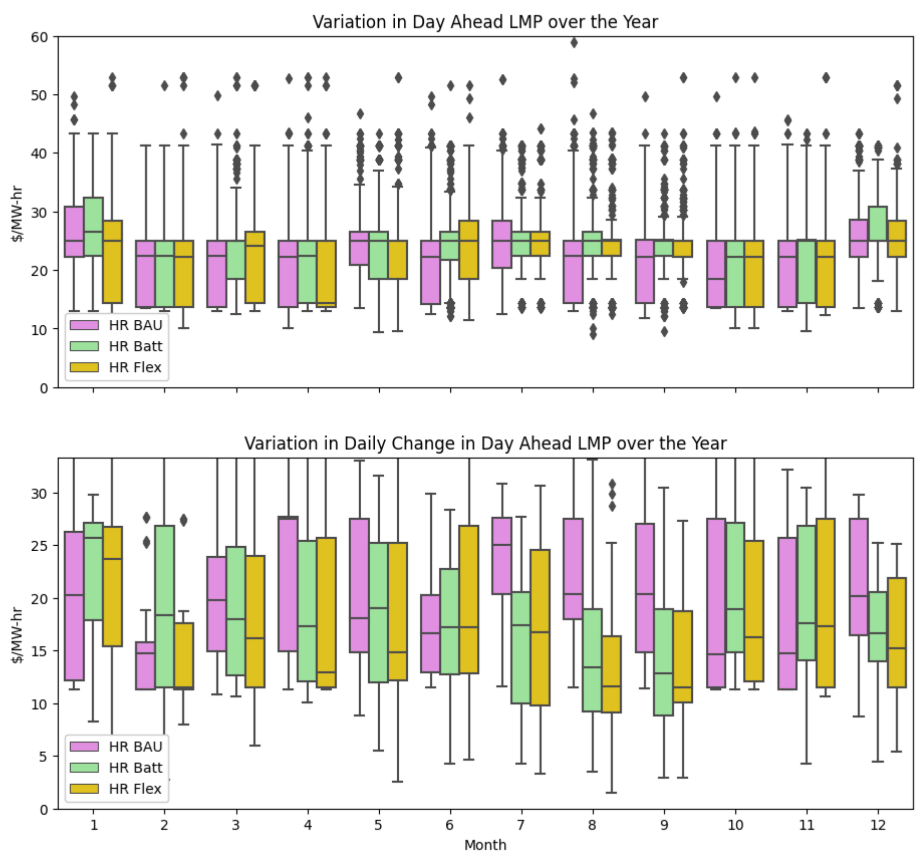


Figure 41. Monthly summary of day-ahead LMP (top) and daily variation in day-ahead LMP (bottom) for the HR scenario.

6.2 Resulting Annualized Cash Flow Impacts

The simulation results (in particular, peak system loads and energy market purchases) are key inputs into the economic analysis that determines changes in annualized cash flow by stakeholder. Figure 42 shows a summary of the changes in annualized cash flow between the BAU and battery case for the MR scenario. This will be used to illustrate the drivers behind system benefits as well as implementation costs. Net benefits will then be presented for the other cases along with a sensitivity analysis. Details of the benefits and costs breakdowns for the other cases is provided in Volume 5 (Reeve et al. 2022b).

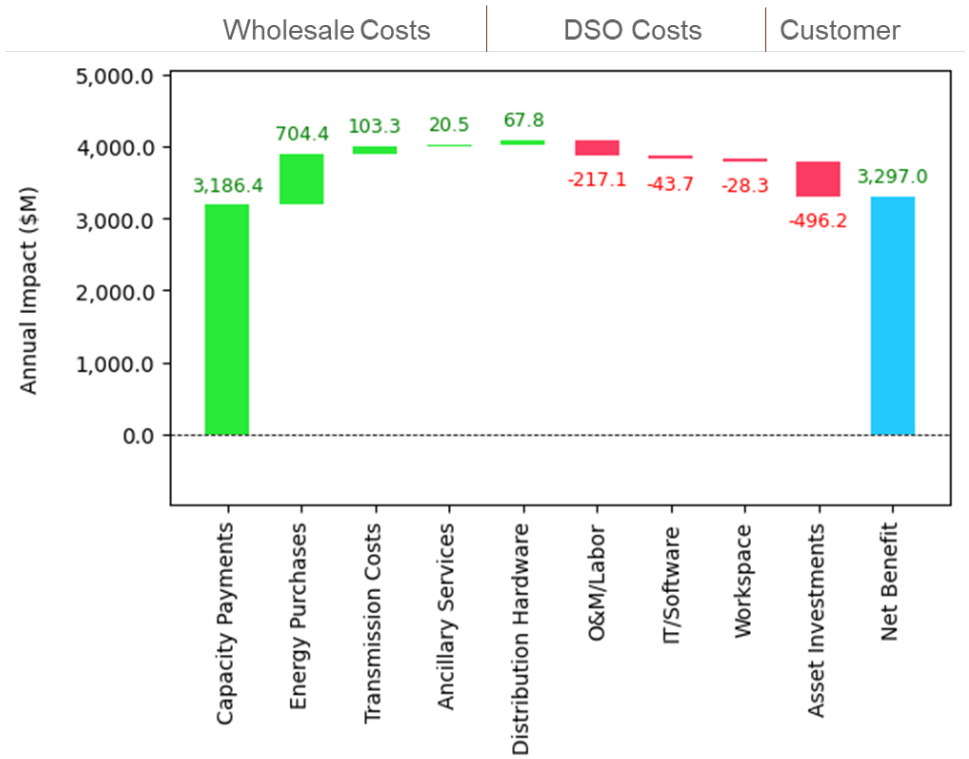


Figure 42. Summary of changes in annualized cash flow between the BAU and battery cases showing economic benefits and costs of implementation (MR scenario).

The primary benefit of a DSO+T implementation is due to the reduction in system peak load and, in particular, in required generation capacity payments. Peak load reduction not only lessens the quantity of generation capacity that must be procured in a capacity market, but also substantially reduces the resulting auction price for this capacity. It is this second attribute that results in large savings. This study assumes that a 1% reduction in required capacity lowers the capacity price 5% consistent with other studies (Pratt et al. 2022, Section 3.3.1.3). It should be noted that the battery case would still have a net benefit even in the absence of a capacity market and the resulting savings in capacity payments.

The reduction in peak load also saves in transmission and distribution costs resulting from the deferral of growth-driven capital investments in this infrastructure. These benefits have been calculated for general growth rates and transmission and distribution system designs. Actual benefits will be dependent on the actual load growth rates and system constraints seen on an operator’s system.

There are also wholesale market benefits from savings in the purchases of energy. These savings are due to the reduction in peak loads (and therefore not having to dispatch expensive generation) that results in lower average prices. More importantly, however, is the fact that flexible assets shift more of their consumption to periods of lower prices. So, while for the MR battery case average prices dropped 1.8%, energy purchases dropped 7.3%. The impact of ancillary services was not found to be a significant source of economic benefit in this study. This is because ancillary services represent <3% of total cost of electricity and we assume no change in their price as they are purchased based on the total energy volume (which varies by only a few percent between cases). Demand flexibility may significantly mitigate the increased need for ancillary services associated with increased load and generation variability in the future. These direct benefits warrant further investigation.

The costs to implement a transactive retail market as well as the flexible assets are borne by the DSOs and customers. DSO labor is increased due to the personnel needed to run the retail marketplace, additional AMI operations capability, and strengthened retail operations. This increase in employee headcount results in a small increase in workspace costs. Software costs are also estimated to increase due to the implementation of a retail marketplace, integration into the existing distribution management system, and the required DER communications network. Finally, we are assuming that the cost to implement or upgrade flexible assets is borne by the customer and captured in their annualized cash flow.

The net result of these wholesale and capital infrastructure benefits combined with DSO and customer implementation costs is an annualized benefit of $3.3B for the MR battery case. This is representative of the nominal net benefit for all cases that ranged from $3.3B to $5.0B as shown in Figure 43. The flexible load cases achieve slightly lower peak load reductions and therefore have reduced savings in capacity payment, transmission, and distribution expenses. This is more than offset by increases in energy purchase savings as well as lower asset investment costs. For flexible loads, customers only pay the incremental cost to implement smart controls and connectivity on existing devices to enable participation. For the battery case we assume the full investment cost (assuming aggress battery cost reductions). The region wide difference in asset investment costs between the MR battery and MR flexible loads case is $226M/year. The HR cases result in higher overall benefits due to the large load reductions achieved by the addition of flexible EV charging. Full detail of the case results is provided in Volume 5 (Reeve et al. 2022b). Figure 43. also shows the expected net benefit under both high and low capacity market price assumptions. These assumptions and other sensitivity analysis are discussed in the next section.

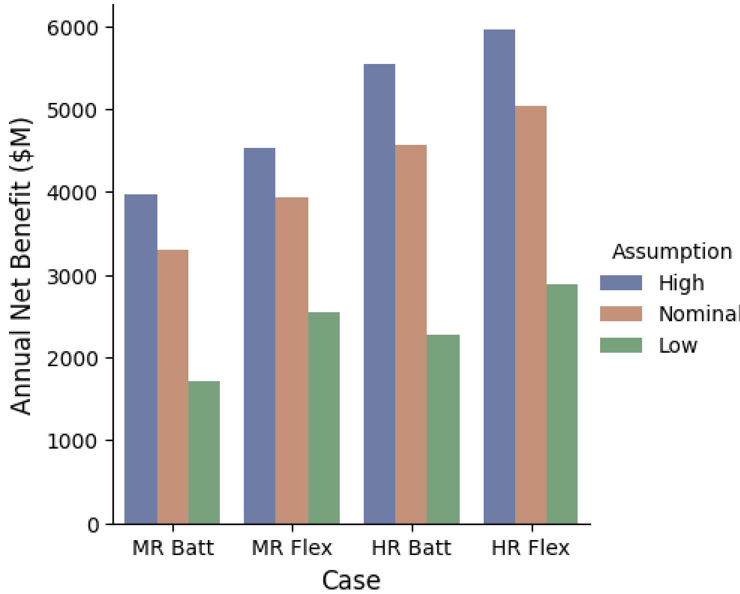


Figure 43. Summary of annualized net benefit to customers for each case under high, nominal and low capacity price assumptions.

6.2.1 Sensitivity Analysis

The range of results shown in Figure 43. are based on an economic sensitivity analysis using a range of capacity market assumptions. Future capacity market prices will likely be driven by the addition of renewable generation (which may suppress capacity market prices), load growth due to electrification of space heating and transportation, and growing needs for resource adequacy for extreme events. Both these needs will tend to increase the demand for new generation and potentially increase capacity market prices. For this study, the nominal analysis assumed a capacity market price of $75/kW-year for the BAU case based on an examination of reported U.S. capacity market prices over time (Jenkin et al. 2016). This study also applied a quantity-price sensitivity factor to capture the nontrivial impact that reducing the required capacity has on the cleared capacity market price. We assumed a sensitivity factor of 5 based a range of reported sensitivities (Jenkin et al. 2016; Bowring 2013). These assumptions are identical to the values used in the Grid-Interactive Efficient Buildings Roadmap value analysis for their 'High Capacity Value' case (DOE 2021). For the 'low' capacity price case we assumed a halving of the capacity cost ($37.5/MWh). This is at the lower end of almost all the regions for which 2030 average generation capacity cost was calculated (DOE 2021, Figure 23). For the 'high' capacity price assumption we used a capacity value of $91/kW-yr to reflect the full annualized cost of a peaker plant. Even under low capacity market assumptions, the net benefit was $1.7-2.9B. Full documentation of the capacity price assumptions is provided in Volume 4, Section 3.3.1.3 (Pratt et al. 2022).

The overall system benefits are less sensitive to other key assumptions. Analysis of the transmission infrastructure cost basis determined a capital cost of $169/kW (Pratt et al. 2022). Based on the calculated annual cost of capital of 8.25%, this results in an annual cost of transmission infrastructure of $13.9/kW-year. This agrees well with the avoided cost of transmission ($15/kW-year) used in DOE (2021). This does, however, assume that there is a one-to-one relationship between reduction in system peak load and required transmission infrastructure. In a complex mesh-network transmission system design this may not hold. If load reduction is assumed to only result in a 50% reduction in transmission system infrastructure deferral, the overall benefits would be reduced by $48-91M/yr.

We consider the calculated energy purchases cost reduction to likely underestimate the actual savings. This is because the DSO+T simulation does not replicate the infrequent but large deviations in day-ahead and real-time LMPs. For 2016, ERCOT experienced day-ahead LMPs above $40/MWh approximately 8% of the time, accounting for 27% of annual purchases if all load was bought at day-ahead prices; however in the simulation, prices only occurred above $40/MWh 4.5% of the time and accounted for 9% of energy market costs. This suggests that the simulation is underpredicting the benefit of reducing energy consumption during periods of high prices. However, when 2016 ERCOT day-ahead LMP prices are used with simulation load profiles (without assuming any elasticity in prices with loads), the energy purchases benefit is only slightly larger (7%). This suggests that the simulation is capturing the overall trends in wholesale energy cost benefits but the value of lowering extreme prices warrants further investigation. The study results were considered insensitive to the cost of ancillary services, so these were not included in the sensitivity analysis.

Finally, doubling select implementation costs does not substantially alter the overall system benefit. For example, doubling the DSO implementation costs, including required labor for AMI network operation, cybersecurity, and retail operations as well as the software costs associated with the retail market and DER network would decrease the overall benefits $150-240M/yr. In terms of customer implementation costs, the main uncertainty is in future battery implementation costs. A doubling of battery implementation costs would reduce the overall benefits approximately $0.5B/yr. Since all other customer implementation costs (i.e., smart chargers and thermostats) were based on available products, it was assumed these would only further decrease in price when deployed at scale.

6.3 DSO and Customer Level Performance

6.3.1 DSO Savings by Type

The 200-bus simulation explicitly modeled the performance of the largest 40 DSOs (representing 90% of the system load). This allows the analysis of savings as a function of DSO type (urban, rural, or suburban), size, and overall performance. Figure 44 shows the reduction in expenses of each DSO as a function of size (number of customers), peak coincident load reduction, and wholesale energy savings for the MR battery case. There is small correlation between overall cost reduction and DSO size, with larger DSOs seeing slightly increased savings due to the implementation costs (particularly labor costs) not scaling linearly with DSO size. Furthermore, while the major driver of net benefit is the reduction in system coincident peak load, this is not the major factor differentiating the performance of various DSOs. This is because much of the reduction in capacity payment expenses comes from the reduction in capacity price, which is set by the reduction in system-wide coincident load reduction, not specific DSO reduction. Only the reduction in capacity quantity varies by DSO, resulting in a slight trend in increasing benefits with larger coincident load reductions.

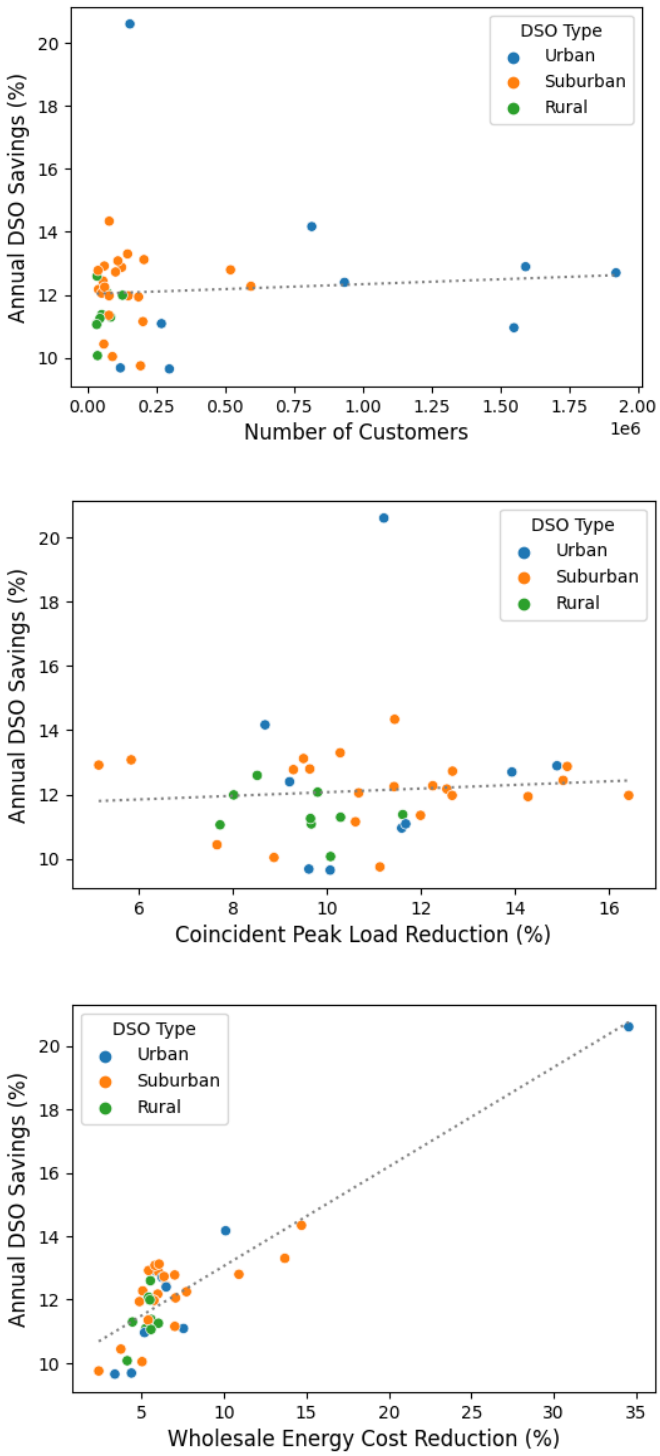


Figure 44. Net system benefit for each DSO as a function of number of customers (top), reduction in peak coincident load (middle), and wholesale energy savings (bottom) for the MR battery case.

The main factor that differentiates the individual savings of each DSO is its savings in wholesale energy purchases. This is a function of is each DSO's demand flexibility, overall changes in annual energy consumption, and ultimately changes in its nodal LMPs throughout the year. For example, Figure 44 shows an urban DSO (DSO #166) that has substantially higher net benefit savings than would be expected from its coincident peak load reduction. This increased benefit is due to demand flexibility providing substantial reductions in this DSO's wholesale energy purchase cost. DSO #166 experiences a 20% reduction in average day-ahead wholesale prices resulting in a 35% reduction in wholesale energy purchases (compared to a system-wide average reduction in energy purchases of 7%).

This is likely due to demand flexibility reducing transmission congestion or enabling the dispatch of a lower cost generation reducing the LMP at this DSO's transmission node. DSO #166 is not large enough (with only ~1% of the total region's customers) to sway the overall trends. Overall urban and suburban DSOs have similar savings with rural DSOs having slightly lower savings (Table 7). This result does show, however, the potential for demand flexibility to provide much larger benefits for individual DSOs with specific circumstances or constraints. Overall, the analysis shows that all DSOs saw meaningful economic benefit regardless of type, size, or whether they are summer or winter peaking.

Table 7. Summary of DSO costs ($B) and percent savings by type.

Type	MR BAU	MR Battery	MR Flex	HR BAU	HR Battery	HR Flex
Urban	19.9	17.4 (12.4%)	17.2 (13.4%)	18.9	15.5 (18.1%)	15.4 (18.6%)
Suburban	9.2	8.1 (12.2%)	7.9 (14.2%)	8.4	6.9 (17.6%)	6.7 (19.6%)
Rural	1.6	1.4 (11.4%)	1.4 (12.7%)	1.4	1.2 (13.2%)	1.2 (13.4%)
Total	30.7	26.9 (12.3%)	26.5 (13.6%)	28.7	23.6 (17.7%)	23.4 (18.6%)

6.3.2 Customer Savings by Participation and Rate Class

This section presents changes in energy consumption, peak load, electric bills, and annual total energy expenses across the customer population. The focus of this section will primarily be on comparing residential participating and nonparticipating customers. The section concludes with a comparison between residential and commercial customers and the impact of slider setting (level of participation) on customer savings. Results are shown for the MR scenario and are indicative of overall trends. Results for all cases are documented in Volume 5 (Reeve et al. 2022b).

These comparisons of customer metrics are enabled by modeling the individual characteristics and performance of tens of thousands of customer buildings. The distributions in building size, insulation levels, operating schedule, and equipment performance result in variations in annual energy consumption and electric bills across the customer population. Examples of such variation are shown in Figure 45. The simulation results show that residential customers in multifamily housing (i.e., apartment buildings) have lower annual electric bills than manufactured or single-family detached homes. This is due, primarily, to the reduced exterior envelope area per housing unit and, therefore, heat transfer with the outside. This reduces the required space air conditioning load and the annual electricity consumption. Similar trends are seen for building heating type. Buildings with gas heat pay less in electric bills than customers with heat pumps or resistance heat, due to the eliminated electric space and water heating electricity consumption. This behavior matches expected trends and illustrates the granularity achievable from the simulation given the customer attributes and population size.

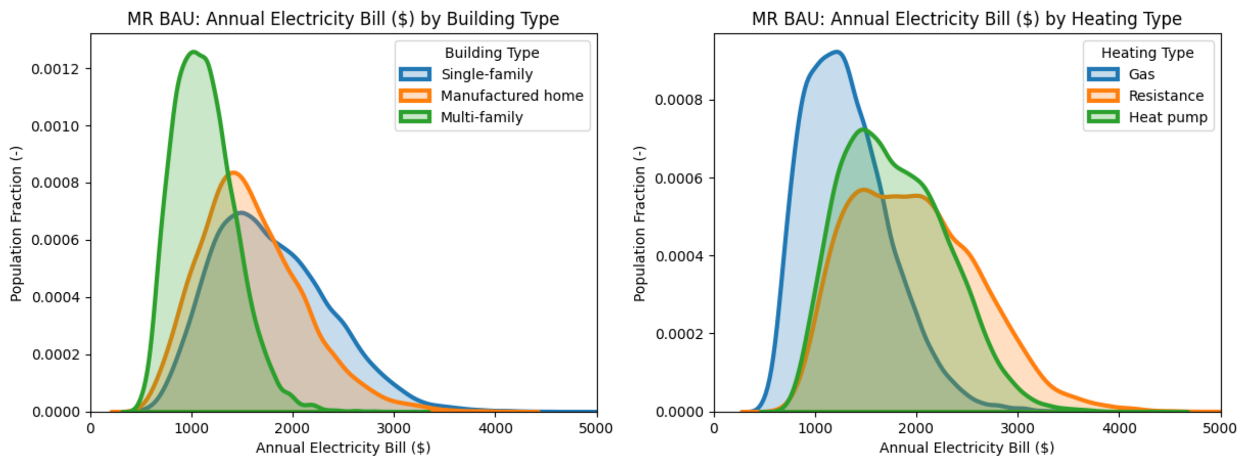


Figure 45. Examples of residential customers' annual electricity bills as a function of building type (left) and space heating system (right) for the MR BAU case.

Figure 46 shows the percent change in annual energy consumption for both participating and nonparticipating residential customers[1]. In the battery case residential customers consume slightly more energy (0.8%) over the course of the year due to the round-trip efficiency of the battery. In the flexible loads case, the operation of HVAC units with setback thermostat schedules and operating precooling/heating (often at more efficient outdoor air temperatures) reduces the average residential customer's energy consumption 4.4%. In both cases the energy consumption of nonparticipating customers is practically unchanged with the transactive cases within 0.3% of the BAU case demonstrating the consistency in results between simulations.

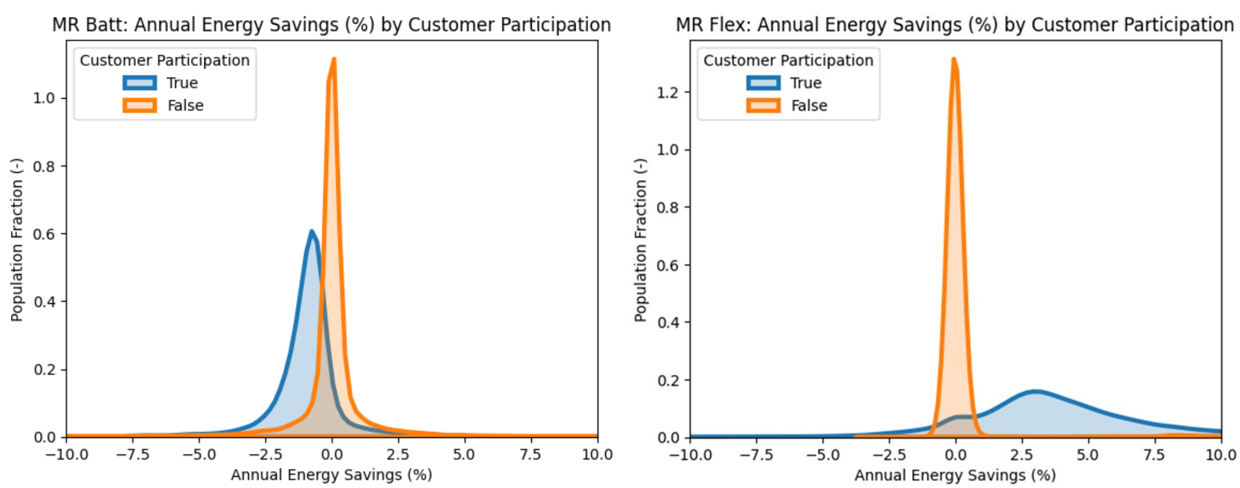


Figure 46. Change in annual energy consumption for participating and nonparticipating residential customers for the MR battery (left) and MR flexible load cases (right).

On average residential customers' annual peak load did not substantially decrease (Figure 47). This is initially surprising given that the MR scenario cases saw coincident system peak load reductions of 9-10%. This is because the transactive coordination scheme incentivizes load

[1] Note that all simulated customers across the 40 DSOs (in this case 58,500 residential customers) are shown in this and subsequent figures. Customer distributions are not scaled by the weighting factor of each DSO. This ensures trends in smaller (mostly rural) DSOs are visible.

reduction during periods of high energy prices and distribution-level delivery constraints. The resulting demand flexibility and load shifting can result in peak loads occurring at other times of the day. In fact, several DSOs switched from summer to winter peaking when the transactive retail market was implemented. Figure 47 plots the change in a customer's 15-minute peak annual load (on which demand charges are based for commercial and industrial customers on the fixed tariff). This suggests that the monthly demand peaks of many customers do not align with the system coincident peak, or that demand flexibility effectively moves these peaks to other, non-coincident, times.

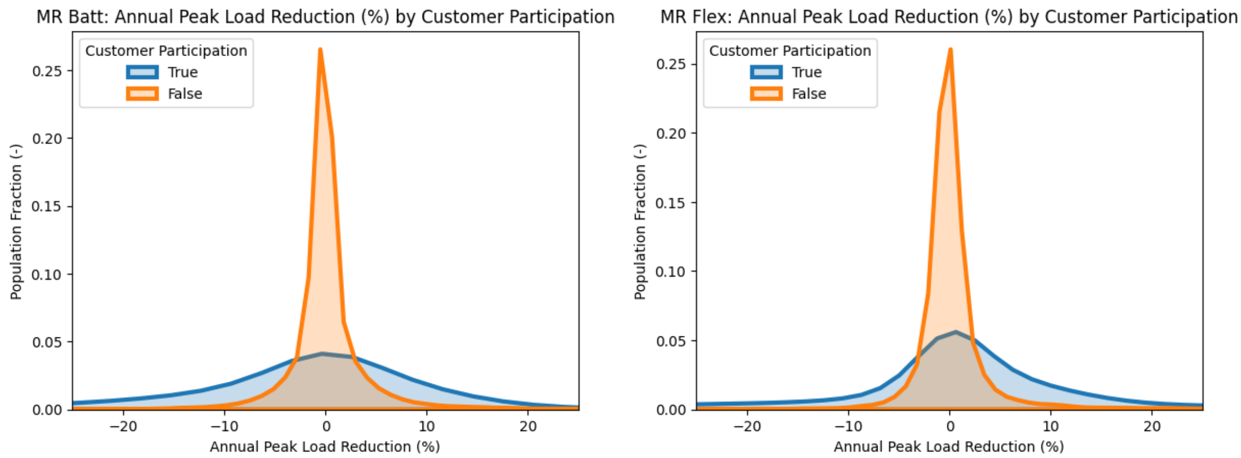


Figure 47. Change in annual peak load for participating and nonparticipating residential customers for the MR battery (left) and MR flexible load cases (right).

The changes in individual customers' annual energy profile, consumption, and peak loads impact the DSO's expenses (as discussed in Section 6.2) and required revenue recovery. This ultimately impacts the customer's annual utility bill (whose calculation is described in Section 5.2.5). The annual utility bill savings for participating and nonparticipating residential customers is shown in Figure 48 for all DSOs in the MR scenario[1]. Participating residential customers experience similar annual savings for the battery and flexible load cases (14% and 17% respectively for the MR scenario). Of significant importance is the fact that nonparticipating customers save on their average annual utility bill and practically all customers see a reduction in their bills. Nonparticipating customers see an average reduction (of ~10%) in utility bills because their fixed rate tariff is designed to recover revenue equivalent to what would have been collected under the dynamic transactive rate. This ensures that nonparticipating customers also benefit from the reduced overall cost basis of their DSO. However, participating customers do, on average, experience larger savings. This confirms an important rate design principle: that customers who participate and provide flexibility achieve higher savings than those who do not.

[1] Note that the customer probability distributions of utility bill savings are multi-modal due to customer savings being primarily driven by the savings of each of the 40 DSOs that comprise the population of the entire region. This is exasperated in the flexible load case as the non-participating customer base in only ~20% of the entire population and the resulting required rate recovery and fixed tariff from this smaller simulated customer base can be influence by a few customers (particularly large commercial customers). While showing results for only one DSO would eliminate the multi-modal nature of the results, we chose to show the largest possible representation of the simulated population.

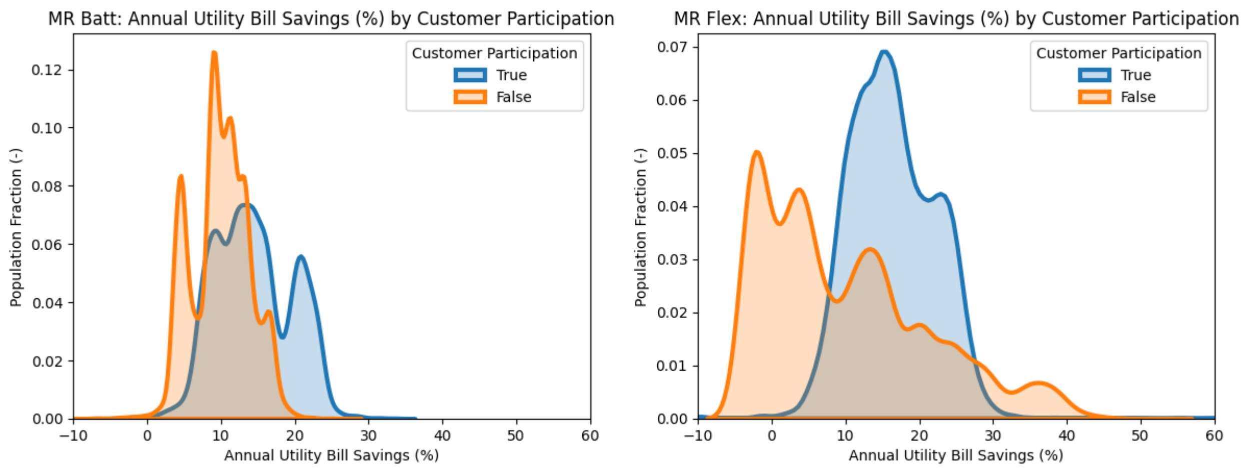


Figure 48. Change in annual utility bill payments for participating and nonparticipating residential customers for the MR battery (left) and MR flexible load cases (right).

A customer's annual utility bill savings is offset by the annualized expense of any flexible asset installation and operation. The net result is the total savings in annual customer energy expenses, as shown in Figure 49. For the battery case the annualized cost of installing and operating the system can result in negative overall savings for a small portion of customers. More importantly, the resulting annual net energy expense benefit becomes lower for participating customers versus nonparticipating customers (8% versus 10%). This may be acceptable to participating customers given the additional value propositions of battery ownership (e.g., back-up power and self-consumption of onsite renewable generation). The flexible load case does not see such a large reduction in overall benefits due to the much smaller flexible asset investment expense associated with installing smart thermostats and water heater controllers. A summary of the key residential customer metrics is provided in Table 8.

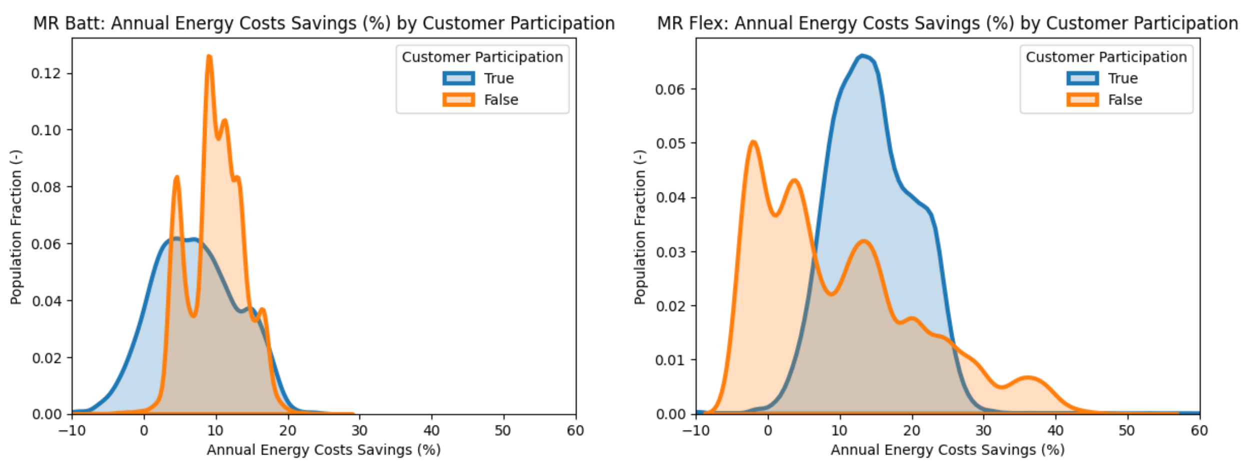


Figure 49. Change in total annual energy expenses for participating and nonparticipating residential customers for the MR battery (left) and MR flexible load cases (right).

Table 8 also includes key residential customer metrics for the HR scenario. In this scenario there are similar small changes in annual energy consumption and an increase in peak load by participating customers. In the HR flexible load case participants see a smaller benefit over no participating customers than in the MR flexible load case. This is due flexible asset costs including EV smart charging for the fraction of customers with EVs. In addition, since 40% of customers have rooftop solar the annual net energy consumption and electric bill is lower, resulting in the investment costs of flexible assets becoming a larger fraction of bill savings. The impact of flexible asset type and rooftop solar on customer benefits is discussed more in Section 6.3.3.

Table 8. Summary of metrics for average participating and nonparticipating residential customers.

Metric	MR Flexible Loads		MR Battery	
	Nonparticipating	Participating	Nonparticipating	Participating
Annual Energy (kW-hrs)	13,340 (-0.3%)	12,740 (-4.4%)	13,330 (0%)	13,460 (0.8%)
Peak Load (kW)	9.4 (-0.5%)	9.5 (1.2%)	9.4 (-0.5%)	9.6 (1.2%)
Annual Utility Bill ($)	1,500 (-10.2%)	1,390 (-16.6%)	1,500 (-10.1%)	1,430 (-14.2%)
Annual Energy Expenses ($)	1,500 (-10.2%)	1,420 (-14.8%)	1,500 (-10.1%)	1,540 (-7.8%)
	MR Flexible Loads		MR Battery	
	Nonparticipating	Participating	Nonparticipating	Participating
Annual Energy (kW-hrs)	11,270 (-0.3%)	12,680 (-4%)	11,260 (0%)	14,260 (0.4%)
Peak Load (kW)	9.3 (0.2%)	10.2 (-12.3%)	9.3 (0.2%)	11.6 (-8.7%)
Annual Utility Bill ($)	1,170 (-13.6%)	1,290 (-16.6%)	1,190 (-11.2%)	1,390 (-15.9%)
Annual Energy Expenses ($)	1,680 (-9.9%)	1,850 (-10.8%)	1,710 (-8.1%)	2,000 (-8.2%)

Table 9. Summary of metrics for average participating and nonparticipating commercial customers.

Metric	MR Flexible Loads		MR Battery	
	Nonparticipating	Participating	Nonparticipating	Participating
Annual Energy (kW-hrs)	149,720 (-0.5%)	140,760 (-2.5%)	147,460 (0.1%)	142,980 (0.2%)
Peak Load (kW)	47 (0.2%)	45 (-3.8%)	47 (0.2%)	45 (-1.4%)
Annual Utility Bill ($)	15,520 (-8.9%)	13,950 (-15.7%)	15,030 (-10.6%)	14,040 (-14.3%)
Annual Energy Expenses ($)	11,940 (-8.9%)	10,870 (-15.1%)	11,640 (-10.6%)	10,980 (-13.1%)
	MR Flexible Loads		MR Battery	
	Nonparticipating	Participating	Nonparticipating	Participating
Annual Energy (kW-hrs)	142,100 (-0.6%)	130,360 (-2.4%)	134,670 (0%)	135,060 (0.1%)
Peak Load (kW)	46 (0.1%)	44 (-5.3%)	45 (0%)	45 (-3.8%)
Annual Utility Bill ($)	13,460 (-10.9%)	11,720 (-20.4%)	12,920 (-11.2%)	11,970 (-19.9%)
Annual Energy Expenses ($)	12,080 (-9.5%)	11,000 (-17.1%)	11,830 (-9.7%)	11,210 (-16.3%)

A comparison of the annual total energy expenses between participating residential and commercial customers is shown in Figure 50. The commercial customer population exhibits a greater range in benefits and a more substantial portion of customers who see an increase in annual energy costs. These trends are likely due to two reasons. First, some commercial customers likely experience much higher savings due to the elimination of the demand charge. Second, there is likely more variation in the load profiles of the commercial building fleet, resulting in a larger variation in impact of customers switching to a dynamic rate structure that more closely reflects the cost of electricity sold. Even with these effects the average reduction in annual energy expenses is similar between commercial (

Table 9) and residential customers (Table 8).

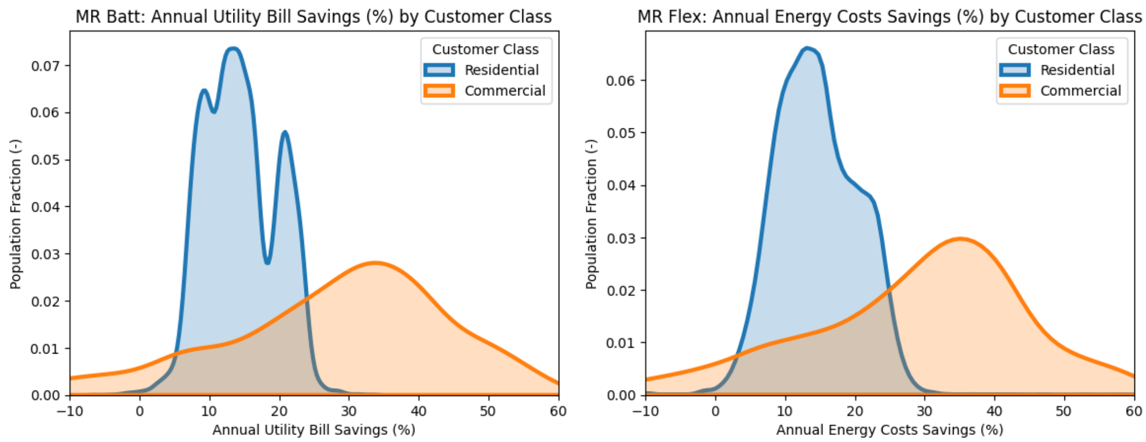


Figure 50. Comparison of annual energy expenses for participating residential and commercial customers for the MR battery (left) and MR flexible load cases (right).

Finally, the impact of slider setting (sensitivity to price changes) on annual utility bill savings is shown in Figure 51 for a single DSO. The slider setting is configured by customers based on the level of flexibility they would like to offer. A slider setting of zero corresponds to a preference for increased comfort and amenity while a slider setting of one corresponds to a preference for increased savings. While there is a slight increase in savings as slider setting is increased, it is lower than expected. This is likely due to two reasons. First, the rate design provides meaningful savings (10%) to non-participants who provide no flexibility. This may attenuate the range of savings that participating customers may experience. More importantly, for HVAC control this study assumed that a slider setting of zero enables 2 F of thermostat setback and a slider setting of one equates to a maximum setback of 5 F. HVAC flexibility may experience diminishing returns at higher slider settings with most of the available flexibility being achieved with a setback of only 2 F.

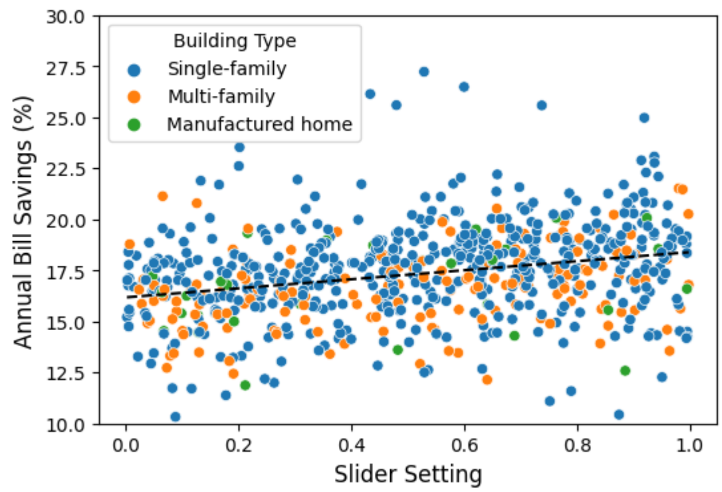


Figure 51. Annual bill savings as a function of slider setting for residential customers (MR Flex case, DSO #1).

6.3.3 Customer Savings by DSO, Building, and DER Type

The granularity of the simulation allows customer benefits to be investigated as a function of DSO, building, and DER types. Since the majority of the benefit is a function of the reduction in coincident load and wholesale energy purchases by each DSO only modest changes were seen as a function of these other factors. The impact of DSO type (rural, urban, and suburban) on residential customer energy expenses is shown in Figure 52. Greater savings are seen in the larger urban DSOs due, in part, to the DSO implementation costs not scaling linearly with number of customers (as discussed in Section 6.3.1). The urban distribution is also swayed by the one outlier DSO (#166) that experienced substantially higher wholesale energy expense savings and hence overall savings. If the distributions were weighted by regional customer population (not simulation population) its contribution would be substantially diminished. Suburban and rural DSOs show similar performance, with suburban DSOs showing slightly higher savings as they are typically larger and some have higher reductions in wholesale energy purchases.

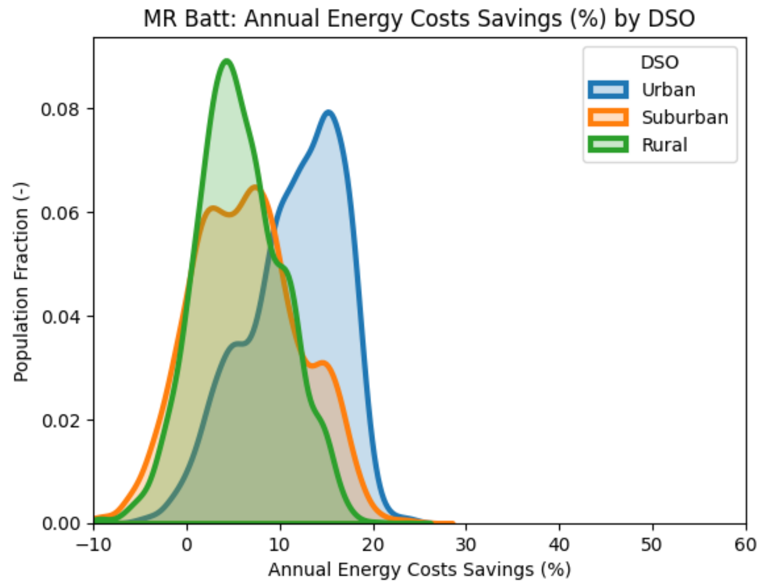


Figure 52. Residential customer annual energy expense savings as a function of DSO type (MR battery case).

The analysis shows similar relative savings between residential customers in single-, multifamily, or manufactured homes (Figure 53, left). Similar relative benefit was seen as a function of heating type (Figure 53, right). While we do see variations in energy consumption as a function of building and heating type (as discussed in Section 6.3.2) the relative electric bill savings is similar due to a large portion of the transactive bill remaining as a volumetric charge.

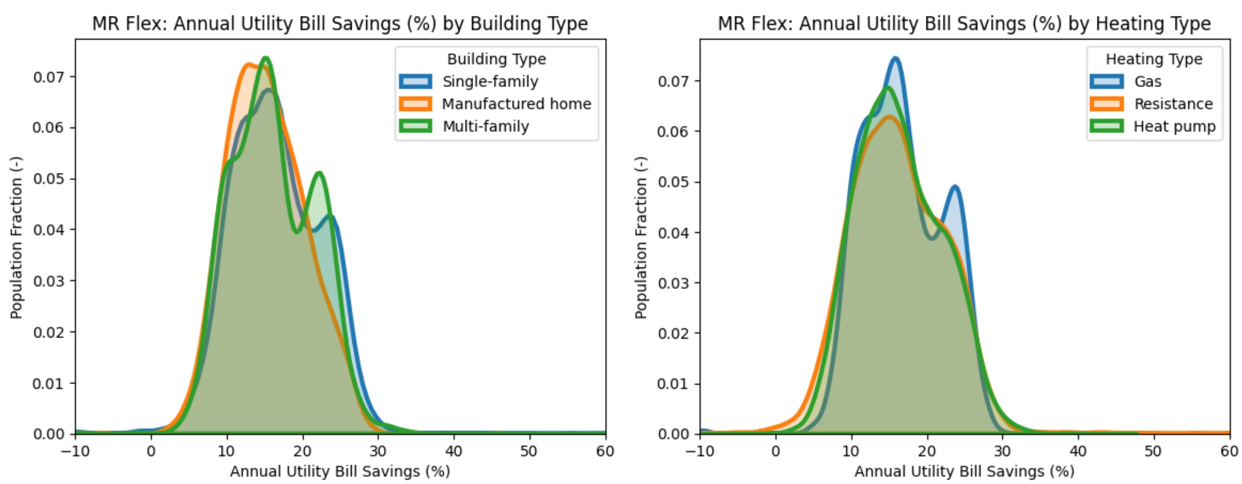


Figure 53. Residential participating customer bill savings as a function of building type (left) and heating type (right) for the MR flexible load case.

The high renewable scenario, which included the presence of EVs, allowed the performance of various combinations of flexible assets to be investigated. For the flexible load case there is similar performance for all the flexible asset combinations (Figure 54, right). This is due, in part, to HVAC, WH, and EV assets having lower implementation expenses associated with the marginal cost of provisioning smart connected controllers. Also, the customer population in the flexible load case is dominated by HVAC participation, as 90% of customers have HVAC in this summer peaking region. Only a very small portion of customers had participating EVs and no HVAC system. There were no customers with stand-alone participating water heaters, so the performance of these systems could not be investigated in isolation.

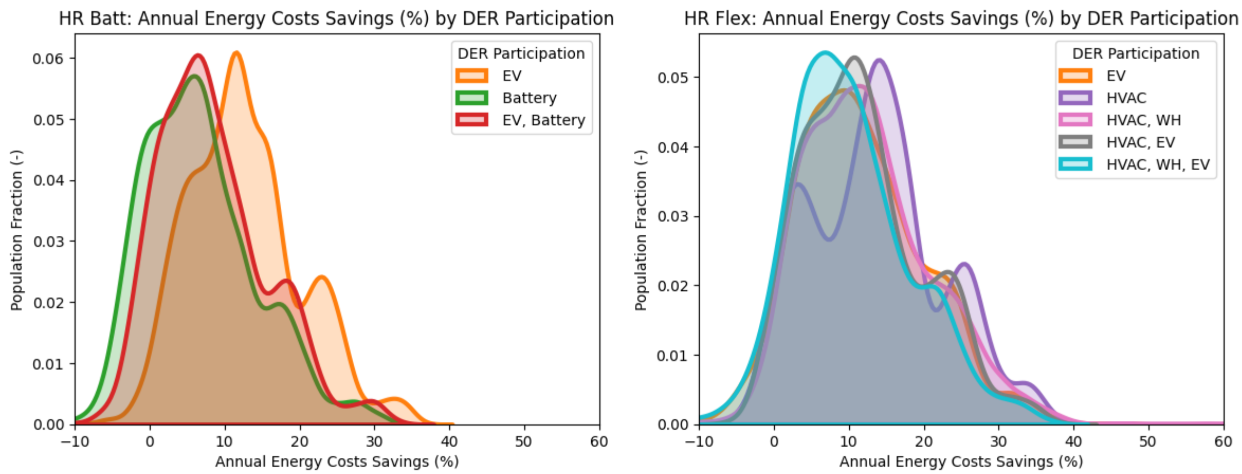


Figure 54. Annual energy expense savings of participating customers with different combinations of battery/EV (left) and flexible load/EV (right) flexible assets. HR scenario.

Unlike flexible loads and EVs, customers with batteries allocate the entire cost of ownership to their total annualized energy expenses (albeit, assuming aggressive reductions in battery cost). This results in customers with batteries alone experiencing lower (but still beneficial) average annual savings in total energy expenses (Figure 54, left). This reinforces the importance of low (marginal) implementation costs to reduce the barrier to entry and preserve annual utility bill savings once all energy expenses are accounted for.

Finally, the impact dynamic rates have on customers with rooftop solar is investigated. Figure 55 shows the relative utility bill and total energy expense savings for participating residential customers[1]. Solar rooftop customers still see substantial utility bill savings on a dynamic transactive rate versus the BAU fixed rate. This is because a large portion of the dynamic transactive rate still comprises of a volumetric charge that recovers delivery and DSO operation expenses. The dynamic real-time portion of the transactive rate is designed to only recover wholesale energy purchase costs, which make up approximately 30% of total cost of grid operation. Customers with rooftop solar have slightly lower savings than those without rooftop solar. This is because customers, who are still on net metering, now typically experience lower prices during the day when rooftop and utility-scale solar is in abundance, reducing the wholesale cost of electricity, and therefore reducing the avoided cost and overall benefit of self-generation versus the BAU case.

[1] Note that a small portion of simulated rooftop solar customers had utility bills that were negative or very close to zero over the course of the year. Near-zero annual utility bills can result in asymptotic values of relative percentage savings. For this reason, the percentage change in annual utility bills were clipped to ±100%.

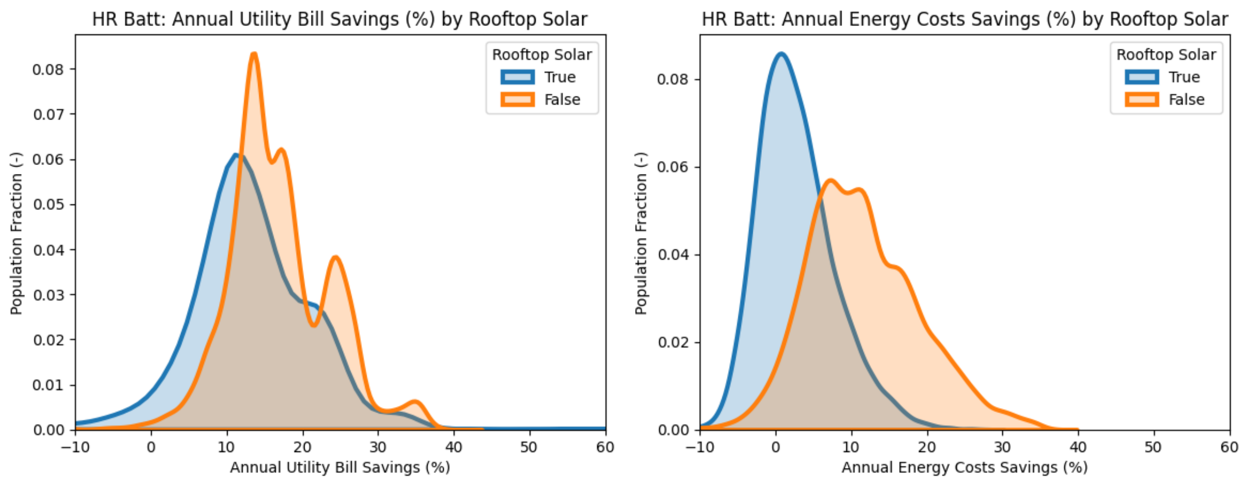


Figure 55. The difference in bill savings (left) and total energy expenses (right) for participating residential customers with and without rooftop solar. HR battery case.

The change in total annualized energy expenses for solar customers is shown on the right of Figure 55. They experience a larger decrease in savings when the expense of flexible assets (in this case batteries) is included. This is due to the simple reason that the average solar customer’s annual utility bill is lower than a non-solar customer’s bill. This results in the annualized expense of the flexible asset having a larger impact on the total annualized savings.

7.0 Conclusions and Future Directions

The results of this study offer credible evidence of the impacts of DSOs using transactive energy approaches to unlock the value of coordinating flexible assets with system operations. It developed a plausible DSO business framework and designed a compatible transactive network for flexible assets, established a corresponding simulation environment, valuation framework, and performance metrics, and conducted an analysis of the engineering performance and economic impacts of the DSO and transactive flexible assets from the perspectives of various stakeholders that is unprecedented in scope and scale. These artifacts will form foundational material for subsequent partnering with industry and other research institutions to further maturation and deployment of transactive approaches and supporting regulators in decisions on rate and incentive design.

7.1 Revisiting Study Objectives

This study laid out several key objectives (Section 1.2) related to understanding the engineering and economic performance of a DSO implementing a transactive energy retail market in comparison to BAU operation. The resulting integrated simulation and economic analysis of the transactive retail market design has enabled these objectives to be met and key questions to be answered. This section systematically revisits and discusses the study objectives in the context of the study results presented above.

A DSO+T implementation is cost effective for consumers

The DSO+T study found that customers on average save 12-19% in annual energy expenses under a transactive retail market. This includes the annualized cost borne by customers to upgrade assets to provide flexibility (for example purchasing smart connected controllers) or to install dedicated DERs such as batteries. While increased savings were seen under the high renewable scenario (due to the contributions of EVs) and for the deployment of flexible loads, appreciable benefits were seen for all cases. The level of savings seen by customers was most dependent on the change in cost basis of the DSO serving their region, and in particular the decrease in coincident peak load. For a region the size of Texas the nominal total net annual savings was \$3.3-5.0B. This equates to an equivalent national net savings of \$33-50B per year.

A DSO+T implementation maintains sufficient revenue recovery for DSOs, transmission owners, and ISOs

The DSO+T study developed and executed an economic analysis of the cost basis to operate the grid. This included a detailed cost model of DSO operation as well as the design and implementation of BAU and transactive retail rates that were applied to the customer base to recover the required revenue for operation. This analysis shows that DSOs can recover sufficient revenue to maintain operations. This revenue is sufficient to cover the estimated costs for implementing and operating a transactive retail market as well as the associated DER and AMI networks. DSOs do see a reduced cost basis from the deferral of substation upgrades. Likewise, the study assumes continued revenue recovery by the ISO and transmission operator to cover operating expenses. The transmission operator does see reduced annualized capital expenses related to the deferral of transmission growth requirements.

The majority of the DSOs' reduced revenue requirement comes from decreases in wholesale market purchases, particularly reductions in capacity payments. In aggregate the DSOs saw a reduction in annualized costs of $3.8-5.3B (12-19%).

A DSO+T implementation provides sufficient economic benefit and engineering performance for both MR and HR scenarios

The study analysis showed the effective engineering performance of the transactive retail market and the resulting coordination of tens of thousands of various flexible assets for both moderate and high renewable scenarios. The detailed simulation of the market operation identified the required market and agent design features required for stable and effective operation. This included interpolating day-ahead price signals when used as the basis for real-time correction strategies to avoid device synchronization. This study also identified requirements on the accurate aggregate of customer quantity bids by the retail market.

Simulation of the high renewable scenario illustrated the additional grid operational impacts of rooftop solar and EVs. The study assumed a third of homes had one EV. While this only resulted in a 3% increase in average annual grid load, the afternoon and evening charging of EVs coincides with the system peak load, increasing it 9%. In addition, the presence of rooftop and utility-scale solar results in much lower minimum net loads, particularly in the shoulder and winter seasons, when solar production does not align with peak space conditioning or EV charging loads. The net result is that the HR scenario experiences large daily variations in system load and wholesale price throughout the year, not just the summer months as seen in the MR scenario. These findings demonstrate that the need and benefit of transactive energy coordination schemes will only increase with the increasing deployment of renewable generation sources and load growth from the electrification of space heating and transportation.

A DSO+T implementation is equally applicable and beneficial to both the deployment of batteries and flexible loads

This study has demonstrated that a transactive retail market is effective for a range of flexible assets, both traditional flexible loads (such as water heaters and HVAC units) as well as stationary batteries and the managed charging of EV batteries. Economic benefits were seen from the battery and flexible load cases. Based on the assumptions used in this study the battery case provided slightly larger load reductions and therefore larger capacity payment reductions. The flexible load case offered superior reductions in wholesale energy purchases and lower customer implementation costs.

The annual simulation of both cases across the moderate and high renewable scenarios provides insights into the relative suitability and potential of various flexible assets to manage load. Flexible loads provided effective flexibility when grid constraints and price incentives aligned with their operation. This is the case during the system's peak load that occurs during the summer afternoon, which aligns with peak HVAC operation and EV charging. Flexible loads were found to be less effective when grid needs did not align with the assets' availability or operation. For example, HVAC heating and EV charging only provided minor increases in minimum winter load caused by the solar 'duck' curve. Batteries provided much greater flexibility and resulting reductions to daily system load variation during these times. This suggests the need for a mix of flexible assets: flexible loads that can alleviate their contributions to system peak loads and local delivery constraints; and batteries and other storage mechanisms that can address excess renewable generation that does not align with nominal loads, either due to mild temperatures not requiring space conditioning or EVs being in-use and away from charging stations. Ultimately this study does not recommend any specific mix of flexible assets or prescribe a renewable future scenario. The cases and scenarios defined in this report sought to show the performance and economic impact of a transactive implementation over a board range of flexible asset and renewable deployment scenarios.

A DSO+T implementation provides benefits that persist even with adverse future changes in market prices and implementation costs

The economic benefits of a DSO+T implementation were found to persist for a range of key assumptions. Of greatest importance is the fact that there is a still a net economic benefit of $1.7-2.9B/year even when assuming the low end of regional capacity prices for 2030. In fact, almost all cases have a positive economic benefit even if the capacity market (and associated benefits) is eliminated. The calculated wholesale energy market savings are assumed to be conservative given that the simulation underpredicts day-ahead and real-time LMP price excursions. It is also expected that wholesale market prices will continue to become more volatile than the 2016 data to which we compared as the continued deployment of renewable generation results in more numerous periods of negative market prices and extreme events (such as heat waves and winter storms) increase the likelihood of prices hitting market caps of $2,000-9,000/MW-hr. Such trends will increase the economic benefit and value proposition of demand flexibility and their associated enabling coordination schemes.

A sensitivity analysis also demonstrated that the overall benefits are insensitive to implementation costs. Even a doubling in DSO implementation cost only represents 2-6% of the total economic benefit seen by DSOs. The greatest uncertainty lies in the pace of cost reduction for stationary batteries. This study assumed an aggressive first cost for batteries ($83/kWh). It is assumed that the additional value propositions that batteries provide to customers and grid operators (resiliency, ancillary services, etc.) will bridge any shortfall in price reductions. The rapid deployment of batteries suggests this is the case. For example, Green Mountain Power has already deployed a fleet of behind-the-meter batteries equivalent to 2% of its peak load.

A DSO+T implementation provides benefits across a range of DSO types and customer classes

The integrated simulation and economic analysis methodology enables granular 'micro-economic' views of individual customer and DSO performance in conjunction with understanding the overall system-wide economic impact. This enables the impact of a DSO+T implementation to be understood as a function of DSO type, customer class, building and heating type, and mix of flexible assets. Ultimately the benefits seen by customers is a function of the overall cost savings seen by the DSO that serves them, which is in turn a function of peak load reduction. Beyond this trend, however, this study has shown that the average customer in practically every subclass sees a meaningful reduction in their annual electrical bill.

Larger (typically urban) DSOs do see slightly higher savings due to the relatively lower implementation costs on a per customer basis. Residential and commercial customers saw, on average, similar savings, however, commercial customers experienced a much wider range in savings, potentially due to eliminating the monthly demand charges as well as the diversity of load profiles. Similar relative savings were seen as a function of residential building type or heating fuel. Finally, somewhat higher benefits were seen for flexible loads versus batteries due to their greater wholesale energy purchase savings and lower implementation costs. The implementation of dynamic pricing did not disadvantage customers with rooftop solar who also saw reductions in annual utility bills. Their lower annual utility payments and subsequent absolute savings where more significantly impacted by the expense of flexible asset investment.

A DSO+T implementation is fair and equitable to participating and nonparticipating customers

An important feature of the transactive rate design and outcome of this study is the fact that nonparticipating customers share in the overall benefits. The customer rate structure assumes that nonparticipating customers remain on a fixed tariff and that this tariff is designed to recover revenue equivalent to the amount that would be collected if nonparticipating customers were on the dynamic transactive rate. This ensures that nonparticipating customers are charged under the reduced cost basis that the DSO experiences due to overall demand flexibility, thereby sharing in the savings. Nonparticipating residential customers see average annual utility bill savings of 10-14% (compared to 14-16% for participating customers). This ensures that customers who may not be able to install flexible assets (e.g., disadvantaged communities, renters, etc.) are not burdened by increased costs. An important feature of the rate design, confirmed in this analysis, is that nonparticipating customers typically save less on their utility bills than participating customers. This validates a key rate design principle, that participating customers should save more (on average) than nonparticipating customers to ensure the offering of flexibility is rewarded. Customers who provide more flexibility, for example through increased slider settings, should also see greater savings. The study found that customers who provide more flexibility see only slightly higher savings, however these may not be sufficient to incentivize the provisioning of greater flexibility and is an area warranting further investigation.

7.2 Lessons Learned and Future Research Directions

7.2.1 Co-simulation and Modeling

The large scale of the simulation, in terms of number of cases, full annual analysis, and large number of building and flexible asset models, combined with the fully integrated nature of the simulation challenged the robustness and computational efficiency of both the distribution and bulk system simulation tools. Debugging integration and performance issues within such a computationally heavy, integrated, and multidisciplinary environment is challenging and would benefit from improved diagnostic tools. Simulating the integrated market operation for the high renewable scenario was particularly challenging and we expect that modeling annual performance of more aggressive decarbonization scenarios (at relevant grid dynamics and market time scales) will be even more difficult. Despite these challenges, the study identified and implemented many robustness, computational efficiency, integration, and accuracy improvements through the course of executing the simulation. In addition, the comparison of key system-level and customer results with real-world data has shown that the resulting model captures overall trends and average values well.

There are three areas that warrant improvement. First, while the overall simulated load shapes captured aggregate daily and seasonal demand trends well, the daily change in load was consistently over predicted. Better capturing these daily changes in load is important to capture the absolute rate of change of system load and resulting ramping requirements on the providers of flexibility, whether they be the generation fleet or distributed assets. Efforts by the United States Department of Energy (DOE 2019) on updating and improving the understanding of commercial and residential building load profiles could aid in this. Better representations of industrial customers and their load profiles are also needed.

Second, the wholesale market model captured overall price trends but did not capture price excursions. This resulted in a substantial underprediction in the average daily price range, likely resulting in a conservative estimate of the wholesale energy market benefits of demand flexibility. Given that wholesale energy savings was the key differentiator of individual DSO benefits improved representation of wholesale price volatility, and the specific market features and transmission constraints that drive them is needed. Related to this is the need to better understand and model bilateral energy purchases. Given their nature there is a lack of data and analysis of bilateral energy contracts. A better understanding of the factors causing wholesale price volatility, and which (if any) can be captured in an improved market model, is also important to not only to better estimate the overall value of transactive energy approaches, but more importantly to evaluate the performance of distributed assets coordinated using signals based on these wholesale market prices. Improved market price modeling will become more important as the continued deployment of renewables increases periods of negative prices, and more frequent extreme events result in prices hitting market caps.

Finally, this study includes flexible assets that currently have lower levels of deployment (such as EVs and batteries). As more data is collected on their real-world operation improvements in how they are modeled may be required. For example, a limitation of the current modeling platform requires that EVs only charge and discharge at a single location (in this study at a residence). If data suggests a substantial fraction of EVs charge in multiple locations (fully realizing the EV ability to move demand in space and time) updates to the modeling platform will be warranted. There are also many other end-use loads (e.g., appliances, commercial refrigeration, lighting, pumping and irrigation) that were not included in this study that offer flexibility potential.

7.2.2 Transactive Coordination and Market Design

The high fidelity of the study's simulation enabled a thorough verification of the performance of the transactive marketplace and its interactions with tens of thousands of price-responsive flexible assets. This environment demonstrated several key elements contributing to the transactive agent development and demonstration effort, such as the need for the coordination and bidding scheme to ensure both individual asset and overall population operations were stable. This was achieved via the convergence obtained through the iterative 48-hour rolling window market projection.

Additional design features also contributed to system stability including use of quadratic price-response terms and deadbands in the development of asset price-quantity curves. Another key contribution was the development of asset strategies that ensured day-ahead and real-time bids that accurately represent resulting price-responsive demand even with the uncertainty inherit in weather and real-time price forecasts.

The simulations showed that care is required to ensure customer bids are aggregated in full fidelity for proper market clearing. In addition, the implementation of day-ahead prices and the resulting operational strategies of flexible assets need a smooth transition when moving to real-time operation to avoid discontinuities that can result in unintended synchronization of the asset population. An example of this issue is shown in Figure 56.

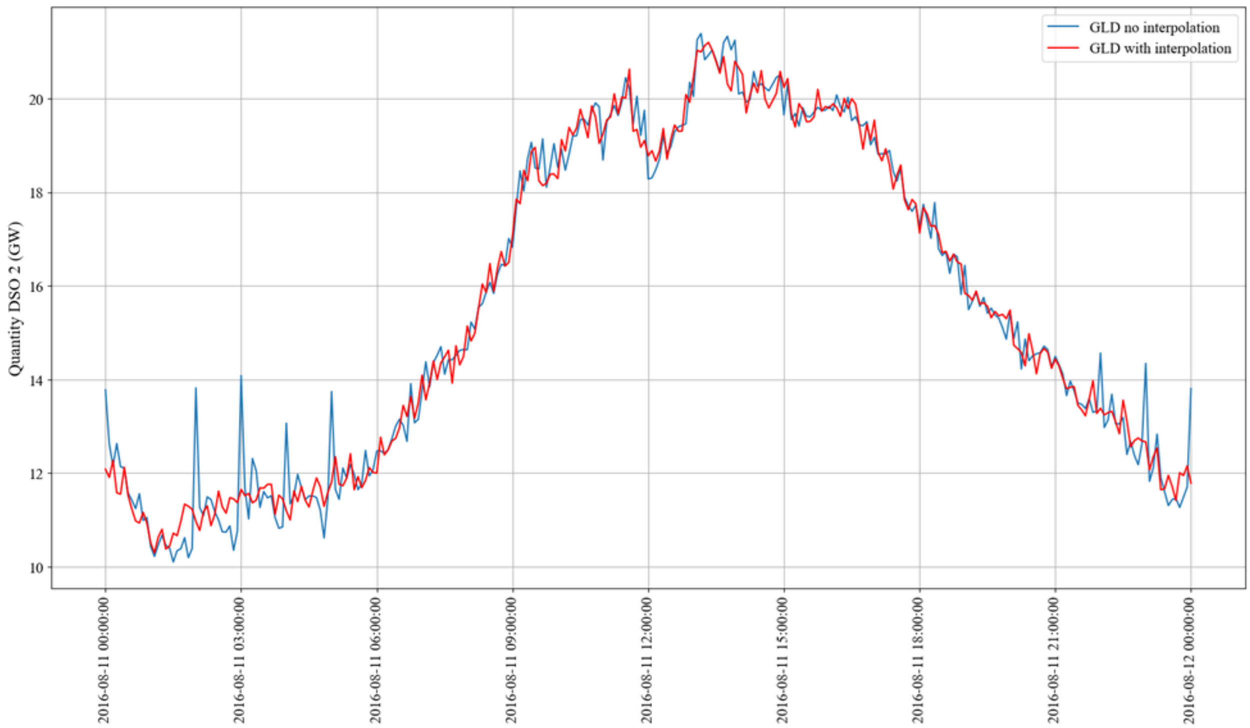


Figure 56. Simulated daily load profile for DSO 2 with and without smoothing of the operating hour result from the day-ahead market when transitioning to real-time bidding.

This study focused on integrating into an existing competitive wholesale day-ahead and real-time markets. While the wholesale-retail market interaction was designed to accept DSO price-quantity flexibility bids (the demand counterpart to generator supply bids), the complexity of tuning the wholesale market simulation to run stably over all time periods and seasons of the year was a challenge. More robust wholesale market simulation software with better error processing is needed. Eventually, the study was able to tune the BAU case to run smoothly; but to manage further project risk in the MR and HR transactive cases, the DSOs' price sensitive bids in the real-time market were modeled as fixed load forecasts. The downside is that the full impact of flexibility to wholesale real-time price fluctuations is not captured in each wholesale real-time market clearing. Nevertheless, the DSOs' asset flexibility is substantially captured as each retail real-time market cycle reacts to the wholesale market price every 5 minutes. This is then used by the DSOs in forming their demand bids for the next wholesale real-time market cycle. An open question for future analysis is the market efficiency impact that fully represented DSO price-quantity bids can have on the wholesale real-time market.

Beyond the assumptions used in the study, better understanding of how various regional wholesale markets incorporate representations of DSO price responsiveness now and in the future will be important for wholesale market integration. To effectively coordinate customer flexibility, the study designed an hourly retail market with projections of each of the next 48 hours. This was done for the DSO to bid into the wholesale day-ahead market. A more straightforward wholesale-retail integration could occur if the wholesale market ran an hourly (rather than daily) market with projections of each of the next 24 hours. Such a change to wholesale market design has been proposed for some time and many forward markets have intraday features to enhance operational efficiency. The nature and amount of value so obtained for wholesale-retail interaction is an area of future research needs.

There is also a need to investigate how DSOs and their customers can best manage risk in their participation in the retail and wholesale markets. Effective risk management, inherent in agent design and the retail tariff structure will be a key requirement for market efficiency and the acceptance of dynamic-price based coordination approaches.

Also, while this study demonstrated the stable and successful operation of a transactive market with representative levels of forecast uncertainty. It was not within our scope to determine the required forecast accuracy for the system to operate in a stable manner nor how much performance would improve with superior forecasts.

Ultimately the transition to a decarbonized grid whose economic operation is not dominated by marginal fuel cost will likely require a new wholesale market operating scheme. The requirements, necessity, and nature of this future market design are not well defined. As research and definition of a future zero-carbon grid wholesale market matures, implications on how it will integrate with a transactive retail market and coordination of distributed flexible assets will be important to understand. For example, the implementation intraday, hourly market cycles may improve flexible asset response and value to increasing levels of variability from bulk power generation and electrified loads.

7.2.3 Economic Valuation

The valuation framework successfully applied rigorous value mapping and analysis to determine system- and stakeholder-level impacts. This has ensured that all economic impacts can be viewed in the context of the overall financial structure of grid operation. The valuation framework and supporting financial models will allow other researchers, practitioners, and decision-makers to conduct their own region-specific analysis. This level of transparency is important as the economic impacts are a function of existing infrastructure, growth rates, market conditions, and delivery constraints. These factors vary across regional markets and key characteristics, such as future growth rates, are highly uncertain. This will make region-specific scenario design (and associated sensitive and uncertainty analysis) of critical importance. In addition, the deployment of customer asset flexibility coordination schemes will provide more accurate data on the cost to implement such schemes.

Given the large impact that the reduction of generation capacity has on the overall value proposition this is an area that needs further investigation. Understanding both the societal and market-based value of requiring less generation capacity is needed for both current operation as well as in the context of the need to decarbonize the electric grid and electrify the building and transportation sectors. Having standardized capacity value and price models that are applicable for large levels of flexibility in system demand-side assets are necessary to understand the value of coordination schemes in future scenarios. In addition, the reduced load variation and price volatility demand flexibility will impact generators' economic performance and, potentially, the need for a capacity market to ensure sufficient revenue. Investigating this was outside the scope of this study and is an area of interest.

Finally, this study assumed that DSOs and their transactive market operated in a mature, quasi-steady environment. Given the need to rapidly decarbonize the electric gird, demand flexibility offers the potential to accelerate the pace of transition by reducing and delaying distribution and transmission systems upgrades necessary to support renewable generation and load growth. Understanding the role and value of demand flexibility to aid the pace of transition requires a better understanding the interplay between planning, deployment, and operational strategies in a transitory environment.

7.2.4 Rate Design and Analysis

Ultimately, the purpose of the electrical grid (and any future improvements to its operation) is to provide affordable, reliable, and sustainable electricity to its customers. This study has demonstrated a rate structure and design that when applied to the large-scale deployment of flexible assets reduces costs for both participating and nonparticipating customers. While considerable effort was spent on defining diverse and representative customer building populations additional refinement and validation is warranted. First, the simulated customer population does not contain metadata representing socioeconomic attributes. While some building attributes (such as multifamily and manufactured home building types) can be used as proxies, integrating socioeconomic statistics would allow the benefits for energy burdened customers to be better understood. In addition, such data would support capturing the covariance of flexible asset ownership and potentially allow more accurate usage profiles (such as thermostat setting). In addition, more granular end-use load profile data will allow improvement and validation of customer load profile distributions.

Finally, improvements and refinements are expected to be made in the rate structure design. There are opportunities to improve the recovery the wholesale capacity payment based on load profiles rather than through a volumetric charge. There is also a need to investigate incorporating risk management features into the rate design to prevent customers experiencing extreme prices that will not incentivize additional demand flexibility but may reduce acceptance by customers and regulators. The journey to a future dynamic-price rate design will likely be incremental. Hence, understand the performance of transactive coordination approaches and customer population benefits when using time-of-use based approaches would also be of value.

7.3 Summary

The DSO+T study developed and exercised an integrated system and valuation model to a assess the coordination of flexible assets at a scale and fidelity not achieved before. The integrated system model ensured that the dynamic interplay between flexible asset performance, customer preferences, market prices, and system constraints was captured. The resulting model captured daily and seasonal system loads and market prices well, even without systematic calibration of model parameters. In addition, simulating significant numbers of DSOs and customers enabled the performance of stakeholders to be investigated by various attributes. The accompanying valuation analysis ensured that in addition to reporting aggregate net benefits, the economic impact for various classes and sub-classes could be determined.

The study results show a decrease of 9-15% in peak regional loads and a net regional benefit of $3.3-5.0B/year. These benefits were shared across all types of DSOs and customers regardless of DSO setting (rural, suburban, or urban), customer class (residential or commercial), participation level, or flexible asset type. For example, in the MR scenario, the average participating residential customer saw reductions in their annual utility bill of 14-16%. Average nonparticipating residential customers saw annual utility bill savings of 10%.

To manage study scope and complexity we implemented a single transactive coordination system and retail market design that was assumed to be run by a DSO. This is not intended to be prescriptive as we would expect comparable benefits from a range of advanced flexible asset coordination schemes that achieve equivalent performance levels. Such schemes may be managed by a DSO or by a third-party aggregator. The intent of this study was to show the feasible engineering performance of transactive schemes, the resulting beneficial system impacts, and compelling economic outcomes at a scale and fidelity that catalyzes further development, investment, deployment, and regulatory support of advanced methods to coordinate flexible assets. This is increasingly important, given the beneficial role demand and DER flexibility can play in accelerating the ongoing energy transition.

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Appendix A – Example DSO Cashflow Results

Table 10 illustrates the granularity of a DSO CFS and shows how they are used as the basis of analyzing the financial impacts deployment of a transactive system and flexible assets on a DSO. The leftmost column portrays the hierarchical structure of the CFS, with up to four levels of line items at its finest granularity rolling up to various subtotals. The next column contains the expenses and revenues for DSO No. 1 of the 200-bus model for the MR BAU case. The next column contains the results for the corresponding transactive battery case. The difference between them is shown in absolute and percentage terms in the rightmost two columns.

Table 10. DSO CFS comparing BAU and battery cases for the MR scenario (for DSO #1 of the 8-bus DSO+T testbench)

Organizational Level	BAU Case	Transactive-Batteries Case		
Category / Sub-Category / Element / Sub-Element	Annual Cash Flow ($K/yr)	Annual Cash Flow ($K/yr)	Difference ($K/yr)	Difference (%)
Capital Expenses[a]	**$366,807**	**$361,137**	**($5,670)**	**-1.55%**
Distribution Plant	**$339,018**	**$327,675**	**($11,343)**	**-3.35%**
Substations	$134,823	$123,480	($11,343)	-8.41%
Feeders	$175,953	$175,953	$0	0.00%
Meters	$28,242	$28,242	$0	0.00%
IT Systems	**$27,789**	**$33,462**	**$5,673**	**20.41%**
Retail Market Software & Hardware	$0	$302	$302	100.00%
Retail market hardware	$0	$281	$281	100.00%
Retail market software	$0	$22	$22	100.00%
AMI/DER Network	$21,704	$27,129	$5,426	25.00%
AMI network	$21,704	$21,704	$0	0.00%
DER network(s)	$0	$5,426	$5,426	100.00%
Day Ahead Network	$4,522	$4,522	$0	0.00%
Distribution Mgmt. System Software	$361	$330	($31)	-8.54%
Outage Mgmt. System Software	$324	$312	($12)	-3.80%
Customer Info. System Software	$725	$725	$0	0.00%
Billing Software	$155	$142	($12)	-7.98%
Operating Expenses	**$3,577,544**	**$3,077,534**	**($500,010)**	**-14.%**
Peak Capacity Charges	**$758,611**	**$312,533**	**($446,078)**	**-58.80%**
Transmission Access Fees	**$481,007**	**$462,733**	**($18,274)**	**-3.80%**
Wholesale Energy Purchases	**$1,154,239**	**$1,086,045**	**($68,194)**	**-5.91%**
Day Ahead Energy Costs	$580,810	$376,189	($204,621)	-35.23%
Real Time Energy Costs	($44,661)	($69,549)	($24,889)	55.73%
Bilateral Energy Costs	$618,090	$779,406	$161,316	26.10%
Other Wholesale Costs	**$106,062**	**$103,049**	**($3,013)**	**-2.84%**
ISO Reserves	$84,499	$81,485	($3,013)	-3.57%
ISO Losses	$0	$0	$0	100.00%
ISO Fees	$21,564	$21,564	$0	0.00%
O&M Materials	**$718,009**	**$718,969**	**$960**	**0.13%**
O&M Labor	**$159,841**	**$159,841**	**$0**	**0.00%**
Linemen Labor	$136,698	$136,698	$0	0.00%
Operator Labor	$4,577	$4,577	$0	0.00%

Organizational Level	BAU Case	Transactive-Batteries Case		
Category / Sub-Category / Element / Sub-Element	Annual Cash Flow ($K/yr)	Annual Cash Flow ($K/yr)	Difference ($K/yr)	Difference (%)
Planning Labor	$5,165	$5,165	$0	0.00%
Metering Labor	$13,401	$13,401	$0	0.00%
Market Operations	**$0**	**$2,860**	**$2,860**	**100.00%**
AMI/Customer Network Operations	**$8,916**	**$13,315**	**$4,399**	**49.33%**
AMI Ops Labor	$8,916	$10,547	$1,630	18.29%
Network labor (AMI)	$5,923	$7,404	$1,481	25.00%
Cybersecurity labor (AMI)	$2,993	$3,143	$150	5.00%
Customer Network Ops Labor	$0	$2,768	$2,768	100.00%
Network labor (customer)	$0	$1,801	$1,801	100.00%
Cybersecurity labor (customer)	$0	$967	$967	100.00%
DMS Operations	**$6,129**	**$6,129**	**$0**	**0.00%**
Network labor (DMS)	$4,194	$4,194	$0	0.00%
Cybersecurity labor (DMS)	$1,935	$1,935	$0	0.00%
Retail Operations	**$115,512**	**$138,503**	**$22,991**	**19.90%**
Customer Service Labor	$106,347	$106,347	$0	0.00%
DER Recruitment & Retention Labor	$0	$20,700	$20,700	100.00%
Billing Labor	$9,165	$11,456	$2,291	25.00%
Administration	**$39,257**	**$39,359**	**$102**	**0.26%**
Workspace	**$29,961**	**$34,197**	**$4,237**	**14.14%**
Revenues	**$3,944,351**	**$3,438,618**	**($505,733)**	**-12.8%**
Retail Sales	**$3,944,351**	**$3,438,618**	**($505,733)**	**-12.82%**
Fixed-Price Sales	$3,944,351	$2,098,496	($1,845,855)	-46.80%
Fixed-price energy charges	$3,175,138	$1,632,707	($1,542,431)	-48.58%
Demand charges (C & I)	$584,026	$358,135	($225,891)	-38.68%
Connect charges (fixed-price)	$185,187	$107,654	($77,533)	-41.87%
Transactive Rate Sales	$0	$1,340,121	$1,340,121	100.00%
Day-ahead energy charges	$0	$494,352	$494,352	100.00%
Real-time energy charges	$0	($93,847)	($93,847)	100.00%
Distribution charges	$0	$862,083	$862,083	100.00%
Connect charges (transact. rate)	$0	$77,533	$77,533	100.00%
Balance	**$0**	**$0**	-	-

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