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DSO+T: Valuation Methodology and Economic Metrics

DSO+T Study: Volume 4

January 2022

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U.S. DEPARTMENT OF ENERGY

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Abstract

This report summarizes a rigorous valuation analysis methodology used by the Distribution System Operator with Transactive (DSO+T) study to estimate the financial benefits and costs of adopting transactive energy coordination of distributed energy resources for key stakeholders (for example distribution system operators and customers). This was achieved by modeling the value exchanges between stakeholders and determining the annualized costs and revenues experienced by stakeholders, enabling the evaluation of overall impact on stakeholder's annualized cash flow. Extensive work was conducted developing methods to estimate the operating costs of distribution system operators at a level of granularity that would allow the financial impact of implementing a transactive energy approach to be estimated. This work included developing parametric models for labor and software costs, distribution system capital and maintenance costs, growth rates, and factors to determine annualized costs of capital investments. Simulation results were used to calculate wholesale energy costs and revenues from retail sales. Valuation analysis methods were also developed for other stakeholders including customers, the transmission system operator, independent system operator, and generators. The resulting capability allows a complete mapping of the flow of financial value between stakeholders that can be directly integrated with the results of demand flexibility simulations. Example results are provided for a business-as-usual case and compared to a transactive energy case as well as to actual cost data.

Summary

The purpose of the Distribution System Operator with Transactive (DSO+T) study is to simulate and analyze how a DSO can engage flexible distributed energy resources (flexible assets) by utilizing a coordination strategy based on transactive energy mechanisms. It seeks to compare two transactive cases (one with flexible loads, the other with batteries) against a business-as-usual (BAU) case. These three cases are analyzed over two renewable energy scenarios, the first with moderate levels (< 20%) of annual renewable generation and the second with high levels of renewable generation (~40%). To successfully understand the impact of this demand flexibility on the financial performance of stakeholders, a valuation analysis was developed based on the Pacific Northwest National Laboratory Transactive Systems Program valuation methodology which uses a value activity model. This valuation analysis determined the annualized cash flow of grid operation participants (customers, DSOs, transmission system operators, generators, and independent system operators [ISOs]) at a level of granularity sufficient to understand the financial benefits and costs incurred by each party. This report details the resulting value activity models and integrated analysis and provides illustrative results. It is one of five reports documenting the DSO+T study.

The primary focus of this portion of the study is modeling the annualized cash flow of a DSO for both BAU and transactive energy implementations. Revenues are determined by applying applicable retail rate structures to customers modeled in a large-scale simulation. This necessitated the development of a transactive rate design that incorporated dynamic day-ahead and real-time pricing. To determine DSO costs, simulation results are also used to calculate wholesale energy purchases (including bilateral, day-ahead, and real-time purchases) as well as capacity, ancillary services, transmission access, and ISO payments. Parametric models were developed to estimate the capital costs of investments including substations, feeders, meters, and information technology systems. The impact of both greenfield and brownfield growth rates on capital costs was included through the development of a dedicated growth rate model. In addition, an annualized capital cost factor was developed for all stakeholders to represent a common annualized basis. Fixed operating costs were estimated for labor, workspace, and operations and maintenance materials. The labor expenses where based on a dedicated parametric employee count and organizational structure model that estimated the total number of DSO employees by job category (e.g., accounting, retail operations, engineering). This was combined with U.S. Bureau of Labor Statistics data for hourly wages to determine total labor costs. Finally, the effect of DSO attributes (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.

The resulting calculated systemwide effective cost of energy sold was within 10% of national averages. In addition, the relative proportions of expenditure on energy purchases, capacity costs, transmission charges, and other wholesale costs such as ancillary services and reserves were similar to those cited by PJM. This confirms that the developed model is very representative of typical distribution system operating expenses. An example comparison is also provided between the BAU results and a transactive case. This illustrates the ability of these models to estimate savings (for example, in wholesale energy purchases, capacity payments, transmission access fees, distribution capital costs) and increased expenditures (in communication network expenses and retail operations) associated with a demand flexibility scheme such as transactive energy.

Cash flow models and analysis methodologies were also developed for customers, generators, the independent system operator, and transmission operator. Customer cash flows included both retail utility charges and annualized costs for applicable distributed energy resources (e.g., smart thermostats and water heaters, batteries, and electric vehicle chargers). The generation fleet is made up of nuclear, coal, natural gas, wind, and solar fueled generators. Simulation results were used to determine variable operating costs (primarily fuel cost, but also variable repairs and maintenance costs) as well as startup costs. To this were added the annualized cost of capital investment and estimates for fixed operating costs. The transmission operator's revenues are based on a fixed 'postage stamp' representative of typical values. A detailed transmission capital cost model was used that captured substation, transmission line, right of way, and planning costs. The remainder of the transmission cost structure is assumed for fixed operating costs. Finally, ISO costs are based on a fixed ISO fee.

The end result is a rigorous parametric modeling framework that can track value flows throughout the entire electrical delivery system. It has a level of granularity that allows analysts to understand the sources of value arising from implementing demand flexibility solutions as well as sources for increased expenditure. Many studies produce results of either total system economic feasibility or the economic impact of a particular isolated portion of the system; the valuation analysis described in this report accomplishes both. These results can be assessed both at the entire system level and broken down by stakeholder to understand the benefits to various parties within the electricity delivery system. Stakeholders can take these results and isolate the economic outcomes applicable to their interests. This dynamic nature of the valuation analysis greatly increases the applicability of the study results. Comparisons to available public data demonstrate that the model is representative of typical North American grid operation cost structures.

Acknowledgments

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Acronyms and Abbreviations

ACCF	annualized capital cost factor
AMI	Advanced Metering Infrastructure
BAU	business as usual
BLS	U.S. Bureau of Labor Statistics
CAISO	California Independent System Operator
CEO	chief executive officer
CFO	chief financial officer
CFS	cash flow statement
CHR	chief human resources
CIO	chief information officer
CLO	chief legal officer
COO	chief operations officer
CPUC	California Public Utilities Commission
CRO	chief of retail operations
DER	distributed energy resource
DMS	device management system
DOE	Department of Energy
DSO	distribution system operator
DSO+T	Distribution System Operation with Transactive
EIA	Energy Information Administration
ERCOT	Electricity Reliability Council of Texas
EV	electric vehicle
EVSE	electric vehicle supply equipment
FTE	full-time equivalent
HR	high renewable
HVAC	heating, ventilation, and air conditioning
IRP	integrated resource plan
ISO	independent system operator
IT	information technology
LMP	locational marginal price
LSE	load-serving entity
MR	moderate renewables
NREL	National Renewable Energy Laboratory
O&M	operations and maintenance
WACC	weighted-average cost of capital

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1.0 Introduction

1.1 Overview of the DSO+T Study

The Distribution System Operation with Transactive (DSO+T) study simulates and analyzes how a DSO can engage flexible customer assets in operation of the electric power system by utilizing a coordination strategy based on transactive energy mechanisms (Hammerstrom et al. 2008). This study is designed to:

- Create a design of a DSO transactive network capable of coordinating distributed energy resources (DERs) 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 2018; Mukherjee 2020) frameworks developed previously for the U.S. Department of Energy's (DOE's) Transactive Systems Program.
- Issue the simulation and valuation framework to industry as an open challenge to the transactive energy community to develop and improve their designs in preparation for field experiments.

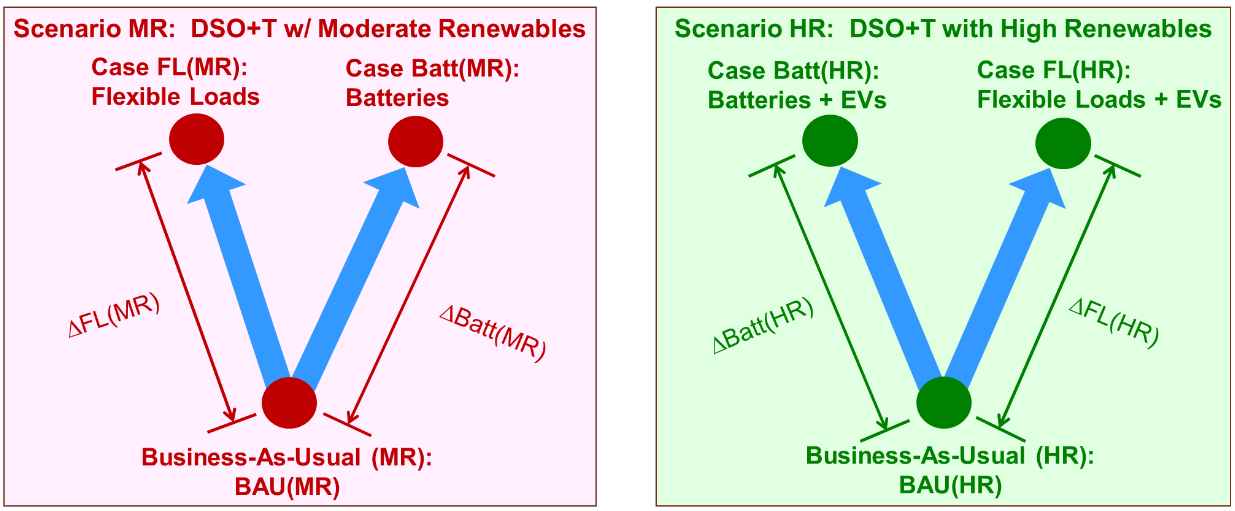
The DSO+T study involves comparing the engineering and economic performance of business-as-usual (BAU) cases representing today's distribution utilities with fixed-price rates for all customer classes and no active participation of price-responsive flexible assets with that of transactive cases in which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

The primary results of the DSO+T study are summarized in Volume 1: Main Report (Reeve et al. 2022a), with considerable additional detail on the results of the analysis provided in Volume 5: Study Results (Reeve 2022c). The instantiation of a large multiscale annual time-series co-simulation that is the foundation of the analysis, representing the Electricity Reliability Council of Texas (ERCOT) generation fleet, transmission system, a generic independent system operator (ISO), and a DSO's infrastructure, customer characteristics, and controllable and uncontrollable loads and DERs representative of ERCOT, are summarized in Volume 2: Scenario and System Definition Report (Reeve et al. 2022b). The design of the transactive rates, retail markets, and DER control agents, and the presumed regulatory policies associated with the design, are described in Volume 3: Markets and Transactive Agents (Widergren et al. 2022). This report is Volume 4.

This document describes the process used for the valuation analysis of DSO+T (which complements the simulation analysis) in which the *value* of adopting the DSO+T strategy is estimated for the primary stakeholders (customers and DSOs) by comparing the change in various metrics between any two cases of the study. The remainder of this section discusses the scenarios to be evaluated as well as an overview of the stakeholders, metrics, and value flows that will serve as the basis of the analysis. This is followed by a review of prior relevant efforts and a summary of the remainder of the report structure.

1.2 Analysis Scenarios

Figure 1 illustrates the DSO+T study's analysis framework and resulting two scenarios and six analysis cases. Two levels of renewable generation are examined: a moderate renewables (MR) scenario representing penetration at levels approximating those seen in parts of the Western United States in 2016 and a second high renewables (HR) scenario with considerably more renewable generation at the bulk system level and significant penetration of customer-owned solar photovoltaic (PV) at the distribution level. The HR scenario also includes significant penetration of EVs with smart charging systems.



Primary Results:	
	ΔFL(MR) = Value of DSO + Transactive + Flexible Loads (Moderate Renewables)
	ΔBatt(MR) = Value of DSO + Transactive + Batteries (Moderate Renewables)
	ΔFL(HR) = Value of DSO + Transactive + Flexible Loads + EVs (High Renewables)
	ΔBatt(HR) = Value of DSO + Transactive + Batteries + EVs (High Renewables)

Figure 1. DSO+T study structure and basis of primary results.

For each scenario a BAU case served as the datum for comparisons to transactive cases. Note that the study simulated the system under 2016 conditions and where possible data were used from this year for comparisons. The BAU cases in the study are pertinent to today's distribution utilities; the study presumes that in the future distribution utilities have become DSOs (Kristov and De Martini 2014)—entities that are responsible for the 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 study examined 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 the planning, operations, and retail functions 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 utilization 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.

Note that this report does not continue to distinguish between traditional distribution utilities in the BAU case and DSOs in a transactive case. That is, the term "DSO" is used here to refer to either a traditional distribution utility (in the BAU cases) or a distribution utility that has evolved to become a DSO (in the transactive cases).

In addition to the BAU case, the study examined two types of transactive flexible asset deployments for each scenario. The first is based on a very high participation rate of flexible customer loads. The other is based on a presumption that customer participation with flexible loads is not ultimately significant and instead that batteries become the flexibility asset of choice. Both deployments leverage the capabilities of advanced inverters that control the injection or consumption of reactive power to assist with managing voltage on the distribution system. The intent is to show that transactive energy exchange mechanisms are relevant and provide value regardless of what types of flexible assets predominate in the future.

Engaged by the DSO's transactive exchange mechanisms, transactive cases deploying flexible loads and batteries were compared against a BAU case without flexible customer assets. This primary focus of the study is to quantitatively estimate the relative performance and value of the DSO and its transactive coordination of the flexible assets, as the need for flexibility increases from renewables generation deployment scenarios from moderate to high levels. The Transactive Systems Program's previously developed a valuation framework to identify the value streams and relevant metrics (e.g., reliability and resiliency) through simulation or other analysis techniques. The results were extrapolated to estimate the benefits of a national deployment.

The study makes a fundamental assumption that the adoption and deployment of the DSO+T strategy has reached steady state. The initial period of rapid penetration of responsive assets has concluded and DSOs confidently take them into account when constructing new substations or upgrades. Further, they have learned that they need to monitor peak demand closely (on at least an annual basis) to assess whether relying on response from flexible assets continues to be more cost-effective for the general ratepayer than the traditional infrastructure upgrade being deferred. This is because the incentives provided to local consumers for the response of their flexible assets, in the form of reduced energy bills (and, hence, DSO revenues), gradually increase as more and more response is required over the years. Eventually, the annual incentives those customers receive exceed the annualized cost of the upgrade, which then becomes the prudent option.

1.3 Valuation Overview

The DSO+T study valuation addresses several unique challenges presented by the use of customer assets to provide flexibility and reduced costs for grid operations. Value from the grid's perspective is associated with 1) reduced costs to produce electricity and for the infrastructure that generates and transports it to consumers, and 2) the imperative to spend what it takes to provide power with the very high level of reliability demanded by society (via utility regulators). However, customers view it as (almost) a right to consume electricity when and where they see fit, albeit one for which they historically have paid simple volume-based charges to exercise that have little tangible relationship to grid costs. Unlike gasoline prices, for example, they have no appreciation or exposure to the fact that the true cost of power varies strongly by time and location. Transactive approaches attempt to bridge the gap between value from the grid and consumers perspective in a way that is tangible, motivational, and equitable to consumers of various sorts—whether they are served by infrastructure that is constrained or not, whether and to what degree they choose to participate or not, and what limits to participation they may have based on the type and size of the buildings they occupy or their end uses that are powered by electricity. The need to understand these impacts necessarily drives valuation into the territory of microeconomics in order to provide credible insights into how effective such an approach is for <u>all</u> stakeholders, not just consumers.

This document describes the process used for the valuation analysis of DSO+T in which the *value* of adopting the DSO+T strategy is estimated for all the *primary stakeholders* by comparing the change in various metrics between any two cases of the study. These metrics are primarily, but not limited to, the change in annual costs reflecting value exchanges among the primary stakeholders and between them and *external stakeholders*. Within the valuation context both the primary and external stakeholders are commonly referred to as *actors*. In the DSO+T study the primary stakeholders whose physical assets and/or economic cash flows are modeled explicitly are:

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

External stakeholders 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; employees of grid entities; and federal, state, and local governments (in the form of collecting taxes).

The metrics are computed based on the simulation results for each case, and a set of (primarily economic) procedures and assumptions about the values exchanged and for quantifying the associated cash flows. This requires 1) formal definition of the stakeholders involved and value exchanges among them that are to be analyzed and 2) development and documentation of the procedures and assumptions used to calculate the value exchanges and other metrics. Many of these are portrayed in Figure 2, mapped to the primary stakeholders of the DSO+T analysis (not shown are the ISO or unbundled DSO entities). Documenting value flows and metrics and their provenance is the primary objective of this report.

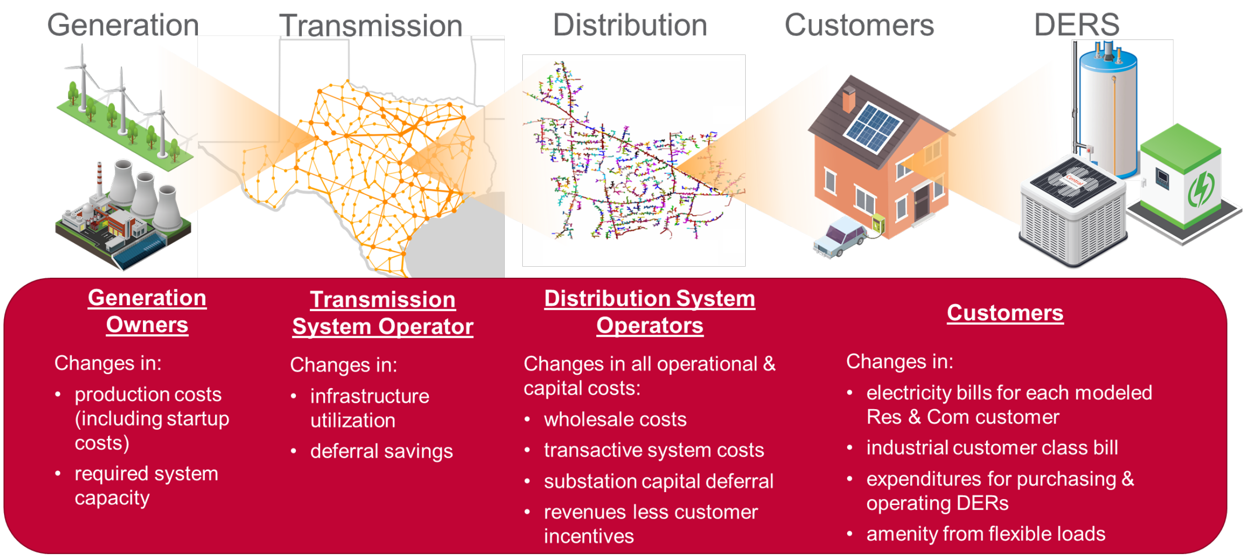


Figure 2. Primary metrics and economic values analyzed.

Figure 3 provides a summary of the cashflow between grid entities to help illustrate primary stakeholders, key financial interactions, and the level of granularity undertaken in the value analysis for this study. Figure 3follows Sankey diagram conventions where quantities flow from left to right, with values flowing into the left side of an entity representing revenues and values flowing out of the right side representing expenses.

Starting at the far left of Figure 3, retail customers are charged for electricity service through a range of mechanisms (energy and demand charges as well as connection charges). These charges represent the entire revenue for the region's DSOs, who then use the revenue to pay for operating expenses to maintain and operate the distribution system, transmission and ISO fees, and wholesale generation expenses (including energy, capacity, and ancillary service payments). Finally, this cash flow is used to pay for 'terminal expenses' that 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 and wind) and dedicated terminal expenses to capture the generation unit startup costs and variable fuel and operations and maintenance (O&M) costs associated with generation.

Figure 3 also helps place the relative expenses for gird operation in context. For example, wholesale energy purchases represent less than a third of the grid's operating cost, with variable costs (fuel and variable generation O&M) accounting for less than 15%. Conversely, capital costs represent almost half (44%) of the grid's annualized cost. Finally, approximately 40% of the grid's cost structure is associated with labor, maintenance, and operations costs.

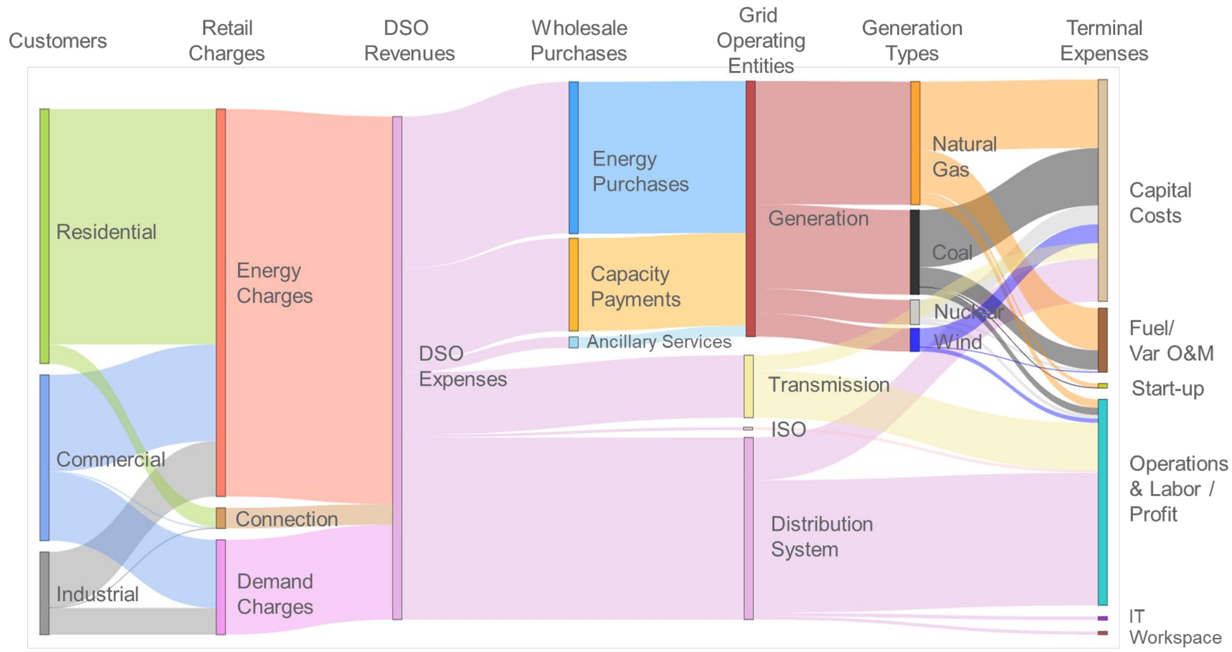


Figure 3. Annualized cash flow between various stakeholders for the MR BAU case.

1.4 Relevant Prior Work

The DSO+T's valuation effort has similarities to valuation analysis procedures associated with the development of integrated resource plans (IRPs), capacity expansion plans, utility energy efficiency and demand response program analysis, and rate case analysis. This section reviews select work in this area as well as other relevant cost modeling and grid economic analysis work.

IRPs are commonly used to identify the best resource mix that meets future needs, given forecasts of future demand for electricity and including any constraints placed by the regulatory process (e.g., carbon reduction, renewable portfolio standards accommodation of customer-owned solar generation). As described by the Regulatory Assistance Project (Lazar 2016), the "best" resources in IRPs generally means those with the lowest total cost over the long-term planning horizon that also ensure reliable service; accounting for known risks such as uncertainties in weather, fuel costs, and wholesale market prices; timing and quantity of any increases in load; and availability and costs of newly constructed resources.

A prototypical example is the seventh regional power plan for the Pacific Northwest developed by the Northwest Power and Conservation Council (NPPC 2016). Like the DSO+T study, the power plans use levelized annual retail cost of electricity (supplied or displaced) as the primary means of comparing the costs of meeting future energy and peak demand for electricity with new supply resources to those for demand-side alternatives (utility funded energy efficiency and demand response programs). The computation of levelized annual costs is described by Doane et al. (1976) and is directly related to net present values in the California Public Utilities Commission's (CPUC's) *Avoided Cost Calculator* (2019). Demand-side alternatives are typically represented in IRPs in terms of supply curves that express the escalating costs for energy and peak demand supplied as the deployment of those resources increases in quantity (Meier et al. 1983). Demand-side investments made directly by customers are included in forecasts of future loads but are not included as a cost. Recently, the IRP concept has been extended to analyze distribution system investments and the potential for alternative investments to cost-effectively displace them (Lazar 2016).

Capacity expansion plans are similar to IRPs in many respects. Traditionally, they only model and directly optimize supply-side resources and storage, treating deployment of demand-side resources as boundary conditions or scenarios. Compared to IRPs, they typically apply much more rigor to analysis of reliability in terms of loss-of-load (i.e., outage) probabilities, and therefore often model a region's transmission system explicitly. Load duration curves are a common basis for such plans. Capacity expansion modeling has been used by the National Renewable Energy Laboratory (NREL) as the basis for the Renewable Energy Futures Study of the implications and challenges of very high renewable electricity generation levels—80% of all U.S. electricity generation—in 2050 (Hand et al. 2012). This study focuses on the many technical issues related to the operability of the U.S. electricity grid, rather than on a market or policy appraisal based on a full assessment of benefits and costs.

That study does, however, estimate the associated direct incremental costs for a set of renewables scenarios compared to a baseline scenario. These stem from replacing existing generation with new, more capital-intensive renewable generators, additional transmission capacity, and additional expenditures for combustion turbines and storage. The study adds new generation to the system based on the capacity expansion model, analyzing 17 different time slices (four time slices for each season representing morning, afternoon, evening, and nighttime loads, and a summer peak time slice) as opposed to a full-time series and wholesale market model. For the baseline and some scenarios, it uses a commercially available production cost model[1] that implements security-constrained unit commitment and hourly economic dispatch to operate the supply resources and estimate wholesale power costs, rather than modeling wholesale power market operations.[2] For each scenario analyzed, the study computes 1) the present value of investments for generation, storage, interruptible load, and transmission capacity plus annual fuel and O&M costs; and 2) year-by-year national average retail electricity prices, with all other utility costs assumed to remain constant across scenarios and represented by a retail markup.

The *National Roadmap for Grid-Interactive Efficient Buildings,* recently developed by Lawrence Berkeley National Laboratory (DOE 2021), takes an entirely different approach to valuation and focuses specifically on the gross benefits of response from flexible building loads in addition to energy efficiency, given an achievable level of deployment through 2030. The benefits are based on model projections of power system hourly loads and marginal costs for energy, avoided generation and transmission capacity, and ancillary services through 2050 in 134 U.S. balancing areas. Another basis is an hourly time-series analysis of energy efficiency and demand flexibility technology performance in a large population of simulated buildings representative of the U.S. building stock. Today's commercially available energy efficiency

[1] Production cost models—given a generation fleet and transmission system plus weather conditions and demand for electricity—determine the costs of energy production assuming the least-cost power plants are operated with reliability constraints in the form of a security-constrained dispatch. Generally include reserves for reliability and frequency regulation.

[2] Wholesale market models simulate time-series hourly day-ahead and sub-hourly real-time market clearing prices according to a set of market rules (which vary widely based on region). Generally computes locational marginal price for any given node as the bid price of the marginal plant that must be dispatched to serve load at that node given transmission line constraints. Market rules may simultaneously optimize reservation of capacity for reliability and frequency regulation, and generally allow aggregations of distributed generation, storage, and demand response to bid as supply resources. May allow LSEs to offer price-responsive demand in their bids.

technologies and demand flexibility based on automated building controls (not customer behavior) are also considered. Other sources of flexibility associated with buildings were not analyzed, such as rooftop solar, batteries, and EV charging.

Demand flexibility is dispatched by a price-elasticity model (Satchwell and Hledik 2014) providing optimal timing of load shifting for up to four consecutive hours per day within an end-use's physical constraints on the quantity of energy shifted. The marginal value of the first increment of demand reduction are reduced by 5% for each additional 1% reduction in load, based on energy supply curves fitted to the capacities and short-run marginal costs of generators in the dataset. Values are expressed as the annual avoided cost of electricity.

Utility energy efficiency and demand response programs are designed and routinely evaluated to show financial impacts on various stakeholders are positive (Lazar 2016). The DSO+T study presumes that regulatory oversight resulting in the adoption of a DSO+T strategy resembles that of approving a demand-side program. The *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects* (CPUC 2001) describes four basic program cost "tests" used by regulators and utilities to determine if demand-side programs are prudent investments. Like the DSO+T study's valuation, these tests quantify value from various stakeholder perspectives or combinations thereof.

- Program administrator cost test compares all direct economic benefits and costs of the program that affect the utility, including production, transmission, distribution, line losses, reserves, costs for or taxes on emissions credits or taxes, and customer bills and incentives (i.e., the DSO's perspective).
- Participant cost test measures whether participants are better off, balancing bill savings and incentives against any costs incurred (i.e., the participating customers' perspective).
- Rate impact measure test measures whether a program causes rates to rise (i.e., the nonparticipating customers' perspective).
- Total resource cost test compares the direct economic benefits and costs to the utility plus any costs incurred directly by the customers (in the DSO+T study, a combination of the DSO's and customers' perspectives). It falls short of a total societal test in that it excludes costs for externalities such as emissions and to the general economy in terms of tax revenues or profits and losses to shareholders in generation companies, for example.

The DSO+T study presumes that adoption of a transactive approach is, in effect, a DSM program and so must pass the same (or similar) regulatory hurdles.

Finally, by their nature, *rate cases* are a comprehensive valuation approach from the utility perspective because they are based on the principle that a utility's annual revenues must equal its annual costs for capital and operational expenditures (plus, in the case of investor-owned utilities, a regulated rate of return for shareholders' portion of capital infrastructure investments). The California Energy Commission's *Utility General Rate Case – A Manual for Regulatory Analysts* (Ghadessi and Zafar 2001) provides a detailed technical discussion of how rates are designed to recover revenue and appropriately allocate costs to customer classes. As part of its valuation process, the DSO+T study implements automated rate designs that conform to these principles and processes in the form of a BAU fixed-rate design and a dynamic, transactive rate design for each DSO. The form of the dynamic transactive rate design follows many of the principles and proposals described by the Regulatory Assistance Project in *Smart Rate Design for a Smart Future* (Lazar and Gonzalez 2015).

The DSO+T study requires numerous cost data input assumptions of several types. Dagle and Brown (1997) developed a means of estimating distribution substation costs based on key characteristics and design rules of thumb. Similarly, Black and Veatch developed a procedure for estimating transmission system costs including substations, lines, and rights-of-way for the Western Electricity Coordinating Council (WECC 2012). Generation startup costs used in the DSO+T study were estimated by Kumar et al. (2012). Various means of assessing the avoided costs for transmission and distribution systems as a function of reduced loads are analyzed by Synapse Energy Economics et al. (2018). Assumed asset costs for flexible loads appear in Dyson et al. (2015) and cost data from various sources are summarized and evaluated by Potter and Cappers (2017). Current costs for a wide range of storage technologies can be found in Mongird et al. (2020).

Finally, it is worth noting prior work by DOE and Oak Ridge National Laboratory (Lee 2016, Zeng 2017) that sought to collect power sector data and visualize it in a Sankey diagram. This work broke down estimated revenues by LSE type, regional transmission organization/ISO region, generator ownership model, and finally generation fuel source. Terminal expenses (capital, labor, etc.) where not included. Key simplifying assumptions were made on the magnitudes of certain flows and no quantitative results were published on individual flows.

1.5 Report Structure

The Transactive Systems Program's prior efforts toward establishing a transparent framework for the economic analysis of transactive systems in general have been adopted and extended by the DSO+T study. Primary among these are e3-value modeling fundamentals used to define how economic value is created and exchanged within a network of actors. The e-3 value models used as the basis for the DSO+T study's valuation are documented in Section 2.0 of this report.

The quantitative analyses of the annual value exchanges to and from each primary stakeholder or group of stakeholders are embodied in their annual cash flow statements (CFSs). The CFS is a hierarchical, tabular representation of all the annual costs and revenues pertinent to the stakeholder or group, with each line containing the numerical estimate of a value exchange or one of its components. CFSs and how they are related to the e-3 value model are introduced in Section 2.0 of this report.

Costs for capital assets are among the most important in the study because they are a large component of power system costs, appear in nearly every primary stakeholder CFS, and have significant potential for reducing grid infrastructure by adopting a DSO+T strategy. Section 2.0 also describes how the capital costs for all primary stakeholders are expressed in a form compatible with the CFS as levelized annual costs.

The remainder of this report documents how the procedures, assumptions, and inputs from the simulation are used to calculate or estimate each line item in the CFS that describes the economic perspectives of simulated DSOs, customers, generation owners, transmission owners, and ISO.

Section 3.0 documents the procedures and assumptions associated with computing or estimating the capital costs and operating expenses for DSOs. Capital costs include those for DSO substation fleet in light of assumptions about load growth and costs for substation capacity, circuits and meters, and information technology (IT) costs for communications, control, and business systems. DSO operating expenses include 1) all wholesale costs and charges for purchasing electricity and 2) costs for O&M labor, materials, and workspace.

Section 4.0 provides a specification for how all retail transactions in the DSO+T study are computed in the valuation, including customer bills and DSO revenues. This includes the ratemaking process that recovers the required revenue from fixed-price customers in BAU cases and the (presumably reduced) required revenue in transactive cases from transactive customers (and a small number of nonparticipants remaining on fixed-price rates).

Section 5.0 describes how customer costs for various flexible assets and responsive loads combined with reductions in their electricity bill to form their CFS. Section 6.0 explains how the bulk power system stakeholder cash flows for the transmission system owner, generation owners, and ISO are computed for their abbreviated CFS. Finally, key conclusions and areas of future work are presented in Section 7.0.

2.0 Economic Stakeholders and Value Flows

2.1 Value Activity Models

The valuation methodology developed within the Transactive Systems Program at Pacific Northwest National Laboratory (Bender et al. 2021a, 2021b) uses unified modeling language principles to develop visual value activity models that enable evaluation of different use cases. The value activity models are developed as a part of the analysis design and are used to generate the structure for the CFSs that are a key result of the DSO+T study. This approach is based on the e3-value modeling methodology that was designed for e-businesses to define how economic value is created and exchanged between actors within a system (Gordijn and Akkermans 2001).

In following this methodology, an economic model was developed that allows for both microeconomic analyses of an individual's activities and the economic impact derived from that activity, and macroeconomic analyses of how the totality of the individual's activities impacted the system and society as a whole. The value activity models not only include the systemwide value creations and exchanges but also show value exchanges between the various actors, or stakeholders, within a system. In addition to the primary metrics described in Figure 2 that capture the change in expenditures of the entire system between cases, these models allow for analysis of each actor's individual business case for each BAU and transactive case. Structuring the valuation analysis in this way produces an economic model with similar fidelity as the simulation model, where each change in action within the system is associated with impacts to the results of the study.

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, in this case the annualized cash flows. Many studies report the total economic benefit or cost to an entire system, failing to distinguish which stakeholders experience losses and gains and to what extent. The valuation approach applied to the DSO+T study allows this greater granularity where each action taken within the system results in a unique economic experience and outcome.

The value activity models shown in this section of the report are generated as a part of the analysis design, taking place before simulation models were built. They directly inform the analysis that takes place once the simulation is complete and are a key aspect of defining what data are needed from simulation and other analyses to produce the desired results described in Figure 2. The values shown entering and exiting the actors in the business value model inform the structure of the actor's CFS for each BAU and transactive case. The actor's CFS, seen in Table 1 (once populated) report the actor's business case. The CFSs reflect the value exchanges as annualized revenues and expenses for the actor.

In the business value models shown in Figure 4 through Figure 6, the actors, or stakeholders, are depicted as gray rectangles. Within each actor is another rectangle that is the value activity. The arrows and ports that are attached to the value activities are the value exchanges associated with the given activity of the actor. This structure exists within the valuation methodology so the business case of different activities for the same actor could be analyzed if desired.

Figure 4 shows the value flows being modeled in the DSO+T study. The system border is a black rectangle labeled “DSO+T Analysis” and exists to separate out the stakeholders that are being considered within the analysis from those that are not. For example, this valuation study includes the costs paid by the customer to a DER vendor from the customer’s perspective only, whereas expenses between the customer and the DSO are considered from both perspectives because both actors are within the analysis boundary.

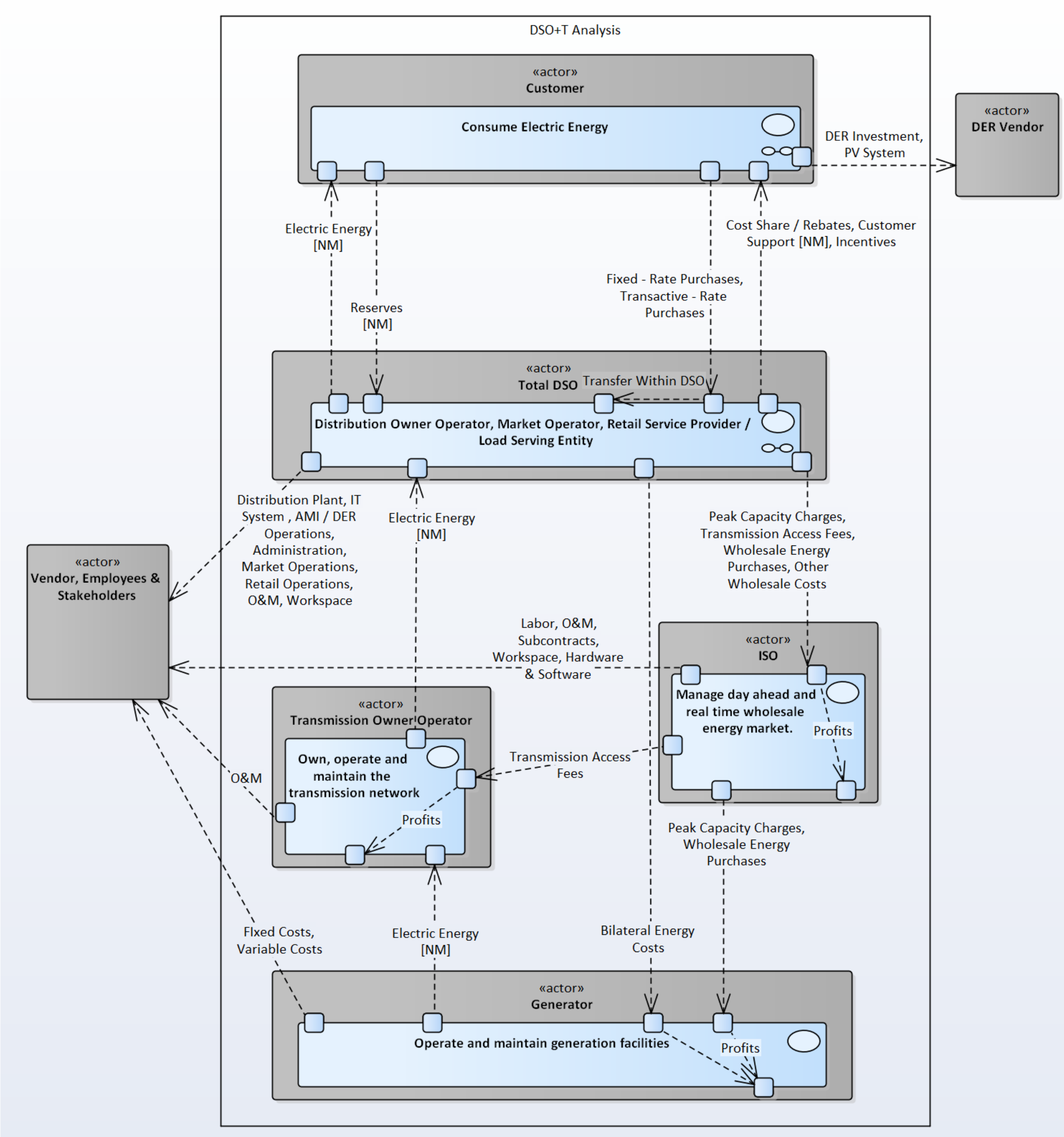


Figure 4. DSO+T system value activity model.

Figure 4 shows the e-3 value model for the DSO+T study. The dashed arrows represent the value objects being exchanged within the system, the nonmonetary values are identified with a

"[NM]" and do not appear within the CFS, but are shown in these models at a high level of what the monetary values are being exchanged for. For example, generators provide electrical energy and are compensated through bilateral contract, day-ahead and real-time market, and capacity market payments. The values flowing into an actor would be seen as revenues on the CFS and the values flowing out of an actor would show up as expenses. The actors shown outside of the "DSO+T Analysis" boundary on Figure 4 are not stakeholders included within the scope of the DSO+T study, meaning they do not have CFSs, but the value flows shown crossing the boundary are included within the analysis because they appear as expenses on their source actors CFSs. Details on the calculation of these value exchanges for each actor's CFS can be found in later sections of this report.

Figure 5 models the same values as Figure 4, but in more detail and for only the DSO actor. This provides more insight on the value exchanges that are included in the DSO CFS.

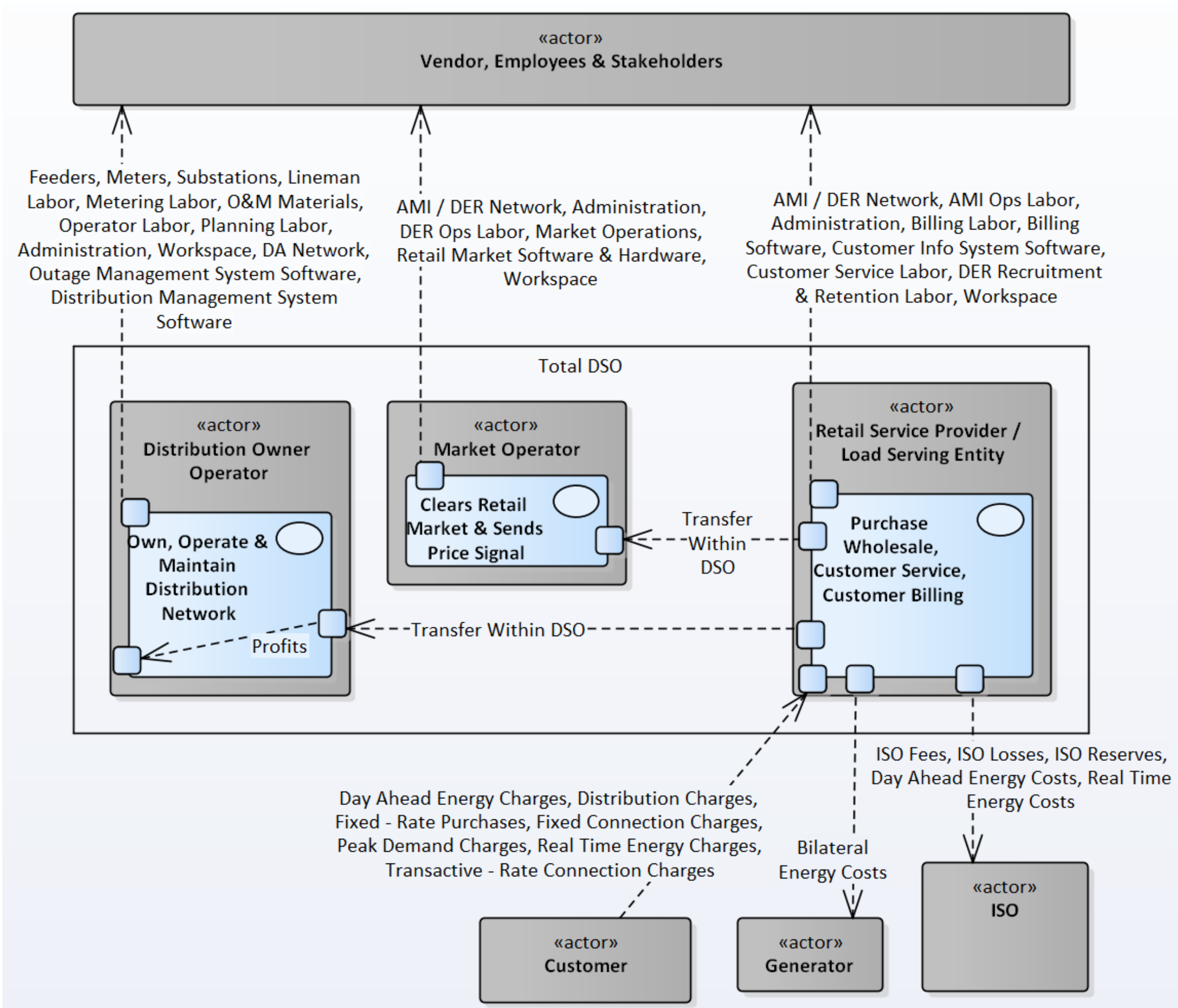


Figure 5. DSO value activity model.

Figure 6 models the customer actor participating in the transactive energy market in a similar, more detailed manner. The customer and DSO have the most complex CFSs and economic analyses, so it is helpful to see a more detailed business value model.

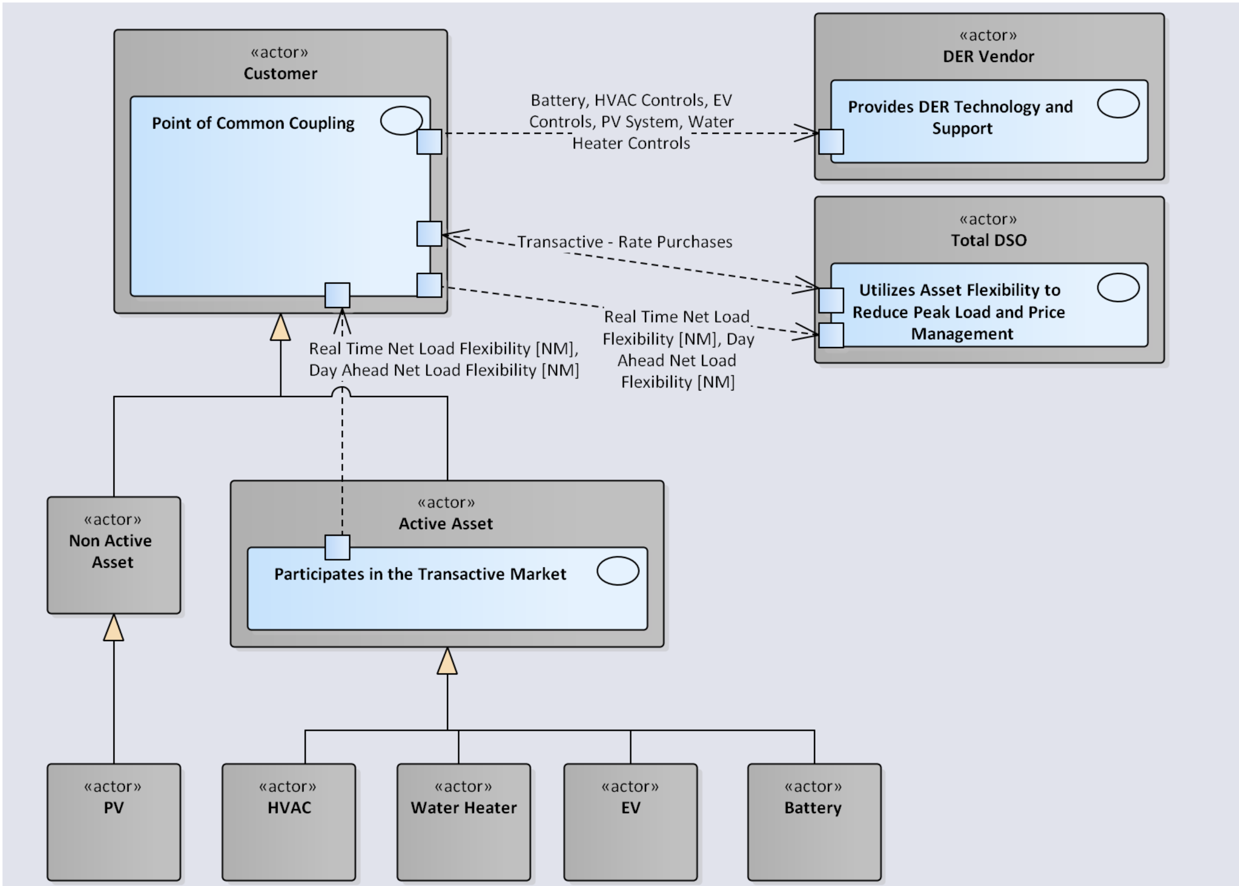


Figure 6. Customer value activity model: transactive energy participant.

Like many accounting tables the CFS show revenues and expenses at different levels of aggregation, this can be seen in Table 1. The differences between Figure 4, Figure 5, and Figure 6 are that the value exchanges modeled represent different levels of aggregation of value exchanges. Although the arrows are labeled differently in the DSO and customer business value model, they are the same values shown in Figure 4, just disaggregated. In reference to Table 1, Figure 4 shows the Subcategory lines of the CFS. Figure 5 and Figure 6 show the more detailed, Element lines of the CFS.

Figure 4 and Figure 5 are the value models that were created to specifically show a greater granularity of the value exchanges for the DSO and customer and ultimately compose the DSO business case. The value model shown in Figure 5 also shows the value exchanges between the unbundled DSO. Showing the unbundled DSO in this format clarifies which aspects of the DSO are responsible for what value activities and exchanges. More information on the DSO CFS and the calculations of value exchanges are in Section 3.0.

Figure 6 shows the exchanges that take place for the customer stakeholder. This model includes the values that are provided from the assets that the customer utilizes within the study. More details on calculating the customer CFS are in Section 5.0.

Table 1. Form of a customer CFS (three levels of detail).

Category / Subcategory / Element	Annual Cash Flow ($K/yr)		
Electricity Bill[a]	**$E**		
Fixed Rate Purchases		**$E1**	
Fixed-Rate Energy Charges			$E1a
Peak Demand Charges			$E1b
Fixed-Rate Connect Charges			$E1c
Transactive Rate Purchases		**$E2**	
Day-Ahead Energy Charges			$E2a
Real-Time Energy Charges			$E2b
Distribution Charges			$E2c
Transactive Rate Connect Charges			$E2d
Capital and Installation Costs[b]	**$C**		
Flexible Asset Investment (Transactive)		**$C1**	
Residential HVAC Controls			$C1a
Water Heater Controls			$C1b
Commercial HVAC Controls			$C1c
Battery			$C1d
Electric Vehicle Charging Controls			$C1e
Photovoltaic solar system		**$C2**	
Revenues	**$R**		
Income Allocated for Electricity Costs		**$R1**	
Taxes	**$T**		
Increase from Reduced Electric Bill Deduction		**$T1**	
Balance = Electricity Bills + Capital/Install − Revenues + Taxes	**$B**		

[a] Including net metering of energy from discharging batteries and solar PVs

[b] Levelized annual capital and installation costs include tax deductions for depreciation and interest for business customers

2.2 Annual Cash Flow Statements

A key objective of the DSO+T study is to make a simple estimate of the economic impacts of a national deployment of DERs with a DSO+T strategy at scale. A basic assumption of the valuation methodology is that electricity customers ultimately pay for the entire cost of the power system through their electric bills from the DSOs and their own investments in flexible assets and any self-generation from solar PV and other technologies. The DSOs, in turn, pay for the entire cost of the electric power system, including transmission and generation, net of the customer investments.

The assumption that customers pay the entire cost of the system is not strictly true, of course, because it can be argued that it does not include costs for any externalities such as emissions or other impacts that are not explicit costs for a power system entity in today's system. On a more subtle level, generation is assumed to be fully deregulated, so there may be costs that accrue to equity investors in bulk generators that are ultimately stranded by changes in resource policies and, to a more limited extent, by managing peak demand using DSO+T flexible assets. The valuation methodology does not attempt to estimate these societal costs.

Finally, DSOs pay for generation in the form of their wholesale energy purchases and capacity payments. In the DSO+T study, the latter are presumed to be a requirement from the ISO that DSOs cover their peak demand by purchases from a capacity market at typical U.S. prices (these prices are assumed but such a market is not simulated explicitly in the study). However, as discussed later, current U.S. capacity market prices are well under typical construction costs, by roughly 30%. The effect of this difference will be examined explicitly in the valuation.

Despite these limitations, the premise that customers pay for the cost of the system via their own investments and retail electric bills from the DSOs implies that the valuation methodology analyze their costs via their CFSs with considerable fidelity. 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 need for detail to simply illustrate this point. 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 types of bulk generators, not whether those revenues are sufficient in sustaining a particular generator.

An extrapolation of the study results to a national deployment scale will be based on the percentage change in the total cost of the power system, with the simplifying assumption that the fractional reduction in total annual costs are not greatly affected by the differences in climate, generation mix, and load in various regions. It is beyond the scope of this study to examine the impact of these differences, but having such estimates of the potential national impact is nonetheless valuable for making decisions on policy and technology development.

To support such an extrapolation, the total annual cost of the DSO with and without implementing the DSO+T strategy is estimated, so net savings in percentage terms can be estimated (beyond just changes in the costs for individual line items that are expected to increase or decrease). This is because the DSO must recover its costs (and regulated rate of return when investor owned) with revenue from customer bills. Therefore, the DSO CFSs need to be both comprehensive and far more detailed than for other grid entities. The customer bills are then added to customer costs for investing in DER and flexible-load assets to obtain the total power system cost so a percentage change in annual levelized costs can be reported.

An illustration of a CFS is shown in Table 1, with the numerical values indicated by placeholder variables. Note that the presence of cash flow from an external stakeholder is implied by the presence of the line item *Income Allocated for Electricity Costs* representing income from an implied household or business associated with the customer.[3]

Each actor in the DSO+T study simulation that is a primary stakeholder has a CFS. This includes each of the 40 DSOs and ~64,000 customers explicitly simulated. However, these customers are instantiated in the simulation to represent over 12 million customers in ERCOT in 2016. This is done with statistical distributions of key characteristics that drive consumption and the amount of flexibility obtained from their responsive assets, such as customer classes, building types, efficiencies, end-use devices, and behaviors. Similarly, the 40 DSOs are

[3] The customer stakeholder in the DSO+T study does not represent the entire financial life of the associated household, business, or organization beyond their need to allocate some income to pay the customer's electricity bill and purchase any DER or responsive load assets.

designed to represent a population of 200 DSOs in ERCOT, with a mixture of key characteristics such as sizes, customer class shares, and customer density types and load growth rates (represented as rural, suburban, and urban service territories).

This is accomplished by populating the representative substation simulated for each DSO with an appropriate mix of commercial and residential customers and building types with distributions of their key characteristics, and adding in an industrial class load, to represent an entire DSO using a customer weighting factor. Similarly, each DSO has a weighting factor representing DSOs in ERCOT with similar characteristics. Details about how this was done are presented in Volume 2 (Reeve et al. 2022b).

The CFS for each instantiated customer and DSO reflects their simulated physical characteristics and behavior but represents a larger population of similar stakeholders in ERCOT. However, there are other important *economic* characteristics that drive the *value* they obtain from their flexibility, such as how they finance their capital investments and the interest rates they pay, net of considerations such as depreciation and deduction of business expenses and interest on debt. For example, in the simulation a single-family home customer is not instantiated with status as either a homeowner or a renter, or as paying for smart thermostat with cash or a mortgage, etc., because these are not expected to affect their simulated behavior. So, distributions of *economic parameters* are applied after the simulation as the customer and DSO CFSs are computed as discussed in Sections 2.3 and 3.1. The simulated stakeholder's behavior is, in effect, cloned and applied to each combination of such economic parameters, and then added by application of the weighting factors to create a total representing ERCOT.[4]

Although CFSs are developed for all individual primary stakeholders simulated in the DSO+T study, it is often useful to create CFSs representing the aggregate, composite results for groups of stakeholders for subsequent analysis. For example, customers are grouped for comparative reporting and analysis in various ways, such as their customer class, building type, heating fuels, types of flexible assets, degree of flexibility offered, etc. Likewise, impacts on DSOs are analyzed by comparing groupings by service territory type (rural, suburban, urban) and results for generation are presented by fuel type.

2.3 Levelized Annual Costs for Capital Investments

The DSO+T 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 operational costs in the stakeholder CFSs that are the primary basis for its economic analysis.

Levelized annual costs are a common, convenient way for investments in utility infrastructure (or avoidance thereof) to be compared with one another. This stems from the inherently annual nature of the fundamental social bargain between a utility monopoly and its customers—that the utility will set rates for the electricity it sells such that the annual revenue it collects is sufficient to cover its annual costs—including, for a regulated investor-owned utility, its income taxes and

[4] This works because these economic parameters have independent linear effects on any given CFS line item; however, it does not allow the effect of each economic parameter to be studied directly. An alternative approach supporting such analysis would create multiple CFSs for each simulated primary stakeholder, one for each possible combination of the economic parameters, with proper weighting factors for each resulting CFS. This is beyond the scope of the study but could be the subject of future analysis. Fortunately, it would not require the simulation to be reconducted.

a rate of return on the capital investment of its equity shareholders (as prescribed by utility regulators).

Over time, utility planning processes have evolved to incorporate explicit consideration of alternatives to traditional utility investments in infrastructure. These include nontraditional generation sources such as renewables that may receive tax credits or accelerated depreciation benefits, as well as energy efficiency and demand response measures. Since these alternative investments have different expected lifetimes and cash flows, and in some cases are made by customers or other non-utility entities, comparing their impact on a utility's electric rates and hence on customers is most directly made on an annualized basis. That has led utilities and regulators to adopt levelized annual costs as the primary basis for making such decisions.

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:

- Principle and interest payments on any debt undertaken by the investor
- Any cash down payment made by the investor
- A rate of return to any equity stakeholders the investor may have in the form of stock earnings and return of principle
- 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 doing so, the procedure explicitly accounts for providing a regulated return on investment to equity shareholders in investor-owned utilities in the DSO+T study (DSOs and transmission system owner) as the basis for their retail ratemaking process in both BAU and transactive cases. For publicly owned utilities (municipal or rural cooperative) rates are simply set to recover annual expenses including their levelized capital costs.

Appendix A documents how levelized annual costs are computed for the DSO+T study based on annualized capital cost factors (ACCFs), which are defined as the fraction of an initial capital investment (first costs) represented by the sum of those constant, levelized annual payments. Appendix A has two main sections. Section A.1 defines an efficient procedure for computing ACCFs and shows it is consistent with both a full pro forma analysis of net present value[5] and the original derivation of levelized annual costs for utility investments. It also generalizes the procedure so it can be used for customer investments for flexible loads and DERs in addition to investments in grid infrastructure.

Section A.2 defines the input assumptions need to compute ACCFs for the primary stakeholders. These include if and how they are capitalized by stockholder, rates and terms of the instruments they use to finance their purchases of various types of assets, and their positions with respect to income and sales taxes. The resulting ACCFs are then blended to form population-weighted averages representing the primary stakeholders in ERCOT.

The resulting ACCFs for grid assets and assets purchased by consumers occupying residential and commercial buildings are shown in Table 2, Table 3, and Table 4, respectively. These

[5] As embodied by the CPUC's *Avoided Cost Calculator* (CPUC, 2019)

values will be used in the calculation of annualized capital costs for DSOs in Section 3.2 and customer annualized capital costs in Section 5.1.

Table 2. Ownership weighted-average ACCFs and effective income tax rates for grid assets.

Asset Owner Type	Utility Type	Asset Type	Asset Life (yr)	ACCF (%)	Effective Income Tax Rate (%)
Generation Owner	Blended Average	Generator	20[6]	9.13%	12.60%
		Controls and software	10	12.58%	
Transmission Utility	Total System	Transmission infrastructure	20	8.25%	13.65%
		Controls and software	10	11.19%	
Distribution Utility	Rural	Distribution infrastructure	20	5.90%	2.10%
		Controls and software	10	10.59%	
	Suburban	Distribution infrastructure	20	7.72%	10.50%
		Controls and software	10	11.14%	
	Urban	Distribution infrastructure	20	8.74%	15.75%
		Controls and software	10	11.36%	

Table 3. Weighted-average ACCFs by residential customer type and asset type.

Residential Customer Type	Asset Type	ACCF (%)
Single-Family	Smart thermostat marginal	8.23%
	Smart water heater marginal	8.23%
	Battery total	9.19%
	Smart EV charger marginal	8.66%
	Smart EV inverter marginal	8.75%
	PV total	9.65%
Manufactured	Smart thermostat marginal	7.83%
	Smart water heater marginal	7.83%
	Battery total	8.89%
	Smart EV charger marginal	8.21%
	Smart EV inverter marginal	8.39%
	PV total	9.26%
Multifamily	Smart thermostat marginal	5.00%
	Smart water heater marginal	5.00%
	Battery total	6.81%
	Smart EV charger marginal	5.04%
	Smart EV inverter marginal	5.87%
	PV total	6.57%

[6] The U.S. Internal Revenue Service (Internal Revenue Service 2019) defines the equipment lifetime for accelerated depreciation of most electric generation, transmission, and distribution equipment as 20 years, although their useful lifetimes in many cases are longer.

Table 4. Weighted-average ACCFs for commercial customers by building type and asset type.

Commercial Customer Type	Capital Asset Type	Population-Weighted ACCF (%)	Commercial Customer Type	Capital Asset Type	Population-Weighted ACCF (%)
Office, Large	Smart thermostat marginal Smart large HVAC marginal Battery total PV total	4.67% 9.42% 7.11% 7.85%	Food Service	Smart thermostat marginal Smart large HVAC marginal Battery total PV total	4.67% 9.42% 7.11% 7.85%
Office, Medium/ Small	Smart thermostat marginal Smart large HVAC marginal Battery total PV total	5.17% 7.60% 6.15% 7.28%	Food Sales	Smart thermostat marginal Smart large HVAC marginal Battery total PV total	4.64% 9.53% 7.16% 7.88%
Warehouse and Storage	Smart thermostat marginal Smart large HVAC marginal Battery total PV total	4.61% 9.64% 7.22% 7.91%	Lodging	Smart thermostat marginal Smart large HVAC marginal Battery total PV total	4.76% 9.10% 6.94% 7.75%
Big Box Retail	Smart thermostat marginal Smart large HVAC marginal Battery total PV total	4.67% 9.42% 7.11% 7.85%	Healthcare, Inpatient	Smart thermostat marginal Smart large HVAC marginal Battery total PV total	4.90% 8.56% 6.66% 7.58%
Strip Retail	Smart thermostat marginal Smart large HVAC marginal Battery total PV total	4.67% 9.42% 7.11% 7.85%	Low Occupancy	Smart thermostat marginal Smart large HVAC marginal Battery total PV total	4.61% 9.64% 7.22% 7.91%
Education	Smart thermostat marginal Smart large HVAC marginal Battery total PV total	5.17% 7.60% 6.15% 7.28%			

3.0 Distribution System Operator Expenses

The form of a DSO's CFS at two levels of detail is illustrated in Table 5. It serves as a useful introduction to this section of the report, which describes how the annual cash flows for the first two categories (capital expenses and operating expenses) of a DSO are estimated. A description of how DSOs revenues, the third category of DSO costs in Table 5, is deferred to Section 4.0 where they are described in conjunction with customer bills.

Table 5. Form of a DSO CFS at two levels of detail.

Category / Subcategory	**Annual Cash Flow ($K/yr)**	
Capital Expenses[a]	**$C**	
Distribution Plant		$C1
IT Systems		$C2
Operating Expenses	**$O**	
Peak Capacity Charges		$O1
Transmission Access Fees		$O2
Wholesale Energy Purchases		$O3
Other Wholesale Costs		$O4
O&M Materials		$O5
O&M Labor		$O6
Market Operations		$O7
AMI/Customer Network Operations		$O8
Device Management System (DMS) Operations		$O9
Retail Operations		$O10
Administration		$O11
Workspace		$O12
Revenues	**$R**	
Balance	$B	

[a] Annualized capital expenses include return on shareholder equity investment in capital assets and taxes on revenues after depreciation and interest deductions for investor-owned DSOs.

The remainder of this section is organized as follows: Section 3.1 introduces how key characteristics of DSOs are incorporated into the study's valuation process. This provides important context for the discussion that follows because it affects how many of the line items in the DSO's CFS are estimated and defines the how DSOs can be grouped in various ways to form composite CFS for comparing how these characteristics affect the DSO's financial outcomes from adopting a DSO+T strategy.

Section 3.2 focuses on a DSO's capital expenses and how annual costs for its substations, feeders and circuits, meters, and IT systems infrastructure are estimated. Likewise, Section 3.3 describes how annual costs for the DSO's operational expenses are estimated. These include generation capacity payments, transmission access fees, and costs for wholesale purchases from bilateral contracts with generators and the ISO wholesale electricity marketplace. Other wholesale costs include the DSO's share of the ISO's general operational expenses and for ancillary services. O&M costs include labor and materials to maintain the DSO's physical infrastructure. The remainder of the operational expense subcategories are driven by labor for its retail and operations and running its infrastructure networks and associated IT systems, including administration and the costs of workspace.

Section 3.4 provides example results from the DSO CFS process. Results of typical DSO expenses are presented and compared to actual overall grid operator costs. In addition, examples of the overall changes in DSO expenses between a BAU and transactive case are presented. This is followed by a brief discussion of how the CFS line items might be allocated to a DSO's sub-entities if it were to be unbundled at some point.

3.1 Effects of Key DSO Characteristics

The key characteristics of DSOs and how they are reflected in the DSO+T study's valuation analysis are discussed in this section.

3.1.1 DSO Types: Rural, Urban, and Suburban

For the study, DSOs are classified as belonging to one of three types based on the predominant nature of their service territories as either rural, suburban, or urban. This distinction is important because the customer density (no./mi^2) and load density (MW/mi^2) vary widely across these types. These, in turn, directly affect capital costs for substations, circuits, communication networks, substation automation, and advanced metering infrastructure (AMI). For example, the average substation's capacity in rural areas will be significantly less than in suburban and urban areas due to the spatially diffuse customer populations they serve. Similarly, costs for distribution circuits are dependent on their length and communication network costs per-customer increase as the customer density decreases. All these effects drive the cost of the distribution infrastructure per unit of peak load served ($/MW-peak) upward. A countervailing effect is that DSO type also affects land and operational costs for labor and workspace to varying extents, typically being lower in rural areas.

The relative proportion of customers in the primary customer classes (residential, commercial, and industrial) and their composition (e.g., building types) also varies considerably with DSO type. For example, there tends to be fewer large multifamily (apartment), commercial, and industrial customers in rural areas, and a larger share of manufactured homes (Reeve et al. 2022b, Section 6). Further, both the pattern and rates of load growth also vary strongly across the DSO types as discussed below.

Finally, it should be noted that a DSO's service territory is generally not purely rural, suburban, or urban in nature. Each territory is considered as having service areas that are better described as *undeveloped* (rural areas), *rapidly developing* (areas at the rural-suburban fringe), or *fully developed* (urban and mature suburban areas). The DSO+T study's analysis of DSO substation fleet capacity takes into account the relative proportions of these service areas for each DSO+T based on assumptions about load growth rates, which are assumed to vary by DSO type, and typical load densities that vary by service area as discussed below in Section 3.2.1.

For these reasons the DSO+T study's valuation process creates a stakeholder group CFS for each type of DSO so that the effects of DSO type (i.e., service territory type) can be examined by comparing them.

3.1.2 Ownership

The ownership of a DSO (e.g., investor owned, municipal, rural cooperative) has a number of effects on the value of a DSO+T strategy (or any such investment decision in general). Primary among these is the interest rates each type pays for the debt financed share of their capital investments. Each type has its own source of financing. Investor-owned utilities typically finance about 55% of their capital assets from debt by issuing interest-paying corporate bonds. Municipal utilities typically fund all their capital investment by issuing tax-free municipal bonds and rural cooperatives borrow from the federal government at approximately the federal bond rate, both of which result in considerably discounted interest rates.

Equally important is whether a DSO is a for-profit investor-owned utility or a publicly owned utility (municipal or rural cooperative). Publicly owned utilities are nonprofit by definition and therefore pay no income taxes nor can they deduct depreciation and interest payments on debt. Investor-owned utilities earn a regulated rate of return (typically in the vicinity of 9%) to their stockholders for the equity financed share of capital investments undertaken and pay taxes on that portion of their revenue. This is partially offset by an investor-owned utility's ability to deduct interest payments on their debt financing as a business expense (their noncapital operating expenses are entirely deductible and so the share of revenues that recover those costs are, in effect, not taxed). All these effects are taken into account when computing the population-weighted blended average ACCFs for capital investments for each kind of ownership (as described in Section 2.3).

As in ERCOT, in the study DSO ownership type is highly correlated with DSO type. Investor-owned utilities predominate in large metropolitan centers and their surrounding suburban areas, since high-load densities were necessary for profits in the early days of electrification. Municipal utilities arose in smaller communities, some of which have grown to the point where they have urban cores, but nearly all of which of have a strong suburban component. Rural areas were not attractive for private investments in electrification, so the federal government continues to provide low-cost financing that allowed the widespread advent of rural cooperatives in those areas. In ERCOT, some of these rural electric cooperatives located in areas that were previously rural but near urbans cores and their suburbs, have subsequently been overrun by development and are now more properly classified as suburban in nature.

So, the study's valuation takes into account that there is not a one-to-one correspondence of DSO type and ownership. Instead, it assumes there is a preponderance of investor ownership in urban DSOs (75%), a preponderance of rural cooperative ownership in rural DSOs (75%), with many suburban DSOs being municipally owned (40%) and lying between these extremes. These assumptions are documented in Table 36 of Appendix A.

3.1.3 Seasonality of Peak Loads

Each DSO in the study has a nominal winter and summer peak load assigned to it based on historical 2016 DOE-Energy Information Administration (EIA) distribution utility survey data (DOE-EIA n.d.) for Texas distribution utilities and recorded 2016 ERCOT nodal loads (ERCOT n.d.). Examination of these data shows that a substantial fraction of the DSOs exhibit winter peak demand that is as high (dual peaking) or higher than their summer peak demand (i.e., winter peaking). This is almost exclusively among rural utilities and is attributed to the fact that natural gas is much less available in many rural areas. So customers are left to choose between electricity and propane gas for their space- and water heating energy, which in turn drives much higher electricity use because of the relative costs between electricity and propane. This has important implications for the winter peak demand and load shape, as well as the potential to reduce substation capacities by deploying a DSO+T strategy focused on flexible end-use loads, so it is yet another reason that rural DSOs are distinguished from their suburban and urban counterparts in the study.

3.2 Capital Expenses

This section describes how the cost of a DSO's annual capital expenses are estimated based on the DSO's characteristics, example simulation results for BAU and transactive cases, and a set of assumptions and models about distribution system infrastructure and capital costs.

3.2.1 Substations

The DSO+T study requires that capital costs for distribution infrastructure be estimated because they are an important component of a DSO's required revenue. Even more important to the study, the deferral or reduction in costs for a DSO's substation capacity is one of the opportunities to reduce DSO expenses. So, savings in capital costs for substation infrastructure are reflected in the difference of the levelized annual capital costs for a DSO substation fleet for a BAU case when compared to a transactive case.

Estimating a DSO's annualized capital costs for its substation fleet requires knowledge of existing substations and their capacities, the annual rate at which new substations are being constructed to meet load growth and their capacities, and the costs of capacity in both new and existing substations. The study estimates the levelized annual costs for a DSO's substation fleet as the product of its capital investments in the substations and its ACCF:

$$SubCost_A = \left(Cap_{exist}\, Cost_{exist} + \dot{Cap}_{up}\, Cost_{up} + \dot{Cap}_g\, Cost_{new}\right) ACCF_{di} \tag{1}$$

where: $SubCost_A$ ≡ levelized annual cost of the entire substation fleet

Cap_{exist} ≡ capacity of existing substations

$\dot{C}ap_{up}$ ≡ capacity of upgrades added to existing substations per year

$\dot{C}ap_{g}$ ≡ capacity of new greenfield substations constructed per year

$Cost_{exist}$ ≡ cost of existing substation capacity per MVA

$Cost_{up}$ ≡ cost of upgrading substation capacity per MVA

$Cost_{new}$ ≡ cost of new substation capacity per MVA

$ACCF_{di}$ ≡ annualized capital cost factor for distribution infrastructure

Note that the cost of the existing brownfield substation capacity is a weighted average of 1) the capacity cost for substations that are "new", f_{new}, i.e., still in their first design lifecycle, purchased at the cost of new substation capacity, and not yet fully depreciated; and 2) the capacity cost for substations in their second or subsequent design cycles, i.e., for substations whose initial capital cost has been fully depreciated and whose capacity cost is then equal to upgrade costs:

$$Cost_{exist} = f_{new}\, Cost_{new} + (1 - f_{new})\, Cost_{up} \tag{2}$$

based on the fraction of the existing substation fleet capacity that was built in the form of new substations (f_{new}) not fully depreciated, as opposed to capacity added during subsequent upgrades to existing substations. 20% was assumed.

How the cost of capacity in the form of new substations or upgrades to existing substations is estimated is described in the following subsection. The subsequent subsection describes how the capacity of a DSO's substation fleet is estimated, given the peak load it serves and the DSO type (rural, suburban, urban).

3.2.1.1 Cost of Capacity in New and Upgraded 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 (Dagle and Brown 1997). Overarching among these is the peak load served. On the high-voltage side of the substation these include the number and voltage of the transmission lines that serve the substation and the breaker configuration (either single-bus or main and transfer bus). On the low-voltage side, itemized costs include the number of transformers, the number and voltage of the feeders serving the load, the number and rating of capacitor banks, and the low-voltage breaker configuration. Based on this design information the number of bays in the substation on its high- and low-voltage sections are tabulated and costed. Finally, costs for land and a control building are added, along with costs for planning, design, and associated overheads in the form of an allowance for funds used during construction of 15%, to produce the total substation cost. The model includes the effects of other design practices common to many utilities, such as the use of voltage regulators or transformer tap changers for voltage control, as rules of thumb based on the size and criticality of the load being served.

The model also includes assumptions for all these itemized costs. It was validated by comparing actual and estimated costs for 21 substations constructed by a variety of utilities that are part of the Western Interconnection (Dagle and Brown 1997). All costs are inflated from the base year of the model (1997) to the year of the DSO+T study (2016) at a rate of 1.7%.

Finally, it should be noted that, while a DSO generally has a set of substation design practices it tends to follow, for a variety of reasons all substations will not be identical in design or configuration. The model clearly shows that substation costs do not increase directly as their capacity increases. For example, the number of feeders and the breaker configurations affect costs in ways that are not directly dependent on capacity to serve peak demand. It is beyond the scope of the study to account explicitly for this variation, primarily because distributions of substation design characteristics representing utilities' installed infrastructure are not available.

So, rather than using the model to compute the cost of substations themselves, the study uses it to compute the cost of substation capacity [$/MVA] for a prototypical substation design specific to each DSO type that is presumed to represent the median effect of these characteristics on the capacity cost. For new substations it does this by normalizing the cost of the prototypical substation by its rated capacity. For existing substations receiving upgrades, the cost is estimated as the difference between a new prototypical substation with the additional capacity of the upgrade and a new substation without the added capacity (the prototype itself). This cost is then normalized by the capacity added in the upgrade to determine the marginal capacity cost of substation upgrades.

The assumed peak demand characteristics and land costs for the prototypical substations are shown in Table 6 for each DSO type. The number of customers per substation and peak load per customer are estimated based on averages for 11 utilities, primarily in Texas, ranging in size from large urban utilities serving millions of customers to small rural cooperatives serving a few thousand.[7] The average peak load per feeder and, hence, number of feeders and nominal peak load per substation are based on assumptions about typical utility infrastructure. The power

[7] The number of substations a utility has is not readily available in any standard or centralized form, nor is it universally made available. The information was gleaned from internet searches for utility summary overviews and "quick facts," often posted in the form of flyers or presentations. Given that the publication dates for these sources varied, the number of customers served was taken from the same source so they are coincident in time.

factor at peak demand is assumed to be 0.9. The transformer redundancy factor is the ratio of the transformer capacity to the nominal peak demand. It is assumed to be 1.5 in suburban and urban utilities, a common practice that allows redundant capacity sufficient to power a substation's service area from tie lines to two adjacent substations if necessary when recovering from an outage. Assumed land costs vary by orders of magnitude from rural to suburban and urban areas, based on standard assumptions about average land costs by the U.S. Bureau of Land Management's land-use classification system.

The design features for the prototypical substation for each DSO type are shown in Table 7 along with the resulting substation and capacity costs based on the cost model. The distribution voltages are assumed to be 13.8 kV and urban substations are assumed to have a second transformer to increase reliability. The resulting total cost of each prototypical substation and its cost per unit of capacity are shown in the columns at the right. The first three rows of Table 7 define the prototypical new substations. The following three define prototypical substations after a subsequent upgrade, as if they were constructed to those specifications when new. The cost of substation upgrade is then defined as the difference between the two.

3.2.1.2 Capacity of a DSO Substation Fleet

This section provides an overview of how a DSO's substation capacity and rate of growth are estimated. Utilities generally evaluate the need to construct new infrastructure on an annual basis. In any given year, their existing capacity is greater than that need to serve their peak demand, because of

- the lead time for planning and constructing new infrastructure combined with their rate of load growth (i.e., growth in peak demand)
- the need to accommodate the expected load growth over the lifetime of a substation after it is constructed or upgraded.

While engineering tools for designing new and upgraded substations are abundant, a literature search did not find tools or models that describe how long-term growth due to changing population, land use, and load density relates to growth in substation fleet capacity and the amount of marginal capacity in excess of current peak demand that exists at any point in time. So the study developed a model of substation fleet capacity and expansion based on changing land use that reflects population growth and resulting load growth, substation capacity, and rate of addition to that capacity. It is introduced here and described in detail in Appendix B.

The study presumes there is a strong correlation between the DSO type (rural, suburban, or urban) and its load growth rates. Rural DSOs may exhibit zero or negative load growth overall. Suburban DSOs that may surround urban cores are often the locus of a majority of a region's load growth due to rapid population growth near the suburban-rural fringe from development on vacant parcels and subsequent infill of remaining islands of undeveloped land. Annual load growth rates there can be very high, with sustained rates as high as 10% over multiple decades being possible. In urban DSOs, load growth is largely due to densification as more high-rise buildings and apartment-type residences replace previous customer buildings.

Table 6. Prototypical substation peak demand characteristics and land costs by DSO type.

DSO Type	Peak Demand								Land Costs	
	Customers per Sub-station, Avg. (-)	Peak Demand per Customer, Avg. (kW)	Peak Demand per Sub-station, Avg. (MW)	Peak Demand per Feeder, Avg. (MW)	No. Feeders per Sub-station, Avg. (-)	Peak Demand per Sub-station, Nominal (MW)	Power Factor at Peak Demand (-)	Transformer Redundancy Factor (-)	BLM Zone No. (-)	Market Value ($/acre)
Rural	1,709	4.5	7.7	4	2	8	0.9	1.0	5	$683
Suburban	6,862	5.5	37.7	10	4	40	0.9	1.5	12	$34,141
Urban	11,072	8.0	88.6	15	6	90	0.9	1.5	14	$396,000

Table 7. Prototypical substation design features and costs by DSO type.

DSO Type	Substation			High-Voltage		Low-Voltage			Cost	
	New Substation or Upgrade	Capacity (MVA)	Breaker Configurations	Volt-age (kV)	No. Lines (-)	Volt-age (kV)	Trans-form-ers (-)	Feeders (-)	Total Sub-station ($K)	Cost per kVA ($/kVA)
Rural	New	8.9	Single-Bus	138	1	13.8	1	2	$8,346	$939
Suburban	New	66.7	Main & Transfer Bus	138	2	13.8	1	4	$14,853	$223
Urban	New	150.0	Main & Transfer Bus	138	4	13.8	2	6	$27,828	$186
Rural	New + Upgrade	13.3	Single-Bus	138	1	13.8	1	3	$9,953	$747
Suburban	New + Upgrade	83.3	Main & Transfer Bus	138	2	13.8	1	5	$16,677	$200
Urban	New + Upgrade	175.0	Main & Transfer Bus	138	4	13.8	2	7	$30,548	$175
Rural	Upgrade	4.4			0		0	1	$1,608	$362
Suburban	Upgrade	16.7			0		0	1	$1,824	$109
Urban	Upgrade	25.0			0		0	1	$2,720	$109

In the DSO+T study, the rate of overall load growth in DSO substation capacity is assumed to result from two distinct types of load growth:

- Greenfield growth rate that reflects the construction of new substations to serve customers in rapidly developing areas, typically at suburban fringe near the suburban-rural boundary
- Brownfield growth rate for existing substations (including newly constructed greenfield substations) that reflects the sum of:
  - growth in the number of customers served by the substation due to population growth including densification, i.e., conversion of single-family neighborhoods to multifamily housing, or low-rise commercial areas to high-rise commercial
  - growth in load of existing customers due to the addition of electric loads less any reductions due to increasing levels of energy efficiency and self-generation (net can be negative).

The distinction between brownfield and greenfield growth is important to the study for several reasons. Over time, brownfield growth may eventually exhaust any marginal capacity provided at the time a substation was constructed or last upgraded. However, increasing the capacity of an existing (brownfield) substation primarily involves the addition of transformer capacity, which is only one itemized cost.[8] Costs for land and other fixed substation costs have already been attributed to the initial (greenfield) substation construction, so subsequent capacity upgrades are substantially less expensive than entirely new substations per unit of capacity added. In contrast, the costs for new (greenfield) substations reflect all initial substation costs, including land and other costs that are ancillary to the direct provision of capacity such as those for communications and control. So, the cost of capacity in new substations built to serve areas undergoing greenfield growth is much higher than that for upgrading existing substations serving brownfield areas (both undeveloped and fully developed).

There is also an important distinction between brownfield and greenfield load growth and hence substation costs in transactive cases. The study assumes the initial period of rapid penetration of responsive assets after the adoption of the DSO+T strategy has concluded, and subsequently DSOs confidently take the availability of transactive flexible assets into account when constructing new substations or upgrades to them.[9] When greenfield substations are constructed in a transactive case, immediate substation fleet cost savings occur, as the substations are then constructed with a lower initial capacity margin reflecting the ability to manage peak demand in the future. In contrast, among brownfield substations in a transactive case, savings in substation costs begin only when brownfield load growth eventually triggers the need for a capacity upgrade, which may be some time in the future for any given substation.

A conceptual model of load growth and substation capacity growth in a utility is shown in Figure 7 for a DSO with a fixed service territory indicated as the outermost circle shown. At the core of

[8] New feeders may also be added if any have reached the practical limit of their load-carrying capacity (associated with voltage drops and/or energy line losses). Adding feeders requires additional switchgear, protection, voltage management, and other equipment, and hence associated costs. The DSO+T study assumes that a new feeder is added to a substation during a substation upgrade.

[9] The DSOs have learned to monitor peak demand closely (on at least an annual basis) to assess whether an infrastructure upgrade to a constrained substation has finally become more cost effective for ratepayers than continuing to rely on response from flexibility assets. This is needed due to the associated gradual, albeit predictable, escalating value of incentives required to elicit a steadily increasing degree of response from them.

the service territory is a suburban or urban area (shown in brown) that has previously undergone a rapid growth spurt and subsequently is only growing slowly due to brownfield growth, i.e., the fully developed brownfield service area. The bulk of the remainder of the service territory is essentially undeveloped rural land that also is undergoing relatively slow brownfield load growth, i.e., an undeveloped brownfield service area shown in tan. At the interface between these two, i.e., at the rural-suburban fringe, is a rapidly developing greenfield service area where rural land is being converted into suburbs. The number of years for this conversion from undeveloped to fully developed is defined as the greenfield transition period.

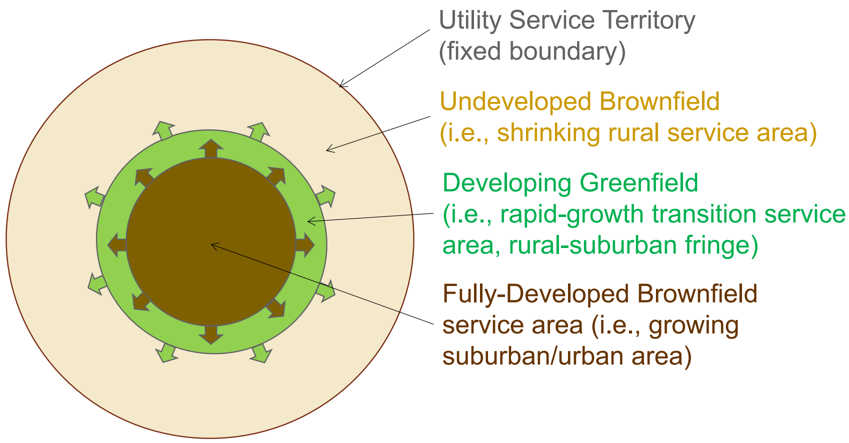


Figure 7. Conceptual model of land use and load growth for distribution capacity expansion.

The developing greenfield area is analogous to the liquid layer surrounding a block of ice, in which water vapor representing population growth is condensing on the surface of the solid ice (representing the fully developed suburban/urban area). As it freezes the condensate slowly enlarges the fully developed frozen core, indicated by the brown arrows. The thickness of the developing greenfield area is directly related to the greenfield load growth rate and the transition time associated with that development. These relationships are formally derived as a model of load growth and substation capacity expansion in Section B.3 of Appendix B.

Each DSO in the study is assigned a brownfield and greenfield growth rate based on its DSO type as shown in Table 8, where the total growth rate for a DSO is the sum of the greenfield and brownfield growth rates.

Table 8 also shows substation design parameters assumed for each DSO type. The peak demand density ratio is the ratio of undeveloped brownfield service areas to developed brownfield areas. This was simply estimated based on an assumed ratio of single-family residential homes in undeveloped areas (two homes per 40 acres) to that in fully developed suburban areas (eight homes per acre), resulting in a density ratio of 0.63% for undeveloped service areas that is applied to all DSO types. Assumptions about the fraction of a DSO's service territory that is fully developed are also shown as a function of DSO type. The substation nominal design lifetime—the number of years over which a new or upgraded substation is likely to serve peak demand if expected load growth occurs—is assumed to be 20 years in the DSO+T study for all DSO types, as shown. Similarly, the greenfield transition period is assumed to be 4 years across all DSO types.

Given these assumptions, with knowledge of a DSO's peak demand, Appendix B shows that all the other relevant parameters describing a DSO's service territory and substation fleet can be derived for BAU cases. This is also true for transactive cases with the additional knowledge of the fractional reduction in peak demand achieved as determined by the DSO+T simulation.

The result is a methodology used to estimate the capacity of a DSO's existing substations and the annual capacity added by construction of new substations and upgrades to existing substations, represented as Cap_{exist}, Cap_{new}, and Cap_{up} (respectively) in Equation (3). With the assumptions about the prototypical substation capacity for each DSO type shown in Table 6, each of these substation capacity subtotals can be estimated.

Given these assumptions, the methodology is illustrated here by the resulting substation fleet capacities and rates of construction shown in Table 9. It shows parameters describing the substation fleets for prototypical rural, suburban, and urban DSOs, in total and by service area development stage (undeveloped, greenfield, and fully developed). For an example of each type of DSO, Table 9 shows the total capacity of its existing fleet (Cap_{exist}) and the total annual rate of capacity construction (the sum of Cap_{new} and Cap_{up}). The peak load of the urban DSO is that of DSO #1 of the study's eight-node case, so the parameters of the example urban substation fleet are literally the estimates for DSO #1.

Since the DSO's levelized annual capital cost for its substation infrastructure is based on its total fleet capacity and annual construction, the number of substations it has is implicit in the cost calculation. However, some software- and network-related costs discussed in Section 3.2.3 are based in part on the number of DSO-owned substations, which can be estimated by dividing its substation fleet capacity by the average substation capacity for its DSO type as indicated in Table 7.

$$NoSubs = \left(Cap_{exist} + Cap_{up} + Cap_{new}\right) / SubCap_{avg} \tag{3}$$

where: NoSubs ≡ Number of substations in substation fleet at the end of the year

Cap_{exist} ≡ capacity of existing substations

Cap_{up} ≡ added capacity of upgrades to existing substations for the year

Cap_{new} ≡ capacity of new substations constructed for the year

$SubCap_{avg}$ ≡ average capacity for substations for the DSO type

Table 8. Peak demand growth rates and substation design parameters by DSO type.

DSO Type	Brownfield (%)	Greenfield (%)	Total (%)	Peak Demand Density Ratio* (%)	Fully Developed Frac. of Service Territory (%)	Substation Design Lifetime (yr)	Greenfield Transition Period (yr)
Rural	0.5%	1.0%	1.5%	0.63%	10%	20	4
Suburban	1.0%	10.0%	11.0%	0.63%	63%	20	4
Urban	2.0%	1.0%	3.0%	0.63%	90%	20	4

Table 9. Exemplary BAU substation fleets by DSO type and service area development stage.

DSO Type	Peak Demand (MW)	Service Area Development Stage	Existing Fleet Total			Annual Construction (New and Upgrades)		
			Capacity Factor (%)	Total Capacity (MVA)	Sub-stations (-)	Substation Capacity (MVA/yr)	Substation Capacity (%/yr)	Substations (1/yr)
Rural	1,200	Undeveloped	95%	74	33	0.4	0.5%	0.0
		Greenfield	18%	29	1	14.8	50.2%	0.7
		Fully Developed	95%	1,321	59	6.9	0.5%	0.0
		Total		1,425	94	22.1	1.6%	0.7
Suburban	10,000	Undeveloped	91%	28	13	0.3	1.1%	0.0
		Greenfield	16%	2,708	122	1,361.1	50.3%	61.2
		Fully Developed	91%	11,746	529	130.0	1.1%	0.0
		Total		14,482	663	1,491.3	10.3%	61.2
Urban (DSO #1[a])	25,304	Undeveloped	83%	19	9	0.5	2.5%	0.0
		Greenfield	13%	835	38	421.0	50.5%	18.9
		Fully Developed	83%	33,897	1,525	831.8	2.5%	0.0
		Total		34,751	1,572	1,253.3	3.6%	18.9

[a] Of the study's eight-node case

3.2.2 Feeders, Circuits and Meters

The cost of the balance of DSO distribution infrastructure beyond substations is estimated here.

3.2.2.1 Feeders and Circuits

Unlike substations, the capacity of a DSO's distribution feeders and circuits are 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. Only their marginal cost of capacity – that associated with nominal voltage and rated current – can be avoided. When construction labor is included, the relatively high proportion of non-capacity related costs for feeders and circuits leads to their being sized to serve all likely future demand for the area being served with significant margin for error. Combined with the fact that there are finite increments of capacity offered by equipment manufacturers that often significantly exceed the potential reduction in peak demand from the flexible assets (~15%), opportunities to reduce their sizing during construction of infrastructure serving new customers or subsequent upgrade deferrals appear to be rare and are not considered in this analysis. Some savings are possible under various circumstances, but these are left for future efforts to investigate as much more detailed modeling of feeder and circuit infrastructure costs akin to that conducted for substations is required.

Nonetheless, a DSO's total annualized capital cost for its feeders and circuits is a significant part of ther annual expenses that contributed to their annual revenue requirement and hence rates, so it is estimated from:

$$FeederCost_A = FeederCostMva\left(Peak_{MW}/PF_{peak}\right)ACCF_{di}\left(1 + g_g + g_b\right) \tag{4}$$

where: $FeederCost_A$ ≡ levelized annual cost of feeders and circuits

$FeederCostMva$ ≡ initial capital cost of substation capacity per MVA

$Peak_{MW}$ ≡ peak demand

PF_{peak} ≡ power factor at peak demand

$ACCF_{di}$ ≡ annualized capital cost factor for distribution infrastructure

g_g ≡ annual greenfield load growth rate

g_b ≡ annual brownfield load growth rate

where the power factor at peak load is assumed to be 0.9 MVAR/MW.

The capacity cost for feeders and circuits able to deliver power from its substations to customers during peak load periods is assumed to be $200/kVA, including service transformers and service drops. It is assumed to be the same for all DSO types. This assumption is obtained by subtracting the average cost of substation capacity ($250/kVA; see the previous section) from an estimated average cost for the entire distribution infrastructure in the United States ($450/kVA) that is based on Kannberg et al. (2003).

3.2.2.2 Meters

The number of meters a DSO has in any given year assumes there is one meter per customer site. (This is not strictly the case, as a few large customer facilities or campuses have more than one meter but are billed as a single customer.) In addition, the DSO must purchase meters for new customers. The annual growth rate of new customers stems from 100% of the greenfield growth and the fraction of annual brownfield growth results from the addition of new customers rather than densification, which is assumed to be 50%. So:

$$N_{meters} = \mathrm{N}_{cust} \left(1 + g_g + f_{new,b}\, g_b\right) \tag{5}$$

where: N_{meters} ≡ number of meters

N_{cust} ≡ number of customers

g_g ≡ annual greenfield load growth rate

g_b ≡ annual brownfield load growth rate

$f_{new,b}$ ≡ fraction of brownfield load growth resulting in a new meter

A DSO's total levelized annual cost for its customer meters is then the product of the number of meters, its customer class weighted-average cost of meters, and the ACCF for meters:

$$\begin{aligned} MeterCost_A = {} & N_{meters}\,(MeterCost_{res}\, f_{res} + MeterCost_{com}\, f_{com} \\ & + MeterCost_{ind}\, f_{ind})\, ACCF_{di} \end{aligned} \tag{6}$$

where: $MeterCost_A$ ≡ levelized annual cost of meters

$MeterCost_c$ ≡ initial capital cost of meter for customer class c

f_c ≡ customer class c's fraction of total customers

c ≡ customer class (residential: res, commercial: com, industrial: ind)

$ACCF_{di}$ ≡ annualized capital cost factor for distribution infrastructure

By using the ACCF for distribution infrastructure, the meters are assumed to have an average lifetime of 20 years. Thus, in steady state, they are replaced at an average annual rate of 5%, representing a combination of hardware failures and replacement due to obsolescence.

Costs per meter are assumed to vary by customer class as shown in Table 10. Based on a survey of smart metering costs conducted in 2011, costs reported for meters purchased in bulk by San Diego Gas & Electric were estimated at $50-$75, while Pacific Gas & Electric reported costs of $220 including installation (Doris and Peterson 2011). Residential meter costs assumed by the DSO+T study for hardware, installation, and in total are shown in Table 10. No corresponding cost data were found for commercial or industrial customer classes. Hardware costs for commercial meters are assumed to triple since they are three-phase meters whereas residential meters are single-phase. The hardware and installation costs are assumed to increase somewhat because higher voltages are often involved. Industrial meter costs are assumed to roughly triple above that of commercial customers. As the number of residential customers and, hence meters in the DSO+T study, represents 87% of all customers, the rough estimates for commercial and industrial meter costs were deemed adequate (for 11% and ~2% of customers, respectively).

Table 10. Meter costs by customer class.

Customer Class	Hardware ($)	Installation ($)	Total ($)
Residential	$100	$70	$170
Commercial	$370	$150	$520
Industrial	$1,000	$500	$1,500

The cost for customer meters is also assumed to not be affected by the adoption of a DSO+T strategy. While the transactive system design analyzed requires 5-minute interval data to be recorded by the meters rather than today's standard 15-minute interval, the assumption is that the meters are simply read three times as often using a higher bandwidth (and correspondingly more expensive) customer communications network for flexible assets that supplants the BAU AMI network. The additional cost for this network is included in the IT systems costs discussed in the following section.

3.2.3 Information Technology Systems

This section describes the assumptions and process used to estimate the costs of a DSO's IT systems for commonly deployed distribution system controls systems and management software packages. Costs for IT systems are estimated based on a simple generalized model of costs as the sum of a linear function and the cube root of the number of customers, plus a linear function of the number of substations and a constant cost:

$$SysCost = \left(a + b\,(N_{cust}/1000) + c\,(N_{cust}/1000)^{1/3} + d\,N_{sub}\right) ACCF_{dcs} \qquad (7)$$

where: SysCost ≡ initial capital cost of the IT system

N_{cust} ≡ number of customers in DSO

N_{sub} ≡ number of substations in DSO

a ≡ constant cost (minimal cost for smallest DSOs)

b ≡ linear coefficient of number of customers term

c ≡ linear coefficient of number of customers term

d ≡ linear coefficient of number of customers term

$ACCF_{dcs}$ ≡ annualized capital cost factor for distribution controls and software

Note that the coefficient for any given term in the model for an IT system type may be zero.

3.2.3.1 Controls and Management Software

Most DSOs have control and management software packages that automate various distribution system management functions to some degree. These include distribution management systems (i.e., distribution automation systems used for controlling substations), customer information systems, outage management systems, and customer billing systems. The assumed coefficients of the cost model for these systems are shown in Table 11. Also shown are the resulting costs for DSO #1, the largest DSO in the study's eight-node case with 3.8 million customers and an estimated 1,442 substations.

Vendor costs for these systems are a closely held competitive trade secret. Discussions with consultants and former employees of such firms suggest there is not a formulaic process by which they set prices for utilities of various sizes. To some degree they are set by the "price that the market will bear." In addition to what a given utility can afford, the size of the utility is certainly taken into account, as is the degree of assistance that may be required to set up the software and system models for them. Since cost data were not available, the DSO+T study used interviews with subject matter experts and considerable judgment in attributing system costs to them. Nonetheless, such estimates were required for individual systems to allow their costs to be attributed to DSO sub-entities (owner operator, market operator, or LSE) should they be unbundled from the parent DSO.

Finally, it should be noted that control and management software packages do not have a uniform set of functionality and capabilities across all DSOs. The larger the DSO is in terms of number of customers and peak demand, the more likely it utilizes more advanced, feature-filled versions of these packages. This is simply because they can afford to do so, since their revenues tend to increase linearly with sales of electricity, but the package costs from vendors exhibit considerable economy of scale. While all DSOs likely have some form of software investment, some DSOs in ERCOT serve as few as a thousand customers. Accordingly, their "customer information system" may consist of a simple mail list or even an Excel spreadsheet, for example.[10] So, it should be noted that the constant coefficient (a) in Equation (7) represents the cost of the rudimentary systems used by the smallest DSOs and forms an insignificant part of the system cost for larger DSOs driven by the other coefficients of the cost model (b, c, and d). Hence, the cost model attempts to represent both the vendors' sliding scale of software costs as a function of DSO size and range of capabilities purchased by DSOs as a function of their size.

Hence, the general process for establishing the cost model coefficients was largely one of trial and error until the results matched sparse anecdotal costs obtained for specific (generally large) utilities and exhibiting reasonable increasing costs for utilities ranging in size from the smallest to those serving a few hundred thousand customers. Fortunately, these software costs are not a large component compared to a DSO's hardware infrastructure and only the functionality of the billing system is expected to change when a DSO+T strategy is adopted. This is indicated in Table 11 by the addition of a 25% cost adder for a system capable of supporting transactive rate billing. It is estimated as the marginal cost of billing at 5-minute instead of 30-minute intervals and using a dynamic price from the retail market at each substation. There are no examples of commercially available software upon which to base this estimate.

3.2.3.2 Communications Networks

Each DSO in the study is assumed to have two communication networks:

- Customer network is the AMI network in a BAU case and an enhanced AMI network capable of handling data traffic involved in collecting bid curves from and broadcasting cleared retail prices to customers on a transactive rate
- Distribution automation network, also known as the distribution system supervisory control and data acquisition network, capable of supporting monitoring and supervisory control of substations (historically radio frequency networks and sometimes optical fiber networks).

The cost model used for these communication networks is shown in Table 12.

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[10] Many also use a billing cooperative rather than perform billing themselves, so in this instance the associated annualized capital cost reflects the annual cost of this service.

Table 11. Controls and software costs.

Controls or Software Package	Controls and Software Cost Model Coefficients ($)						Capital Cost ($K) for DSO #1[a]
	Constant	Per 1000 Customers	(Per 1000 Customers)$^{1/3}$	Per Sub-station	Transactive Cost		Customers: 3,843,475 DSO Type: Urban Substations: 1,442
	a	b	c	d	Line Item	Adder (%)	
Distribution management system	$50,000			$25,000	No	0%	$36,110
Outage management system	$10,000	$1,000		$10,000	No	0%	$18,278
Customer information system	$10,000	$4,000	-0.20		No	0%	$15,384
Billing system	$30,000	$50		$10,000	No	25%	$14,646
Transactive retail markets	$30,000	$100	1.00	$20,000	Yes	0%	$29,264

[a] In the study's eight-node case.

Table 12. Communication network costs.

Communication Network	Communication Network Cost Model Coefficients ($)						Capital Cost ($K) For DSO #1[a]
	Constant	Per 1000 Customers	(Per 1000 Customers)$^{1/3}$	Per Sub-station	Transactive Cost		Customers: 3,843,475 DSO Type: Urban Substations: 1,442
	a	b	c	d	Line Item	Adder (%)	
AMI/Customer network - Rural		$349,894			No	25%	N/A
AMI/Customer network - Suburban		$119,894			No	25%	N/A
AMI/Customer network - Urban		$119,894			No	25%	$460,810
Day-ahead network		$25,000			No	0%	$96,087

[a] In the study's eight-node case.

Also shown are the resulting costs for DSO #1, the largest DSO in the study's eight-node case with 3.8 million customers and an estimated 1,442 substations. Note that the coefficients a, c, and d of the general IT system cost model in Equation (7) are not used for network costs. Separate cost models for AMI/customer networks in rural, suburban, and urban DSO types allow for different assumptions about the effect of customer densities per square mile and network technologies to be included (especially in rural vs. suburban or urban areas).

Costs for the distribution automation network were based on a commercially available survey of markets for utility control and outage management systems (Newton-Evans 2020) and interviews with subject matter experts. They are also shown in Table 12.

Of these two networks, by far the costliest is the customer network. The costs per customer are based on average total AMI system costs (including meters and communications network) reported by the federal Smart Grid Investment Grant program for 12 investor-owned utilities, municipals, and rural cooperatives using a variety of network technologies (DOE-OE 2016). The cost estimates for meters are described above in Section 3.2.2. Subtracting the estimated per-customer meter cost from the average total system cost produces an estimate of the average communications network cost shown in Table 12.

This model is then validated by comparing total AMI system costs for two utilities that were not among the 12 used to develop the model. A survey of smart metering costs cited total AMI system costs (meters plus communications network) for two major utilities (Doris and Peterson 2011). San Diego Gas and Electric was reported as having replaced 1.4 million meters at a cost of $500 million, and Southern California Edison was reported to be replacing 5 million meters at a cost of $1.6 billion. Table 13 shows the network cost model combined with the meter cost estimates predicted total AMI system costs within 6%.

Table 13. Comparison of modeled and reported total AMI system costs.

Utility	AMI Meters[a]	AMI System Costs ($K)			
		Modeled			Reported Total[b]
		Meters	Network	Total	
Pacific Gas & Electric	5,000,000	$1,100,530	$599,470	$1,700,000	$1,600,000
San Diego Gas & Electric	1,400,000	$308,148	$167,852	$476,000	$500,000

[a] AMI meters in 2011

[b] AMI total cost net of estimated meter costs in 2011

3.3 Operational Expenses

3.3.1 Wholesale Purchases

A DSO's total annual cost for wholesale energy purchases is the sum of its cost for energy purchased with bilateral contracts, the day-ahead wholesale market, and the real-time market:

$$CostEnergy_{whls} = (CostEnergy_{bi} + CostEnergy_{da} + CostEnergy_{rt}) \quad (8)$$

where: $CostEnergy_{whls}$ ≡ total cost of wholesale energy purchases

$CostEnergy_{bi}$ ≡ cost of wholesale energy purchased via bilateral contract

$CostEnergy_{da}$ ≡ cost of wholesale energy purchased from ISO's day-ahead market

$CostEnergy_{rt}$ ≡ cost of wholesale energy purchased from ISO's real-time market

Each of the wholesale cost components in Equation (8) are discussed further in the subsections that follow.

3.3.1.1 Bilateral Energy Contracts

The study assumes that each DSO buys a substantial fraction of its annual energy via a bilateral contract with generators, displacing some of its exposure to market prices in the day-ahead and real-time markets. Bilateral contracts take many forms in structure and terms in the real-power system, but the study assumes the DSO's bilateral contracts are all in the form of three blocks of energy at constant power over three time blocks (weekdays, weekday evenings and daytime weekends, and nighttime), with fixed prices for each block. The block prices are based on an analysis of the annual time series of wholesale day-ahead market prices (from the study's simulation) that results in a wholesale time-of-use rate. The time blocks are defined by observing average hourly prices for weekdays and weekends and arbitrarily selecting hours defining daytimes and evenings to capture the major transitions in the price shapes, as shown in Table 14.

Table 14. Wholesale bilateral contract time blocks.

Day of Week	Time Block	Starts at	Ends at
Weekday	Daytime	5 a.m.	4 p.m.
	Evening	4 p.m.	8 p.m.
	Nighttime	8 p.m.	5 a.m.
Weekend	Daytime	5 a.m.	8 p.m.
	Nighttime	8 p.m.	5 a.m.

The price for each block is simply the consumption weighted-average day-ahead market price over the course of the year. The resulting bilateral wholesale contract prices are shown in Table 15.

Table 15. Wholesale bilateral contract time block prices (DSO #1 MR-BAU 8-node case).

Contract Time Block	Bilateral ($/MWh)
Weekday-Daytime	$28.5
Weekday-Evening and Weekend-Daytime	$31.4
Nighttime	$25.6

From the DSO simulation results, the daily quantity of energy purchased by a DSO in each block is based on their minimum load during that block over the course of the year. That is, the DSO purchases its base-load energy [MWh] via the bilateral contract at a constant power [MW] that never exceeds the load from its customers during the block, including distribution system losses. Although this varies, a typical DSO in this study purchases about 55% of its annual energy via such contracts. Then, the cost of a DSO's wholesale energy purchased via its bilateral contract is simply:

$$CostEnergy_{bi} = \sum_{h=1}^{8760} Q_{bi}(h)\, P_{bi}(h) \qquad (9)$$

where: $CostEnergy_{bi}$ ≡ annual cost of wholesale energy purchased via bilateral contract

$Q_{bi}(h)$ ≡ energy purchased via bilateral contract for hour h

$P_{bi}(h)$ ≡ bilateral contract price in hour h

H ≡ index, hour of the year

3.3.1.2 Energy Market Purchases

Having purchased a fixed block of energy at a fixed price via a bilateral contract, a DSO then purchases the remainder of the energy needed to serve its customers from ISO day-ahead and real-time markets. In most U.S. wholesale electricity markets, DSOs are required to submit their forecast separate from their day-ahead bid and thus can purchase a different quantity than their forecast in the day-ahead market should they chose to do so.[11] The ISO market clearing process also requires their schedule and sources of hourly power purchased via bilateral contracts will have been submitted and approved for feasibility, and these power flows are accounted for as part of the unit commitments in the day-ahead market clearing process. The ISO also typically allows a DSO's bid to be price-responsive, generally by allowing them to increment or decrement their bid for each hour in blocks defined by price thresholds (PJM 2017).

The wholesale market simulation tool used in the study does not support this level of detail. It does not explicitly account for scheduling power flows from bilateral purchases. Further, the study does not presume to know which specific generators are under bilateral contract to deliver any given DSO. So in the study the wholesale markets clear assuming there are no bilateral contracts that must be specifically scheduled. This treats bilateral purchases as purely economic transactions that lock in the bilateral price for a portion of the energy a DSO "purchases" instead of the market price. So, each DSO in the study bids its entire forecasted hourly load into the day-ahead market, but pays the prices stipulated in its bilateral contract for the portion represented by the contracted quantities. Fortunately in the United States, DSOs tend to purchase their entire forecast in the day-ahead market, so this assumption conforms to prototypical DSO behavior, and so it should have a small effect on the clearing price.

By the same token it is also presumed that allowing the markets to "dispatch" the generators under bilateral contracts does not distort the power flows enough to significantly alter the market clearing price. This seems like a reasonable assumption given that generators holding bilateral contracts are also market participants and hence may trade their commitments to lower cost providers in the marketplace, which tends to drive power flows to resemble that predicted by the simulated market clearing of the entire load.

Having submitted its bids into the ISO day-ahead market, the market then returns the cleared quantity purchased and the locational marginal price to each DSO. The cost of the energy a DSO purchases in the day-ahead market at market prices in any hour is simply the product of the locational marginal price and the difference between the cleared quantity and the quantity in its bilateral contract for that hour:

[11] To inform the ISO day-ahead unit commitment process. Typically the ISO also makes its own independent forecasts. The methods the DSO+T study uses for these forecasts and for assembling the price-response curves in transactive cases are described in (Widergren et al. 2022).

$$CostEnergy_{da} = \sum_{h=1}^{8760} LMP_{da}(h)\left(Q_{clear}(h) - Q_{bi}(h)\right) \quad (10)$$

where: $CostEnergy_{da}$ ≡ annual cost of energy purchased from day-ahead market

$LMP_{da}(h)$ ≡ day-ahead wholesale locational marginal price for node serving DSO for hour h

$Q_{clear}(h)$ ≡ DSO's energy cleared in the day-ahead market for hour h[12]

$Q_{bi}(h)$ ≡ energy purchased via bilateral contract by DSO for hour h

h ≡ index, hour of the year

The ISO real-time market operates on 5-minute intervals and the DSO either pays for or receives payment for the difference between its actual consumption and the sum of its advance purchases in the day-ahead market and via bilateral contract, that is if either buys or sells its 5-minute energy imbalance in the ISO real-time market. Its actual consumption is metered at its point of delivery on the high-voltage side of the substation and therefore includes consumption by its customers plus losses in the substation transformer(s) and the DSO's feeders and circuits. The energy a DSO bought in advance in the day-ahead market and via bilateral contract for any given hour is assumed to be spread uniformly among the 12 5-minute intervals of the hour, so the cost of the real-time energy it must purchase to reconcile its advanced purchases with its consumption is:

$$CostEnergy_{rt} = \sum_{h=1}^{8760}\sum_{i=1}^{12} LMP_{rt}(i)\left[Q_{dso}(i) - \frac{Q_{clear}(h)}{12}\right] \quad (11)$$

where: $CostEnergy_{rt}$ ≡ annual cost of energy purchased from day-ahead market

$LMP_{rt}(i)$ ≡ real-time wholesale locational marginal price for node serving DSO for 5-min. interval i of hour h

$Q_{dso}(i)$ ≡ bulk system energy delivered to DSO in 5-min. interval i of hour h

$Q_{clear}(h)$ ≡ DSO's energy cleared in the day-ahead market for hour h

$Q_{bi}(h)$ ≡ energy purchased by DSO via bilateral contract for hour h

h ≡ index, hour of the year

i ≡ index, 5-minute interval within an hour h

3.3.1.3 Capacity Payments

Many but not all ISOs in the United States have capacity markets that are used to incentivize construction of new capacity. ERCOT is one notable exception in that it does not have a capacity market, and in the absence of such incentives to construct new resources, ERCOT's energy market prices are instead allowed to increase to comparatively very high levels when

[12] Note that, per the discussion above, because bilateral contracts are "dispatched" by the day-ahead market clearing process in the DSO+T study's simulation, $Q_{clear}(h)$ includes the total energy the DSO purchases in advance, i.e., the sum of its bilateral and day-ahead market purchases.

supply becomes scarce. Thus, the cost of capacity in ERCOT is combined with the cost of energy and generators can charge “scarcity rent” well above their costs when supply tightens.

The wholesale market model used in the study does not support the complex bidding strategies involved as a standard feature, however, and the study is designed to represent conditions in the U.S. power system broadly rather than the market design of ERCOT specifically.[13] 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.[14] 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. Furthermore, while bilateral contracts between generators and DSOs are common, the study presumes that the clearing price sets a price benchmark toward which such bilateral capacity contracts converge.

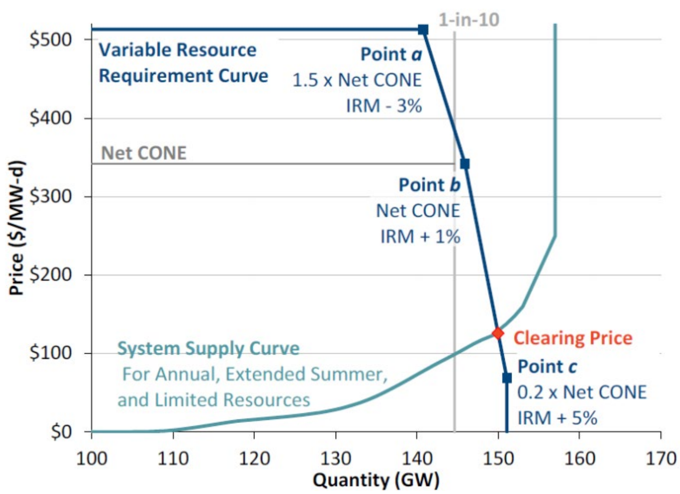

Figure 8. Example of capacity demand and supply curves for PJM (Jenkin et al. 2016; Meyn et al. 2018, page 93).

The study does not actually simulate such an auction, as data to populate it with realistic supply bids are not readily available. Instead, it simply uses typical U.S. capacity market clearing prices, along with quantity-price sensitivity factors to determine actual prices for each case. The quantity-price sensitivity factor is included to capture the nontrivial impact that reducing the required capacity has on the cleared capacity market price. For example, as can be seen in Figure 8, a 7.5% reduction in required capacity would reduce the cleared price by approximately 30% (a sensitivity factor of ~4). In addition, Bowring (2013) found that a “2.5 percent demand reduction resulted in a 21 percent reduction in [Reliability Pricing Model] revenues for the 2015/2016 Base Residual Auction (a difference of $2.7 billion in market revenues) compared to

[13] The AMES market model allows sophisticated learning algorithms for supply bidders that have been used to study closely related effects such as market collusion but using such advanced capabilities was beyond the scope of the DSO+T study. Most U.S. ISOs prohibit suppliers from charging more than their costs and enforce such rules by closely monitoring their markets in any event.
[14] Wholesale markets such as PJM’s allow vertically integrated utilities to count the generation they own as capacity. In the DSO+T study all generators are owned by private investors.

the revenues that would have resulted without the reduction” (a sensitivity factor of ~8.4). For this study we assume a sensitivity factor of 5, identical to the value used in the Grid-Interactive Efficient Buildings Roadmap value analysis (DOE 2021, page 106). That is, a 1% reduction in required capacity reduces the cleared capacity market price by 5%.

The study assumes a nominal capacity price of $75/kW-yr for the BAU cases based on an examination of reported U.S. capacity market prices over time (Jenkin et al. 2016). It is known that these are well 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).

By way of example, because they are the lowest cost supply resources available, simple-cycle natural gas turbines, at a capital cost of $1000/kW, are often used to define the marginal cost of additional capacity. Table 2 indicates the levelized ACCF for such a resource owned by a corporate entity is 9.13%, so if the capacity market reflected the full levelized annual cost of such capacity a clearing price of $91/kW might be expected (21% more than the $75/kW-yr assumption).

A DSO’s annual cost for capacity is estimated as:

$$CostCapacity_A = C_w \; \bar{P}_{max} \; \text{IRM SF} \; (1-(\bar{P}_{max\text{-}BAU} - \bar{P}_{max})/\,\bar{P}_{max\text{-}BAU}) \qquad (12)$$

where: $CostCapacity_A$ ≡ DSO’s annual cost of capacity reservation

C_w ≡ annual capacity market clearing price = $75/MW-yr

$\bar{P}_{max}$ ≡ annual maximum average power consumed in 5-min. interval

$\bar{P}_{max\text{-}BAU}$ ≡ annual maximum average power for the base case

IRM ≡ installed reserve margin = 115%

SF ≡ price-quantity sensitivity factor = 5

3.3.1.4 Transmission Access Fees

The annual transmission access fees paid by DSOs are collected by the ISO and distributed to the transmission system owners as part of their regulator-approved wholesale transmission rates. In the study a fixed, postage stamp energy rate of $12.30/MWh was assumed, based on California Independent System Operator’s (CAISO's) 2020 rate for high-voltage transmission access.[15] 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. Transmission access fees are computed in various regions of the United States in a number of ways, some very complex (ERCOT). Since the impacts of transactive energy on transmission owners is not a primary focus of the DSO+T study, a simple volumetric basis like that used by the CAISO is used. California’s postage stamp rate was assumed because its transmission system resembles ERCOT’s in geography and vintage.

In the DSO+T study a DSO’s annual transmission fee is computed as:

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[15] For a western U.S. transmission system roughly resembling California

$$TransFee_A = \bar{P}_t \sum_{h=1}^{8760} \sum_{i=1}^{12} Q_{dso}(i) \qquad (13)$$

where: $TransFee_A$ ≡ annual transmission access fee

$\bar{P}_t$ ≡ transmission access postage stamp rate = $12.30/MWh

$Q_{dso}(i)$ ≡ bulk system energy delivered to DSO in 5-min. interval I of hour h

h ≡ index, hour of the year

i ≡ index, 5-minute interval within an hour

3.3.1.5 ISO Fees

ISOs recover their annual operating costs by collecting operations fees paid by the DSOs. The ISO fee assessed on energy supplied to DSOs varies somewhat from the study's transactive cases relative to the corresponding BAU case so as to maintain recovery of the ISO's annual expenses, as described in Section 6.3.

The annual cost of a DSO's ISO fee is computed as:

$$IsoFee_A = \bar{P}_I \sum_{h=1}^{8760} \sum_{i=1}^{12} Q_{dso}(i) \qquad (14)$$

where: $IsoFee_A$ ≡ annual cost of ISO fees

$\bar{P}_I$ ≡ ISO fee for DSO+T Study case (see Section 6.3)

$Q_{dso}(i)$ ≡ bulk system energy delivered to DSO in 5-min. interval i of hour of year h

h ≡ index, hour of the year

i ≡ index, 5-min. interval within an hour

3.3.1.6 Ancillary Services

A power system requires ancillary services to provide:

- Frequency regulation – balancing continual, short-term fluctuations in supply and demand that otherwise would manifest as unacceptable deviations from the desired frequency (60.00 + 0.05 Hz). It is typically supplied by increasing or decreasing the output of generators quickly (within ~2–4 seconds of receiving a signal to do so).[16] In the United States, the typical quantity of regulating reserves is about ½% to 1% of the total demand at any time.
- Spinning (synchronous) reserve – generation capacity on standby to quickly (~1–5 minutes) but temporarily take the place of a generator that suffers an unplanned outage. This is typically provided by generators that are running but at less than full capacity. The amount of spinning reserve required varies by 5% of total demand is a typical amount.

[16] Some U.S. ISOs allow flexible customer assets to participate by changing net load. As with bulk system generators, fast communications and performance guarantees are required.

- Nonspinning (replacement) reserve – generation capacity on cold standby that can start up quickly (~10-30 minutes) to relieve spinning reserves if an outage persists, thereby restoring the safety margin provided by spinning reserves in case another outage occurs. The quantity of nonspinning reserve is typically equal to that for the spinning reserve it must replace.

ISOs purchase ancillary services in the form of reservation payments to generators or other qualified resources to reserve a block of power (MW) for one of these purposes. The ISO specifies the amount of each type of reserve that is required to maintain reliable electric power in the face of these uncertainties and contingencies, and the hourly prices for these services are determined by a periodic auction in which they are purchased from suppliers. Hence, prices for ancillary services fluctuate with operational and market conditions. In addition, generators are paid for their incurred operating costs when they are called upon and other suppliers are rewarded on a similar basis. Increasingly, ISOs are also utilizing a sliding scale of payments to reward faster and more accurate responses.

While flexible assets are increasingly allowed to participate in supplying these ancillary services, the study did not undertake to estimate these potential value streams. Doing so was deemed too challenging at the time the study was conducted for several reasons. First, it would have had to develop the capability to a model ancillary service markets and how suppliers develop time-series bids into them. Second, the study would have had to model time lags associated with communication systems to flexible assets, in addition to their physical response to dynamic signals from the DSO. Third, it would need to add considerable capability to the agents that are used to control the response of flexible customer assets and account for sliding-scale payments based on the assets' performance.

Finally, the overall quantities of power and energy involved are relatively small and could easily be provided by a fraction of the flexible customer assets analyzed by the study. The effect of competition among these assets to supply a limited demand for ancillary services is uncertain but has been envisioned as potentially leading to a collapse in market prices.

Therefore in light of these technical barriers and market uncertainties, analyzing the value of flexible customer assets providing ancillary services is left for future studies. Since ancillary services do not represent a significant cost of operating a power system and DSOs pay for their prorated share of those costs, the study accounts for the payments they make to the ISO to cover them, but based on average annual prices for each service (Potomac Economics 2017) rather than using hourly prices reported by the ERCOT market monitor, as shown in Table 16. The study uses the average of the prices reported separately for regulation up and down.

Table 16. ERCOT average annual ancillary service prices.

Ancillary Service	Avg. Annual Price ($/MWh)
Spinning Reserve	$11.10
Nonspinning Reserve	$3.91
Regulation, Up	$8.20
Regulation, Down	$6.47
Regulation, Average Up and Down	$7.34

A DSO's annual cost of its share of the ISO's ancillary service reservation payments for each service is estimated as the product of the average price and the fraction of the annual total energy supplied to the DSO represented by each ancillary service

$$CostReserve_A = \left(f_{reg}\,\bar{P}_{reg} + f_{spin}\,\bar{P}_{spin} + f_{nspin}\,\bar{P}_{nspin}\right)\sum_{h=1}^{8760}\sum_{i=1}^{12} Q_{dso}(i) \tag{15}$$

where: f_{reg} ≡ fraction of total system demand required for regulation reserve = 1%

f_{spin} ≡ fraction of total system demand required for spinning reserve = 5%

f_{nspin} ≡ fraction of total system demand required for nonspinning reserve = 5%

$\bar{P}_{reg}$ ≡ annual average hourly reservation price for regulation = \$7.34/MWh

$\bar{P}_{spin}$ ≡ annual average hourly reservation price for spinning reserve = \$11.10/MWh

$\bar{P}_{nspin}$ ≡ annual average hourly reservation price for nonspinning reserve = \$3.91/MWh

$Q_{dso}(i)$ ≡ bulk system energy delivered to DSO in 5-min. interval i

h ≡ index, hour of the year

i ≡ index, 5-minute interval within an hour

The fraction of the total system demand that is required and for spinning and nonspinning reserves is assumed to 5%, and that for regulation is assumed to be 1%.

3.3.1.7 Transmission Losses

In the study transmission losses are not computed with meaningful fidelity. In the United States they are generally small, in the range of 1%-3%, so this is not a significant effect on the study results. In its CFS, a DSO's cost for transmission losses is assigned a value of zero (pending future instantiation of simulating them in the future).

3.3.2 Labor and Workspace

Labor and workspace costs are significant components of a DSO's annual expenditures. The study estimates these based on a model of the number of utility employees in various job classifications as a function of the number of utility customers. These are then multiplied by the annual labor costs for each job classification to estimate the costs and by assumptions about the workspace required for office workers and linemen to estimate the workspace costs. These are each described in more detail in this section.

3.3.2.1 Labor

A DSO's costs associated with labor represent the largest portion of a DSO's operational expenses after its wholesale costs. This primarily consists of the salaries of its employees but also includes the cost of workspace for them. So, estimating the number of employees within a DSO is necessary. Further, salaries vary widely depending on skill set—linemen are paid considerably more than customer service representatives, for example, so some breakdown of the total number of employees into job classifications is useful for making these estimates. This is particularly important to the extent that adoption of a DSO+T strategy is projected to require more employees in some job classifications but not in others.

To facilitate this breakdown, the employees in each job classification are defined here as a team. A team consists of a set of base team members plus a hierarchical set of line managers for them that is dependent on the number of base team members. The base team members are all assumed to be in the same job classification based on the skills involved in performing the team's work and make the same average salary. Hence, a team within a DSO corresponds to all employees in a job classification and their line managers. A simple algorithm based on the minimum and maximum number of direct reports is used to estimate the number of layers of line management needed to supervise the team and the number of line managers in each layer. The algorithm also uses a salary escalation factor to define the relationship between the average salary of the line managers at any layer relative to the average salary of the base team members. This line management algorithm is described in Appendix C.

The study developed a simple regression model of the total number of employees a utility has overall as the initial step in making such estimates. As a basis for this, the number of employees in a sample of 11 utilities spanning the range of sizes in the United States, nine of them from Texas, was tabulated along with the number of customers served and other characteristics. A simple regression model of the total number of employees was developed based on these data, as described in Appendix D. This regression model provides control totals used here to help calibrate assumptions about the number of employees in each team so as to maintain those control totals.

The size of the DSO workforce in many job classifications should not be assumed to be linearly proportional to the number of customers. For example, the legal team, the number of control room operators, and the employees that operate business or communications networks all exhibit strong "economies of scale" as a utility serves more customers and do not grow linearly with the number of customers served. On the other hand, the number of employees in other job classifications such as customer service representatives and linemen, by their nature, tend to grow in proportion to the number of customers served. In other cases, there is a relationship to the number of substations. So, a general model of the number of employees in any team is

$$NoEmployees_t = a_t + \left(b_t \, (N_{cust}/1000) + c_t \, (N_{cust}/1000)^{1/2} + d_t \, N_{sub} \right) TeamFactor_t \quad (16)$$

where: $NoEmployees_t$ ≡ number of base-level employees for team t

t ≡ index indicating team t

a_t ≡ minimum number of base-level employees for team t

b_t ≡ number of base-level employees per thousand DSO customers

c_t ≡ number of base-level employees per square root of DSO customers/1000

d_t ≡ number of base-level employees per substation

N_{cust} ≡ number of DSO customers

N_{sub} ≡ number of the DSO substations

$TeamFactor_t$ ≡ ratio of total employees to base-level employees

The TeamFactor accounts for the number of line managers in each layer of line management required to supervise a team with a given number of base-level team members. It is estimated by the algorithm described in Appendix C.

The general structure of the DSO employee model is shown in Table 17, where a DSO's employees involved in three broad categories of administration, engineering, and retail operations are broken down into a set of teams.[17] Note that the customer network, retail market operations, and flexible asset recruiting and retention teams only apply to a DSO in a transactive case and do not exist in a BAU case, as indicated by the table's footnote.

Table 17. DSO employees model.

Organizational Level	Con-stant a	Per 1K Cust. b	(Per 1K Cust.)$^{1/2}$ c	Per Sub. d	TEAM Factor	Trans-active Factor
Utility Total	**3.1**	**2.836**	**0.000**	**0.00**	**1.00**	
Administration and Business Labor	1.1	0.072	2.054	0.00	1.00	
Chief Executive Officer (CEO)	1.0	-	-	-	-	0.00
Admin Labor (CEO Support)	0.0	0.000	0.050	0.00	1.11	0.00
Public Relations	0.0	0.000	0.200	0.00	1.11	0.00
Chief Financial Officer (CFO)	2	-	-	-	-	0.00
Accounting Labor						
Accounting	0.0	0.010	0.100	0.00	1.11	0.00
Purchasing	0.0	0.020	0.100	0.00	1.11	0.00
Payroll	0.0	0.010	0.100	0.00	1.11	0.00
Economics Labor						
Wholesale market	0.0	0.000	0.300	0.00	1.11	0.00
Rates	0.0	0.000	0.150	0.00	1.11	0.00
Regulatory affairs	0.0	0.000	0.150	0.00	1.11	0.00
Chief Human Resources Officer (CHO) & Human Resources Team Labor	0.0	0.010	0.200	0.00	1.11	0.00
Chief Legal Officer (CLO) & Legal Team Labor	0.1	0.000	0.300	0.00	1.11	0.00
Chief Information Officer (CIO)	3	-	-	-	-	0.00
Business Network Labor						
Network admin (business network)	0.0	0.010	0.100	0.00	1.11	0.00
Cyber admin (business network)	0.0	0.005	0.100	0.00	1.11	0.00
Engineering Operations Labor including Chief Operations Officer (COO)	2.0	1.177	-0.874	0.00	1.00	
AMI Network Operations Labor						
Network labor (AMI)	0.0	0.010	0.300	0.00	1.11	0.25
Cybersecurity labor (AMI)	0.0	0.010	0.100	0.00	1.11	0.05
Customer Network Operations Labor[1]						
Network labor (DER)[1]	0.0	0.003	0.090	0.00	1.11	0.00
Cybersecurity labor (DER)[1]	0.0	0.003	0.030	0.00	1.11	0.00
Distribution Automation/*DMS Network Labor*						
Network admin	0.0	0.010	0.100	0.00	1.11	0.00
Cyber admin	0.0	0.005	0.100	0.00	1.11	0.00
Operations Labor (incl. COO)						
Linemen labor (incl. COO)	2.0	0.935	-1.597	0.00	1.11	0.00
Operator labor	0.0	0.020	0.200	0.00	1.11	0.00
Metering labor	0.0	0.050	0.010	0.00	1.11	0.00
Planning labor	0.0	0.020	0.000	0.00	1.11	0.00
Retail market operations labor[1]	1.0	0.000	0.010	0.20	1.11	0.00
Retail Operations Labor including Chief of Retail Operations (CRO)	0.0	1.587	-1.180	0.00	1.00	

[17] Some teams in Table 17 represent a single employee with no line management, such as the CEO and other C-level officers.

Organizational Level	Con-stant a	Per 1K Cust. b	(Per 1K Cust.)$^{1/2}$ c	Per Sub. d	TEAM Factor	Trans-active Factor
Customer Service Labor (incl. CRO)	0.0	1.330	-1.073	0.00	1.11	0.00
Billing Labor	0.0	0.100	0.010	0.00	1.11	0.25
Flex. Asset Recruit. & Retention Labor[1]	0.0	0.250	0.050	0.00	1.11	0.00

[1] Only non-zero for transactive case [2] See discussion below

A CEO leads the utility and has direct reports from a COO, CRO, CFO, CLO, and CHR, in addition to a small administrative support team and public relations team. Note that the COO, CRO, CLO, and CHR are modeled as the leaders of the linemen and customer service agent teams, respectively, and so do not appear as individual line items the way the CEO, CFO, and CIO do. Note that the DSO employee model is constructed such that in very small utilities the C-level officers do not exist as such and are simply the most senior member of a very small team.[18] The accounting and economics teams report to a CFO.[19] All communications network teams (business, AMI, customer, and distribution automation/DMS) report to a CIO.

The coefficients of the employee model for each team in Table 17 are based on judgment from experience working with utilities of various sizes. They provide a plausible breakdown of a DSO's number of employees as a function of the utility's size that, in turn, drive labor costs that are highly dependent on job classification.[20]

The team models have not been validated individually for lack of detailed information about employment by job classification. However, when the coefficients of the team models are aggregated to the level of engineering and retail operations, with the administrative employees allocated to them proportionately, these aggregations exactly match the control totals developed by a regression model of the total employees in actual utilities. This is described in Appendix D.

Table 18 shows the hourly labor costs (unburdened) that were estimated for the study's job classifications. For each classification an hourly wage was found for each DSO type (rural, suburban, and urban). These hourly rates were found using the U.S. Bureau of Labor Statistics (BLS) data for hourly wages in Texas for the appropriate occupation codes (BLS 2018) which are noted in the source column of Table 18. BLS includes an area type classifier with hourly wage data that classifies if the data were from a metropolitan statistical area or not. This was used to infer the differences in hourly wages between rural, suburban, and urban DSOs.

Note that the rates in Table 18 are unburdened, meaning they are the wage rates paid to the employee without costs for benefits and other overheads. The study computes total annual labor costs for an employee as the product of the unburdened hourly rate and an assumed 2,080 working hours per year, divided by a wage-to-total-compensation ratio of around 70% (BLS 2020). So, from Equation (16), the total annual fully burdened labor cost for a DSO team is:

$$TeamCost_t \ = \ NoEmployees_t \, TeamFactor_t \, HrYr \ / \ CompRatio \qquad (17)$$

[18] These team models are allowed to predict a fraction of a single employee, indicating a single employee who has multiple roles in a very small utility.

[19] If the total number of team members is greater than five; otherwise there is no such executive function.

[20] The study could have chosen to use a weighted-average employee salary instead. However, estimating a weighted-average salary essentially entails these steps and is not constant for transactive cases because they change the employee mix to some extent. Therefore, the valuation processes uses these employee estimates by job classification explicitly.

where: $NoEmployees_t$ ≡ number of base-level employees for team t

t ≡ index indicating team t

HrYr ≡ working hours per year = 2080 hr/yr

CompRatio ≡ ratio of unburdened to fully burdened labor cost = 70%

$TeamFactor_t$ ≡ ratio of total employees to base-level employees

These team labor costs are entered into the DSO's CFS as indicated by Table 19.

3.3.2.2 Workspace

The annual cost of a DSO's workspace is assumed to be a linear function of the number of employees of two classes. Base-level linemen are assumed to occupy 600 square feet of warehouse/stockyard space each (providing room for storage of tools, equipment, and parts). Their line managers and the rest of the DSO's employees are assumed to occupy 200 square feet of office space each.

So, a DSO's total annual cost for workspace is estimated as:

$$WorkspaceCost_t = NoEmployees_{linemen}\, SqftLinemen\, CostIndustrialSqft + \sum_{t=1}^{T} NoEmployees_t\, SqftOffice\, CostOfficeSqft - NoEmployees_{linemen}\, SqftOffice\, CostOfficeSqft \tag{18}$$

where: $NoEmployees_t$ ≡ number of employees for team t

t ≡ index indicating team t

SqftLinemen ≡ workspace per base-level lineman

SqftOffice ≡ workspace per base-level lineman

CostIndustrialSqft ≡ annual cost of industrial space

CostOfficeSqft ≡ annual cost of office space

Table 18. Hourly DSO labor costs (unburdened).

Labor Category	Rural ($/hr)	Suburban ($/hr)	Urban ($/hr)	Source
Admin Labor	$14.81	$15.64	$15.66	43-6014 Secretaries and Administrative Assistants
Public Relations	$20.00	$35.00	$45.00	Public Relations
Accounting	$34.34	$34.62	$34.69	General Accounting Labor Rates
Purchasing	$34.34	$34.62	$34.69	General Accounting Labor Rates
Payroll	$34.34	$34.62	$34.69	General Accounting Labor Rates
Wholesale market	$47.68	$51.19	$51.57	Economist Labor Rates
Rates	$47.68	$51.19	$51.57	Economist Labor Rates
Regulatory affairs	$47.68	$51.19	$51.57	Economist Labor Rates
CHO & Human Resources Team Labor	$26.71	$27.64	$27.86	Human Resources Specialist
CLO & Legal Team Labor	$105.00	$210.00	$280.00	Corporate Lawyer
Network admin	$53.05	$62.07	$62.70	11-3021 Computer and Information Systems Managers
Cyber admin	$41.38	$44.42	$44.75	15-1122 Information Security Analysts
Operator labor	$31.63	$33.96	$34.21	49-9051 Power Distributors and Dispatchers
Linemen labor	$27.62	$27.60	$27.60	49-9051 Electrical Power-Line Installers and Repairers
Metering Labor	$46.69	$46.89	$46.93	17-2017 Electrical Engineers
Planning Labor	$46.69	$46.88	$46.93	17-2017 Electrical Engineers
Retail Market Operations Labor	$31.63	$33.96	$34.21	49-9051 Power Distributors and Dispatchers
Billing Labor	$16.31	$16.61	$16.69	43-3021 Billing and Posting Clerks
Customer Service Labor	$14.43	$14.62	$14.78	43-4051 Customer Service Representatives
Flexible Assets Recruiting & Retention Labor	$14.43	$14.62	$14.78	43-4051 Customer Service Representatives

Table 19. Labor in DSO CFS at four levels of detail.

Organizational Level **Category / Sub-Category / *Element*** / Sub-Element
O&M Labor
Operator Labor
Planning Labor
Metering Labor
Market Operations
AMI/Customer Network Operations
AMI Ops Labor
Network labor (AMI)
Cybersecurity labor (AMI)
Customer Network Ops Labor
Network labor (customer)
Cybersecurity labor (customer)
DMS Operations
Network labor (DMS)
Cybersecurity labor (DMS)
Retail Operations
Customer Service Labor
Flexible Assets Recruitment & Retention Labor
Billing Labor
Administration
CEO
Admin Labor (CEO Support)
Public Relations
CFO
Accounting Labor
Accounting
Purchasing
Payroll
Economics Labor
Wholesale market
Rates
Regulatory affairs
CHO & Human Resources Team Labor
CLO & Legal Team Labor
CIO
Business Network Labor
Network admin (business network)
Cyber admin (business network)

The assumed costs for office and industrial workspace for rural, suburban, and urban DSOs are shown in Table 20.

Table 20. Workspace rent, annual (per sq ft).

Office	Rural	$16.13
	Suburban	$363.74
	Urban	$466.58
Industrial	Rural	$6.44
	Suburban	$57.81
	Urban	$65.75

3.3.3 Operations and Maintenance Materials

The materials a DSO consumes for O&M cover a broad range of goods used throughout the organization. The largest of these are spare parts (e.g., transformers, switches, breakers, fuses, insulators, poles, overhead wires, underground conduit and cables). Tools and vehicles used for line operations are another large component. At the other end of the scale are items like computers, routers, and printers, down to mundane office supplies like pens, pencils, and paper.

As none of these costs are expected to change as a result of adopting a DSO+T strategy, the composition of these costs is not important and are estimated as a simple lumped line item equal to a cost of $0.02/kWh of electricity sold. This estimate was tested by comparing published figures for the blended average cost of electricity in Texas with those that result from the entire set of assumptions and cost estimates discussed above, including this one. This comparison is discussed in Section 3.4.1 below.

3.4 Example of Representative DSO Expenses

This section provides illustrative results showing the expenses for an example DSO. In this case the results are for DSO #1 of the study's eight-node case for the MR BAU case. DSO #1 is urban with 3.8 million customers, annual energy purchases of 130.4 TW-hrs, and a peak demand of 24.4 GW. The overall proportions of expenses were similar for other DSOs.

3.4.1 Business-as-Usual Results

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 for DSO #1 for the BAU case, in which all customers are on a fixed-price rate. The ratemaking process described in Section 4.3 was used to translate these DSO #1 expenses into a resulting fixed-price rate. This process ensures that each DSO will obtain revenues from its customers to exactly match its total expenses. The blended cost of electricity sold is the sum of the customer bills divided by the total energy they consume, so the blended cost includes the effect of monthly connection (meter) charges and peak demand charges on commercial and industrial customers.

In this example, DSO #1 sold 103 TW-hrs of electricity resulting in an effective electricity rate of 11.99 cents/kW-hr. Across all DSOs in the 8-node case the effective rate varied from 10.09–10.94 cents/kW-hr with an average of 10.56 cents/kW-hr. This is slightly higher (3%) than the average 2016 U.S. value of 10.27 cents/kW-hr and within the cited range of 7.46–17.24 cents/kW-hr 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 eight-node case are within 10% of PJM data for 2018 and the relative proportions are representative. For example, on average in this study DSOs spend 51% of wholesale expenses on energy purchases (versus 63% for PJM), 25% on capacity costs (versus 20%), 20% on transmission charges (versus 15%), and ~3% on other wholesale costs such as ancillary services and reserves (versus 2% for PJM).

The relative proportions of the DSO expenses for DSO #1 for the MR BAU case are shown in Figure 9. Wholesale energy and market costs represent over half of all DSO costs and are dominated by wholesale energy costs (27%), peak capacity charges (16%), and transmission charges (11%). Other wholesale costs, such as reserves, ancillary services, and ISO fees account for less than 2%. Capital expenses are dominated by the distribution plant (13%) and nonmarket operations costs are dominated by O&M costs (20%). All other expenses account for less than 12% of the overall DSO's cost of doing business.

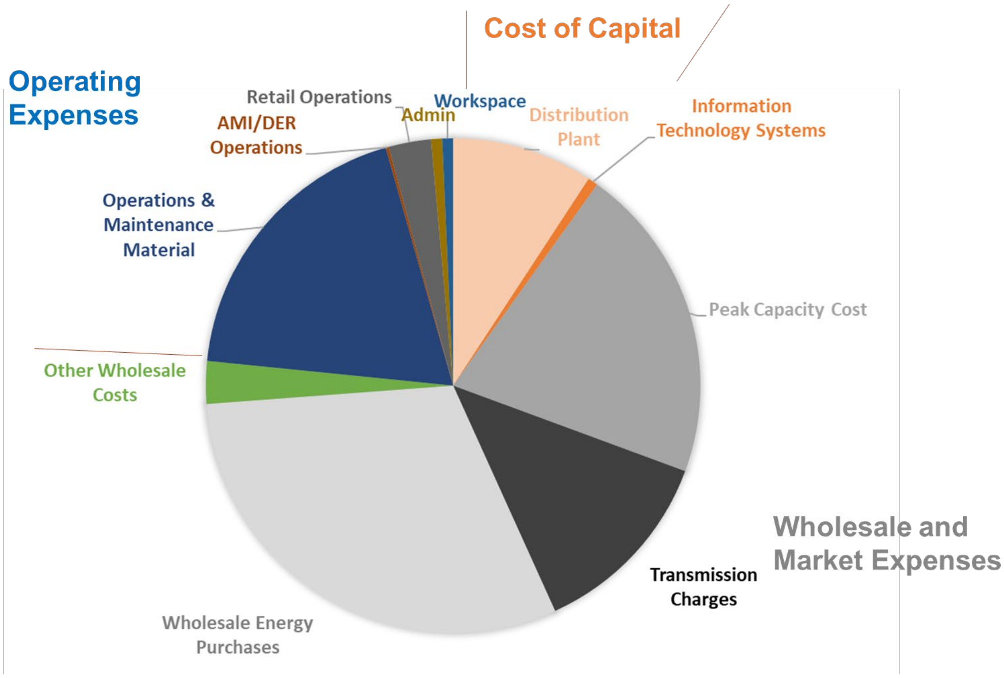

Figure 9. Summary of relative DSO expenses for the BAU case.

A summary of DSO #1's expenses in the MR BAU case are further detailed in Table 21 in the form of its CFS at all four levels of detail.

3.4.2 Transactive Results

Table 21 also shows the results of DSO #1 for the corresponding transactive battery case and the difference between the two cases in absolute and relative (%) terms. The actions of the battery fleet reduce the coincident peak load to 22.5 GW (a reduction of 7.5%). This results in the distribution substation plant reducing its capital cost 4%. This is offset by the need to invest in retail market and DER network IT systems. The overall effect is a negligible change in the overall distribution system capital cost.

Overall operating costs were reduced by 14.9%. This is led by a reduction in wholesale market costs, including a reduction in capacity payments (-42.2%), transmission access fees (-9.8%), and wholesale energy purchases (-10.3%). There are also small changes in ancillary service payments (noted as other wholesale costs) and ISO fees. These operating cost reductions are counteracted in part by the increased labor and workspace required to implement and maintain the DER network and retail operations.

The overall reduction in the DSO's annualized cost to operate is ultimately reflected in the revenue it needs to recover. The required revenues are reduced 13.6%. Detailed discussion of the economic valuation results are provided in Volume 1 (Reeve 2022a), with considerable additional detail on the results of the analysis provided in Volume 5 (Reeve 2022c).

Table 21. DSO cash flow sheet comparing BAU and battery cases for the moderate-renewables scenario (for DSO #1 of the eight-node case)

Organizational Level	BAU Case	Transactive Batteries Case		
Category / Subcategory / Element / Subelement	Annual Cash Flow ($K/yr)	Annual Cash Flow ($K/yr)	Difference ($K/yr)	(%)
Capital Expenses[a]	$1,004,240	$1,002,640	($1,600)	-0.16%
Distribution Plant	$936,942	$921,465	($15,477)	-1.65%
Substations	$373,753	$358,277	($15,477)	-4.14%
Feeders	$487,772	$487,772	$0	0.00%
Meters	$75,417	$75,417	$0	0.00%
IT Systems	$67,298	$81,175	$13,877	20.62%
Retail Market Software & Hardware	$0	$854	$854	100.00%
Retail market hardware	$0	$801	$801	100.00%
Retail market software	$0	$53	$53	100.00%
AMI/DER Network	$52,394	$65,493	$13,099	25.00%
AMI network	$52,394	$52,394	$0	0.00%
DER network(s)	$0	$13,099	$13,099	100.00%
Distribution Automation Network	$10,915	$10,915	$0	0.00%
Distribution Mgmt. System Software	$990	$948	($42)	-4.25%
Outage Mgmt. System Software	$832	$815	($17)	-2.03%
Customer Info. System Software	$1,748	$1,748	$0	0.00%
Billing Software	$419	$402	($17)	-4.02%
Operating Expenses	$9,546,443	$8,123,838	($1,422,605)	-14.90%
Peak Capacity Charges	$2,103,002	$1,214,579	($888,423)	-42.25%
Transmission Access Fees	$1,280,164	$1,154,748	($125,416)	-9.80%
Wholesale Energy Purchases	$3,102,147	$2,783,970	($318,178)	-10.26%
Day Ahead Energy Costs	$1,640,813	$1,043,656	($597,158)	-36.39%
Real Time Energy Costs	($173,643)	($124,644)	$48,999	-28.22%
Bilateral Energy Costs	$1,634,977	$1,864,958	$229,981	14.07%
Other Wholesale Costs	$282,277	$260,577	($21,701)	-7.69%
ISO Reserves	$224,887	$207,664	($17,223)	-7.66%
ISO Losses	$0	$0	$0	0.00%
ISO Fees	$57,390	$52,912	($4,478)	-7.80%
O&M Materials	$1,928,952	$1,777,150	($151,802)	-7.87%
O&M Labor	$390,130	$390,130	$0	0.00%
Linemen Labor	$335,513	$335,513	$0	0.00%
Operator Labor	$10,710	$10,710	$0	0.00%
Planning Labor	$12,476	$12,476	$0	0.00%

Organizational Level	BAU Case	Transactive Batteries Case		
Category / Subcategory / Element / Subelement	Annual Cash Flow	Annual Cash Flow	Difference	
	($K/yr)	($K/yr)	($K/yr)	(%)
Metering Labor	$31,430	$31,430	$0	0.00%
Market Operations	$0	$8,059	$8,059	100.00%
AMI/Customer Network Operations	$19,580	$28,855	$9,275	47.37%
AMI Ops Labor	$19,580	$23,057	$3,477	17.76%
Network labor (AMI)	$12,488	$15,610	$3,122	25.00%
Cybersecurity labor (AMI)	$7,092	$7,446	$355	5.00%
Customer Network Ops Labor	$0	$5,798	$5,798	100%
Network labor (customer)	$0	$3,672	$3,672	100%
Cybersecurity labor (customer)	$0	$2,126	$2,126	100%
DMS Operations	$13,834	$13,834	$0	0.00%
Network labor (DMS)	$9,936	$9,936	$0	0.00%
Cybersecurity labor (DMS)	$3,898	$3,898	$0	0.00%
Retail Operations	$281,277	$336,426	$55,149	19.61%
Customer Service Labor	$258,887	$258,887	$0	0.00%
DER Recruitment & Retention Labor	$0	$49,552	$49,552	100%
Billing Labor	$22,390	$27,988	$5,598	25.00%
Administration	$72,951	$73,176	$225	0.31%
Workspace	$72,128	$82,333	$10,206	14.15%
Revenues	$10,550,683	$9,117,542	($1,433,141)	-13.58%
Retail Sales	$10,550,683	$9,117,542	($1,433,141)	-13.58%
Fixed-Price Sales	$10,550,683	$6,508,797	($4,041,886)	-38.31%
Fixed-price energy charges	$8,121,025	$4,768,704	($3,352,320)	-41.28%
Demand charges (C & I)	$1,992,800	$1,504,645	($488,155)	-24.50%
Connect charges (fixed-price)	$436,858	$235,448	($201,411)	-46.10%
Transactive Rate Sales	$0	$2,608,745	$2,608,745	100.00%
Day-ahead energy charges	$0	$912,772	$912,772	100.00%
Real-time energy charges	$0	($192,106)	($192,106)	100.00%
Distribution charges	$0	$1,723,073	$1,723,073	100.00%
Connect charges (transact. rate)	$0	$165,006	$165,006	100.00%
Balance	$0	$0		

4.0 DSO Revenues and Customer Bills

This section describes:

1. How customer bills are computed for the customer's CFSs
2. How a DSO's revenues from sales to customers are computed for its CFS
3. The ratemaking process that sets fixed-price rates to recover a DSO's required revenues in BAU cases
4. The ratemaking process that sets transactive rates (for participating customers) and fixed rates (for nonparticipating customers) to recover a DSO's required revenues in transactive cases.

4.1 Customer Bills

In the DSO+T study, each customer's monthly and annual electricity consumption and electric bills are calculated. Note that the fixed-rate and transactive rate retail prices are defined by their ratemaking processes as described in Section 4.3.

All customers in a BAU case are on a declining block fixed rate. In a transactive case, ~20-60% of customers are assumed to remain on that rate because they have opted out of the transactive rate.

All customer rates are net metering plans. That is, if a customer's solar PV system output or discharge from a battery 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 is a common, but not universal, rate design practice among U.S. utilities.

The study assumes net metering for two reasons. First, it rewards solar PV and battery systems for their entire output (if this were not the case, it is unlikely they would penetrate to the levels assumed in the HR scenarios). Second, net metering keeps all rate calculations simple and linear, with no truncation at zero when the meter reading is negative. This greatly simplifies the computation of customer bills in the study.

4.1.1 Fixed Retail Rate Structure

This section describes how electric bills for customers on a (flat) fixed rate are computed based on three components:

- Charge for energy purchased
- Peak demand charge (for commercial and industrial customers only)
- Connection charge.

The process for computing fixed-price customer bills based on their consumption is described below. The customer's monthly energy consumption is simply the sum of their consumption during each 15-minute interval in the month:

$$Qcust_m = \sum_{d=1}^{D_m} \sum_{h=1}^{24} \sum_{f=1}^{4} Qcust_{m,d,h,f} \tag{19}$$

In the study the fixed-price rate for customers is assumed to be a three-tier declining block rate, reflecting a volumetric discount for large customers as is common in many utilities. The study uses this declining block rate in lieu of producing fixed prices specific for each customer class, based on separate ratemaking rules and processes for each class. It reflects a common practice of establishing a lower residential rate for homes with electric space heating and a volumetric discount on energy for commercial and industrial customers, both of which reflect the presumed reduced costs of infrastructure per unit energy delivered as monthly consumption levels increase for these customers. It also serves to compensate for the peak demand charge imposed on commercial and industrial customers. Thus, the ratemaking process used in the study mimics the general effect of typical utility fixed-price ratemaking, but does not specifically reproduce any process used in the real world.

The energy component of a fixed-price customer's monthly bill is then the sum of the products of their consumption in each of the three tiers' fixed retail price for the customer rate class (residential, commercial, industrial) and the quantity consumed based on 15-minute interval metered data:

$$\begin{aligned} FixEnergyCharge_m = {} & P_{fix}\, Qcust_m \\ & - M_2 P_{fix} (Qcust_m - Q_{1max}) \{Qcust_m > Q_{1max}\} \\ & - M_3 P_{fix} (Qcust_m - Q_{2max}) \{Qcust_m > Q_{2max}\} \end{aligned} \tag{20}$$

where: $FixEnergyCharge_m$ ≡ fixed energy charge component of customer bill in month m

$Qcust_m$ ≡ energy consumed by customer in month m

Q_{1max} ≡ monthly energy consumption boundary between tiers 1 and 2

Q_{2max} ≡ monthly energy consumption boundary between tiers 2 and 3

P_{fix} ≡ block rate for tier 1 energy consumption

M_2 ≡ fractional decrease of block rate for tier 2 energy consumption

M_3 ≡ fractional decrease of block rate for tier 3 energy consumption

Note that from Equation (20) the resulting prices for tier 2 and tier 3 energy consumption are:

$$P_{fix2} = (1 - M_2)\, P_{fix} \tag{21}$$

$$P_{fix3} = (1 - M_2 - M_3)\, P_{fix} \tag{22}$$

Commercial and industrial customers have a monthly noncoincident peak-demand charge for their highest average power consumption over any 15-minute period in the month. The demand charge is the product of the peak demand price (P_{demand}) and the monthly peak power consumption averaged over any 15-minute interval f in the month:

$$DemandCharge_m = \mathrm{MAX}\{Qcust_{m,d,h,f}\}\, P_{demand} \tag{23}$$

All customers pay a fixed monthly connection (meter) charge independent of consumption, $ConnectFix_m(k)$, which did not vary by customer class k.

Section 4.3 describes how the fixed retail price, demand charge, and connection charge for fixed-price customers are determined by the ratemaking process.

The monthly electric bill for a fixed-price customer is the sum of 1) the monthly energy charge, 2) the peak demand charge, and 3) the monthly customer connection charge:

$$FixBill_m = FixEnergyCharge_m + DemandCharge_m + ConnectFix_m \tag{24}$$

The annual consumption and electric bill components are sum of the 12 monthly values.

4.1.2 Transactive Rate Design Principles

The guiding principles, DSO revenue requirements, and ratemaking processes used by the DSO+T study to set dynamic, transactive rates are described in the following subsections. The design of the transactive rate under a DSO+T strategy is based on the following fundamental policies that we assume will be adopted by regulators:

1. Adoption of the DSO+T strategy should (on average) benefit consumers: the DSO's net revenue requirements should decrease enough to offer reductions in participants' electric bills that cover the costs of their flexible assets plus recompence for any inconvenience or costs caused by their responses.
2. The combined (sometimes conflicting) interests of fairness, simplicity, and transparency are best served by using dynamic rates and a retail market design, rather than pay-for-performance approaches, to reward valuable customer responses.
3. As in fixed-price ratemaking, DSO+T ratemaking must recover revenue via transactive customer bills that, combined with those from remaining fixed-price customers, is designed to equal the DSO's fixed and variable costs, including a regulated rate of return on capital infrastructure investments for investor-owned DSOs.
4. Customers who choose to migrate to transactive rates but do not participate by responding to them should (in aggregate) pay no more on their electric bill than they would in the BAU case.
5. On aggregate, customers who choose not to migrate to transactive rates should pay no more on their bills than they would in the BAU case.
6. Customers on transactive rates should 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.
7. A desired outcome is that transactive ratemaking as embodied by the DSO's retail markets and transactive rates results in a simpler, more transparent, and more accurate representation of actual DSO costs across customer classes.
8. All substations in a DSO should have the same rate design, whether congested or not, to maintain equity between customers on congested and uncongested substations, while socializing needed and cost-effective distribution capacity investments across all DSO customers.

Policies 1 and 2 are the major drivers for the transactive rate structure. To a considerable extent, Policies 3 through 8 reflect corollaries or implementation details driven by Policies 1 and 2. Each policy is discussed in more detail in 8.0Appendix E.

An acceptable transactive rate design will also necessitate features that protect customers from very large dynamic price escalations due to extreme wholesale market prices (that can hit market caps of $2,000–9,000/MWh, approximately 80–300 times typical values). Designing and evaluating such a feature was outside the scope of this study, which was focused on the evaluation of transactive coordination schemes during nominal operation. Customers could be protected from such high prices by capping the retail dynamic rate to a multiple of its nominal value (for example 4 times). This would ensure sufficient incentives for demand flexibility remain but customers are not exposed to asymptotic prices during extreme grid events. Wholesale energy purchases not recovered via the dynamic rate could be recouped in the future through increases in the volumetric rate. How best to maintain effective economic incentives for demand flexibility, protect customers from extreme prices, and ensure sufficient revenue recovery warrants future investigation.

4.1.3 Transactive Retail Rate Structure

Policy 2 above calls for the use of real-time prices as the basis for the transactive rate. Policy 6 calls for the savings seen by transactive customers to be proportional to the actual benefits they create by responding to retail prices. Using customer savings in response to real-time prices as the incentive for their participation implies that prices must maintain as much fidelity to actual costs as possible (Policy 7). The combined effect of these policies suggests the transactive rate structure be patterned after the DSO cost structure; therefore, the rate structure is reflected in five components of the customer bill (independent of customer class, substation constraints, or DSO):

$$\begin{aligned} Bill_{n,c,s,d} = {} & EnergyCost_{n,d} + CongestCost_{n,s,d} + DistribtionCost_{n,c,d} \\ & + MeterCharge_{c,d} \end{aligned} \qquad (25)$$

where:

EnergyCost$_n$ – The wholesale dynamic retail energy cost of a customer’s consumption, reflecting the wholesale terms (locational marginal price [LMP]-related terms) in the DSO cost structure, plus distribution losses (since they do not appear in the customer metered load) and reserves and ancillary service payments.

CongestCost$_{n,s}$ – Marginal retail congestion costs associated with peak capacity at a substation’s retail market node, reflecting the peak capacity terms in the DSO cost structure as the cost to utilize flexible loads and DERs to manage the DSO’s local and global constraints. This is the difference between the actual retail market clearing price and the uncongested retail clearing price at a substation and reflects DSO costs associated with meeting peak demand.

DistributionCost$_{n,c}$ – 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. This is a constant energy price term added to the customer bill over and above the retail market clearing price. This covers the costs of transmission access fees and the capital investments and operating costs for the transmission system.

MeterCharge – The constant (monthly) charge reflecting the constant terms of the DSO cost structure, for example market and retail operations.

The process for computing transactive rate customer bills based on their consumption is as follows. The whole energy costs are broken into day-ahead and real-time components. The day-ahead energy component of a transactive customer's monthly bill is the product of the retail day-ahead market clearing price for the substation serving the customer and the quantity purchased the day ahead for each of the 24 hours:

$$DayAheadCharge_m = \sum_{d=1}^{D_m} \sum_{h=1}^{24} Qda_{m,d,h} \; A \; LMPda_{m,d,h} \tag{26}$$

where: $DayAheadCharge_m$ ≡ day-ahead energy charge component of customer bill in month m

$Qda_{m,d,h}$ ≡ energy purchased day-ahead for hour h of day d of month m

$LMPda_{m,d,h}$ ≡ day-ahead wholesale market clearing price for the substation serving the customer

A ≡ factor to account for distribution losses and other wholesale payments

D_m ≡ number of days in month m

The real-time energy component of a transactive rate customer's monthly bill is the product of the fixed retail price for the customer rate class and the quantity consumed based on 5-minute interval metered data:

$$RealTimeCharge_m = \sum_{d=1}^{D_m} \sum_{h=1}^{24} \sum_{i=1}^{12} \left(Qcust_{m,d,h,i} - \frac{1}{12} Qda_{m,d,h} \right) \left(A \; LMPrt_{m,d,h,i} \right) \tag{27}$$

where: $RealTimeCharge_m$ ≡ real-time energy charge component of customer bill in month m

$Qcust_{m,d,h,i}$ ≡ energy consumed by customer in 5-minute interval i of hour h of day d of month m

$Qda_{m,d,h}$ ≡ energy purchased day-ahead for hour h of day d of month m

$LMPrt_{m,d,h}$ ≡ retail real-time market clearing price for the substation serving the customer

A ≡ factor to account for distribution losses and other wholesale payments

D_m ≡ number of days in month m

Note that the customer is, in effect, buying (or selling), in the real-time market, their imbalance, i.e., the difference between their energy consumption and the energy they purchased day-ahead.

Section 4.3 describes how the day-ahead and real-time market clearing prices are related to their wholesale market price counterparts as part of the transactive ratemaking process.

The distribution component of a transactive rate customer's monthly bill is the product of the fixed distribution energy price for the customer rate class and the quantity consumed based on 5-minute interval metered data:

$$DistCharge_m = \sum_{d=1}^{D_m} \sum_{h=1}^{24} \sum_{i=1}^{12} Qcust_{m,d,h,i} \, (c_t) \, (P_{dist} - \Delta P_m) \tag{28}$$

where: $DistCharge_m$ ≡ distribution charge component of customer bill in month m

$Qcust_{m,d,h,i}$ ≡ energy consumed by customer in 5-minute interval i of hour h of day d of month m

$P_{dist}(c_t)$ ≡ fixed distribution energy price for the customer c_t's (rate) class

ΔP_m ≡ congestion rebate for substation serving customer for month m

D_m ≡ number of days in month m

The process by which the monthly substation congestion rebate is computed is described in Section 4.3.2.2.

All transactive customers pay a fixed monthly connection (meter) charge independent of consumption, $ConnectTrx_m$, which may vary by customer class, but by design is the same as that paid by fixed-price customers of the same class as described in Section 4.3.

The monthly electric bill for a transactive rate customer is the sum of 1) the day-ahead energy charge, 2) the real-time energy charge, 3) the distribution charge, and 4) the monthly customer connection charge:

$$\begin{aligned} TrxBill_m = {} & DayAheadCharge_m + RealTimeCharge_m \\ & + DistCharge_m + ConnectTrx_m \end{aligned} \tag{29}$$

The annual electric bill and its components are simply the sum of their 12 monthly values.

4.2 DSO Sales and Revenues

This section describes how a DSO's revenues are computed from its customer bills. The study does not simulate every customer in ERCOT. Rather, it simulates a single substation serving a representative sample of the DSO's residential and commercial customer classes. The study then uses the DSO's weighting factor, the multiplier for substation and loads actually simulated, to represent the DSO's entire population of such loads. The customers in the industrial class are modeled as a lump sum rather than individual customers.

Therefore, DSO revenues are the sum of its residential and commercial customers' annual bills multiplied by the weighting factor and the industrial customer class bill (industrial customers are not simulated individually, so a single bill for the industrial class represents the entire revenue from the industrial sector).

The procedures for computing DSO revenues in the BAU and transactive cases are slightly different because 10% of the customers in transactive cases are presumed to remain on fixed-price rates. Each of these is addressed in the subsections that follow.

4.2.1 BAU Case DSO Sales and Revenues

The components of a DSO's annual revenue from its fixed-price customers are simply the products of the DSO's weighting factor and sum of the monthly components of the customer bills:

$$RevFixEnergy_A = WF_{dso} \sum_{c_f=1}^{N_f} \sum_{m=1}^{12} FixEnergyCharge_m(c_f) \tag{30}$$

$$RevPeakDemand_A = WF_{dso} \sum_{c_f=1}^{N_f} \sum_{m=1}^{12} DemandCharge_m(c_f) \tag{31}$$

$$RevConnectFix_A = WF_{dso} \sum_{c_f=1}^{N_f} \sum_{m=1}^{12} ConnectFix_m(c_f) \tag{32}$$

and the total revenue from sales of electricity to a DSO's fixed-price customers is:

$$RevFixSales_A = RevFixEnergy_A + RevDemandCharges_A + RevConnectFix_A \tag{33}$$

where: $RevFixSales_A$ ≡ annual revenue from sales of fixed-price electricity

$RevFixEnergy_A$ ≡ annual revenue component from fixed energy charges

$RevPeakDemand_A$ ≡ annual revenue component from peak demand charges

$RevConnectFix_y$ ≡ annual revenue component from connection charges to fixed-price customers

WF_{dso} ≡ DSO weighting factor

(c_f) ≡ specifies bills or bill components for fixed-price customer c_f

N_f ≡ number of DSO's fixed-price customers

For a BAU case, there are no transactive customers, so a DSO's total sales are equal to the revenue from its fixed-price and transactive rate sales are zero.

A useful metric commonly used by utilities, regulators, and policymakers to describe the overall cost of electricity to consumers is the blended average cost of electricity. For fixed-price customers it is simply the total revenues divided by the total energy sold:

$$BlendedAvgElecCost_f = \frac{RevFixSales_A}{WF_{dso}} \Bigg/ \sum_{c_f=1}^{N_f} Qcust_A(c_f) \tag{34}$$

where: $Qcust_A(c_f)$ ≡ annual energy consumed by fixed-price customer c_f.

4.2.2 Transactive Case DSO Sales and Revenues

The components of a DSO's annual revenue from its transactive rate customers are simply the products of the DSO's weighting factor and the sum of the monthly components of the customer bills:

$$RevDaEnergy_A = WF_{dso} \sum_{c_t=1}^{N_t} \sum_{m=1}^{12} DayAheadCharge_m(c_t) \tag{35}$$

$$RevRtEnergy_A = WF_{dso} \sum_{c_t=1}^{N_t} \sum_{m=1}^{12} RealTimeCharge_m(c_t) \tag{36}$$

$$RevDistCharges_A = WF_{dso} \sum_{c_t=1}^{N_t} \sum_{m=1}^{12} DistCharge_m(c_t) \tag{37}$$

$$RevConnectTrx_A = WF_{dso} \sum_{c_t=1}^{N_t} \sum_{m=1}^{12} ConnectTrx_m(c_t) \tag{38}$$

and the total revenue from sales of electricity to a DSO's transactive rate customers is:

$$\begin{aligned} RevTrxSales_A &= RevDaEnergy_A + RevRtEnergy_A \\ &\quad + RevDistCharges_A + RevConnectTrx_A \end{aligned} \tag{39}$$

where: $RevTrxSales_A$ ≡ annual revenue from sales of transactive rate electricity

$RevDaEnergy_A$ ≡ annual revenue component from retail day-ahead energy

$RevRtEnergy_A$ ≡ annual revenue component from retail real-time energy

$RevDistCharges_A$ ≡ annual revenue component from distribution charges

$RevConnectTrx_A$ ≡ annual revenue component from connection charges to transactive rate customers

WF_{dso} ≡ DSO weighting factor

(c_t) ≡ specifies bills or bill components for fixed-price customer c_t

N_t ≡ number of DSO's transactive rate customers

A useful metric commonly used by utilities, regulators, and policymakers to describe the overall cost of electricity to consumers is the blended average cost of electricity. For transactive rate customers it is simply the total revenues divided by the total energy sold:

$$BlendedAvgElecCost_t = \frac{RevTrxSales_A}{WF_{dso}} \Bigg/ \sum_{c_t=1}^{N_t} Qcust_y(c_t) \tag{40}$$

where: $Qcust_y(c_t)$ ≡ annual energy consumed by transactive rate customer c_t

For a transactive case, there participating customers on the transactive rate and and nonparticipating customers are on a fixed-price rate. So, a DSO's total retail sales ($RetailSales_A$) are equal to the revenue from its fixed-price and transactive rate sales:

$$RetailSales_A = RevFixSales_A + RevTrxSales_A \quad (41)$$

4.3 Retail Ratemaking and Revenue Recovery

Retail rates for utilities are typically developed based on:

1. Annual time series of consumption data from representative samples of interval metered customers of each customer class over the course of a base year
2. Annual time series of metered DSO total load
3. Annual time series of quantities purchased in the wholesale day-ahead market
4. Bilateral contract(s) for wholesale energy purchased in advance directly from generators, expressed in terms of block quantities and prices (for example), or annual time series thereof
5. Documented, historical costs for capital expenses, including rate of return on capital investment for equity investors and associated taxes on income
6. Documented, historical operational costs for O&M of the infrastructure and for retail operations.

The basic ratemaking process for a utility in general and for the study's DSOs is that the required revenue recovered from customers is equal to the sum of the capital expenses and operational expenses:

$$RevReq_A = CapEx_A + OpEx_A \quad (42)$$

where: $RevReq_A$ ≡ annual DSO revenue requirement

$CapEx_A$ ≡ annual DSO capital expenses (from CFS)

$OpEx_A$ ≡ annual DSO operational expenses (from CFS)

In the real world, rates are based on years of experience with actual costs and associated adjustments. In the DSO+T study, since it only simulates one year, there is no such experience. The design of the study allows rates to be adjusted after the simulation has been conducted, as long as the adjustment is a constant price adjustment rather than varying over time within a month. This is not intuitive without considering the operation of the flexible assets and design of the transactive agents controlling them. Why it is possible, and the limitations of this key assumption, are discussed in Section 4.3.3. The ability to apply after-the-fact adjustments to rates in effect represents the net result of real-world experience on ratemaking and revenue recovery. This allows the valuation process to base its ratemaking on the results of a simulation, and then compute customer bills and proceed to the economic analysis.

The process of defining fixed-price rates and transactive rates (and how transactive retail prices are related to wholesale market prices) are described in the next two subsections.

4.3.1 BAU Case Ratemaking

The declining block rate for fixed-price customers defined in Section 4.1.1 indicates that parameters (i.e., unknowns) that define the resulting rate are:

- P_{fix} – the block rate for tier 1 energy consumption
- M_2 and M_3 – the fractional decreases of block rates for tier 2 and tier 3 energy consumption relative to the tier 1 rate
- Q_{1max} and Q_{2max} – the monthly energy consumption boundaries between tiers 1 and 2 and tiers 2 and 3
- P_{demand} – the price of monthly noncoincident peak demand
- $ConnectFix_m(k)$ – the monthly connection charge for customer class k.

The process of establishing fair and equitable values for these parameters is a primary subject of utility regulation, by state public utility commissions in the case of investor-owned utilities or the governing boards of publicly owned utilities. While this process varies across jurisdictions in the real world, the study uses a uniform automated process by which rates will be established. This necessarily involves making some arbitrary assumptions about the process. The steps in the procedure used to establish a fixed-price rate design for a DSO is as follows:

1. Define the monthly connection charge, $ConnectFix_m(k)$, for each customer class k based on the evidence for actual fixed costs. In the study, the fixed charge is set to \$10/month consistent with typical national values.
2. Define the demand charge P_{demand}. For this analysis the monthly peak demand price was set to \$15/kW based on the average of survey values described in McLaren and Mullendore (2017).
3. Define the monthly consumption boundaries Q_{1max} and Q_{2max}. In the study, this is a set of assumed kilowatt hour values. Q_{1max} was set to 2,000 kWh/month in an effort to lie between the monthly electricity consumption of a typical gas-heated home and below that of an electrically heated home in winter months. Q_{2max} was set to 10,000 kWh/month in an effort to lie between the monthly electricity consumption of typical small/medium commercial buildings and large office buildings (and industrial customers).
4. Define the fractional decreases of the block rate for tier 2 and tier 3 energy consumption. A reduction of \$0.04/kWh for tier 2 and an additional reduction of \$0.03/kWh for tier 3 are assumed for M_1 and M_2, respectively.
5. With all other parameters defined, the ratemaking is then completed by determining the block rate for tier 1 energy consumption (P_{fix}) that recovers the required revenue for the DSO.

The following procedure determines the block rate for tier 1 energy consumption (P_{fix}) such that the DSO's revenue requirement is exactly met.[21] First, an initial guess is made for P_{fix} (denoted $P_{fix\text{-}g}$) and used to calculate customer bills and the resulting total DSO revenue. The difference between this revenue and the required revenue (DSO expenses) is found and divided by the total volumetric energy consumed at the meter by all customers. This results in a correction that

[21] This is true in the DSO+T study, but in practice is strictly true only for a year during which the weather, general economic conditions, and wholesale market prices are equal to those in the base year selected for the ratemaking.

can be applied directly to the initial guess to determine the value of P_{fix} that will exactly match revenues to expenses:

$$P_{fix} = P_{fix\text{-}g} - \frac{RevFixSales_A\left(P_{fix\text{-}g}\right) - RevReq_A}{WF_{dso} \sum_{c_t=1}^{N_t} Qcust_y(c_t)} \tag{43}$$

4.3.2 Transactive Case Ratemaking

4.3.2.1 Fixed-Price Rates for Nontransactive Participants

The fixed-price rate for the proportion of customers who decline to adopt the transactive rate is intended to collect the same amount of revenue as if these customers were on the transactive rate design. This ensures that, on aggregate, customers who choose not to migrate to transactive rates should pay no more on their bills than they would if they had signed up for a transactive rate, but not participated in demand flexibility. The required revenue to be collected from nontransactive customers is determined by the process described in Section 4.3.2.2. Once this revenue requirement is determined the fixed rate is calculated for this set of customers using the BAU ratemaking described in Section 4.3.1.

This study had considered simply keeping nontransactive customers on the fixed-price rates determined for the BAU case; however, this was problematic for several reasons. First, ratemakers will not have the benefit of a BAU case in practice to provide a counterfactual on what customers would have paid had a transactive scheme not been implemented. More importantly, the implementation of transactive energy changes the cost basis for all customers in the region. Charging nontransactive customers a tariff based on counterfactual cost structure that does not exist is unfair and results in cost transfer between transactive and nontransactive customers. Finally, to the degree that the transactive rate design represents cost causality, using it to determine the revenue recovery from a subpopulation satisfies the rate design principles described in Section 4.1.2. Future work could explore whether nontransactive customers on a fixed rate should pay a slight premium to the DSO to cover the risk it bears buying wholesale electricity in a dynamic and competitive market and selling it at a fixed rate.

4.3.2.2 Dynamic Rates for Transactive Participants

For any given transactive case, the basis for the DSOs transactive rate is the annual time series of hourly wholesale day-ahead market LMPs for the node serving it. This assumes that most customers purchase most of their energy in the day-ahead retail market rather than the real-time market, which matches the behavior designed into the transactive agents for the flexible assets in the study.[22]

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[22] To the extent that transactive customers intentionally purchase energy on the real-time retail market, they may see slightly lower prices on average. If so, they reduce the DSO's revenues accordingly. However, they simultaneously have assumed that part of the DSO's risk premium on the wholesale real-time market, so the net impact on the DSO is assumed to be zero.

Structure of the Transactive Rate. The general structure of the monthly electric bill for transactive rate customer c_t has the form:[23]

$$TrxBill_m(c_t) = A \sum_{t=1}^{24\,D_m} LMP_{m,h}\, Qcust_h(c_t) + \sum_{t=1}^{24\,D_m} DCP_{m,h}(c_t)\, Qcust_{m,h}(c_t) + (P_{dist} - \Delta P_m)\, Qcust_m(c_t) + ConnectTrx(c_t) \quad (44)$$

where:

A	≡	the retail multiplier, i.e., the ratio of the wholesale energy component of retail clearing price to the wholesale LMP
$LMP_{m,h}$	≡	wholesale day-ahead and real-time market clearing prices in time t of month m for the node serving the DSO
$Qcust_{m,h}(c_t)$	≡	energy consumed by transactive rate customer c_t in time t of month m
$DCP_{m,h}(c_t)$	≡	the distribution congestion price, i.e., the difference between the retail market clearing price ($Prt_{m,h}$) for the substation serving customer c_t and the uncongested retail clearing price,[24] where: $DCP_{m,h}(c_t) = Prt_{m,h}(c_t) - (A\ LMP_{m,h})$
P_{dist}	≡	fixed distribution energy price
ΔP_m	≡	congestion discount for substation serving customer c_t for month m (see subsequent discussion of congestion rebate below)
ConnectTrx	≡	monthly connection charge for customer c_t's (rate) class
D_m	≡	number of days in month m

Transactive Ratemaking Process. Thus, aside from the time-series wholesale and retail market prices in Equation (44), the parameters defining the transactive rate that must be determined are:

- A – the retail multiplier
- P_{dist} – the fixed distribution energy price
- ConnectTrx(k) – the monthly connection charge for each customer class k (equal to those in the fixed-price rate)

The ratemaking procedure is to:

1. Define the monthly connection charge, ConnectFixm(k), for each customer class k based on the evidence for actual fixed costs. In the study this will be the same as assumed for the fixed-price rate of $10/month.

[23] This expression differs from the billing computation in two ways because it is directed at setting the parameters of the rate (ratemaking) rather than computing the customer bill. First, it does not have separate terms for real-time and day-ahead purchases because it is concerned with expressing the structure of the rate, not the billing computation per se. Second, it disaggregates the retail market clearing price into two components: the retail reflection of the wholesale price (i.e., the clearing price when the substation is uncongested), and a distribution congestion price that is the difference between the retail market clearing price and the uncongested clearing price.

[24] The distribution congestion price will be nonzero only when substation is congested.

2. Define the retail multiplier (A) based on representing actual wholesale costs that are considered to be directly proportional to the wholesale clearing price for the purposes of ratemaking, i.e., costs associated with additional energy charges for reserves and losses. This is addressed in the following subsection.
3. With all other parameters defining the rate known, the fixed distribution energy price (P_{dist}) can then be determined so the transactive rate will recover the DSO's required revenues. This is addressed in the second subsection below.

Estimation of the Retail Multiplier. Based on the analysis of the transactive rate structure in Appendix F, the retail multiplier can be expressed as:

$$A \equiv \left(1 - Fbi_A \frac{\overline{LMPbi_A}}{\overline{LMP_A}} + Fbi_A \frac{\overline{Pbi_A}}{\overline{LMP_A}} + \bar{F}tloss_A + \frac{\bar{P}_T}{\overline{LMP_A}} + \frac{\bar{P}_I}{\overline{LMP_A}} + f_{reg}\frac{\bar{P}_{reg}}{\overline{LMP_A}} + f_{spin}\frac{\bar{P}_{spin}}{\overline{LMP_A}} + f_{nspin}\frac{\bar{P}_{nspin}}{\overline{LMP_A}}\right)(1 + \bar{F}dloss_A) \tag{45}$$

where:
$Qdso_A$ ≡ the annual energy supplied to the DSO
Qbi_A ≡ the annual energy purchased by the DSO via the bilateral contract
Fbi_A ≡ the fraction of DSO's annual energy supply purchased via bilateral contract
$\overline{LMP}_A$ ≡ the weighted-average wholesale LMP of energy
$\overline{LMPbi}_A$ ≡ the weighted-average wholesale LMP of energy displaced by the bilateral contract purchases
$\overline{Pbi}_A$ ≡ the weighted-average bilateral contract energy price
$\bar{F}tloss_A$ ≡ the annual transmission system losses as a fraction of the energy delivered (2% assumed)
$\bar{F}dloss_A$ ≡ the annual distribution system losses as a fraction of the energy consumed by customers (5% assumed)
freg ≡ fraction of total system demand required for regulation reserve = 1%
fspin ≡ fraction of total system demand required for spinning reserve = 5%
fnspin ≡ fraction of total system demand required for nonspinning reserve = 5%
$\bar{P}_T$ ≡ the transmission access postage stamp rate (see Section 3.3.1.4)
$\bar{P}_I$ ≡ the ISO fee rate (see Section 3.3.1.5)
$\bar{P}_{reg}$ ≡ the average annual price for regulation reserves (see Section 3.3.1.6)
$\bar{P}_{spin}$ ≡ the average annual price for spinning reserves (see Section 3.3.1.6)
$\bar{P}_{nspin}$ ≡ the average annual price for nonspinning reserves (see Section 3.3.1.6)

and these are defined as:

$$Qdso_A \equiv \sum_{h=1}^{8760} Qdso_h \tag{46}$$

$$Qbi_A \equiv \sum_{h=1}^{8760} Qbi_h \tag{47}$$

$$Fbi_A \equiv \frac{Qbi_A}{Qdso_A} \tag{48}$$

$$\overline{LMP}_{\mathrm{A}} \equiv \left(\sum_{h=1}^{8760} LMP_h \, Qdso_h \right) \Big/ \, Qdso_A \tag{49}$$

$$\bar{P}bi_A \equiv \left(\sum_{h=1}^{8760} Pbi_h \, Qbi_h \right) \Big/ \, Qbi_A \tag{50}$$

$$\overline{LMPbi}_A \equiv \left(\sum_{h=1}^{8760} LMP_h \, Qbi_h \right) \Big/ \, Qbi_A \tag{51}$$

Note that losses also vary in real-time as a non-linear function of system total demand, but are commonly represented as a fraction of total demand. Since the transmission losses are not available from the DSO+T simulation, the valuation uses the simplifying assumption that they are a constant 2% and distribution losses a constant 5%, or a total of 7%, corresponding to published annual averages.

Although the study's valuation treats prices for reserves as a constant average annual price (see Section 3.3.1.6), the quantity of those reserves varies in real-time because they are each fractions of the system total demand. The prices for reserves are generally substantially less than wholesale market clearing prices but they do vary over time and at least partially reflect the variation in wholesale market clearing prices. So the contribution to the retail multiplier (A) due to the cost of reserves is approximated as the product of the ratio of the annual average cost of each type of reserve to the annual average cost of energy sold in the wholesale market (LMP_{avg}).

Defining the Distribution Energy Rate to Recover Required Revenues. The annual revenue required from the DSO's transactive customers ($RevTrxSales_A$) is then the difference between the total annual revenue required by the DSO as expressed in Equation (42) and the revenue recovered from the fixed-price customers ($RevFixSales_A$):

$$RevTrxSales_A = RevReq_A - RevFixSales_A \tag{52}$$

Substituting Equation (39) for the total revenue from sales to transactive customers ($RevTrxSales_A$) in Equation (52) and solving for the DSO's total annual revenue from distribution charges ($RevDistCharges_A$):

$$\begin{aligned} RevDistCharges_A = {} & RevReq_A - RevFixSales_A \\ & - RevDaEnergy_A - RevRtEnergy_A - RevConnectTrx_A \end{aligned} \tag{53}$$

Substituting the expression for a customer's monthly distribution charge by Equation (28) into Equation (37) that expresses the DSO's annual revenues from its distribution charges to customers:

$$RevDistCharges_A = WF_{dso} \sum_{c_t=1}^{N_t} \sum_{h=1}^{8760} Qcust_h(c_t)\, P_{dist} \tag{54}$$

Noting that P_{dist} is constant and the annual energy consumed by the DSO's transactive customers is:

$$Qtrx_A = WF_{dso} \sum_{c_t=1}^{N_t} \sum_{h=1}^{8760} Qcust_h(c_t) \tag{55}$$

Then Equation (54) can be simplified to:

$$RevDistCharges_A = P_{dist}\, Qtrx_A \tag{56}$$

then substituted into Equation (53) and solved for the distribution energy fixed-price (P_{dist}):

$$P_{dist} = \frac{RevReq_A - RevFixSales_A - RevDaEnergy_A - RevRtEnergy_A - RevConnectTrx_A}{Qtrx_A} \tag{57}$$

The resulting D_d [$/kWh] component defines a transactive rate that recovers the required revenue when all customer classes are treated uniformly.

Congestion Rebate. The transactive rate structure's design calls for a congestion rebate to be applied each month to make the rate plan equitable between transactive customers on congested and uncongested substations. The rationale behind this and the design of the rebate itself are part of the transactive coordination scheme described in Widergren et al. (2022). The rebate is accomplished by discounting a portion of the distribution energy charge each month, the congestion discount. This section describes how the monthly congestion discount (ΔP_m) is computed for a substation for the DSO's use in billing the customers served by the substation.

Consistent with the design of the transactive rate structure, the monthly congestion revenue collected by the DSO from all transactive customers served by a substation in both the day-ahead and real-time retail markets ($CongRev_m$) is the difference between the actual monthly revenue collected and the revenue that would have been collected if there was no congestion during the month. Following the pattern established by Equations (26) and (27) for the monthly retail day-ahead and real-time charges for customers, the congestion revenue for the month is:

$$\begin{aligned} CngstRev_m = {} & WF_{dso} \left(\sum_{c_t=1}^{N_t} \sum_{d=1}^{D_m} \sum_{h=1}^{24} DCPda_{m,d,h}\; Qda_{m,d,h}(c_t) \right) \\ & + WF_{dso} \left(\sum_{c_t=1}^{N_t} \sum_{d=1}^{D_m} \sum_{h=1}^{24} \sum_{i=1}^{12} DCPrt_{m,d,h,i} \left(Qcust_{m,d,h,i}(c_t) - \frac{1}{12} Qda_{m,d,h}(c_t) \right) \right) \end{aligned} \tag{58}$$

where: $$DCPda_{m,d,h} = Pda_{m,d,h} - \left(A\, LMPda_{m,d,h} + P_{dist}\right) \tag{59}$$

$$DCPrt_{m,d,h,i} = Prt_{m,d,h,i} - \left(A\, LMPrt_{m,d,h,i} + P_{dist}\right) \tag{60}$$

The time series of wholesale and retail day-ahead and real-time market clearing prices, and of each customer's day-ahead purchases and real-time consumption, are all known results from the simulation. The retail multiplier (A) and the distribution energy rate (P_{dist}) are known from the transactive ratemaking. So the monthly congestion revenue can be calculated at the end of each month and applied to the billing of customers served by a DSO substation.

The congestion discount that exactly rebates the congestion revenue during month m is then equal to the congestion revenue divided by the total monthly consumption by the transactive customers:

$$\Delta P_m = \frac{CngstRev_m}{Qtrx_m} \qquad (61)$$

where: $Qtrx_m = WF_{dso} \sum_{c_t=1}^{N_t} \sum_{d=1}^{D_m} \sum_{h=1}^{24} \sum_{i=1}^{12} Qcust_{m,d,h,i}(c_t)$

4.3.3 After-the-Fact Transactive Ratemaking

In the utility industry, rates are adjusted at irregular intervals (~2 to 5 years) so that the utility continues to recover its required revenue as its costs escalate (or drop). A utility's historical variable and fixed costs are key inputs to the process. Since costs and revenues change over time for a wide variety of reasons, rates are adjusted as needed. Some jurisdictions have built-in adjustments that automatically reflect certain types of changes in externally driven utility costs (e.g., fuel adjustment charges) on a monthly basis. Occasionally entirely new rates are designed, introduced, and their parameters determined by a new ratemaking process for them. The adoption of a transactive rate is an example of such an instance.

As discussed previously, the DSO+T study does not have the luxury of many years of experience and continual adjustments to rates. Even the annual energy consumed by customers is unknown until a BAU case simulation is completed. Fortunately, in the BAU case there is no response by customers or their assets to fixed-price retail rates. So, a simple solution to the lack of experience is to conduct the BAU simulation, record each customer's load, and finalize the rate design to recover the required revenue and calculate their monthly bills for the valuation. The term *after-the-fact ratemaking* is used for this shortcut.

The same dilemma arises for the transactive ratemaking, however, because retail prices affect customer use of their flexible assets, and hence their bills and the DSO's revenues. In transactive cases, how much the DSO's infrastructure and energy costs, and hence required revenues, are reduced by the transactive rate customers is not known prior to the simulation. So, if neither the required revenues nor the customer loads are known, how are the transactive rates to be determined, short of extensive iteration or simulating the full year-by-year evolution of the DSO+T strategy over ~20 years to gain the requisite experience?[25]

It is fortuitous that the flexible-load asset control agents are all fundamentally based on either an optimization of the DER's response for the day-ahead market over the 48-hour sliding window or a real-time control that uses the difference of the retail price from the mean price (or forecasted price) normalized by the standard deviation over the next 48-hours. So, although this is done without regard to the valuation, the flexible-load asset agents respond to relative differences in retail prices over time, rather than absolute prices. Thus, transactive rates for

[25] Simulating the annual evolution of a DSO+T strategy would be highly informative and is a useful long-term goal but is deemed too ambitious for the DSO+T study.

flexible-load cases can be finalized after the fact since the constant offset on prices represented by the distribution energy fixed-price can be set after the simulation has been conducted.[26]

Battery cases present a more nuanced problem for after-the-fact ratemaking in the DSO+T valuation process. In general, a battery operates such that, given a forecasted series of prices, it optimizes when to charge and when to discharge. This is logically based on accounting for whether the price differential between high-price hours and low-price hours is sufficient to overcome to degradation of battery lifetime pay for a battery cycle, i.e., they are responding to relative prices.

However, batteries also have a round-trip efficiency for which they must account. Here, the ratio of the high and low prices in absolute terms matters. The more the distribution energy fixed-price rate contributes to the overall transactive retail price, the closer this ratio approaches one, and the more difficult it is to justify a battery cycle given the battery system's round-trip efficiency. So, the battery control agents in the study optimize with absolute prices rather than relative normalized prices that the flexible-load control agents use.

To facilitate reasonably valid comparisons of transactive approaches, the study uses an assumed value of the distribution energy price that is used as a proxy for the lack of experience in setting transactive rates for the battery case. While not guaranteed to balance actual and required revenues in transactive cases, the resulting economic impacts on stakeholders should be accurate enough to provide meaningful insight into how a DSO+T strategy based on batteries compares to that of one based on flexible loads.

[26] This is only true for loads that offer flexibility in the form of load shifting on a diurnal (or less) timescale. The same cannot be said for long-term effects on loads, such as driving energy efficiency, where the absolute level of prices on average drive response, not the fluctuations in prices that occur during the course of the day.

5.0 Customer Costs for Flexible Assets

The Customer's CFS structure is shown in Table 22, below. The Customer CFS is composed of four categories, the first being the retail electricity bills which is described in Section 4.1 of this report. The following section will describe how the cash flows for the remaining three categories, capital and installation costs, revenues, and taxes, are estimated within the study.

Table 22. Customer CSF in three levels of detail

Category / **Sub-Category** / Element	**Annual Cash Flow (2016 $K/yr)**
Electricity Bill	**$E**
Capital and Installation Costs	**$C**
Flexible Asset Investment (Transactive)	**$C1**
Residential HVAC Controls	$C1a
Water Heater Controls	$C1b
Commercial HVAC Controls	$C1c
Battery	$C1d
Electric Vehicle Charging Controls	$C1e
Photovoltaic Solar System	**$C2**
Revenues	**$R**
Income Allocated for Electricity Costs	**$R1**
Taxes	**$T**
Increase from Reduced Electric Bill Deduction	**$T1**
Balance = Electricity Bills + Capital + Taxes - Revenues	$B

5.1 Customer Asset Costs

The following sections include details on how elements within the capital and installation costs category of the customer CFS were calculated when applicable. As discussed in Section 2.3, the CFS provides a levelized annual capital cost, not the entire capital cost. This is found by multiplying the capital cost by the ACCF value. The ACCF is the fraction of an initial capital investment (first costs) represented by the sum of those constant, levelized annual payments and is overviewed in Section 2.3 and described in detail in Appendix A.

The labor costs associated with the installation of DERs is estimated based hourly wage data (BLS 2018) or the appropriate occupation and DSO type (rural, suburban, or urban) in the state of Texas. Since the cost to the customer is realistically greater than the hourly wages of the labor, the BLS employer costs for employee compensation survey data were used to calculate fully burdened labor rates for the customer CFS (BLS 2020). Wages and salaries were found to be 70% of total compensation, so Texas hourly wage data were divided by 0.7 to get the hourly installation labor costs for customer CFS calculations.

5.1.1 Heating, Ventilation, and Air Conditioning

The heating, ventilation, and air conditioning (HVAC)-related elements of the customer CFS refer to the cost of the controls needed for the customer to participate in the transactive energy market using their existing HVAC system. The same equation was used to estimate the HVAC controls for both residential and commercial customers. For residential and small commercial buildings with unitary HVAC systems, the cost of making their HVAC flexible is the cost of replacing their thermostats with smart thermostats. The additional cost of a smart thermostat that is capable of participation in the transactive energy system versus the cost of a standard thermostat is the value calculated for this element. It is assumed there are no additional annual maintenance costs associated with this DER, but there are increased installation labor costs and capital expenses for the smart thermostat.

The following equation was used to calculate the HVAC cost to a customer in the study:

$$Zones * (ACCF * (Price + InstallCapital + (InstallTime * Labor))) \quad (62)$$

where *Zones* = The number of HVAC zones, or thermostats required

Price = Additional purchase price of a smart thermostat

InstallCapital = Additional cost of smart thermostat installation capital

InstallTime = Additional hours required to install smart thermostat

Labor = Hourly cost of electrician

The following values were used to calculate the cost to the customer using Equation (62). Based on publicly available prices, a smart thermostat cost on average is $154.90 more than a standard thermostat. The additional costs to install a smart thermostat rather than a standard thermostat are related to the addition of a Common Wire (C-Wire) which is often necessary but missing from a home (Nunley and Love 2019). It was found based on various public reports that on average this can lead to a marginal cost of 0.7 hours of labor and approximately $13 in material. The 0.7 hours was multiplied by the hourly expense of maintenance and repair labor in Texas. These are the total costs, represented in 2016 dollars and the ACCF is applied to these to calculate the annual levelized cost per zone. The number of zones assigned to any given customer is based on the square footage of the building and determines how many thermostats would need to be purchased and installed.

For some commercial customers with large, complex HVAC systems, primarily large office buildings, the cost to have a participating HVAC system would not be the marginal expense for a smart thermostat, it would be the additional expense for a control engineer to reprogram the system to have its setpoints respond to price, using the same algorithm. The study assumes the cost per zone is comparable, whether the ability to participate comes from equipment (smart thermostats) or labor (control engineer). Because of this assumption, Equation (62) is used to estimate costs for all customers, including those in large commercial buildings.

5.1.2 Water Heater

This element represents the levelized annual cost associated with equipping a water heater to participate in the transactive energy system. Similar to HVAC this does not include costs for a water heater itself, but the costs specifically associated with the necessary controllers and mixing valves that allow a water heater to safely participate by overheating in a transactive system. Equation (63) was used to calculate these associated water heater cost to a customer in the DSO+T study:

$$ACCF * (Price + (InstallTime * LaborCost)) \quad (63)$$

where *Price* = Controller and mixing valve cost

InstallTime = Hours required to install equipment

LaborCost = Hourly cost of a plumber

To estimate the price of the equipment needed, different controller prices were found for different types of water heaters. The prevalence in type of water heater was taken into account to find a weighted-average cost for a controller of $141.76 in 2016 dollars. The average price of the mixing valves available for purchase at the time of this study was $90.48 once deflated to 2016 dollars, making the combined price of the equipment needed $232. The installation time was assumed to be 3 hours and the hourly fully burdened cost of a plumber in Texas in 2016 dollars, $28.90, was used. This total installation costs was then applied to the ACCF.

5.1.3 Battery

Unlike other elements of the customer CFS, the entire cost of the battery is included rather than the marginal cost required to upgrade a piece of equipment to be transactive. It is assumed that the purchase and installation of a battery is motivated primarily to provide energy services. In addition, first cost and battery lifetime assumptions were determined to ensure that the cyclic degradation (and resulting depreciation) incurred during battery operation would be more than offset by typical daily variations in energy prices. If these assumptions were not made, and the cyclic degradation cost was too high, the transactive battery agent would not identify financially beneficial opportunities, resulting in no participation in the market. This approach results in a first cost of $83/kWh, which is aggressive compared to projected battery price ranges of $190-270 (Mongrid et al. 2019). It is important to remember there are many additional value propositions other than energy price arbitrage that exist for battery storage, such as reliability and self-consumption of renewable energy, that are not taken into account in the study and would justify a higher overall purchase price. The development of the first cost assumption is presented in more detail in Widergren et al. (2022, Section 4.2.2.4).

Equation (64) was used to calculate the battery cost to a customer:

$$ACCF * \big((InstalledCost * Rated\ Size) + (Variable\ O\&M * Rated\ Size) + Fixed\ O\&M\big) \tag{64}$$

As discussed above, the installed cost is assumed to be $83/kWh. In addition, the battery element of the customer CFS includes a fixed O&M cost of $9.56 per year and variable O&M cost of.03₵ per kWh applying a deflator to the values from Mongrid et al. (2019) to put costs in 2016 dollars.

5.1.4 Electric Vehicle Chargers

Similar to how HVAC was handled, the costs associated with electric vehicle supply equipment (EVSE) on the Customer CFS are the additional installation costs between a standard EVSE and one that has the controls features that enable participation in the transactive energy market, a smart EVSE.

Equation (65) was used to calculate the EV-related cost to a customer in the study:

$$ACCF * \big(Price + InstallCapital + (InstallTime * Labor)\big) \tag{65}$$

where *Price* = Additional purchase price of a smart EVSE

InstallCapital = Additional cost of installation capital

InstallTime = Additional hours required to install

Labor = Hourly cost of electrician

The additional price for a smart EVSE was found by comparing the average prices of standard EVSE with prices for comparable EVSE capable of participating in the transactive energy market; the prices used were all publicly available on vendor websites. The average marginal price for a transactive energy capable EVSE was found to be $254. The installation costs, both capital and labor, were found not to differ between the standard and smart EVSE so are values with zero change for the DSO+T analysis.

5.1.5 Photovoltaic Rooftop Solar Systems

Costs were calculated for a solar PV system and assumed to be present for a portion of customers. PV systems were modeled differently than the other DERs discussed in the study because they did not directly participate in the transactive energy market. The base cases assume a level of PV is present, so the annual costs that customers pay for these systems were included in the analysis so that a percentage change in costs can be accurately estimated for customers.

The annual cost of a PV system on the customer CFS consists of a levelized annual cost for the first costs and an annual operating expense. Annual O&M expenses for both residential and commercial customers were found from the NREL Annual Technology Baseline. At the time of this analysis the residential and commercial annual operating expenses were reported at $23.50 and $17.62/kW (in 2017 dollars). The levelized annual cost for the first costs were calculated by applying the appropriate ACCF to the total installed cost of the system. The installed cost of the system is estimated using the rated system size (typically 5 kW for residential systems; see Reeve 2022b, Section 2.4.3) and the median installed price of systems per rated kW from the *Tracking the Sun* report (Barbose and Darghouth 2019). The residential systems varied between $3,132 and $4,087/kW (rated) depending on the size of the system. Commercial systems varied between $1,922 and $3,230/kW (rated) also depending on the size.

Equation (66) was used to calculate the PV cost to a customer in the DSO+T study:

$$ACCF * \left((Installed\ Price * Rated\ Size) + O\&M\right) \qquad (66)$$

5.2 Revenues

The customer CFS differs from the DSO CFS in that there is no traditional revenue source. The portion of household or business income that is allocated to electricity-related purchases is viewed as the customer CFS revenues in the DSO+T study. There are other potential revenues for a customer that are not modeled in this study such as rebates or incentives to install DERs and participate in the transactive energy market. In this study the customer's revenue, or benefit for their participation, is calculated as the decreased electricity payments made.

5.3 Taxes

For commercial customers within the study their electricity payments are modeled as a tax deductible expense. The study calculates their tax liability, and change in tax liability using the tax deduction rates shown below in Table 23. For commercial customers it is expected that the tax responsibility will be impacted in an inverse way to the electricity bill. For taxpaying entities, their utility payments are a tax deduction, so when the electricity bill is lower their deduction is also lower leading to a potentially higher tax responsibility.

There are obviously many factors that can impact an entity's tax liability. The purpose within the study is to include how taxes are directly impacted by changes in total electricity bills. It is important to note here that the sales taxes associated with purchasing and installing DERs are captured within the ACCF and not included in this portion of the CFS.

Table 23. Electricity bill expense tax deductions by commercial building type and occupancy.

Building Type	Occupancy		Electric Bill Tax Deduction		
	Business (%)	Public/ Nonprofit (%)	Business (%)	Public/ Nonprofit (%)	Building Type Weighted-Avg. (%)
Office, Large	90%	10%	28%	0%	25.2%
Office, Medium/Small	5%	95%	28%	0%	1.4%
Warehouse & Storage	100%	0%	28%	0%	28.0%
Big Box Retail	90%	10%	28%	0%	25.2%
Strip Retail	90%	10%	28%	0%	25.2%
Education	5%	95%	28%	0%	1.4%
Food Service	90%	10%	28%	0%	25.2%
Food Sales	95%	5%	28%	0%	26.6%
Lodging	75%	25%	28%	0%	21.0%
Healthcare, Inpatient	50%	50%	28%	0%	14.0%
Low Occupancy	100%	0%	28%	0%	28.0%

6.0 Bulk Power System Stakeholder Cash Flows

6.1 Generator Owners

This section discusses the cost basis for the generation fleet assumed in this study. The purpose of this study was not to evaluate the impact of transactive energy cases or the HR scenario on the economics and profitability of the generation fleet. Furthermore, the DSO wholesale expenses are based on the simulated LMPs, which are only impacted by the generators' variable costs. Fixed capital and operating costs are estimated to provide an overall view of the cost basis for grid operation. As such, the study's CFS for generators is shown in Table 24. Note that some generators may not earn enough revenue to cover all costs or have additional revenue sources (such as production tax credits) that are not included in this study. In these cases, the Sankey diagram cost summary (Figure 3) allocates the calculated revenue to the costs described below in proportion to their relative value. When revenue exceeds costs profit is included in the fixed operating costs.

Table 24. Generation owner CFS.

Category / Line / Item	Annual Cash Flow ($K/yr)
Capital Costs[a]	$C
Operational Costs	$O
Fixed Cost	**$O1**
Variable Cost	**$O2**
Fuel and Variable O&M	$02a
Startup Costs	$O2b
Revenue	$R
Wholesale Energy Market Sales	**$R1**
Capacity Sales	**$R3**
Balance = Profit after Return to Equity	**$B**

[a] Annualized capital costs include return on shareholder equity investment and taxes on revenues after depreciation and interest deductions

6.1.1 Capital Costs

The levelized annual capital expenses for the generator operator are based on the estimate for capital investment in the entire generation plant:

$$GenCapExp_A = GenCapCost\ ACCF_{gen} \tag{67}$$

where: $GenCapExp_A$ ≡ levelized annual cost of the generation plant

$GenCapCost_A$ ≡ capital cost of the generation plant

$ACCF_{gen}$ ≡ annualized capital cost factor for generation infrastructure (Table 2)

The generation fleet's capital costs ($GenCapCost_A$) were based on published data of the 2016 overnight capital costs for generators as shown in Table 25.

Table 25. Generation capital and operating costs in 2016 dollars (DOE-EIA, 2016).

Technology	Overnight Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
Ultra-supercritical coal	3,636	42.1	4.6
Natural gas combined cycle	978	11	3.5
Advanced nuclear	5,945	100.28	2.3
Onshore wind	1,877	39.7	0
Photovoltaic – fixed	2,671	23.4	0

6.1.2 Operational Costs

6.1.2.1 Fixed Costs

The generation fleet's fixed operating costs were based on published data shown in The levelized annual capital expenses for the generator operator are based on the estimate for capital investment in the entire generation plant:

$$\mathrm{GenCapExp_A} = \mathrm{GenCapCost\ ACCF_{gen}} \tag{67}$$

where: GenCapExpA ≡ levelized annual cost of the generation plant

GenCapCostA ≡ capital cost of the generation plant

ACCFgen ≡ annualized capital cost factor for generation infrastructure (Table 2)

The generation fleet's capital costs (GenCapCostA) were based on published data of the 2016 overnight capital costs for generators as shown in Table 25.

Table 25.

6.1.2.2 Variable Costs

The study's simulation computes variable generation costs only for the thermal generation fleet (coal, natural gas, and nuclear generators). Renewable generation sources (wind and solar) are considered to have zero marginal fuel-based generation costs. The variable costs of the thermal generation fleet are divided into two categories: fuel costs (including variable O&M costs) and startup costs. More details on the calculation of these values is given in Reeve et al. (2021b, Section 2.2.1).

Thermal generation variable production costs are typically driven by the cost of fuel and are therefore determined by representative generator heat rates and fuel unit costs. To ensure market prices that are representative of 2016 values, the simulation used generator heat rates (as a function of system load) that were inferred from observed market prices (Potomac Economics 2017). This showed a five-times change in heat rate as the system net load changed throughout the year. This suggests other variable system costs (e.g., variable O&M) or factors beyond heat rate may be captured in the fuel variable cost number. As such, the fuel variable cost line item should be assumed to include all variable costs, for example variable O&M costs, except for startup costs. Estimates of the cost to start each generator were based on other work (Kumar et al. 2012) used by NREL in their *Phase 2 Western Wind and Solar Integration Study* (Lew et al. 2013). This work estimated the fuel, capital and maintenance, and other startup costs associated with various generator types and severity of start (hot, warm, and cold starts).

Therefore, the total thermal generation variable costs are the sum of the variable production costs and startup costs:

$$GenProductionCost_g = GenVarCost_g + GenStartCost_g \tag{68}$$

where the generation variable production costs are given as:

$$GenVarCost_g = \sum_{d=}^{365}\sum_{h=1}^{24}\sum_{i=1}^{12}\frac{Q_{g,d,h,i}}{12}\,C1_g \tag{69}$$

where: $GenVarCost_g$ ≡ the annual variable production cost (excluding startup) for generator g

$Q_{g,d,h,i}$ ≡ power (MW) produced by generator ‘g’ in the 5-minute interval i of hour h of day d of the year

$C1_g$ ≡ the variable production cost coefficient ($/MW-hr) for generator g

and the startup costs are given as

$$GenStartCost_g = \sum_{d=}^{365} NumStarts_{g,d}\ CostPerStart_g \tag{70}$$

where: $GenStartCost_g$ ≡ the annual startup costs for generator g

$NumStarts_{g,d}$ ≡ Number of starts on day d for generator g

$CostPerStart_g$ ≡ the cost per start for generator g

6.1.3 Revenue

6.1.3.1 Wholesale Energy Market

The revenue from wholesale energy market sales for each generator is calculated as the product of actual real-time power generated and real-time LMP at the node where the generator is located:

$$GenRevenue_g = \sum_{d=}^{365}\sum_{h=1}^{24}\sum_{i=1}^{12}\frac{Q_{g,d,h,i}}{12}\,Prt_{n_g,d,h,i} \tag{71}$$

where: $GenRevenue_g$ ≡ the annual energy market revenue of generator g

$Q_{g,d,h,i}$ ≡ power (MW) produced by generator g in the 5-minute interval i of hour h of day d of the year

$Prt_{ng,d,h,i}$ ≡ retail real-time market clearing price for the node n_g at which the generator g is located.

6.1.3.2 Capacity Market and Ancillary Service Sales

Capacity payments made by the DSOs are prorated to all generators based on their nameplate capacity. In addition, capacity payments to wind and solar generators are reduced based on their ability to meet capacity requirements. Solar and wind capacities are multiplied by 0.38 and 0.13, respectively (Jenkin et al. 2016). Ancillary service payments are prorated based on annual energy produced by each generator. It is assumed no ancillary service payments are made to solar or wind generators.

6.2 Transmission Owner

Adoption of the DSO+T strategy on transmission system owners is designed to have no effect in terms of recovering their capital and operating expenses or the rate of return to the equity investors of investor-owned operators. The study's valuation for the transmission owners is simplified in terms of the level of detail involved and the means by which its revenue is recovered. Hence, the study assumes there is only a single investor-owned transmission system operator and the CFS for the transmission owner is a simple statement of its capital expenses, operational expenses, and revenues as shown in Table 26.

Table 26. CFS for transmission owner.

Category / Line	**Annual Cash Flow (2016 $K/yr)**
Total Expenses	**$C**
Capital Expenses[a]	**$C1**
Operational Expenses	**$C2**
Revenue (transmission access fees)	**$R**
Balance	**$B**

[a] Annualized capital expenses include debt service and return on shareholder equity investment in capital assets, plus taxes on revenues after depreciation and interest deductions

The levelized annual capital expenses for the transmission system operator are based on the estimate for capital investment in the entire transmission system:

$$TransCapExp_A = TransCapCost\ ACCF_{trans} \tag{72}$$

where: $TransCapExp_A$ ≡ levelized annual cost of the transmission system

$TransCapCost_A$ ≡ capital cost of the entire transmission system

$ACCF_{trans}$ ≡ annualized capital cost factor for transmission infrastructure (see Table 2)

The capital cost of the study's transmission system[27] is estimated based on the *Transmission Line Capital Cost Calculator*, a detailed bottom-up cost model that itemizes costs for a variety of substation design characteristics and features (WECC 2012). Overarching among these are the number and characteristics of the substations in the system and the length, voltage, and other characteristics of the transmission lines tying them together. On the high-voltage side of the substation these include the number and voltage of the transmission lines that serve the substation and the breaker configuration. On the low-voltage side, itemized costs include the

[27] The cost estimate is based on the system synthesized to represent ERCOT's transmission system (Reeve 2022b) because the physical details of the ERCOT system are not available due to the sensitive national-security infrastructure.

number of transformers, number and voltage of the transmission lines serving the load, number and rating of capacitor and reactor banks, and the low-voltage breaker configuration.

Based on this design information, the number of bays in the substation's high- and low-voltage sections are tabulated and costed. Finally, costs for right of way and transmission line costs are added, along with costs for planning, design, and associated overheads in the form of an allowance for funds used during construction of 15%, to produce the total substation cost. The model also includes cost assumptions for all these itemized costs adjusted for inflation. The result is that the DSO+T's transmission infrastructure represents a $16.6 billion 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).

Wholesale rates for transmission services take a variety of forms across the United States. The simplest common form is a postage stamp rate and the study uses this approach for the transmission owner. A postage stamp rate, by definition, is a fixed energy price added to all transactions regardless of the location of the generator or the DSO in any transaction in the wholesale markets or bilaterally. The study ensures that transmission system capital and operating expenses are recovered through the postage stamp rate collected on DSO wholesale energy purchases, including those from bilateral contracts with generators.

The study does not estimate the annual operating expenses of the transmission owner directly, from the bottom up, but by subtracting the levelized annual capital expenses from the annual revenue collected via the postage stamp rate on all wholesale transactions. The annual transmission system operator's revenues are then:

$$TransOpRev_A = P_{trans} \sum_{D=1}^{N_{dso}} \sum_{h=1}^{8760} Qdso_h(dso) \tag{73}$$

where: $TransOpRev_A$ ≡ transmission system owner's annual total costs

P_{trans} ≡ postage stamp rate for transmission access

$Q_{dso}(h)$ ≡ energy delivered in hour of year h to DSO D

N_{dso} ≡ number of DSOs in the study.

Because transmission system rates in ERCOT are not based on postage stamp rates, CAISO's postage stamp rates are used as the basis for this estimate as the nature of the geography of Texas and California are similar with respect to its effect on transmission system costs. Both are western states that are largely arid, have similar urban clusters with distant generation sources and amounts of renewable bulk system generation, and whose transmission corridors are predominantly not mountainous.

So, in the MR BAU case, the transmission system's annual operating expenses are estimated as:

$$TransOpsCost_A = TransOpRev - TransCapExp_A \tag{74}$$

where: $TransOpsCost_A$ ≡ transmission system owner's annual total costs

6.3 Independent System Operator

Like the transmission owner, the adoption of the DSO+T strategy is designed to have no financial impact on an ISO's recovery of their capital and operating expenses. So, the study's valuation for the ISO is simplified to only two line items—capital and operating expenses and revenue from the ISO fees collected—as shown in Table 27.

Table 27. CFS for ISO.

Category	Annual Cash Flow (2016 $K/yr)
Capital and Operational Expenses	$C
Revenue (ISO fees)	$R
Balance	$B

ISOs in the U.S. use a variety of fee structures to recover their annual expenses. In the DSO+T 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). There may be some change in the energy supplied to the DSOs in transactive cases relative to the corresponding BAU case due to load shifting by flexible loads and the round-trip efficiency in batteries. The ISO's annual expenses are not assumed to change appreciably due to the adoption of the DSO+T strategy, however. (By contrast, the ISO's expenses may increase significantly in high-renewables scenarios over that of moderate-renewable scenarios due to the need for more labor and sophisticated tools for operating the power system.)

So, the published fee rate of $0.555/MWh is assumed to apply only to the BAU case in the moderate-renewables scenario, based on the energy supplied to the DSOs in the study's simulation. The ISO's capital and operating expenses for all moderate-renewables cases is then set equal to its revenues in the BAU case, and the ISO fee adjusted to recover that fixed revenue requirement in the transactive cases. Thus, the ISO's capital and operating expenses are estimated as:

$$IsoCosts_A = (1 + f_{HR})\,\bar{P}_{I-ref} \sum_{dso=1}^{N_{dso}} \sum_{h=1}^{8760} \sum_{i=1}^{12} Q_{dso}(i) \qquad (75)$$

where: $IsoCosts_A$ ≡ annual fees collected by ISO

$\bar{P}_{I\text{-}mr\text{-}bau}$ ≡ moderate-renewables BAU ISO energy fee = $0.555/MWh

f_{HR} ≡ fractional increase in ISO expenses in HR scenario vs. MR scenario = 25% (for high); 0% (for moderate)

$Q_{dso}(i)$ ≡ bulk system energy delivered to each DSO (indexed by 'dso') in 5-min interval i of hour of year h (including dso's weighting factor and industrial loads)

h ≡ index, hour of the year

i ≡ index, 5-min interval within an hour

Note that ISO expenses in high-renewables scenarios are assumed to be 25% higher than in MR scenarios.

Then the ISO fee for any of the study's cases is simply found by solving Equation (75) for the fee needed to recover the ISO's costs:

$$\bar{P}_I = IsoCosts_A \Bigg/ \left((1 + f_{HR}) \sum_{dso=1}^{N_{dso}} \sum_{h=1}^{8760} \sum_{i=1}^{12} Q_{dso}(i) \right) \qquad (76)$$

7.0 Conclusions

The DSO+T study has used value activity models to construct a detailed and rigorous mapping of grid ecosystem stakeholders and the value flows between them. The resulting valuation methodology was then populated with simulation results and parametric cost models to estimate the entire annualized cost structure of grid stakeholders, with a particular focus on customers and DSOs. This has allowed not only detailed estimates of the absolute and relative *net* benefit of DER coordination schemes such as transactive energy, but also provided transparency on where these benefits occur and how they are offset by associated implementation costs. In addition, the valuation model allows for both microeconomic analyses of an individual's activities and the economic impact derived from that activity, and macroeconomic analyses of how the totality of the individual's activities impacted the system and society as a whole. This allows granular analysis of subpopulations (such as rural, urban, and suburban DSOs; or residential versus commercial customers) to understand the impact on various constituents in the grid as well as the overall societal benefit.

The detailed mapping of the grid's cost structure (as illustrated in the Sankey diagram shown in Figure 3) helps practitioners and researchers understand the relative portions of various annualized expenses and the potential for demand flexibility to impact these. The overall study results have shown that the benefits are dominated by reductions in capital market costs, with smaller reductions in wholesale energy payments, and transmission and distributions system capital costs. These benefits were only marginally offset by implementation costs associated with retail market and DER network IT system and labor cost and the customer-borne DER investment costs. Given the high sensitivity of capacity market prices to required quantity, investigation is warranted into future capacity market price scenarios. In addition, as more DER coordination schemes are implemented their actual costs will serve as improved basis of estimate for transactive system implementation costs.

Finally, the relative proportions of the cost structure provide perspective and insight into how the accelerating energy transition may impact the overall operating cost of the grid. Foremost among these is the impact that 'zero-marginal-cost' renewable energy will have on grid economics. The DSO+T study estimates that energy purchases only account for less than a third of the grid's operating cost with fuel and variable generation O&M costs accounting for less than 15% (with the remainder covering capital and fixed operating costs). Even in a future with substantially lower wholesale energy prices, ensuring the reliable delivery of electricity represents a substantial annualized cost. In addition, ancillary services, a vital function of grid operation and the subject of much advanced research, only account for approximately 2% of annualized costs. Conversely, capital costs represent almost half (44%) of the grid's annualized cost. Understanding how demand flexibility approaches and technology can best reduce required capital costs and how to effectively incorporate the impact of demand-side operational strategies in long-term planning activities (such as IRPs) is a critical need. In addition, value (price) signals based on marginal fuel costs may not be appropriate in a future grid dominated by high fixed costs. How to best recover revenue that is fair and incentivizes behavior that reduces required capital investment is a key need. Finally, approximately 40% of the grid's cost structure is associated with labor, maintenance, and operations costs exclusive of capital and generation variable costs. Understanding how a highly renewable, distributed, decentralized, and digital grid will continue to impact these soft costs will be a key need.

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Appendix A – Annual Revenue Required to Recover Capital Costs

This appendix documents how levelized annual costs are computed for the DSO+T study based on initial capital investments (first costs) for utility investments in grid infrastructure and customer investments in flexible-load controls and DER assets. The appendix has two major sections.

A.1 Procedure for Computing Annualized Capital Costs

To be consistent with the structure of the study's CFSs and the utility ratemaking processes used, the annual costs attributed to capital investments over their lifetime include any initial cash outlay plus principle and interest payments on debt, return on equity financing (if any), and return of equity's principle (if any), less tax benefits of depreciation and interest deductions for taxable entities. All other annual costs associated with O&M of infrastructure and other capital assets during the lifetime of the assets are explicitly accounted for in other line items of a stakeholder's CFS and included as expenses in the ratemaking process.

Note these annual time-series value streams are not uniform (constant) except under specific circumstances. So, to be general, they are represented by their levelized annual equivalent, i.e., a uniform annual quantity whose present value over the lifetime of the investment is equal to the present value of the actual, non-uniform time-series value stream over the lifetime of the investment, from the financial perspective of the asset owner.

The discussion that follows uses the general method and nomenclature of Doane et al. (1976) who developed the original method for computing levelized annual costs for capital investments by utilities. This is a convenient form for the calculations since it requires full articulation of the annual cash flows involved, in what is referred to as a *pro forma*, in order to compute present values and levelized costs of all cash flows.

The implementation of this method to execute calculations was verified using the CPUC's *Avoided Cost Calculator,* (CPUC 2019) which is a full pro forma calculation. Some subtle differences between the two were identified and the resolution of these differences are made explicit in the discussion that follows. The result is a hybrid approach convenient for use by the study that is consistent across capital investments by utility and non-utility entities, and who have different financial obligations based on their profit or nonprofit status, utilize different debt instruments (bonds, loans, or none at all), and have different ability to depreciate such investments.

A.1.1 Definitions

Annual time-series cash flows. Define the following variables as time-series annual cash flows comprising the cash flows to a project (i.e., "income" and "costs", respectively), with subscript t indicating the year of the time series:

Cash Flows to Project ("Income")	Cash Flows from Project ("Costs")
REV_t ≡ Revenue	SE_t ≡ Stock (equity) earnings
SS_t ≡ Sale of stock	REP_t ≡ Return on equity principle

BS_t ≡ Bond sales

EQT_t ≡ Equity return, total (to stocks) = $SE_t + REP_t$
INT_t ≡ Interest payments on debt
CSH_t ≡ Cash toward capital investment (in Year 0)
PDR_t ≡ Provision for debt retirement (of the principal)
TX_t ≡ Income taxes on net revenue (after deductions)
OT_t ≡ Other taxes
INS_t ≡ Insurance
OP_t ≡ Operating costs
MNT_t ≡ Maintenance costs
FL_t ≡ Fuel costs

Infrastructure parameters. Define the following parameters associated with the annual cost of maintaining the infrastructure of the capital investment:

CI_0 ≡ Capital investment in Year 0 ($/yr)
FL_0 ≡ Fuel costs in Year 0 ($/yr)
g_o ≡ O&M cost inflation rate (%/yr)
OP_0 ≡ Operations costs in Year 0 ($/yr)
MNT_0 ≡ Maintenance costs in Year 0 ($/yr)

General parameters. Define the following general parameters:

N ≡ Levelization period (years)[28]
g ≡ Inflation rate
r ≡ Discount rate
y_t ≡ Year of capital outlay
y_{co} ≡ First year of commercial operation
y_p ≡ Price year for O&M cost information

Tax parameters. Define the following parameters related to taxes:

τ_f ≡ Federal income tax rate
τ_s ≡ State income tax rate
N_{dprec} ≡ Depreciation term (years)

Financial parameters. Define the following financial parameters associated with the investment:

g_c ≡ Escalation rate for capital costs
N_d ≡ Debt financing term (years)
C/V ≡ Cash financed fraction of the value of the capital investment
E/V ≡ Equity financed ratio, the financed fraction of the value of the capital investment
D/V ≡ Debt financed ratio, the financed fraction of the value of the capital investment
k_d ≡ Debt cost (interest rate on debt)
k_{roi} ≡ Equity's expected rate of return
k_e ≡ Cost of equity financing
k_{wacc} ≡ Weighted-average cost of capital (WACC)
k^* ≡ After-tax WACC – see Equation (80)
k_{up} ≡ "Rationalized" upper limit on an investor's discount rate – see Equation (81)
k_{low} ≡ "Rationalized" lower limit on an investor's discount rate – see Equation (82)
k ≡ Investor's discount rate – see Equation (83)

[28] The lifetime of the investment for accounting purposes. Generally equal to, but may be less than, the actual lifetime of the physical asset. (Some utility assets are utilized longer than their lifetime as part of the utility infrastructure rate base, but for accounting and ratemaking purposes their "book" lifetime is less.)

Equity and debt shares of the capital investment. The entire value of the capital investment consists of cash, equity, and debt, so the sum of the cash, equity, and debt financed ratios must be equal to one:

$$E/V + D/V + C/V + P/V + D/V = 1 \tag{77}$$

The expected rate of return on equity investor (k_e) is defined as:

$$k_e \equiv k_{roi}\text{; iff } E/V \neq 0\text{, i.e., if there } \underline{\text{are}} \text{ equity investors}$$
$$k_e \equiv k_d\, D/V\text{; iff } E/V = 0\text{, i.e., if there } \underline{\text{are no}} \text{ equity investors} \tag{78}$$

The *weighted-average cost of capital* (k_{wacc}) is then defined as:

$$k_{wacc} \equiv k_e\, E/V + k_d\, D/V \tag{79}$$

Since interest payments on debt are deductible as a business expense, the investor's effective cost of capital *after taxes* is its after-tax WACC, k*:

$$k^* = k_{wacc}\, E/V + (1-\tau_i)\, k_d\, D/V \tag{80}$$

Discount rates. In the equations that follow, the generic discount rate, r, is used to represent the time value of money. This is equal to an investor's internal rate of return, which is generally assumed to be equal to its cost of borrowing (k*), as reflected in Equation (80). However, as in the real world, some investors (particularly some consumers) cannot be assumed to be economically rational. In the DSO+T study this manifests by the fact that some investors finance purchases by paying cash (an apparent discount rate of infinity) or with consumer loans or credit card purchases with very high interest rates that do not represent their actual discount rates in a meaningful way.[29] In particular, this "over-discounts" the value these customers actually place in future annual savings from investments in flexible (transactive) assets.

So the method developed allows for "rational" upper and lower bounds to be placed on an investor's pre-tax debt cost (k_{up} and k_{low}, respectively) for purposes of computing the investor's effective discount rate, k, for an investor financing debt at interest rate k_d. From Equation (80 , the corresponding upper and lower bounds on their after-tax WACC (k_{up}^* and k_{low}^*, respectively) are:

$$k_{up}^* \equiv k_e\, E/V + (1-\tau_i)\, k_{up}\, D/V \tag{81}$$
$$k_{low}^* \equiv k_e\, E/V + (1-\tau_i)\, k_{low}\, D/V \tag{82}$$

then the investor's effective discount rate is:

$$k \equiv \text{MAX}\{\ \text{MIN}\{k_{up}^*, k^*\}, k_{low}^*\ \} \tag{83}$$

Present value function. Based on the mathematics of finance, define a function that returns the present value of an arbitrary time series of cash flows X_t, over n years for a generic entity with discount rate r:

$$PV_{r,n}\{X_t\} \equiv \sum_{t=1}^{n} \frac{X_t}{(1+r)^t};\ for\ a\ time\text{-}series\ X_t \tag{84}$$

[29] This is a well-known phenomena taken into account by many studies of benefits of energy efficiency to consumers (Council of Economic Advisers 2017).

For convenience in computing the present value of <u>uniform</u> time series, i.e., when all X_t are uniformly equal to X_A at discount rate r over n years, define the present value of X_A, as (again from the mathematics of finance):

$$PV_{r,n}\{X_A\} \equiv X_A \frac{1 - (1+r)^{-n}}{r}; \; for\ a\ non\ time\text{-}series\ value\ X_A \qquad (85)$$

Note there are two useful identifies associated with the present value function:

Identity 1: $PV_{r,n}\{X_t + Y_t\} = PV_{r,n}\{X_t\} + PV_{r,n}\{Y_t\}$ (86)

Identity 2: $PV_{r,n}\{a\ X_t\} = a\ PV_{r,n}\{X_t\}$ (87)

where a is a constant. Also, from the mathematics of finance, if the time series of cash flows are <u>not</u> constant, but instead are escalating from an initial value in Year 0 of X_0, at rate g represented by the function $ESC_g\{X_0\}$, then:

$PV_{r,n}\{ ESC_g\{X_0\} \} \equiv PV_{r',n}\{X_0\}$ (88)

where r' is the *effective* discount rate:

$r' \equiv (1+r) / (1+g) - 1$ (89)

Capital costs. Capital costs are raised by sale of stocks and bonds (or by a loan's principal) plus any cash investment, so for an investor with discount rate r raising capital:

$CI_0 \equiv PV_{r,n}\{BS_t\} + PV_{r,n}\{SS_t\} + PV_{r,n}\{CSH_t\}$ (90)

Income taxes. Income taxes are based on revenue less deductions:

$TX_t \equiv \tau_i\ [\ REV_t – (DEP_t + INT_t + OT_t + INS_t + OP_t + MNT_t + FL_t)\ ]$ (91)

Where τ_i is the effective income tax rate:

$\tau_i \equiv \tau_f + \tau_s\ (1 - \tau_f)$ (92)

Sinking fund. A sinking fund can used by an investor to set aside a uniform annual cash flow sufficient to repay the principle of a debt at the end of a period of time. Define the sinking fund factor, $SFF_{r,n}$, as the uniform annual fraction of the present value of a capital investment that must be paid into a sinking fund to retire the debt principle in n years at the investor's effective discount rate, r, as:

$SFF_{r,n} \equiv r / [\ (1+r)^n - 1\ ]$ when $r \neq 0$ and $n \neq 0$

and

$SFF_{r,n} \equiv 1/n$ when $r = 0$ and $n \neq 0$ (93)

and

$SFF_{r,n} \equiv 1$ when $n = 0$ (and $r=0$)

Capital recovery factor. The capital recovery factor is defined in the mathematics of finance as the fraction of the original principle necessary to amortize a loan with a uniform set of payments at interest rate r over a period of time of n years as:

$CRF_{r,n} = r / [\ 1 − (1+r)^{-n}\ ]$ when $r \neq 0$ and $n \neq 0$ (94)

and

$CRF_{r,n} = 1/n$ when $r = 0$ and $n \neq 0$

and

$CRF_{r,n} = 1$ $n = 0$ (and $r=0$)

Note that solving Equation (85) for X_A as a fraction of the present value of a uniform set of payments equal to X_A over n years and substituting the result into Equation (94):

$$CRF_{r,n} = X_A / PV_{r,n}\{X_A\}$$

or solving for $PV_{r,n}\{X_A\}$:

$$PV_{r,n}\{X_A\} = X_A / CRF_{r,n} \qquad (95)$$

Further, it can be shown (see proof below) that:

$$SFF_{r,n} = CRF_{r,n} - r \qquad (96)$$

Proof that $CRF_{r,n} = SFF_{r,n} + i$

Let: $a = 1 + r$, $CRF = CRF_{r,n}$, $SFF = SFF_{r,n}$

So: $r = 1 - a$
$CRF = (1-a) / (1-a^{-n})$
$SFF = (1-a) / (a^{n}-1)$

Prove: $CRF = SFF + i$

Proof:

$$\begin{aligned}
(1-a) / (1 - a^{-n}) &\;?=?\; (1-a) / (a^{n}-1) + (1-a) \\
(1-a) / (1 - a^{-n}) &\;?=?\; [(1-a) / (a^{n}-1)] [(1-a^{-n}) / (1-a^{-n})] \\
&\quad + (1-a) [(1-a^{-n}) / (1-a^{-n})] [(a^{n}-1) / (a^{n}-1)] \\
(1-a) / (1 - a^{-n}) &\;?=?\; [(1-a) / (1-a^{-n})] [(1-a^{-n}) / (a^{n}-1)] \\
(1-a) / (1 - a^{-n}) &\;?=?\; CRF [(1-a^{-n}) / (a^{n}-1)] [1 + (a^{n}-1)] \\
(1-a) / (1 - a^{-n}) &\;?=?\; CRF [(1-a^{-n}) / (a^{n}-1)] [a^{n}] \\
(1-a) / (1 - a^{-n}) &\;?=?\; CRF [(a^{n}-1) / (a^{n}-1)] \\
CRF &= CRF
\end{aligned}$$

Q.E.D.

A.1.2 Lifetime Revenues Required to Balance Project Cash Flows

From an accounting standpoint, the present value of all the positive cash flows to a project must be offset by that of all the negative cash flows from the project, from the perspective of an investor with discount rate r. That is, the present value (at discount rate r) of the project's income (revenues plus sales of stocks and bonds or the principle of a loan) must equal that of its costs (the capital investment, total to equity principle, interest payments on debt, provision for debt retirement, income and other taxes, insurance, operating costs, maintenance costs, and fuel costs):

$$PV_{r,N}\{ REV_t + BS_t + SS_t \} = CI_o + PV_{r,N}\{ EQT_t + INT_t + PDR_t + CSH_t + OT_t + INS_t + OP_t + MNT_t + FL_t + TX_t \} \qquad (97)$$

Note that the present value of the capital investment (CI_o) is by definition equal to that of the sum of that raised by the sale of stocks (SS_t) and bonds, the principle of a loan, or cash (BS_t). So, these terms on each side of the equality cancel out. Then, expanding the taxes term (TX_t)

by substituting Equation (91) for it in Equation (97), and solving for the present value of the required revenue:

$$PV_{r,N}\{REV_t\} = PV_{r,N}\{ EQT_t + INT_t + PDR_t + CSH_t + OT_t + INS_t + OP_t + MNT_t + FL_t + \tau_i [REV_t - (DEP_t + INT_t + OT_t + INS_t + OP_t + MNT_t + FL_t)] \}$$

and simplifying and rearranging the result:

$$PV_{r,N}\{REV_t\} = PV_{r,N}\{ EQT_t + INT_t + PDR_t + CSH_t + OT_t + INS_t + OP_t + MNT_t + FL_t + \tau_i REV_t - \tau_i (DEP_t + INT_t + OT_t + INS_t + OP_t + MNT_t + FL_t) \} \quad (98)$$

For convenience, define the annual time-series TDE_t as the sum of the tax deductible expenses in Equation (98):

$$TDE_t \equiv INT_t + OT_t + INS_t + OP_t + MNT_t + FL_t \quad (99)$$

and define the annual time series of expenses before income taxes on revenue, ($EBIT_t$), as the sum of all costs other than taxes on gross revenue (on an as yet to be determined quantity of revenues, REV_t) including the tax benefits of deprecation and deduction of expenses:

$$\begin{aligned} EBIT_t &\equiv PDR_t + CSH_t + TDE_t - \tau_i DEP_t - \tau_i TDE_t \\ &= PDR_t + CSH_t + (1 - \tau_i) TDE_t - \tau_i DEP_t \end{aligned} \quad (100)$$

Note that the definition of $EBIT_t$ includes the principal and interest on debt financing but does not include the total return to equity (EQT_t) or taxes on gross revenue ($\tau_i REV_t$). Given that $EBIT_t$ includes depreciation, and interest tax deductions in the case of a loan, it is not assumed to be a uniform time series in general.

Equation (98) can then be expressed in an even simpler form by substituting the definitions for TDE_t and $EBIT_t$ from Equations (99) and (100), respectively, into it:

$$PV_{r,N}\{REV_t\} = PV_{r,N}\{ EQT_t + EBIT_t + \tau_i REV_t - (1 - \tau_i) TDE_t \}$$

which, using Identity 2 of the present value function, can be rearranged to solve for the present value of the required revenue $PV_{r,N}\{REV_t\}$:

$$PV_{r,N}\{REV_t\} = (PV_{r,N}\{EQT_t\} + PV_{r,N}\{EBIT_t\}) / (1 - \tau_i) \quad (101)$$

A.1.3 Annual Time-Series Cash Flows

Annual interest on debt (bonds). Note that Doane et al. (1976) assume debt is based on bonds, which pay annual interest on the initial principle until the principle is returned in its entirety at the end of the bond term:

$$INT_t = k_d \, D/V \, CI_o; \textit{ for bonds} \quad (102)$$

Retire debt with annual payments into a sinking fund (bonds). Doane et al. (1976) assume debt is financed through the sale of bonds. Similarly, the uniform annual payment (PDR_t) an investor must pay into a sinking fund over an asset's financing term (N_d) at the borrower's discount rate k in order to retire the principal of the debt associated with bonds due at the end of the asset's lifetime, is the product of the sinking fund factor, the debt's share of the investment, and the capital investment itself:

$$PDR_t = SFF_{k,Nd} \, D/V \, CI_o; \textit{ for bonds} \quad (103)$$

where, as before, the discount rate (r) in the sinking fund factor for an investor making annual payments into it is its internal rate of return, which is generally its cost of capital (k). Also, in the general case, the debt term (N_d) may be less than the levelization period (N), so the interest payment only occurs for N_d years and is zero after that, so the term used to calculate the sinking fund factor for bonds is N_d.

The present value of the uniform annual payments PDR_t over the N years of the levelization period is:

$$PV_{r,N}\{PDR_t\} = PV_{r,Nd}\{\ SFF_{k,Nd}\ D/V\ CI_o\ \};\ \textit{for bonds} \quad (104)$$

Principal and interest payments (loan). While the assumption of bond financing is valid for utilities and large corporations, other entities in the study, such as residential customers and businesses, may finance their capital investments with a loan or even a cash outlay. If financing is provided by amortizing a loan instead, the present value of uniform annual loan payments, $PV_{r,Nd}\{PMT_A\}$ must equal debt's share (D/V) of the project principal CI_o at interest rate k_d over N_d annual loan payments:

$$PV_{kd,Nd}\{PMT_A\} = D/V\ CI_o \quad (105)$$

which, by solving Equation (85) for X_A equal to PMT_A, has the well-known solution:

$$PMT_A\ =\ \frac{k_d}{1\ -\ (1+k_d)^{-N_d}}\ D/V\ CI_0 \quad (106)$$

For convenience, define the loan payment fraction, $LPF_{kd,Nd}$, as the annual loan payment (PMT_A) represents of the capital investment (CI_0) by rearranging Equation (106):

$$LPF_{k_d,N_d}\ \equiv\ \frac{PMT_A}{D/V\ CI_0}\ =\ \frac{k_d}{1\ -\ (1+k_d)^{-N_d}};\ when\ k_d \neq 0\ and\ N_d \neq 0$$

and

$$LPF_{k_d,N_d}\ \equiv\ \frac{1}{N};\ when\ k_d = 0\ and\ N_d \neq 0$$

and

$$LPF_{k_d,N_d}\ \equiv\ 1;\ when\ N_d = 0 \quad (107)$$

For an amortized loan, the annual payment consists of the sum of an annual payment of interest (INT_t) and an annual payment toward retiring the debt principal (PDR_t):

$$PMT_A = INT_t + PDR_t \quad (108)$$

The interest paid (INT_t) during any year t is equal to the product of the interest rate (r) and the remaining principal at the <u>beginning</u> of any year t:

$$INT_t\ =\ k_d\left(D/V\ CI_0\ -\ \sum_{p=1}^{t-1} PDR_p\right);\ for\ a\ loan$$

where the index p is introduced to indicate values for years prior to year t. Factoring debt's share of the capital investment from both terms:

$$INT_t = k_d\, D/V\, CI_0 \left(1 - \sum_{p=1}^{t-1} \frac{PDR_p}{D/V\, CI_0}\right);\ for\ a\ loan \tag{109}$$

Note that the term inside the parentheses is the remaining principle as a fraction of debt's share of the capital investment, REM_t, is a function of the interest rate (k_d) where:

$$REM_t \equiv 1 - \sum_{p=1}^{t-1} \frac{PDR_p}{D/V\, CI_0};\ for\ a\ loan \tag{110}$$

and, using this definition Equation (109) can be reduced to:

$$INT_t = k_d\ D/V\ REM_t\ CI_o;\ \textit{for a loan} \tag{111}$$

From Equation (108), the principle debt reduction payment in any year (t), PDR_t, is the difference between the annual loan payment (PMT_A) and the interest payment (INT_t). Then, substituting the relationship in Equation (111) for the interest payment:

$$PDR_t = PMT_A - k_d\ D/V\ REM_t\ CI_o;\ \textit{for a loan} \tag{112}$$

Note that the time series of debt's share of the remaining principal in Equation (110) is recursive in that the principal payment in any given year is dependent on that of all prior years, which in turn is dependent on the interest rate (k_d) and debt term (N_d). It is clearly non-uniform. So, the time-series of interest payments (INT_t) and principle debt reduction payments (PDR_t) are likewise dependent on the interest rate. So, the time-series of principal reduction payments (PDR_t) and interest payments (INT_t) are also non-uniform, and there is not a convenient closed form solution for them. Hence, in the case of debt financing from a loan, a full pro forma calculation is used to calculate their present values, as follows.

Define the *remaining principal factor*, $RPF_{r,kd,Nd}$, for a loan of term N_d at interest rate k_d, as the present value of the annual time-series of the remaining principal for a generic entity with discount rate r:

$$RPF_{r,kd,Nd} \equiv k_d\ PV_{r,Nd}\{REM_t\};\ \text{when } N_d > 0 \tag{113}$$

and

$$RPF_{r,kd,Nd} \equiv 0;\ \text{when } N_d = 0$$

From Equation (111) the present value of the interest payments at discount rate r is:

$$PV_{r,Nd}\{INT_t\} = PV_{r,Nd}\{\ k_d\ D/V\ CI_o\ REM_t\ \};\ \textit{for a loan}$$

which, using Identity 2 of the present value function, can be expressed as:

$$PV_{r,Nd}\{INT_t\} = k_d\ D/V\ CI_o\ PV_{r,Nd}\{REM_t\};\ \textit{for a loan}$$

and substituting the definition of the remaining principal factor

$$PV_{r,Nd}\{INT_t\} = D/V\ RPF_{r,kd,Nd}\ CI_o;\ \textit{for a loan} \tag{114}$$

From Equation (108) the present value of the principle debt reduction payments is the difference between the present values of the annual loan payments (PMT_A) and interest payments (INT_t):

$$PV_{r,Nd}\{PDR_t\} = PV_{r,Nd}\{\ PMT_A - INT_t\ \};\ \textit{for a loan}$$

which, using Identity 1 of the present value function, can be expressed as:

$$PV_{r,Nd}\{PDR_t\} = PV_{r,Nd}\{PMT_A\} - PV_{r,Nd}\{INT_t\}\textit{; for a loan}$$

and by expressing the annual loan payment in terms of the loan payment factor as defined in Equation (107) and substituting the Equation (114) for the present value of the time series of interest payments (INT_t):

$$PV_{r,Nd}\{PDR_t\} = PV_{r,Nd}\{ LPF_A\ D/V\ CI_0 \} - D/V\ RPF_{r,kd,Nd}\ CI_o\textit{; for a loan}$$

then using the definition of the capital recovery factor to express the present value of the debt loan payments, $PV_{r,Nd}\{PMT_A\}$:

$$PV_{r,Nd}\{PDR_t\} = LPF_{kd,Nd}\ D/V\ CI_0 / CRF_{r,Nd} - D/V\ RPF_{r,kd,Nd}\ CI_o\textit{; loan} \tag{115}$$

Cash toward capital investment. The investor may offset a share of the capital investment, C/V, with an injection of cash in Year 0. So, in Year 0, the cash toward capital investment, CSH_0, is:

$$CSH_0 = C/V\ CI_0$$

and the cash invested in all subsequent years is zero, so the present value of the cash investment is simply:

$$PV_{r,n}\{CSH_t\} = CSH_0 = C/V\ CI_0 \tag{116}$$

Depreciation of capital asset. Doane et al. (1976) assume straight-line depreciation over the asset's lifetime (use of general alternative methods is described in their Appendix E). So, with straight-line depreciation, the amount of the annual income deduction for depreciation is:

$$DEP_t = CI_o / N\text{; straight-line depreciation} \tag{117}$$

Note, therefore, that straight-line depreciation over the asset's lifetime is implicit in Doane et al. (1976) Equations (B.17) and (B.19), although they also provide a procedure accounting for accelerated depreciation as described in their Appendix E, as described here.

Define the method-dependent depreciation factor ($DPF_{m,r,n}$) as the fraction of the present value of the capital investment represented by the present value of its depreciation, by any method (m) over N years at a discount rate of r:

$$DPF_{m,r,N} \equiv PV_{r,N}\{DEP_t\} / CI_o = PV_{r,N}\{ DEP_t / CI_o \} \tag{118}$$

where Identity 2 for the present value function has been applied.

Note that the term $PV_{r,N}\{ DEP_t / CI_o \}$ is the present value of the applicable row (i.e., over all N years) of a depreciation schedule table for method m.

Rearranging Equation (118), the general expression for the present value of depreciation using any method is:

$$PV_{r,N}\{DEP_t\} = DPF_{m,r,N}\ CI_o \tag{119}$$

Other taxes. The annual payment for other taxes (i.e., property taxes), expressed as a fraction (β_1) of the present value of the capital investment, is:

$$OT_t = \beta_1 \, CI_o \tag{120}$$

Insurance. The annual payment for insurance, expressed as a fraction (β_2) of the present value of the capital investment, is:

$$INS_t = \beta_2 \, CI_o \tag{121}$$

Required revenue. The levelized annual revenue requirement is defined as the uniform stream of annual required revenue (REV_A) which, at discount rate r over N years, has the equivalent present value of the actual time series of revenues (REV_t):

$$PV_{r,N}\{REV_t\} \equiv PV_{r,N}\{REV_A\} \tag{122}$$

Note the relationship in Equations (122) is used to reflect the present values of these time-series costs from the perspective of the investor (where r is equal to k) and to equity (where r is equal to k_e).

O&M and fuel costs. Define OP_0, MNT_0, and FL_0 as the values of the annual O&M and fuel costs, respectively, at the beginning of the levelization period (i.e., in t=0). Then using Equations (88) and (89) at an escalation-adjusted discount rate r' equal to the escalation rate at a nominal rate g_x, for these costs:

$$PV_{r,N}\{ OP_t + MNT_t + FL_t \} = PV_{r',N}\{ OP_0 + MNT_0 + FL_0 \} \tag{123}$$

where:

$$r' = (1 + r) / (1 + g_x) - 1 \tag{124}$$

Define the sum of O&M and fuel costs in Year 0 as a fraction of the capital, investment as β_0:

$$\beta_0 \equiv (OP_0 + MNT_0 + FL_0) / CI_o \tag{125}$$

Then, using this definition, the relationship in Equation (124) can be simplified as:

$$PV_{r,N}\{ OP_t + MNT_t + FL_t \} = PV_{r',N}\{ \beta_0 \, CI_o \} \tag{126}$$

Return on equity investment (stocks). For a corporation to raise equity capital it must provide competitive rates of return on investment in the form of earnings to its stockholders, k_{roi}. So, the annual time series of stock earnings over the N years of the investment, SE_t, is uniform with a value each year of SE_A, that is the product of equity's expected annual rate of return (k_e=k_{roi}) and equity's share of the capital investment:

$$SE_t = SE_A = k_e \, E/V \, CI_o \tag{127}$$

Retire equity principle with annual payments into a sinking fund. The uniform annual payment (REP_A) that must be set aside into a sinking fund over an asset's lifetime in order to return (i.e., retire) the debt associated with equity's principal is then the product of the sinking fund factor, equity's share of the investment, and the capital investment itself over the N years of its lifetime at the discount rate r:

$$REP_t = REP_A = SFF_{r,N} \, E/V \, CI_o \tag{128}$$

Note that Equation (128) is used two ways: to determine the required revenue from the perspective of equity and to determine the levelized annual capital cost to the investor. The discount rate (r) for an investor setting aside a uniform annual payments into a sinking fund is generally its time value of money, i.e., its internal rate of return. From the perspective of equity this is equity's required rate of return on investment (k_{roi}), and from the perspective of the investor in the capital asset, e.g., a utility or a customer, this is the investor's after-tax WACC (k), as reflected in Equation (80 .

A.1.4 General Solution for the Annual Required Revenue

This section describes the method used to solve for the levelized annual required revenue, REV_A, to satisfy the demand for return on investment by equity stockholders. This is primarily associated with investor-owned utilities, and the regulatory bargain that mandates such returns in exchange for a monopoly franchise and an obligation to make the capital investments needed to serve demand. Large corporations may also raise capital from equity that, in absence of any regulatory requirement, must at least satisfy their investors in order to remain viable. In both cases, the returns to equity must be accounted for in addition to payments for interest and repayment of debt principal as costs attributed to capital investments.

In the DSO+T study, entities that use equity financing include investor-owned DSOs, the transmission owner-operator, and generation owner-operators. Of these, the study assumes that rate of return utility ratemaking regulations apply only to the investor-owned DSOs and the transmission owner-operator. As regulated utilities, their revenues are set via the utility ratemaking process to guarantee a rate of return established by the regulators (at least for a year with average weather, loads, and fuel, and wholesale market prices for example).

In the study, all bulk system generation is assumed to be deregulated, so generation owner-operators are not regulated as utilities. But they still must provide an acceptable rate of return to attract investors, so functionally, they are analyzed as if they are required to provide a specific rate of return after paying for debt, fuel, taxes, etc. Corporations that serve as third-party owners or lessors of flexible assets at customer premises are also assumed to be equity financed.

A general method for attributing capital costs to assets must be equally applicable to all other types of entities in the study. Customers are assumed to have no equity investors, the "revenue" they require is primarily in the form of reduced costs, i.e., from using their responsive assets to reduce their electricity bills.[30] Justifying investment in the responsive assets thus implies their energy cost savings must simply be sufficient to cover their capital costs (after taxes and including repayment of debt). This is considerably simpler than for entities with equity investors. All commercial customers classified as businesses are assumed to be closely held, without public stockholders.[31] Those that are nonprofit have neither equity investors to reward or taxes to pay, so they are even simpler. Publicly owned DSOs (municipal and rural cooperatives) are similarly simple to analyze in that their revenues must cover their costs.

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[30] This is specific to the transactive design being analyzed, which is centered around real-time retail prices. In other designs, responsive asset owners might literally receive payments for performing grid services, instead of or in addition to incentives in the form of bill reductions.

[31] Industrial customers may also be equity financed, but since the study includes industrial customers as nonparticipants, they are not assumed to be investing in responsive assets. Note they are simulated as a customer class load, not as individual customers. This distinction is moot for the purposes of estimating values in their CFSs.

Residential customers occupy homes they either own or rent. In the case of owners, they are not allowed depreciation or interest deductions from their tax liability. In the case of renters, the study assumes the landlord has all the financial attributes of a business, invests in responsive assets, depreciates them and deducts interest payments on them from their tax liability, and recoups their investment by passing along a marginal increase in rent to the customer. The residential renter customer then, in effect, pays for the investment indirectly and balances that against savings on their electric bill. So a residential customer who rents their home is effectively like a business, except they cannot deduct their electricity bill from their income tax liability (because the customer who occupies the rented home is assumed to pay the electricity bill, not the landlord).

Given that a generic entity may have equity to satisfy, it must have revenues over the lifetime of the project sufficient to cover its costs for debt, taxes, and the required total return to equity. This is accomplished through the procedure that follows, using the time-series cash flows defined in the previous Section A.1.3.

From the equity perspective, the present value of the required revenue over the lifetime of the project must be equal to the sum of the cash flows to equity and other expenses before income taxes on revenues, net of tax benefits ($EBIT_t$). This is expressed by Equation (101) using a discount rate equal to the cost of equity (i.e., $r = k_e$):

$$PV_{ke,N}\{REV_t\} = (PV_{ke,N}\{EQT_t\} + PV_{ke,N}\{EBIT_t\}) / (1 - \tau_i) \qquad (129)$$

Then, define the levelized annual required revenue (REV_A) as the annual amount of a uniform stream of revenues which, over the N years of the investment lifetime at equity's discount rate k_e, has the equivalent present value the time series of revenues (REV_t):

$$PV_{ke,N}\{REV_A\} \equiv PV_{ke,N}\{REV_t\} \qquad (130)$$

and substituting this definition for the present value of revenues in Equation (129) and apply the definition of the capital recovery factor in Equation (94):

$$REV_A / CRF_{ke,N} = (PV_{ke,N}\{EQT_t\} + PV_{ke,N}\{EBIT_t\}) / (1 - \tau_i) \qquad (131)$$

Note that tax benefits from deductions for depreciation and interest on debt (if it is in the form of an amortized loan rather than bonds) are not uniform over the lifetime of the investment. Since they are both components of the time-series cash flows $EBIT_t$, it also is not uniform, in general, and therefore neither are the total cash flows to equity (EQT_t).

Regardless, the present value of the cash flows to equity must provide for 1) stock (equity) earnings on investment (SE_t) and 2) the return of equity's initial principle over the lifetime of the investment (REP_t). So the present value of the total cash flow to equity is the sum of present values of each of them:

$$PV_{ke,N}\{EQT_t\} = PV_{ke,N}\{SE_t\} + PV_{ke,N}\{REP_t\} \qquad (132)$$

and, from Equations (127) and (128), with the discount rate for the sinking fund defined from equity's perspective as k_e:

$$PV_{ke,N}\{EQT_t\} = PV_{ke,N}\{ k_e \, E/V \, CI_o \} + PV_{ke,N}\{ SFF_{ke,N} \, E/V \, CI_o \} \qquad (133)$$

Then substituting Equation (133) for the present value of the total cash flows to equity in Equation (131):

$$REV_A / CRF_{ke,N} = (PV_{ke,N}\{ k_e\ E/V\ CI_o + SFF_{k,N}\ E/V\ CI_o \} + PV_{ke,N}\{EBIT_t\}) / (1 - \tau_i)$$

and noting that, from Equation (96):

$$k_e + SFF_{ke,N} = CRF_{ke,N}$$

the terms inside the first present value function can be combined and solved for the levelized annual required revenue REV_A:

$$REV_A / CRF_{ke,N} = [PV_{ke,Nd} \{ CRF_{ke,Nd}\ E/V\ CI_o \} + PV_{ke,N}\{EBIT_t\}] / (1 - \tau_i)$$

and again applying the definition of the capital recovery factor in Equation (94) to simplify the first term in the numerator:

$$REV_A / CRF_{ke,N} = (E/V\ CI_o + PV_{ke,N}\{EBIT_t\}) / (1 - \tau_i) \qquad (134)$$

Equation (134) can then be rearranged to solve for the levelized annual required revenue, REV_A:

$$REV_A / CI_o = CRF_{ke,N} (E/V + PV_{ke,N}\{EBIT_t\} / CI_o) / (1 - \tau_i) \qquad (135)$$

The final step in the method is to develop an equation for the present value of the time series $EBIT_t$ from the equity's point of view by substituting the components of $EBIT_t$ as expressed by the annual cash flow time series for each of its components using the relationships developed in for the annual time-series cash flows in Section A.1.3. Then, factoring the present value of the capital investment, CI_o, out of all the resulting terms using Identify 2 of the present value function:

$PV_{ke,N}\{EBIT_t\} = [\ BONDS\ PV_{ke,Nd}\{ k_d\ D/V \}$	*interest payments on bonds*
$+ LOAN\ RPF_{k,kd,Nd}\ D/V$	*interest payments on loan*
$+ BONDS\ PV_{ke,Nd}\{ SFF_{k,N}\ D/V \}$	*retiring debt principal on bonds*
$+ LOAN\ D/V\ (LPF_{kd,Nd} / CRF_{r,Nd} – RPF_{r,kd,Nd})$	*retiring debt principal on loan*
$+ C/V$	*cash toward capital investment*
$+ PV_{ke,N}\{ \beta_1 + \beta_2 \}$	*other taxes and insurance*
$+ PV_{ke',N}\{ \beta_0 \}$	*O&M and fuel costs*
$– \tau_i\ DPF_{m,ke,Nd}$	*depreciation tax savings*
$– \tau_i\ BONDS\ PV_{ke,Nd}\{ k_d\ D/V \}$	*bonds interest deduction tax savings*
$– \tau_i\ LOAN\ RPF_{ke,kd,Nd}\ D/V$	*loan interest deduction tax savings*
$– \tau_i\ PV_{ke,N}\{ \beta_1 + \beta_2 \}$	*other taxes & insurance tax savings*
$– \tau_i\ PV_{ke',N}\{ \beta_0 \}$	*O&M and fuel costs tax savings*
$]\ CI_o$	(136)

where, since debt financing may be received from sale of bonds <u>or</u> from a loan, two Boolean variables BONDS and LOAN are defined, where BONDS has a value of one if bonds are used, and where:

$$LOAN = 1 – BONDS \qquad (137)$$

and these variables are then used to expand the terms in Equation (98) for interest (INT_t), principle debt retirement (PDR_t), and tax savings from interest deductions ($\tau_i\ INT_t$) into two terms each, one pertinent to bonds and one pertinent to loans, resulting in Equation (136) as shown above. Labels in italics have been added to the right of each term in Equation (136) for clarity.

Note that the term of the debt financing (N_d, in years) may be less than the investment lifetime (N), so bond and loan interest and principal debt retirement cash flows and their present values are only assumed to last N_d years in Equation (136) and subsequently. Further, note that each term within the brackets represents its contribution to the present value of $EBIT_t$ as a fraction of the present value of the capital investment.

Equation (136) can be simplified using the relationship of the capital recovery factor to the present value of a uniform time series in Equation(95), using the appropriate discount rate and lifetime for each term:

$$\begin{aligned}
PV_{ke,N}\{EBIT_t\} = [\ & BONDS\ k_d\ D/V\ /\ CRF_{ke,Nd} && \textit{interest payments on bonds} \\
& + LOAN\ D/V\ RPF_{ke,kd,Nd} && \textit{interest payments on loan} \\
& + BONDS\ D/V\ SFF_{k,Nd}\ /\ CRF_{ke,Nd} && \textit{retiring debt principal on bonds} \\
& + LOAN\ D/V\ (\ LPF_{kd,Nd}\ /\ CRF_{ke,Nd} - RPF_{ke,kd,Nd}\ ) && \textit{retiring debt principal on loan} \\
& + C/V && \textit{cash toward capital investment} \\
& + (\beta_1 + \beta_2)\ /\ CRF_{ke,N} && \textit{other taxes and insurance} \\
& + \beta_0\ /\ CRF_{ke',N} && \textit{O\&M and fuel costs} \\
& - \tau_i\ DPF_{m,ke,N} && \textit{depreciation tax savings} \\
& - \tau_i\ BONDS\ k_d\ D/V\ /\ CRF_{ke,Nd} && \textit{bonds interest deduction tax savings} \\
& - \tau_i\ LOAN\ D/V\ RPF_{ke,kd,Nd} && \textit{loan interest deduction tax savings} \\
& - \tau_i\ (\beta_1 + \beta_2)\ /\ CRF_{ke,N} && \textit{other taxes \& insurance tax savings} \\
& - \tau_i\ \beta_0\ /\ CRF_{ke',N} && \textit{O\&M and fuel costs tax savings} \\
&]\ CI_o && \qquad (\ 138\ )
\end{aligned}$$

With the present value of $EBIT_t$ known from Equation (138), the levelized annual revenue required (REV_A) as a fraction of the capital investment can be determined using Equation (135).

A.1.5 Asset Capital Cost Factor

In this section the ACCF is defined from the perspective of the investor and then expressed in a similar fashion to that in the previous section.

From the investor's perspective, the present value of revenues can be expressed by expanding Equation (98) in a fashion similar to that in Section A.1.4:

$$\begin{aligned}
PV_{k,N}\{REV_A\} = [\ & PV_{k,N}\{\ EQT_t\ \} && \textit{total return to equity} \\
& + BONDS\ PV_{k,Nd}\{\ k_d\ D/V\ \} && \textit{interest payments on bonds} \\
& + LOAN\ RPF_{k,kd,Nd}\ D/V && \textit{interest payments on loan} \\
& + BONDS\ PV_{k,Nd}\{\ SFF_{k,N}\ D/V\ \} && \textit{retiring debt principal on bonds} \\
& + LOAN\ D/V\ (\ LPF_{kd,Nd}\ /\ CRF_{k,Nd} - RPF_{k,kd,Nd}\ ) && \textit{retiring debt principal on loan} \\
& + C/V && \textit{cash toward capital investment} \\
& + PV_{k,N}\{\ \beta_1 + \beta_2\ \} && \textit{other taxes and insurance} \\
& + PV_{k',N}\{\ \beta_0\ \} && \textit{O\&M and fuel costs} \\
& + \tau_i\ PV_{k,N}\{REV_A\} && \textit{taxes on gross revenues} \\
& - \tau_i\ DPF_{m,k,Nd} && \textit{depreciation tax savings} \\
& - \tau_i\ BONDS\ PV_{k,Nd}\{\ k_d\ D/V\ \} && \textit{bonds interest deduction tax savings} \\
& - \tau_i\ LOAN\ RPF_{k,kd,Nd}\ D/V && \textit{loan interest deduction tax savings} \\
& - \tau_i\ PV_{k,N}\{\ \beta_1 + \beta_2\ \} && \textit{other taxes and insurance tax savings} \\
& - \tau_i\ PV_{k',N}\{\ \beta_0\ \} && \textit{O\&M and fuel costs tax savings} \\
&]\ CI_o && \qquad (\ 139\ )
\end{aligned}$$

where the present value of the total return to equity time series, from the investor's point of view (i.e., at discount rate k), is the only time series whose present value has yet to be determined.

(Note that in the previous section, the expression in Equation (133) applies to the point of view of equity, not the investor.)

As in the previous section, Equation (139) can be simplified using the relationship of the capital recovery factor to the present value of a uniform time series in Equation (95) using the appropriate discount rate and lifetime for each term:

$$
\begin{aligned}
REV_A = \{ & PV_{k,N}\{EQT_t\} && \textit{total return to equity} \\
& + BONDS\ k_d\ D/V\ CRF_{k,N} / CRF_{k,Nd} && \textit{interest payments on bonds} \\
& + LOAN\ D/V\ RPF_{k,kd,Nd}\ CRF_{k,N} && \textit{interest payments on loan} \\
& + BONDS\ SFF_{k,N}\ D/V\ CRF_{k,N} / CRF_{k,Nd} && \textit{retiring debt principal on bonds} \\
& + LOAN\ D/V\ (\ LPF_{kd,Nd}\ CRF_{k,N} / CRF_{k,Nd} && \\
& - RPF_{k,kd,Nd}\ CRF_{k,N}\ ) && \textit{retiring debt principal on loan} \\
& + C/V\ CRF_{k,N} && \textit{cash toward capital investment} \\
& + (\beta_1 + \beta_2) && \textit{other taxes and insurance} \\
& + \beta_0\ CRF_{k,N} / CRF_{k',N} && \textit{O\&M and fuel costs} \\
& + \tau_i\ REV_A && \textit{taxes on gross revenues} \\
& - \tau_i\ DPF_{m,k,Nd}\ CRF_{k,N} && \textit{depreciation tax savings} \\
& - \tau_i\ BONDS\ k_d\ D/V\ CRF_{k,N} / CRF_{k,Nd} && \textit{bonds interest deduction tax savings} \\
& - \tau_i\ LOAN\ RPF_{k,kd,Nd}\ D/V\ CRF_{k,N} && \textit{loan interest deduction tax savings} \\
& - \tau_i\ (\beta_1 + \beta_2\ ) && \textit{other taxes and insurance tax savings} \\
& - \tau_i\ \beta_0\ CRF_{k,N} / CRF_{k',N} && \textit{O\&M and fuel costs tax savings} \\
& \}\ CI_o
\end{aligned}
\qquad (\ 140\ )
$$

To further simplify Equation (140), define the following additional levelized annual costs, from the investor's point of view (at discount rate k), associated with the terms in the equation:

$$
\begin{aligned}
EQT_A &\equiv PV_{k,N}\{EQT_t\}\ CI_o \\
INT_A &\equiv (\ BONDS\ k_d\ D/V\ CRF_{k,N}/CRF_{k,Nd} + LOAN\ D/V\ RPF_{k,kd,Nd}\ CRF_{k,N}\ )\ CI_o \\
PDR_A &\equiv (\ BONDS\ SFF_{k,N}\ D/V\ CRF_{k,N}/CRF_{k,Nd} \\
&\quad + LOAN\ D/V\ (\ LPF_{kd,Nd}\ CRF_{k,N}/CRF_{k,Nd} - RPF_{k,kd,Nd}\ CRF_{k,N}\ )\ )\ CI_o \\
CSH_A &\equiv + C/V\ CRF_{k,N}\ )\ CI_o \\
OM_A &\equiv (\ (\beta_1 + \beta_2) + \beta_0\ CI_o\ CRF_{k,N}\ /CRF_{k',N}\ )\ CI_o \\
DEP_A &\equiv DPF_{m,k,Nd}\ CI_o\ CRF_{k,N}
\end{aligned}
$$

then substitute these definitions for the terms in Equation (140):

$$REV_A = EQT_A + INT_A + PDR_A + CSH_A + OM_A + \tau_i\ REV_A - \tau_i\ DEP_A - \tau_i\ INT_A - \tau_i\ OM_A$$

and rearrange the result to solve for the unknown levelized annual total cash flow to equity, EQT_A:

$$EQT_A = REV_A - (\ INT_A + PDR_A + CSH_A + OM_A + \tau_i\ REV_A - \tau_i\ DEP_A - \tau_i\ INT_A - \tau_i\ OM\ ) \qquad (\ 141\ )$$

Then, to construct the method in a fashion that is more consistent with that of Doane et al. (1976), define the total levelized cash flow to equity as consisting of three components, the levelized annual cash flows to stock earnings (SE_A), to return equity's principle (REP_A), and a balancing account (BAL_A):

$$EQT_A \equiv BAL_A + SE_A + REP_A \qquad (\ 142\ )$$

where, as in Doane et al. (1976), the first two are defined as resulting from uniform annual cash flows consistent with Equations (127) and (128):

$$SE_A \equiv SE_t \equiv k_e \; E/V \; CI_o \tag{143}$$

$$REP_A \equiv REP_t \equiv SFF_{k,N} \; E/V \; CI_o \tag{144}$$

and the third, the levelized cash flow to a balancing account (BAL_A), like the total return to equity (EQT_A), is obtained from Equation (142) by subtraction:

$$BAL_A \equiv EQT_A - (SE_A + REP_A) \tag{145}$$

By definition, the annual payments set aside by the investor into a sinking fund to retire equity's principle at the end of the investment lifetime are uniform (REP_A). Similarly, the definition of the stock earnings in Equation (144), to be consistent with Doane et al. (1976), is also uniform with all $SE_t = SE_A$. However, the total cash flows to equity (EQT_t) are not generally uniform. This is due to the potential for tax savings from accelerated depreciation and interest tax deductions for debt financed with a loan instead of bonds, neither of which are uniform for a taxpaying investor. The net result is that the investor is in effect paying into or borrowing from an account financed by either equity (at discount rate k_e) or, for investors that do not use equity financing, debt (at discount rate k_d). The method defined in this appendix satisfies this condition because, in the absence of equity financing (E/V = 0), the investor's after-tax weighted-average cost of equity reduces to the after-tax cost of debt as seen from Equation (80 .

Later, by comparing the full pro forma calculations of the CPUC and the method of Doane et al. (1976), this is shown to have a significant second-order effect on the overall cash flow to equity that the method defined here accounts for explicitly with the levelized cash flow to the balancing account (BAL_A).

Equation (145) can be rearranged to solve for levelized annual total payment to equity (EQT_A), substituting the result into Equation (141), and solving for the unknown BAL_A:

$$\begin{aligned} BAL_A = REV_A - (& SE_A + REP_A + INT_A + PDR_A + CSH_A + OM_A \\ & + \tau_i \, REV_A - \tau_i \, DEP_A - \tau_i \, INT_A - \tau_i \, OM_A) \end{aligned} \tag{146}$$

Finally, in the DSO+T study's investor CFSs, the levelized annual O&M costs (OM_A) are itemized as operational expenses rather than being attributed to capital investments. The levelized annual costs associated a capital investment, $CAP_{A,}$ in Equation (141) are defined as all the costs not associated with OM_A:

$$CAP_A \equiv SE_A + REP_A + BAL_A + INT_A + PDR_A + \tau_i \, REV_A - \tau_i \, DEP_A - \tau_i \, INT_A \tag{147}$$

Define the ACCF for an investment, $ACCF_{k,ke,N}$, as the ratio of the costs associated with that capital investment over its lifetime to the initial capital investment itself:

$$ACCF_{k,ke,N} \equiv CAP_A \, / \, CI_0 \tag{148}$$

so the levelized annual cost associated with a capital investment is the product of the ACCF and the capital investment:

$$CAP_A = ACCF_{k,ke,N} \; CI_0 \tag{149}$$

Note that the ACCF for an investment is not only a function of the investor's after-tax WACC (k) and equity (k_e), and the lifetime of the investment (N), as indicated by its subscripts. It is also dependent on other parameters of the investment not indicated as subscripts: the depreciation method (m), relative proportions of equity, debt, and cash invested (E/C, D/V, and C/V, respectively), debt interest rate (k_d) and term (N_d), and whether the debt is financed with bonds or a loan.

A.2 Input Assumptions for Annualized Capital Cost Factors

This section describes the assumptions and input data used for computing the ACCFs for grid assets and residential and commercial customer assets.

First, a set of financial instruments are defined. Grid and customer investors use these instruments to finance their capital investments in grid infrastructure (generation, transmission, and distribution) and customer assets such as solar PV systems, battery storage, and communications and controls for responsive loads and EV charging. The financial instruments used in the study are defined in terms of their interest rates and terms as shown in Table 1. The interest rates, terms, and fraction paid in cash are based on an internet search for typical values as of April 7, 2020.

As indicated in Table 28, interest rates for consumer credit (credit card purchases) are extreme outliers at 18% annual interest, and therefore formal economic theory implies that "rational" consumers making such purchases have a discount rate of 18%. It is unlikely that any consumer actually values future cash flows over present value at such a rate, so in the instances where consumer credit is used (for example, to finance purchases like a smart thermostat) the consumer's discount rate is arbitrarily capped at a value of 6% (corresponding to a home improvement loan). Note that this does not affect the interest rate on the purchase, however, which remains at 18%.

Table 28. Financial rates and terms.

Financial Instrument	Interest Rate[1]	Debt Term (yr)	Cash Capitalization Fraction
Corporate bonds[2]	2.64%	10	0%
Utility bonds	3.00%	20	0%
Municipal bonds	1.46%	10	0%
Federal bonds	0.76%	10	0%
Consumer credit	18.00%	1	0%
Auto loan	5.00%	3	0%
Mortgage, res.	3.90%	20	10%
Mortgage, com.	3.80%	20	20%
Home loan	6.00%	5	0%
Business loan	6.50%	10	0%
Third-party lease[3]	2.64%	20	0%
Third-party owned	2.64%	20	0%
Expense	0.00%	0	100%
Cash	0.00%	0	100%

[1] Loan rates as of April 7, 2020
[2] Aaa-rated
[3] Lease-to-own contract with third-party investor that finances, installs, and receives tax advantages

Next, a set of assumptions about how a given type of investor purchasing a capital asset capitalizes their purchase. The term *investor* is used here to refer to a specific type of actor (in the e3-Value flow diagram) in terms of their financial perspective. Grid asset owners are classified as being corporate owned (for generation owners), or investor owned (transmission and DSOs), municipal (DSOs), or rural cooperatives (DSOs). Consumers are classified based on their financial perspectives as homeowners, renters, businesses, public/nonprofit organizations, or using third-party providers (most commonly of solar PV and battery systems due to their high capital costs).

Note that in the case of a renter, the study assumes the landlord makes the capital investment and recovers that investment in the form of a marginal increase in the rent. While the renter occupant of the home pays the electric bill and, hence, receives the savings from the investment, the landlord is afforded the benefit of depreciating the asset and deducting the interest costs on the debt financing. This reduces the amount rent must increase to recover the investment for the landlord, and in effect these benefits are passed on to the renter. Thus, the financial perspective a home renter in the study is a hybrid of occupant and landlord. The same is true for commercial building owners that lease space to occupants.

The assumptions about how investors capitalize their investments in grid and consumer assets are shown in Table 29. Large corporations, investor-owned utilities, and third-party providers are assumed to raise capital by selling stock to equity investors and then financing the remainder of the capital for their investments by borrowing against that equity. Table 29 shows which investor types use equity financing, the split between equity and debt (and cash) capitalization for their investments, and the equity's expected return on investment. The latter is the basis for defining the required revenue that must be recovered in the ratemaking process for regulated investor-owned utilities.

In the study, owners of bulk power system generation are assumed to be unregulated, and they and third-party providers are assumed to have equity stockholders. In each case, while a rate of return to those equity stockholders is not guaranteed by any regulatory process, these investors will not long exist as viable financial entities unless their equity investors' expectations of return on investment are satisfied. So, the procedure developed in Section A.1 of this appendix includes this return as part of the cost of financing a capital investment when computing the ACCFs.

Table 29. Investor capitalization.

Investor Type	Uses Equity Financing	Capitalization Ratio		Equity Rate on Investment (%)
		Equity (%)	Debt + Cash (%)	
Corporate owned	TRUE	45%	55%	11.50%
Investor owned	TRUE	45%	55%	11.50%
Municipal	FALSE	0%	100%	0.00%
Cooperative	FALSE	0%	100%	0.00%
Homeowner	FALSE	0%	100%	0.00%
Home renter[1]	FALSE	0%	100%	0.00%
Business[2]	FALSE	0%	100%	0.00%
Public/nonprofit	FALSE	0%	100%	0.00%
Third party[3]	TRUE	45%	55%	11.50%

[1] Renters are assumed to implicitly pay for asset-cost recovery embedded in rent collected by taxable landlord
[2] Building owners, in effect, pass on costs and tax benefits to nonowner occupants via rent or lease, other than electric bills
[3] Third-party corporations that own assets and, in effect, pass on costs and tax benefits from depreciation and interest deductions to nonowner occupants via rent or lease

An investor's financial perspective includes taxation. Table 30 shows the assumptions about taxation for each type of investor in the study. This includes whether the investor is subject to state and local sales taxes and federal and state income taxes. In Texas, state and local sales taxes average 8.91% in 2020. However, sales taxes in Texas and much of the U.S. do not apply to wholesale purchases of equipment involved in the manufacture of goods subsequently sold at retail. This has been ruled to apply to the production and delivery infrastructure for electric power. The study assumes this also applies to third-party providers. Sales tax is added to the ACCFs computed using the procedure in Section A.1 for consumer investments.

Table 30. Investor taxation.

	Sales Tax			Expense Deductions		Income Tax Bracket		
Investor Type	Taxed on Capital Invest-ments[1]	Avg. Sales Tax (%)	Pays Income Tax[2]	Interest on Debt	Electric Bill	Federal (%)	State (%)	Effective (%)
Corporate owned	FALSE	0.00%	TRUE	TRUE	TRUE	21.00%	8.84%	27.98%
Investor owned	FALSE	0.00%	TRUE	TRUE	TRUE	21.00%	8.84%	27.98%
Municipal	FALSE	0.00%	FALSE					
Cooperative	FALSE	0.00%	FALSE					
Homeowner	TRUE	8.91%	FALSE					
Home renter[3]	TRUE	8.91%	TRUE	TRUE	FALSE	21.00%	8.84%	27.98%
Business[4]	TRUE	8.91%	TRUE	TRUE	TRUE	21.00%	8.84%	27.98%
Public/nonprofit	FALSE	0.00%	FALSE					
Third party[5]	FALSE	0.00%	TRUE	TRUE	FALSE	21.00%	8.84%	27.98%

[1] in Texas; this is state specific
[2] For purposes of grid/smart grid investment in the DSO+T study
[3] Renters are assumed to implicitly pay for asset-cost recovery embedded in rent collected by taxable landlord
[4] Building owners, in effect, pass on costs and tax benefits to nonowner occupants via rent or lease, other than electric bills
[5] Third-party corporations that own assets and, in effect, pass on costs and tax benefits from depreciation and interest deductions to nonowner occupants via rent or lease

Table 30 also shows whether the valuation process accounts for income taxes in the CFSs for each type of investor. Again, the financial perspective of the investor of home renters and commercial building business occupants of rental or leased spaces is a hybrid composite reflecting that of the occupant and the landlord as described previously. Public/nonprofit organizations are assumed to occupy public buildings and do not pay taxes nor receive any benefits from depreciation or expense tax deductions.[32]

Note that in the DSO+T the CFSs for homeowner investors do not include income taxes. While a person certainly does, the CFS for consumers does not account for the entirety of a person's, a businesses', or a public/nonprofit organization's economic life. Rather, it reflects only the portion of their economic life associated with being an electricity customer. For example, their CFS does not show their income, although presumably part of that is used to pay their electric bill, which is indicated on their CFS. Further, for customers that do pay income taxes in the study, a portion of any savings on their electric bills achieved by their use of responsive assets is offset in part by the loss of the tax deduction for a business expense in the amount of those savings. The effect of the loss of this tax deduction is included as a line in their CFS. As

[32] This ignores the relatively smaller number of public/nonprofit organizations that occupy leased or rented space, where some tax benefits accrue to the landlord.

indicated in Table 30, the marginal federal income tax rate for businesses and corporations is arbitrarily assumed to be the top corporate income tax bracket in 2020 of 21%.

Applying the assumptions described above as inputs to the process for computing annualized capital costs described in Section A.1 of this appendix, ACCFs can be computed for capital investments in assets with 10- and 20-year lifetimes for each financial instrument used by investors in the study. These are shown in Table 31, which also maps investor types to the nominal asset owners, i.e., actors for whom CFSs are produced as described below.

Table 31. ACCFs for nominal owners and investors in assets with 10- and 20-year lifetimes.

				ACCF	
DSO+T Asset Nominal Owner	Investor Type	Financial Instrument	Asset Lifetime (yr)	Without Sales Tax (%)	With Sales Tax (%)
Corporate owned	Corporate owned	Corporate bonds	20	11.45%	11.45%
	Corporate owned	Corporate bonds	10	13.85%	13.85%
Investor owned	Investor owned	Utility bonds	20	9.72%	9.72%
	Investor owned	Utility bonds	10	11.54%	11.54%
Municipal	Municipal	Municipal bonds	20	5.80%	5.80%
	Municipal	Municipal bonds	10	10.82%	10.82%
Cooperative	Cooperative	Federal bonds	20	5.41%	5.41%
	Cooperative	Federal bonds	10	10.42%	10.42%
Homeowner	Homeowner	Mortgage, res.	20	7.27%	7.92%
	Homeowner	Consumer credit	20	9.71%	10.57%
	Homeowner	Home loan	20	8.72%	9.50%
	Homeowner	Cash	20	5.00%	5.45%
	Homeowner	Auto loan	20	8.02%	8.74%
	Third party	Third-party lease	20	10.63%	10.63%
	Third party	Third-party owned	20	10.63%	10.63%
Home renter	Home renter	Mortgage, com.	20	5.09%	5.54%
	Home renter	Business loan	20	6.38%	6.95%
	Home renter	Expense	20	3.60%	3.92%
	Home renter	Third-party lease	20	4.65%	5.06%
	Home renter	Third-party owned	20	4.65%	5.06%
Business	Business	Mortgage, com.	20	5.09%	5.54%
	Business	Business loan	20	6.38%	6.95%
	Business	Expense	20	3.60%	3.92%
	Third party	Third-party lease	20	10.63%	10.63%
	Third party	Third-party owned	20	10.63%	10.63%
Public/nonprofit	Public/nonprofit	Municipal bonds	20	5.80%	5.80%
	Public/nonprofit	Cash	20	5.00%	5.00%
	Third party	Third-party lease	20	10.63%	10.63%
	Third party	Third-party owned	20	10.63%	10.63%

The CFSs produced by the DSO+T study represent the financial implications of a given BAU or transactive case on the cash flows to actors whose behaviors were individually simulated by the study. Since, in general, each represents a population of others who were not simulated, and who have a diversity of economic perspectives and use a diversity of financial instruments for any given type of asset, the annual capital costs in their CFSs must reflect that diversity.

So, the final step in producing the ACCFs used for capital investments is to produce population weighted-average ACCFs for each class of nominal asset owner for each type of asset investment and the corresponding diversity of financial instruments used for purchase.

Assumptions about this diversity when computing population-weighted ACCFs are described here.

Table 32 shows the type and relative shares of the financial instruments that are presumed to be used by homeowners and home renters, respectively, to purchase assets in new residential buildings. In new homes (constructed in the 20-year time horizon of the study), the default financial instrument used is to assume the asset was included in the purchase of the home and therefore part of the mortgage. The presumed share of the assets so financed in new homes occupied by homeowners varies by asset type and range from a high of 75% for smart EV chargers to a low of 25% for batteries. The remainder of assets in new homes use the alternative financial instrument presumed to vary with asset type as indicated in Table 32.

Table 32. Financial instruments for capital assets in homeowner-occupied new residential buildings and retrofits.

Capital Asset	Asset Life (yr)	New[1] Instrument		Retrofit Instrument		Alternative Financial Instrument
		Type	Share (%)	Type	Share (%)	
Smart thermostat marginal	20	Mortgage, res.	50%	Consumer credit	25%	Cash
Smart water heater marginal	20		50%		25%	Cash
Smart EV charger marginal	20		75%		25%	Auto loan
Smart EV inverter marginal	20		75%		25%	Auto loan
Battery total	20		25%		25%	Third-party owned
PV total	20		75%		50%	Third-party lease

[1] "New" includes major renovations

In the case of older buildings, the default instrument used to retrofit is presumed to be consumer credit, with the remainder using the alternative instrument. Note that highly capital-intensive investments for solar PV systems, batteries, and EV chargers are presumed to be heavily skewed toward third-party provider instruments.

Table 33 shows the same set of information for renter-occupied homes. In this case, the default instrument in new rental homes is a commercial mortgage and for retrofits is a business loan, both held by the landlord. Landlords of rental homes are presumed to make heavy use of third-party providers for solar PV and battery assets.

Table 33. Financial instruments for capital assets in renter-occupied[1] new residential buildings and retrofits.

Capital Asset	Asset Life (yr)	New[2] Instrument		Retrofit Instrument		Alternative Financial Instrument
		Type	Share (%)	Type	Share (%)	
Smart thermostat marginal	20	Mortgage, com.	75%	Business loan	75%	Expense
Smart water heater marginal	20		75%		75%	Expense
Smart EV charger marginal	20		75%		75%	Expense
Smart EV inverter marginal	20		25%		75%	Third-party lease
Battery total	20		10%		5%	Third-party owned
PV total	20		50%		25%	Third-party lease

[1] Renters are assumed to implicitly pay for asset-cost recovery embedded in rent collected by taxable landlords
[2] "New" includes major renovations

In similar fashion, Table 34 and Table 35 show the assumptions made by the study about the diversity of financial instruments used in purchasing assets in new commercial buildings and retrofits from the perspective of business occupants and public/nonprofit occupants, respectively. Owners of buildings occupied by businesses are presumed to roll assets into commercial mortgages by default and typically use business loans to finance retrofit assets. Commercial building owners, too, are presumed to heavily use third-party providers for financing capital-intensive solar PV and battery assets, and for labor- and expertise-intensive investments in large commercial HVAC systems.

Table 34. Financial instruments for business[1] capital assets in new commercial buildings and retrofits.

Capital Asset	Asset Life (yr)	New[2] Instrument Type	New[2] Instrument Share (%)	Retrofit Instrument Type	Retrofit Instrument Share (%)	Alternative Financial Instrument
Smart thermostat marginal	20	Mortgage, com.	75%	Business loan	75%	Expense
Smart large HVAC marginal	20		75%		75%	Third-party lease
Battery total	20		25%		10%	Third-party owned
PV total	20		50%		25%	Third-party lease

[1] Occupants leasing commercial floor space are assumed to implicitly pay for asset-cost recovery embedded in rent collected by taxable building owners
[2] "New" includes major renovations

Table 35. Financial instruments for public/nonprofit[1] capital assets in new commercial buildings and retrofits.

Capital Asset	Asset Life (yr)	New[2] Instrument Type	New[2] Instrument Share (%)	Retrofit Instrument Type	Retrofit Instrument Share (%)	Alternative Financial Instrument
Smart thermostat marginal	20	Municipal bonds	75%	Municipal bonds	75%	Cash
Smart large HVAC marginal	20		75%		25%	Third-party lease
Battery total	20		10%		5%	Third-party owned
PV total	20		50%		25%	Third-party lease

[1] Occupants leasing commercial floor space are assumed to implicitly pay for asset-cost recovery embedded in rent collected by taxable building owners
[2] "New" includes major renovations

Finally, the diversity in financial perspectives and instruments used by generation owners, the transmission system owner, and distribution utilities that are assumed to produce population-weighted ACCFs for investors purchasing grid assets is shown in Table 36. Corporate generation owners are assumed to issue corporate bonds to finance the portion of the capital investment financed with debt, while investor-owned utilities issue utility bonds. Municipal utilities use municipal bonds and rural cooperatives use borrowing authority at rates that are, in effect, equal to the federal bonds rate to finance their capital investments for their distribution infrastructure and any generation assets they own.

Table 36. Ownership shares and financial instruments for power system capital assets.

Asset Owner Type	Utility Type	Generation Owner (corporate bonds)	Investor-Owned Utility (utility bonds)	Municipal Utility (municipal bonds)	Rural Cooperative (federal bonds)
Generation owner	Blended average	60%	0%	25%	15%
Transmission utility	Total system	0%	65%	10%	25%
Distribution utility	Rural	0%	10%	15%	75%
	Suburban	0%	50%	40%	10%
	Urban	0%	75%	25%	0%

Table 36 also indicates the relative share ownership types assumed to be represented in population-weighted ACCFs for the blended average generation owner, the transmission system owner,[33] and for distribution utilities or DSOs. The latter are classified as either rural, suburban, or urban, with a corresponding shift in ownership shares from rural cooperatives to municipal utilities to investor-owned utilities as indicated in Table 36.

With these assumptions, the final population-weighted ACCFs can be computed. The resulting ACCFs are documented in Section 2.3 of this report.

[33] For simplicity, the DSO+T study assumes there is a single investor-owned transmission system owner/operator.

Appendix B – Substation Fleet Capacity Expansion Model

B.1 Introduction

As introduced in Section 3.2.1, this appendix describes the model developed by the DSO+T study of distribution system capacity and its rate of expansion. It is based on modeling 1) how load growth results in shifting land use of largely undeveloped rural areas to developed suburban areas with much higher load density (peak demand per unit of land area) at the rural/suburban boundary and 2) how this greenfield growth is superimposed on general brownfield growth that occurs uniformly across the entire service territory. Greenfield and brownfield growth, in turn, results in the construction of new substations in the greenfield areas to meet rapidly increasing peak demand and slow but steady requirements for capacity upgrades at existing brownfield substations.

The peak load of each DSO in the study is known from the simulation. Given assumptions summarized in Table 8 in Section 3.2.1 about the relative peak load density of undeveloped and fully developed service areas, standard design criteria for substation capacity expansion projects, and growth rates and the fraction of their entire service territory that is fully developed for each of the three DSO types, this appendix describes how all other relevant parameters describing a DSO's substation fleet needed for estimating the current capacity of its fleet and the annual rate of its expansion can be determined. Given assumptions about the average number of customers served by average rural, suburban, and urban substations and the average number of feeders in those substations, and the cost of new and upgraded capacity in those substations, the number of substations and feeders and their capital cost can also be estimated as described in Section 3.2.1.

The mathematical description of this model is the subject of this appendix, which is organized in four sections:

1. A description of the lifecycle of a substation between greenfield construction and between subsequent brownfield capacity upgrades
2. The resulting existing capacity margins of the greenfield and brownfield substation fleets
3. Characterizing the DSO's rural undeveloped, developing greenfield, and fully developed service areas and the substation fleets serving them
4. Estimating the annual rate of growth in substation capacity.

B.2 Substation Lifecycle

B.2.1 Growth in Peak Demand

As described in Section 3.2.1, the greenfield growth rate (g_g) is defined as the rate of the DSO's load growth that is driven by undeveloped areas of a DSO's service territory undergoing rapid transition from rural to suburban load densities and that require construction of new substations.

The brownfield growth rate (g_b) is the underlying rate of growth in existing load for existing <u>and</u> new greenfield substations that reflects the sum of:

- Growth in the number of customers served by existing substations (can be negative in some typically rural areas)

- Growth in load of existing customers due to additional connected loads, less any reduction in load due to increasing levels of energy efficiency (net can be negative)
- Growth due to densification, i.e., due to changing customer types such as conversion of single-family neighborhoods to multifamily housing or low-rise commercial areas to high-rise commercial.

The total growth rate for a DSO, g_d, is then:

$$g_d = g_b + g_g \tag{150}$$

The growth rate seen by one of the DSO substations (g_s) is a localized phenomena. On average, brownfield substations simply undergo growth at the brownfield growth rate $g_s = g_b$. The brownfield growth rate is assumed to be uniform across the DSO's entire service territory because it reflects underlying trends in energy usage that affect all customers, including in greenfield areas.

However, a greenfield substation's localized peak demand growth rate is generally much higher than the DSO overall greenfield growth rate based on the entire DSO load (g_g), because rapid greenfield growth is concentrated in only a relatively small portion of the DSO's entire service territory. Hence its overall greenfield growth rate may be substantially lower. Note the localized greenfield growth rate includes the effect of underlying brownfield growth as well. It will be formally defined later in this analysis.

The DSO's or a substation's current (gross) peak demand for real power is defined as the highest 5-minute value of the weighted time-series power delivered to it by the bulk system in the BAU case simulation (i.e., in the absence of any reduction contributed by its customers' transactive flexible assets). Note that the term *peak demand* as used here always refers to the DSO (gross) peak demand in the corresponding BAU case, even when results for a transactive case with lower net peak demand are being analyzed. In a transactive case, the peak demand of the corresponding BAU case is the counterfactual peak demand.[34]

Assuming a substation's real-power demand grows exponentially from that of the initial year of the design lifecycle (y = 0), in the absence of any reduction due to the participation of transactive flexible assets, its peak real-power demand over time $Peakr_s(y)$ where y indicates the year of substation design lifecycle, is:

$$Peakr_s(y) = Peakr_s(0)(1 + g_s)^y \tag{151}$$

Peak apparent power demand (rather than real-power peak demand) is used for sizing substation transformers and other equipment, and is slightly larger than the real power during peak demand by the inverse of the substation's power factor at peak demand, PF_s. The DSO's peak apparent power demand in the BAU case, $Peaka_s$ in any year y of a design lifecycle, is:

$$Peaka_d(y) = Peakr_d(y)\ /\ PF_d \tag{152}$$

[34] Note that in an actual deployment of a transactive system, where only the net peak demand can be directly observed, the counterfactual reduction in BAU case peak demand can still be estimated from analysis of the history of bids and transactions for a given retail market, or using other analytic methods for measurement and verification evaluation of savings.

Note that, in the absence of a DSO+T strategy capacity, upgrades occur when $\hat{P}eaka_s(y)$ is equal to one.

A transactive case represents the actual net peak apparent power demand as $Ptrxa_s(y)$. $Rtrx_s$ is defined as the fractional reduction in gross (counterfactual) peak demand due to response of the transactive flexible assets.

$$Ptrxa_s(y) = Peaka_s(y)\,(1 - Rtrx_s) = Peaka_s(0)\,(1 + g_s)^y\,(1 - Rtrx_s) \qquad (153)$$

Therefore, in the presence of a DSO+T strategy upgrades occur when $\hat{P}eaka_s(y)$ is equal to 1 / (1 – $Rtrx_s$).

B.2.2 Substation Design Capacity and Lifetime

The design practices of DSOs are an important determinant of how much marginal capacity is added beyond that needed to serve the peak demand at the time of substation construction or upgrade, and hence how much capacity exists over time in the DSO's substation fleet.

The design lifetime of substations (Y_{design}) is defined as the number of years over which a substation's capacity is designed to be sufficient to meet the expected load growth. It is assumed to be 20 years.[35] If the load growth occurs as expected, the substation's transformer capacity will need to be upgraded at that time. At some point, additional feeders may also be required. Any such upgrades will likewise be designed for another 20-year period, i.e., the design lifetime is assumed to apply to new substations and future upgrades. So, 20 years after adopting a DSO+T strategy, an equilibrium is assumed to have been established between the load growth rate and the rate of addition to the DSO's substation capacity via new substation construction and upgrades.

Once a substation has been constructed or upgraded, it typically takes many years before growth overtakes its capacity and requires a subsequent upgrade including, in a transactive case, the utilization of transactive resources to forestall it as long as financially viable. Thus, during any given year, only a fraction of the DSO's existing substations will be operating in a capacity-constrained condition to varying degrees, i.e., those nearing the end of their design lifetime.

The DSOs' design practice regarding the sizing of brownfield substation capacity at the time of an upgrade is assumed to be based on a requirement that the total capacity installed, Cap_s [MVA], is sufficient to meet the then-current peak demand plus additional marginal capacity ($MCap_b$) sufficient to meet expected brownfield peak demand growth over a fixed number of years (i.e., the substation design lifetime, Y_{design}).

New greenfield substations are designed with much larger marginal capacity at the time of their construction sufficient to absorb very rapid growth in peak demand over an average greenfield growth period of Y_{green} years, at which time they are expected to have marginal capacity $MCap_b$ to absorb growth in peak demand at the brownfield rate for Y_{design} more years (for a total of Y_{green} + Y_{design} years).

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[35] Note that a substation may be upgraded several times over its lifetime. Each time marks the beginning of a new design lifecycle as the term is used here.

In addition to a current peak demand, each substation in the DSO's population is defined here as having the following characteristics:

- Classification of its current design cycle as brownfield (subscript b) or greenfield (subscript g)
- A corresponding exponential substation peak demand growth rate, gs
- In a transactive case, a fractional reduction in the gross (counterfactual, from the BAU case) peak demand, Rtrxs
- The age of the substation, i.e., the years elapsed since its construction or last capacity upgrade, y (i.e., at the time of the substation's construction or the last capacity upgrade y = 0).

Define the current substation capacity as $Cap_s(Y_{design})$ and capacity added for substation (s) in Year 0, $\Delta Cap_s(0)$ to meet the peak demand in Year Y_{design}, such that:

$$Cap_s\left(Y_{design}\right) \equiv Cap_s(0) + \Delta Cap_s(0) \tag{154}$$

(Note that the substation capacity at any time in the design lifecycle after the last upgrade, i.e., over the time period $0<y<Y_{design}$, is constant and equal to $Cap_s(Y_{design})$. In other words, Equation (154 represents a step change in capacity at y=0.)

Define the *capacity factor* of substation (s) in any subsequent year (y) as the ratio of its peak demand in year y to its design capacity $Cap_s(Y_{design})$, i.e., its peak demand *normalized* by its current capacity, as $\hat{P}eaka_s(y)$:

$$\hat{P}eaka_s(y) \equiv Peaka_s(y) \,/\, Cap_s\left(Y_{design}\right) \tag{155}$$

The analysis of substation lifecycles and fleet capacity margins in the following sections uses a set of equations describing various properties of exponential growth, such as averages over time and elapsed times until growth reaches a specified level. These are derived in 8.0B.6B.6 of this appendix.

B.2.3 Business-as-Usual Case Brownfield Substation Lifecycle

For a brownfield BAU case substation, i.e., in the absence of any response from transactive flexible assets reducing the gross peak demand, the year of the next upgrade after its last upgrade, or after its reclassification from greenfield to brownfield, is defined as $y = Y_{design}$.

From the definition of the substation design lifetime, the marginal capacity in Year 0 of a brownfield substation must be sufficient to allow the substation to serve the total peak demand in Year Y_{design}. So, its capacity must be over and above its then-current peak demand, $Peaka_s(0)$, plus the growth in peak demand expected from Year 0 to Year Y_{design} at the substation's local peak demand growth rate $g_b = g_b$. Its capacity margin in Year 0, $\Delta Cap_s(0)$, is then by definition:

$$\Delta Cap_s(0) \equiv Peaka_s(0)\,(1 + g_b)^{Y_{design}} - Peaka_s(0) \tag{156}$$

Substituting Equation (156 for ΔCap_s in Equation (154 , the total substation capacity needed to serve the BAU case peak demand in Year Y_{design} is:

$$Cap_s\left(Y_{design}\right) = Cap_s(0) - Peaka_s(0) + Peaka_s(0)\,(1 + g_b)^{Y_{design}} \tag{157}$$

Define the marginal capacity factor of the substation in Year 0, $MCap_n$, as the capacity added by the upgrade in Year 0 as a fraction of the capacity in Year Y_{design}. Since the capacity in year Y_{design} is just adequate to serve the substation's BAU case peak demand in Year Y_{design}:

$$MCap_b \equiv \frac{\Delta Cap_s(0)}{Cap_s(Y_{design})} = \frac{\Delta Cap_s(0)}{Peaka_s(O)\,(1+g_b)^{Y_{design}}} \tag{158}$$

Substituting Equation (156 for the numerator in Equation (158 :

$$MCap_b = \frac{Peaka_s(0)\,(1+g_b)^{Y_{design}} - Peaka_s(0)}{Peaka_s(0)\,(1+g_b)^{Y_{design}}} = 1 - \frac{1}{(1+g_b)^{Y_{design}}} \tag{159}$$

Figure 10 illustrates the lifecycle of a BAU case brownfield substation with Y_{design} equal to 20 years. The substation underwent its previous upgrade in Year 0 and its next 20 years later in Year Y_{design}. Dual vertical axes are used to plot the substation's historical peak demand and capacity. The right axis is units of apparent power and the left axis is the power normalized by the substation capacity in Year Y_{design} and is therefore dimensionless [p.u.].

In Year 0 the marginal capacity added in the last upgrade was $MCap_s$ and the next capacity investment occurs in Year Y_{design} (e.g., Year 20). Note that in the BAU case, upgrades always occur when the peak demand is equal to the substation capacity.

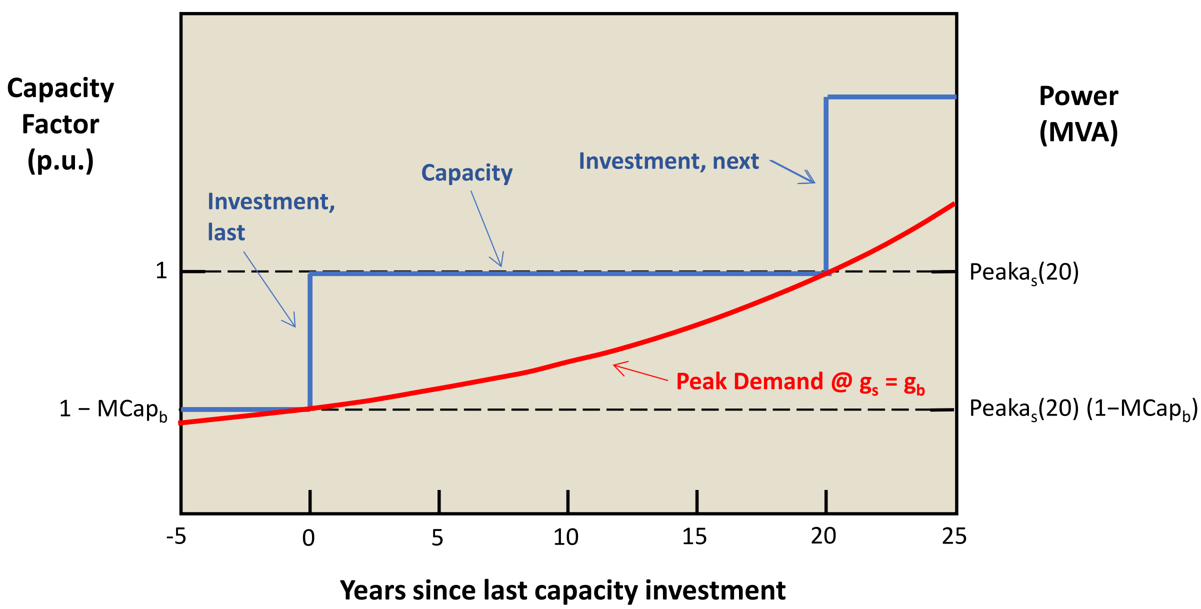

Figure 10. Substation capacity lifecycle (Brownfield, BAU Case).

B.2.4 Transactive Case Brownfield Substation Lifecycle

For brownfield substations in a transactive case, the substation's peak demand is managed using flexible transactive assets so that it is reduced from the counterfactual from the corresponding BAU case by a fraction ($Rtrx_s$) as shown in Figure 11. Note that the last capacity investment is assumed to be identical to that in the BAU case in Figure 10, i.e., the presumed brownfield substation design process does not take into account the potential reduction in peak demand from the flexible assets by downsizing the capacity added during the upgrade. Instead, the benefit of the DSO+T strategy is obtained by extending the substation's lifetime beyond

Y_{design}. While it may be economically beneficial to realize the savings by downsizing the Year 0 upgrade, in practice this is hard to realize in brownfield upgrades because the reduction in peak demand in percentage terms is often too small to allow use of the next smallest transformer.

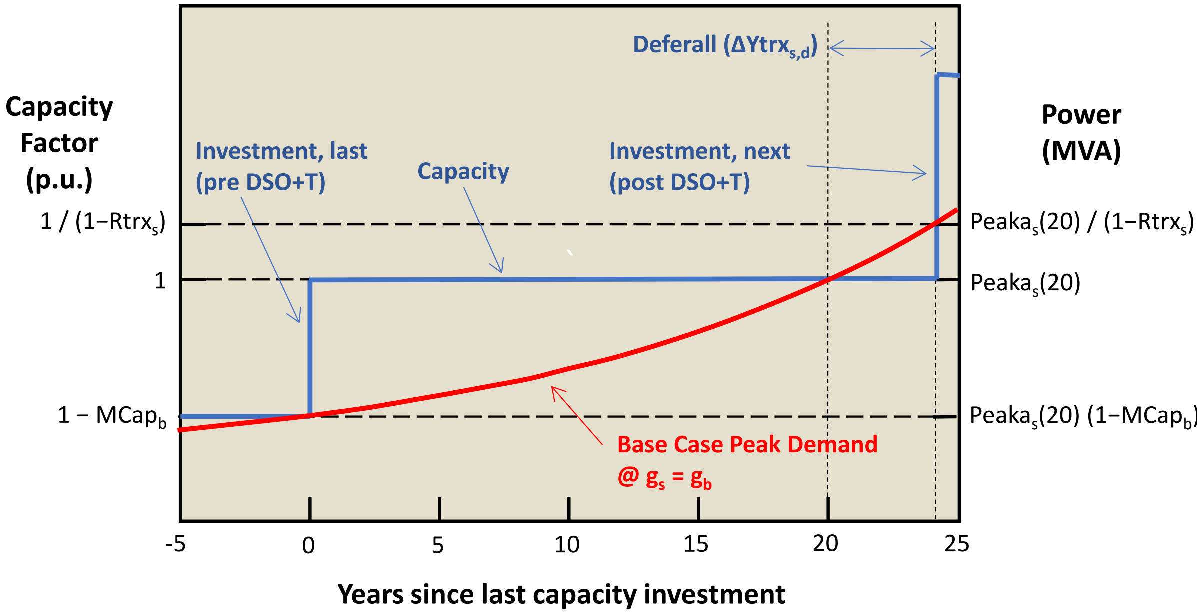

Figure 11. Substation capacity lifecycle (Brownfield, Transactive Case).

From the definition of $Rtrx_s$, the reduction in the BAU case peak demand in any year (y) from peak demand management, $\Delta Ptrx_s(y)$, is then:

$$\Delta Ptrx_s(y) \equiv Peaka_s(y)\; Rtrx_s \qquad (160)$$

This allows the next upgrade to be deferred until the year y = Y_{up} when the counterfactual peak demand becomes $\Delta Ptrx_s(y)$ higher the substation capacity as shown in Figure 11:

$$Peaka_s(Y_{up}) = Peaka_s(Y_{design}) + \Delta Ptrx_s(Y_{up}) \qquad (161)$$

and by substituting Equation (160 for $\Delta Ptrx_{s,d}$ in Equation (161 :

$$Peaka_s(Y_{up}) = Peaka_s(Y_{design}) + Peaka_s(Y_{up})\; Rtrx_s$$

which reduces to

$$Peaka_s(Y_{up}) = Peaka_s(Y_{design}) \,/\, (1 - Rtrx_s) \qquad (162)$$

From Equation (216 in Section B.6 of this appendix, the number of years the transactive peak demand management can defer the capacity upgrade in the substation, $\Delta Ytrx_s$, given a local peak demand growth rate of $g_s = g_b$, is:

$$\Delta Ytrx_s \equiv Y_{up} - Y_{design} = \frac{ln\left(Peaka_s(Y_{up})\right) - ln\left(Peaka_s(Y_{design})\right)}{ln(1 + g_b)} \qquad (163)$$

which, since $Peaka_s(Y_{design})$ is equal to one by definition, and by substituting Equation (162 for $Peaka_s(0)$, Equation (163 reduces to:

$$\Delta Ytrx_s \;=\; \ln\bigl(1/(1 - Rtrx_s)\bigr) \,/\, \ln(1 + g_b) \tag{164}$$

$\Delta Ytrx_s$ as illustrated in Figure 11 is equal to 4 years.

From the design criteria, the brownfield substation's capacity after its last upgrade, or after it was reclassified from greenfield to brownfield, $Cap_s(Y_{design})$, is equal to the counterfactual peak demand in Year Y_{design}:

$$Cap_s(Y_{design}) \;=\; Peaka_s(Y_{design}) \tag{165}$$

So, from Equation (166 , the capacity factor at the time of the capacity upgrade in Year Y_{up} is:

$$\hat{P}eaka_s(Y_{up}) \;=\; 1 \,/\, (1 - Rtrx_s) \tag{166}$$

B.2.5 Business-as-Usual Case Greenfield Substation Lifecycle

There are two key differences between the greenfield and brownfield substations lifecycles. First, the localized peak demand growth rate of greenfield substations ($g_{g,s}$) is much higher than that of brownfield substations. Once the burst of greenfield growth has saturated the substation's service territory, i.e., in Y_{green} years (5 years in the illustration), the growth rate slows to that of brownfield growth and the substation is reclassified as brownfield.

The lifecycle of a BAU case greenfield substation is shown as the green shaded area in Figure 12, which illustrates 30 years of a greenfield substation's history (including its subsequent design lifecycle as a newly reclassified brownfield substation). The substation was constructed in Year 0 with capacity required to meet expected very rapid growth during its greenfield period, at the localized greenfield peak demand growth rate, plus that required by the subsequent period of much slower growth at the brownfield rate over an additional Y_{design} years. The length of the greenfield growth period Y_{green} is a design parameter based on a forecasted growth rate for greenfield substations; in Figure 12 Y_{green} is illustrated as being 5 years.

By design, at the end of its greenfield growth period, the substation has the same remaining capacity margin (1 – $MCap_b$) as would a brownfield substation that was upgraded at that time. It is therefore reclassified to brownfield status at that point (Year 5 in the illustration) and analyzed subsequently as a regular part of the brownfield population. Y_{design} years after that (Year 25 in the illustration), it undergoes its first brownfield capacity upgrade. Again in a BAU case, upgrades always occur when the peak demand is equal to the substation capacity.

The BAU case peak demand for the greenfield substation immediately after its construction (in Year 0) is equal to that of the area it will serve, A_s, as its peak demand density [MW/mi^2] increases from that of an undeveloped brownfield service area (ρ_u) to that of a fully developed brownfield service area (ρ_f) over Y_{green} years. The fully developed peak demand for its service area is needed to size a greenfield substation's capacity at construction.

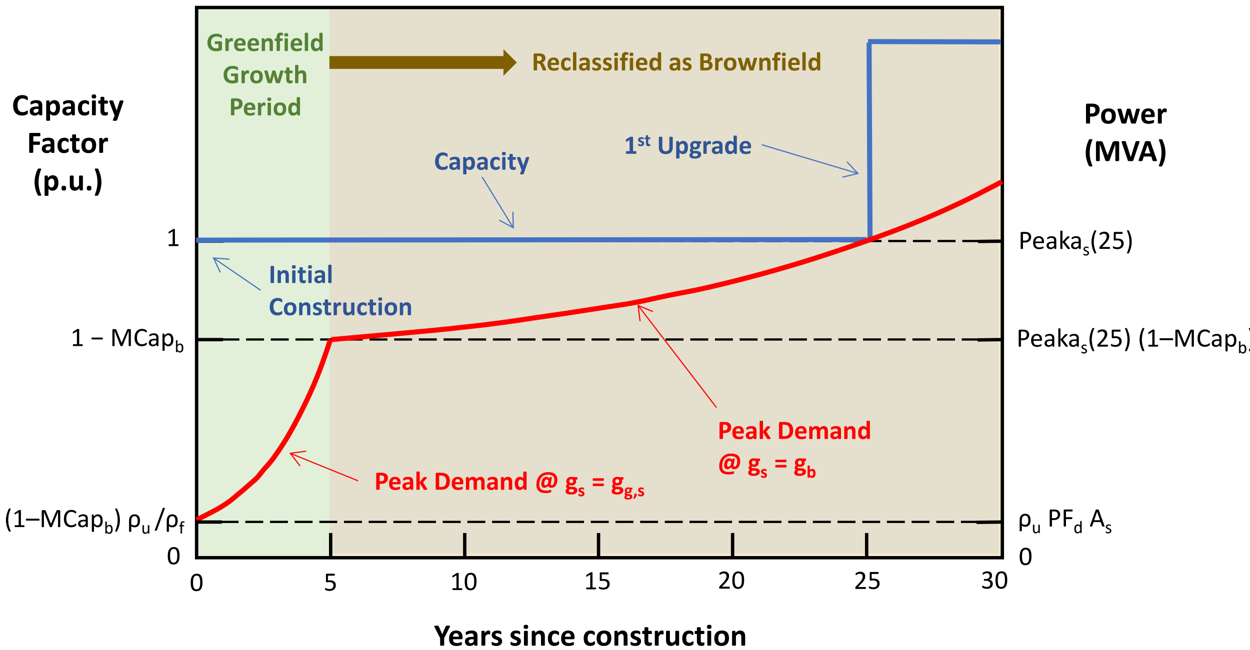

Figure 12. Substation capacity lifecycle (Greenfield, BAU Case).

Given a service area designated for the new greenfield substation (A_s), the substation immediately begins serving the load of that area in its undeveloped state (with a BAU case peak demand density of ρ_u), and so its peak demand in Year 0 is by defintion:

$$Peaka_s(0) = \rho_u \, PF_d \, A_s \tag{167}$$

and at the end of the substation's tenure as a greenfield substation in Year Y_{green} when its service area is fully developed, its peak demand in absence of any brownbfield growth is:

$$Peaka_s(Y_{green}) = \rho_f \, PF_d \, A_s \tag{168}$$

The local greenfield substation peak demand growth rate ($g_{g,s}$) can be determined from Equation (218 in Section B.6:

$$g_{g,s} = \left(\rho_f/\rho_u\right)^{1/Y_{green}} - 1 \tag{169}$$

From the design criteria for greenfield substations, its peak demand in Year Y_{green} is equal to that of a brownfield substation that has just been upgraded and designed to serve for Y_{design} additional years, i.e.:

$$Peaka_s(Y_{green}) = (1 - MCap_b) \, Peaka_s(Y_{green} + Y_{design}) \tag{170}$$

and its capacity factor in Year Y_{green} is:

$$\hat{P}eaka_s(Y_{green}) = \frac{(1 - MCap_b) \, Peaka_s(Y_{green} + Y_{design})}{Peaka_s(Y_{green} + Y_{design})} = 1 - MCap_b \tag{171}$$

The substation's peak demand at the time of construction in Year 0, $Peaka_s(0)$, can be expressed as a function of its peak demand in Year Y_{green} using Equation (151 as:

$$Peaka_s(Y_{green}) = Peaka_s(0)\left(1 + g_{g,s}\right)^{Y_{green}}$$

which can be solved for $Peaka_s(0)$ as:

$$Peaka_s(0) = \frac{Peaka_s(Y_{green})}{\left(1 + g_{g,s}\right)^{Y_{green}}} \quad (172)$$

So, substituting Equation (170 for $Peaka_s(Y_{green})$ in Equation (172), the substation's peak demand at the time of construction is:

$$Peaka_s(0) = \frac{(1 - MCap_b)\, Peaka_s(Y_{green} + Y_{design})}{\left(1 + g_{g,s}\right)^{Y_{green}}} \quad (173)$$

and its capacity factor at the time of construction in Year 0, $\hat{P}eaka_{s,d}(0)$ is:

$$\hat{P}eaka_s(0) = \frac{(1 - MCap_b)\, Peaka_s(Y_{green} + Y_{design})}{\left(1 + g_{g,s}\right)^{Y_{green}} Peaka_s(Y_{green} + Y_{design})} = \frac{(1 - MCap_b)}{\left(1 + g_{g,s}\right)^{Y_{green}}} \quad (174)$$

Alternatively, substituting Equation (169 for $g_{g,s}$ in Equation (174 , the capacity factor at time of construction can be expressed as:

$$\hat{P}eaka_s(0) = (1 - MCap_b)\frac{\rho_u}{\rho_f} \quad (175)$$

The design capacity margin for greenfield substations, $MCap_g$, is then:

$$MCap_g = 1 - \hat{P}eaka_s(0) = 1 - \frac{(1 - MCap_b)}{\left(1 + g_{g,s}\right)^{Y_{green}}} = 1 - (1 - MCap_b)\frac{\rho_u}{\rho_f} \quad (176)$$

B.2.6 Transactive Case Greenfield Substation Lifecycle

The history of a transactive greenfield substation is shown in Figure 13, including its subsequent design lifecycle as a newly reclassified brownfield substation. In a transactive case, a greenfield substation's initial capacity is reduced by a factor of 1 – $Rtrx_{s,d}$ compared to the BAU case in anticipation of the DSO's ability to manage peak demand using the response of the flexible transactive assets. Once the ability of the flexible assets to forestall the first upgrade is exhausted after Y_{design} (e.g., 20) additional years beyond Y_{green}, the upgrade is executed.

Whereas in brownfield substations the capacity benefit of the adoption of a DSO+T strategy is realized in the form of deferring the next upgrade, in greenfield substations the benefit can be realized immediately upon constructed in the form of a reduced initial capacity. This assertion bears some examination. The presumption is that the DSO knows with some certainty the level of peak demand reduction ($Rtrx_S$) it can achieve and immediately applies that knowledge to saving infrastructure costs by downsizing its new substations while maintaining an effective 20-year design lifetime to absorb 20 years of expected greenfield growth. The DSO can dodge the limitation on incremental transformer sizes by simply expanding the service area the new substation will serve.

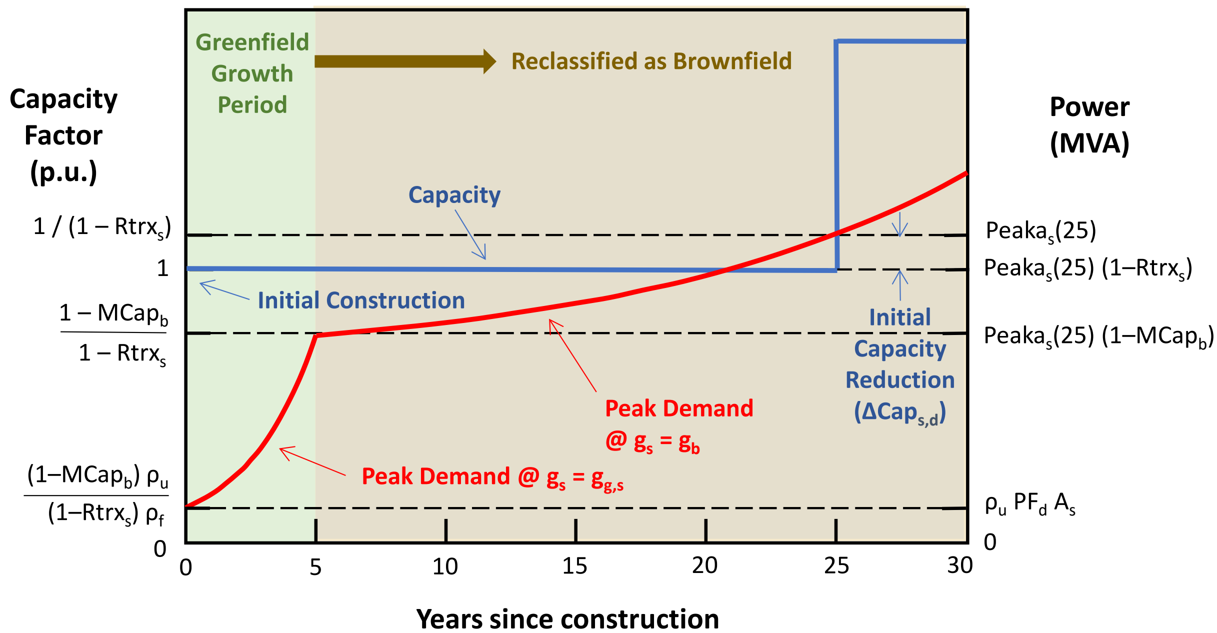

Figure 13. Substation Capacity Lifecycle (Greenfield, Transactive Case)

The question is whether it uses this same knowledge to downsize its capacity upgrades in its brownfield substations, or as proposed in the previous section, simply allows the time between upgrades to be extended from Y_{design} years to $Y_{design} + \Delta Ytrx_s$ years.

So for a greenfield substation in a transactive case, at the time of its first subsequent brownfield capacity upgrade in Year Y_{design}+Y_{green} (Year 25 as illustrated), the gross (counterfactual) peak demand it is able to serve, $Peaka_s(25)$, is higher than its capacity, $Cap_s(Y_{design}+Y_{green})$, because peak demand is being managed using flexible transactive assets to reduce it by a fraction $Rtrx_s$:

$$Cap_s(0) = Peaka_s(Y_{green} + Y_{design})\,(1 - Rtrx_s) \tag{177}$$

The substation's capacity factor at the time of its first brownfield capacity upgrade is the ratio of its counterfactual peak demand in Year Y_{green}+Y_{design} to its capacity:

$$\hat{P}eaka_s(Y_{green} + Y_{design}) = \frac{Peaka_s(Y_{green} + Y_{design})}{Peaka_s(Y_{green} + Y_{design})\,(1 - Rtrx_s)}$$

which reduces to

$$\hat{P}eaka_s(Y_{green} + Y_{design}) = \frac{1}{1 - Rtrx_s} \tag{178}$$

The design criteria for greenfield substations requires that, at the end of its tenure as a greenfield substation in Year Y_{green}, the substation's remaining capacity must be sufficient to serve the counterfactual peak demand as it grows over the subsequent Y_{design} years. So, just as it does for all brownfield substations, the counterfactual peak demand in Year Y_{green} must be a factor of $1–MCap_b$ less than the counterfactual peak demand at the time of its first capacity upgrade as a newly reclassified brownfield substation in Year Y_{green}+Y_{design}. The substation's capacity factor in Year Y_{green} is the ratio of its counterfactual peak demand in Year Y_{green}

expressed by Equation (170 to its capacity at the time of its construction expressed by Equation(177 :

$$\hat{P}eaka_s(Y_{green}) = \frac{Peaka_s(Y_{green} + Y_{design})\,(1 - MCap_b)}{Peaka_s(Y_{green} + Y_{design})\,(1 - Rtrx_s)} = \frac{1 - MCap_b}{1 - Rtrx_s} \qquad (179)$$

Similarly, the capacity factor at the time of substation's construction (Year 0) is:

$$\hat{P}eaka_s(0) = \frac{Peaka_s(0)}{Peaka_s(Y_{green} + Y_{design})\,(1 - Rtrx_s)} \qquad (180)$$

or, substituting Equation (173 for the counterfactual peak demand in Year 0 in Equation (180 :

$$\hat{P}eaka_s(0) = \frac{(1 - MCap_b)\,Peaka_s(Y_{green} + Y_{design})}{(1 + g_{g,s})^{Y_{green}}\,Peaka_s(Y_{green} + Y_{design})\,(1 - Rtrx_s)}$$

which reduces to

$$\hat{P}eaka_s(0) = \frac{(1 - MCap_b)}{(1 - Rtrx_s)\,(1 + g_{g,s})^{Y_{green}}} \qquad (181)$$

Alternatively, substituting Equation (169 for $g_{g,s}$ in Equation (181 , the capacity factor at time of construction can be expressed as:

$$\hat{P}eaka_s(0) = \frac{(1 - MCap_b)\,\rho_u}{(1 - Rtrx_s)\,\rho_f} \qquad (182)$$

B.3 DSO Service Territory Analysis

As the basis for analyzing the relative shares of the total DSO service territory represented by each type of substation service area, the following information is presumed to be known for each DSO:

1. Peak demand (from simulation for dso_n) $Peakr_d$
2. Power factor at peak demand (default, general assumption) PF ≡ 0.9
3. Fraction of total DSO service area that is fully developed (default, by DSO type) $\hat{A}_f$
4. Normalized power density, fully developed service areas (definition) $\hat{\rho}_f \equiv 1$
5. Normalized power density, undeveloped service areas (default, general assumption) $\hat{\rho}_u = 0.6\%$
6. DSO's overall greenfield peak demand growth rate (default, by DSO type) g_g
7. (DSO) brownfield overall peak demand growth rate (default, by DSO type) g_b
8. Length of the greenfield period, years (default, general assumption) Y_{green} = 4 yr

The DSO+T analysis presumes that each DSO's real power in 2016 is known from ERCOT data and that its power factor during peak demand (PF) is known by the DSO and can be assumed for the purpose of the analysis as 0.9, on average across all DSOs.

Further, the analysis assumes that the relative (ratio of) peak demand density of undeveloped service areas to that of fully developed service areas is 0.6%, as shown inTable 37, based on the assumption that the diversified peak demand per home is 3 kW and given that there are 640 acres per square mile.

Table 37. Relative peak demand densities of undeveloped and fully developed service areas.

Development Stage	Homes	Acres	Peak Demand Density	
			Absolute (MW/mi^2)	Relative to Fully Developed (-)
Undeveloped	2	40	0.10	0.6%
Fully developed	8	1	15.36	100.0%

Residential loads are used to develop this estimate, but it is important to note that the analysis uses only the ratio of the two, i.e., the normalized peak demand density in the rightmost column, rather than the absolute peak demand densities. Developing this ratio based on residential areas is an acceptable approximation.

B.3.1 Undeveloped, Greenfield and Fully Developed Service Areas and Peak Demand Densities

Indicate undeveloped, greenfield, and fully developed areas using the subscripts u, g, and f, respectively. Let the absence of subscript indicate a parameter that pertains to the DSO's entire service territory.

Define the fractional share of the service territory's land area that is undeveloped, greenfield, or fully developed as $\hat{A}_u$, $\hat{A}_g$, and $\hat{A}_f$, respectively. Then, by definition,

$$\hat{A}_u + \hat{A}_g + \hat{A}_f = 1 \qquad (183)$$

Define the real-power peak demand density of an area as its peak demand normalized by the land area. So, from these definitions:

$$\rho\, A \equiv Peakr_d \equiv \rho_u\, A_u + \rho_g\, A_g + \rho_f\, A_f$$

Dividing both sides of the equation by the product of a DSO's service territory (A) and the peak demand density of fully developed areas:

$$\frac{\rho}{\rho_f}\frac{A}{A} = \frac{\rho_u}{\rho_f}\frac{A_u}{A} + \frac{\rho_g}{\rho_f}\frac{A_g}{A} + \frac{\rho_f}{\rho_f}\frac{A_f}{A}$$

which, defining the normalized demand density for an area as the ratio of its peak demand density to that of a fully developed area can be expressed in terms of normalized demand desnities and service area shares as:

$$\hat{\rho} = \hat{\rho}_u\, \hat{A}_u + \hat{\rho}_g\, \hat{A}_g + \hat{\rho}_f\, \hat{A}_f \qquad (184)$$

The DSO's greenfield growth is the product of the DSO's greenfield growth rate (g_g), BAU case peak demand density (ρ), and total service area (A). Similarly, the local substation greenfield growth rate ($g_{g,s}$) is defined such that the growth in peak demand in the greenfield service area represents the entirety of the DSO's greenfield growth. So, by definition:

$$G \equiv g_{g,s}\, \rho_g\, A_g = g_g\, \rho\, A$$

which can be solved for the greenfield area's share of the DSO's service territory and expressed in terms of normalized greenfield and total DSO peak demand densities as:

$$\hat{A}_g = \frac{A_g}{A} = \frac{g_g}{g_{g,s}} \frac{\rho}{\rho_g} = \frac{g_g}{g_{g,s}} \frac{\hat{\rho}}{\hat{\rho}_g} \qquad (185)$$

The DSO's local greenfield substation peak demand growth rate ($g_{g,s}$) from Equation (169 can be expressed in terms of the normalized greenfield peak demand density as:

$$g_{g,s} = \left(\rho_f/\rho_u\right)^{1/Y_{green}} - 1 = \hat{\rho}_u^{\;-1/Y_{green}} - 1 \qquad (186)$$

and from Equation (214 in Section B.6 of this appendix, the normalized peak demand density for a greenfield substation's service territory as its peak demand density grows exponentially from an undeveloped value of ρ_u to a fully developed value of ρ_f can be expressed in normalized terms as:

$$\hat{\rho}_g = \frac{\hat{\rho}_f - \hat{\rho}_u}{ln(\hat{\rho}_f) - ln(\hat{\rho}_u)} \qquad (187)$$

B.3.2 Solution

The local greenfield substation growth rate ($g_{g,s}$) and the greenfield peak demand density ($\hat{\rho}_g$) can be computed directly using Equations (186 and (187 , respectively. The remaining system of Equations (183 through (185 has a total of three unknowns $\hat{A}_u$, $\hat{A}_g$, and $\hat{\rho}$. Solving (183 for $\hat{A}_u$ and substituting the result into Equation (184 :

$$\hat{\rho} = \hat{\rho}_u \left(1 - \hat{A}_g - \hat{A}_f\right) + \hat{\rho}_g\, \hat{A}_g + \hat{\rho}_f\, \hat{A}_f \qquad (188)$$

Substituting Equation (188 for the normalized total DSO peak demand density in Equation (185 :

$$\hat{A}_g = \frac{g_g}{g_{g,s}\, \hat{\rho}_g} \left[\hat{\rho}_u \left(1 - \hat{A}_g - \hat{A}_f\right) + \hat{\rho}_g\, \hat{A}_g + \hat{\rho}_f\, \hat{A}_f\right]$$

and solving for the greenfield area share:

$$\hat{A}_g \left(1 - \frac{g_g\, \hat{\rho}_g}{g_{g,s}\, \hat{\rho}_g} + \frac{g_g\, \hat{\rho}_u}{g_{g,s}\, \hat{\rho}_g}\right) = \frac{g_g}{g_{g,s}\, \hat{\rho}_g} \left[\hat{\rho}_u \left(1 - \hat{A}_f\right) + \hat{\rho}_f\, \hat{A}_f\right]$$

$$\hat{A}_g = \frac{g_g}{g_{g,s}\, \hat{\rho}_g} \frac{\hat{\rho}_u \left(1 - \hat{A}_f\right) + \hat{\rho}_f\, \hat{A}_f}{1 + \dfrac{g_g\left(\hat{\rho}_u - \hat{\rho}_g\right)}{g_{g,s}\, \hat{\rho}_g}} \qquad (189)$$

With the greenfield peak demand densisty known ($\hat{A}_g$), the DSO's peak demand density ($\hat{\rho}$) and the share of its service territory that is undeveloped ($\hat{A}_u$) can then be computed using Equations (183 and (188 .

B.4 Substation Fleet Capacity Factors

As part of defining the DSO's revenue requirements and then setting retail rates for the DSO+T study's BAU and transactive cases, the study needs to estimate the capital cost invested in a DSO's existing substation fleet plus the annual rate of new capital investments in the fleet needed to meet growing peak demand. In the transactive cases the capital invested in the existing fleet and the rate of capital additions to it are both reduced by the use of the flexible transactive assets. To make these estimates, an analysis of the evolution DSO substation fleet's capacity over time is developed in this section.

Note that load growth in brownfield substations results in a slow increase in their average capacity sufficient to match the rate of brownfield peak demand growth. The number of brownfield substations only increases as new greenfield substations reach the end of their initial greenfield growth period and then become part of the general brownfield population.

In contrast, new greenfield substations are continually constructed at a rate needed to serve the expected growth in the DSO's greenfield peak demand. After their high greenfield growth period is complete, their status is converted to brownfield.

The quasi-steady analysis of the historical development of the substation fleet presented here makes simplifying assumptions that the DSO's growth rates (g_g and g_b), power factor at peak demand (PF_d), and substation design lifetime (Y_{design}) are all constant over time.

It further assumes that, although the capacity of individual substations varies, the growth and investment in the fleet can be represented by analyzing the brownfield and greenfield fleets' total capacities relative to the total peak demand they each serve, i.e., their fleet average capacity factors. Just as the lifecycle of an individual substation was represented in Figure 10 through Figure 13 in the previous section, these same diagrams can be interpreted as representing the distribution of the capacity factors of the substations in the fleet as a function of their age (within their current lifecycle), i.e., reinterpreting the x-axis as representing the years since any given substation was constructed or last upgraded.

In all cases the ages of the substations in a fleet are assumed to be uniformly distributed; that is, their average age is halfway through their lifecycle, including any extension to the lifecycle in transactive case brownfield substations. This implies that the effect of new (greenfield) substations being constructed and reclassified as brownfield once their greenfield growth period is over is assumed to have a negligible effect on the brownfield fleet's average age. (This does not affect the average ages of the undeveloped brownfield or greenfield fleets, only the fully developed brownfield fleet.) It is a minor effect in the absence of very high greenfield growth rates in DSOs that predominately serve undeveloped areas, where the existing brownfield substation fleet is relatively small and the addition of brownfield substations from reclassfied greenfield substations is significant. Explicitly accounting for this effect is left to future analysis.

With the assumptions discussed above, and the counterfactual peak demand served by the greenfield and brownfield fleets known in transactive cases, the average capacity factors of the brownfield and greenfield fleets can then be determined as follows.

B.4.1 Business-as-Usual Case Substation Fleets

In a BAU case, substation fleet ages are assumed to be uniformly distributed, ranging from zero to Y_{design} years, so their average age is ½ Y_{design} (halfway through their design life).

The corresponding capacity factors of the BAU case brownfield substations range from 1 – $MCap_b$ to one, and using Equation (219 , their average capacity factor $\overline{\hat{P}eaka_b}$ as BAU case peak demand grows exponentially is:

$$\overline{\hat{P}eaka_b} = \frac{1 - (1 - MCap_b)}{ln(1) - ln(1 - MCap_b)} = \frac{-MCap_b}{ln(1 - MCap_b)} \qquad (190)$$

The corresponding capacity factors of the BAU case greenfield substations range from (1 – $MCap_b$) ρ_u/ρ_f to 1 – $MCap_b$ (from Equations (175 and (171 , respectively), and using Equation (219 from Section B.6, their average capacity factor $\overline{\hat{P}eaka_g}$ as BAU case peak demand grows exponentially is:

$$\overline{\hat{P}eaka_g} = \frac{(1 - MCap_b) - (1 - MCap_b)\frac{\rho_u}{\rho_f}}{ln(1 - MCap_b) - ln\left((1 - MCap_b)\frac{\rho_u}{\rho_f}\right)}$$

which reduces to

$$\overline{\hat{P}eaka_g} = \frac{(1 - MCap_b)\left(1 - \frac{\rho_u}{\rho_f}\right)}{ln\left(\frac{\rho_f}{\rho_u}\right)} \qquad (191)$$

B.4.2 Transactive Case Brownfield Substation Fleet

In a transactive case brownfield substation fleet, let $Rtrx_b$ represent the average reduction in peak demand as a fraction of the counterfactual peak demand. Then the lifetime of brownfield substations is extended beyond their design lifetime Y_{design} by an average of $\Delta Ytrx_b$ years as their capacity factors continue to grow exponentially from one to 1/(1–$Rtrx_b$). Equation (216 can be used to express their average lifetime extension as:

$$\Delta Ytrx_b = \frac{ln\left(\frac{1}{1 - Rtrx_b}\right) - ln(1)}{ln(1 + g_b)} = -\frac{ln(1 - Rtrx_b)}{ln(1 + g_b)} \qquad (192)$$

The *effective* average lifetime of brownfield substations, $Ylife_b$, is then:

$$Ylife_b = Y_{design} + \Delta Ytrx_b = Y_{design} - \frac{ln(1 - Rtrx_b)}{ln(1 + g_b)} \qquad (193)$$

and their average age is:

$$Ylife_b = \frac{1}{2} Ylife_b = \frac{1}{2}\left(Y_{design} - \frac{ln(1 - Rtrx_b)}{ln(1 + g_b)}\right) \qquad (194)$$

The distribution of transactive case brownfield substation ages is assumed to remain uniform but now ranges from zero to $Ylife_b$, with an average of ½ $Ylife_b$.

The corresponding distribution of brownfield substation capacity factors remains uniform and still ranges from a low of 1 – $MCap_b$ for substations immediately after an upgrade or upon reclassification from greenfield. But, because of the capability to reduce peak demand, the capacity factors range above one to a maximum of 1/(1–$Rtrx_b$) for substations immediately prior to the next capacity investment, from Equation (166 . When undergoing exponential growth, the average capacity factor of the brownfield substation fleet, $\overline{\hat{P}eaka_b}$, can be found using Equation (219 from Section B.6:

$$\overline{\hat{P}eaka_b} = \frac{\frac{1}{1-Rtrx_b} - (1-MCap_b)}{ln\left(\frac{1}{1-Rtrx_b}\right) - ln(1-MCap_b)}$$

or, simplifying:

$$\overline{\hat{P}eaka_b} = \frac{(1-MCap_b) - \frac{1}{1-Rtrx_b}}{ln(1-Rtrx_b) + ln(1-MCap_b)} \qquad (195)$$

B.4.3 Transactive Case Greenfield Substation Fleet

Again, represent the average reduction in a DSO's greenfield substation's peak demand due to response of transactive flexible assets as a fraction of the counterfactual peak demand as $Rtrx_g$. (Note that in the study, only one substation was simulated per DSO, so $Rtrx_g = Rtrx_b = Rtrx_s$.) Then the capacity factor of each substation at the end of its design life can be determined as follows.

The distribution of transactive case greenfield substation ages is unchanged from the BAU case, ranging from zero to Y_{green} years, and their average age is ½ Y_{green}.

The distribution of transactive case greenfield substation capacity factors range over a lower bound expressed by Equation (182 for substations immediately after construction to an upper bound at end of the design lifetime at age Y_{green} expressed by Equation (179 . Given exponential growth at the rate $g_{s,d}$, the average capacity factor of the transactive case greenfield substation fleet, $\overline{\hat{P}eaka_g}$, can be expressed from Equation (219 of Section B.6 by substituting Equations (182 and (179 as:

$$\overline{\hat{P}eaka_g} = \frac{\frac{1-MCap_b}{1-Rtrx_g} - \frac{(1-MCap_b)\,\rho_u}{(1-Rtrx_g)\,\rho_f}}{ln\left(\frac{1-MCap_b}{1-Rtrx_g}\right) - ln\left(\frac{(1-MCap_b)\,\rho_u}{(1-Rtrx_g)\,\rho_f}\right)}$$

which reduces to:

$$\overline{\hat{P}eaka_g} = \frac{\frac{1-MCap_b}{1-Rtrx_g}\left(1 - \frac{\rho_u}{\rho_f}\right)}{ln\left(\frac{1-MCap_b}{1-Rtrx_g}\right) - ln\left(\frac{(1-MCap_b)}{(1-Rtrx_g)}\right) - \ln\left(\frac{\rho_u}{\rho_f}\right)}$$

or

$$\overline{\hat{P}eaka_g} = \frac{(1-MCap_b)\left(1 - \frac{\rho_u}{\rho_f}\right)}{(1-Rtrx_g)\,ln\left(\frac{\rho_f}{\rho_u}\right)} \qquad (196)$$

Since, by definition, the ratio of two BAU case peak demand densities is equal to the ratio of the corresponding normalized densities, Equation (196 can also be expressed as:

$$\overline{\hat{P}eaka_g} = \frac{(1 - MCap_b)\left(1 - \frac{\hat{\rho}_u}{\hat{\rho}_f}\right)}{\left(1 - Rtrx_g\right) ln\left(\frac{\hat{\rho}_f}{\hat{\rho}_u}\right)} \qquad (197)$$

B.4.4 Summary of Existing Substation Fleet Characteristics

For the above three situations, the age and capacity characteristics of the substation fleets are summarized in Table 38 for convenience. Relevant equation numbers are added in the lower right corner of the table's cells. Note that the equations for the mean substation fleet capacity factors for brownfield and greenfield transactive cases reduce to that of the corresponding BAU cases when the fractional reduction in the BAU case peak demand is zero. For service area of type x, from the definitions in the previous section for the normalized peak demand density ($\hat{\rho}_x$) and the share it represents of the DSO service territory ($\hat{A}_x$) at any given point in time, the land area of the DSO can be expressed in terms of the DSO's peak real-power demand as:

$$A_x = Peakr_d / \rho_x = Peakr_d / \left(\hat{\rho}_x \, \rho_f\right) \qquad (198)$$

the peak real-power demand for service area type x at that point in time, $Peak_x$, can be expressed as:

$$Peakr_x = \rho_x A_x = \left(\hat{\rho}_x \, \rho_f\right)\left(\hat{A}_x A\right) = \hat{\rho}_x \, \rho_f \, \hat{A}_x \, Peakr_d / \left(\hat{\rho} \, \rho_f\right) \qquad (199)$$

and the substation capacity (Cap_x) can be expressed as:

$$Cap_x = \frac{Peakr_x}{\overline{\hat{P}eaka_x} \, PF_d} = \frac{\hat{\rho}_x \, \hat{A}_x \, Peakr_d}{\overline{\hat{P}eaka_x} \, PF_d \, \hat{\rho}} \qquad (200)$$

where $\overline{\hat{P}eaka_x}$ is the average capacity factor of the substation fleet (as developed in the next section) and PF_d is the DSO's average power at the time of peak load.

The DSO total substation capacity in any point in time (Cap_d) can then be expressed as the sum of the capacities of the substation fleets in its service area types, $Cap_x(y)$:

$$Cap_d = Cap_u + Cap_g + Cap_f \qquad (201)$$

Table 38. Existing substation fleet characteristics.

Fleet Characteristic		Brownfield Substation Fleet		Greenfield Substation Fleet	
		BAU Case	Transactive Case	BAU Case	Transactive Case
Substation Ages (yr)	Newest	0	0	0	0
	Oldest	Y_{design}	$Y_{design} - \frac{ln(1 - Rtrx_b)}{ln(1 + g_b)}$ (193	Y_{green}	Y_{green}
	Mean	$½\, Y_{design}$	$½\left(Y_{design} - \frac{ln(1 - Rtrx_b)}{ln(1 + g_b)}\right)$ (194	$½\, Y_{green}$	$½\, Y_{green}$
Substation Fleet Capacity Factors (-)	Newest	$1 - MCap_b$	$1 - MCap_b$	$(1 - MCap_b)\,\frac{\rho_u}{\rho_f}$ (175	$\frac{(1 - MCap_b)\,\rho_u}{(1 - Rtrx_g)\,\rho_f}$ (182
	Oldest	1	$\frac{1}{1 - Rtrx_b}$	$1 - MCap_b$ (171	$\frac{1 - MCap_b}{1 - Rtrx_g}$ (179
	Mean	$\frac{-MCap_b}{ln(1 - MCap_b)}$ (190	$\frac{(1 - MCap_b) - \frac{1}{1 - Rtrx_b}}{ln(1 - Rtrx_b) + ln(1 - MCap_b)}$ (195	$\frac{(1 - MCap_b)\left(1 - \frac{\rho_u}{\rho_f}\right)}{ln\left(\frac{\rho_f}{\rho_u}\right)}$ (191	$\frac{(1 - MCap_b)\left(1 - \frac{\hat{\rho}_u}{\hat{\rho}_f}\right)}{(1 - Rtrx_g)\,ln\left(\frac{\hat{\rho}_f}{\hat{\rho}_u}\right)}$ (197

B.5 Capacity Growth Rates

The cost of a DSO's substation capacity has two components: the return on equity and debt service for 1) its existing capacity and 2) its annual rate of addition of capacity for new substations and upgrades to existing substations. At the time of the DSO+T analysis, the DSO is assumed to have reached equilibrium after its adoption of the DSO+T strategy. So, while its peak demand may be growing exponentially, the distribution of its substation fleets' capacity factors has also reached equilibrium, and hence the average substation fleet capacity factors described in the previous sections also remain constant. This section develops a description of the annual rate of construction of new capacity in a DSO's greenfield and brownfield substations.

B.5.1 Annual Brownfield Capacity Growth

Given the quasi-steady-state equilibrium assumption, the capacity factors of the developed and undeveloped substation fleets are constant, and so the annual capacity growth ($\dot{C}ap_x$) is equal to the growth in peak demand in each service area x divided by the brownfield fleet's average capacity factor. The rates of capacity addition are: (129)

$$\dot{C}ap_u = \frac{MAX\{0, g_b\}\, \rho_u\, A_u}{\overline{\hat{P}eaka_b}} = MAX\{0, g_b\}\, Cap_u \tag{202}$$

and

$$\dot{C}ap_f = \frac{MAX\{0, g_{b,d}\}\, \rho_f\, A_f}{\overline{\hat{P}eaka_b}} = MAX\{0, g_b\}\, Cap_f \tag{203}$$

for the undeveloped and developed service areas, respectively. Note that if the brownfield peak demand growth rate is negative, then no capacity is added to the fleet (but unused existing capacity is not subtracted from it either).

The annual rate of capacity added via upgrades to existing substations is then the sum of the rates for substations in the undeveloped and fully developed areas:

$$C\dot{a}p_{up} = \dot{C}ap_u + \dot{C}ap_f \tag{2b*}$$

B.5.2 Annual Greenfield Capacity Growth

As defined in this analysis, the DSO's construction of entirely new substations is represented within its greenfield service area at any given time. The fraction of its total service territory that is greenfield, $\hat{A}_g$, is known from Equation (189), and the duration of the greenfield transition is assumed to be Y_{green} years, so the annual rate that undeveloped brownfield service land area is being absorbed into the greenfield service area, $\dot{A}_g$, is:

$$\dot{A}_g = A_g / Y_{green} \tag{204}$$

Note that, given the quasi-steady-state equilibrium assumption, this is also equal to the annual rate at which the greenfield service area is reclassified as brownfield after the end of its period in greenfield transition after Y_{green} years.

Since the distributions of substation capacity factors are assumed to remain constant, the rate at which the DSO is constructing distribution capacity is equal to the DSO's rate of growth in BAU case peak demand, $\dot{P}eakr_d$. In turn, this rate of growth in new (greenfield) substation capacity is equal to the sum of the underlying brownfield growth rate that all substations undergo and the greenfield growth rate. The latter is the product of the rate of greenfield service area absorption and the difference between the fully developed and undeveloped BAU case peak demand densities, so:

$$\dot{P}eakr_g = g_b\,(\rho_f - \rho_u)\,A_g + \dot{A}_g\,(\rho_f - \rho_u)$$

$$\dot{P}eakr_g = (g_b\,A_g + \dot{A}_g)\,(\rho_f - \rho_u)$$

$$\dot{P}eakr_g = (g_{b,d}\,A_g + A_g/Y_{green})\,(\rho_f - \rho_u) = (g_{b,d} + 1/Y_{green})\,(\rho_f - \rho_u)\,A_g$$

or in terms of normalized peak demand densities and serice area shares:

$$\dot{P}eakr_g = (g_{b,d} + 1/Y_{green})\,(\hat{\rho}_f - \hat{\rho}_u)\,\rho_f\,\hat{A}_g\,A$$

and substuting Equation (198 for the land area DSO's service territory (A):

$$\begin{aligned}\dot{P}eakr_g &= (g_{b,d} + 1/Y_{green})\,(\hat{\rho}_f - \hat{\rho}_u)\,\rho_f\,\hat{A}_g\;Peakr_d\,/\,(\hat{\rho}_g\,\rho_f)\\ &= (g_{b,d} + 1/Y_{green})\,(\hat{\rho}_f - \hat{\rho}_u)\,\hat{A}_g\;Peakr_d\,/\,\hat{\rho}_g\end{aligned} \qquad (205)$$

Then, given that the greenfield substations reclassified as brownfield have capacity factor at the time they are reclassified, as indicated in Equation (179 , the annual growth in the greenfield substation fleet's capacity is equal to the net annual capacity reclassified:

$$\begin{aligned}\dot{C}ap_g &= \frac{\dot{P}eakr_g\,(1 - Rtrx_g)}{(1 - MCap_b)\,PF_d}\\ &= \frac{(g_{b,d} + 1/Y_{green})\,(\hat{\rho}_f - \hat{\rho}_u)\,\hat{A}_g\,Peakr_d\,(1 - Rtrx_g)}{(1 - MCap_b)\,PF_d\,\hat{\rho}_g}\end{aligned} \qquad (206)$$

B.6 Equations Describing Exponential Growth

B.6.1 Integral of Exponential Growth Equation (known interval and growth rate)

Let a function A(y) that represents the growth of a quantity A in year 0 at rate exponential rate g over the subsequent years y be represented as:

$$A(y) = A_0\,(1 + g)^y \qquad (207)$$

Then the sum of A(y) from Year 0 to any year y, SumA(y), is:

$$SumA(y) = \int_0^y A_0\,(1 + g)^y\;\delta y \qquad (208)$$

Let b = 1 + g, then:

$$SumA(y) = \int_0^y A_0\,(b)^y\;\delta y \qquad (209)$$

which has the well-known general solution:

$$SumA(y) \;=\; \int_0^y A_0\,(b)^y\;\delta y \;=\; \frac{A_0\,b^y}{ln\,b} \;+\; C \tag{210}$$

and where the constant C is determined to satisfy the boundary condition that the sum of f(y) is equal to zero when y is zero, so:

$$SumA(y) \;=\; 0 \;=\; \frac{A_0\,b^0}{ln\,b} \;+\; C \;=\; \frac{A_0}{ln\,b} \;+\; C \tag{211}$$

Solving Equation (211 for the constant C:

$$C \;=\; -\frac{A_0}{ln\,b} \tag{212}$$

and substituting the result and b = 1 + g into Equation (211 gives the expression for the sum of the exponential growth in quantity A(y) over Y_n years:

$$SumA(Y_n) \;=\; \int_0^{Y_n} A_0\,b^y\,\delta y \;=\; \frac{A_0\,(1+g)^{Y_n}}{ln(1+g)} - \frac{A_0}{ln(1+g)} \;=\; A_0\,\frac{(1+g)^{Y_n}\;-\;1}{ln(1+g)} \tag{213}$$

The average of A(y) over Y_n years is then simply SumA(Y_n) divided by Y_n or:

$$AvgA(Y_n) \;=\; \frac{SumA(Y_n)}{Y_n} \;=\; \frac{A_0}{Y_n}\,\frac{(1+g)^{Y_n}\;-\;1}{ln(1+g)} \tag{214}$$

B.6.2 Years of Exponential Growth to Result in a Known Future Quantity

From Equation (207 the number of years Y_n required for exponentially growing quantity A(y) to grow from A_0 to Ay_n is expressed by:

$$A(Y_n) \;=\; A_{Y_n} \;=\; A_0\,(1\;+\;g)^{Y_n} \tag{215}$$

Solving for the required number of years, Y_n:

$$A_{Y_n}/A_0 \;=\; (1\;+\;g)^{Y_n}$$

$$ln\big(A_{Y_n}/A_0\big) \;=\; Y_n\;\ln(1+g)$$

$$Y_n \;=\; \frac{ln\big(A_{Y_n}\big)\;-\;ln(A_0)}{ln(1\;+\;g)} \tag{216}$$

B.6.3 Exponential Growth Rate to Result in Known Future Quantity

From Equation (207 the exponential growth rate g required for exponentially growing quantity A(y) to grow from A_0 to Ay_n in Y_n years is expressed by:

$$A(Y_n) \;=\; A_{Y_n} \;=\; A_0\,(1\;+\;g)^{Y_n} \tag{217}$$

Solving for the required growth rate, g:

$$A_{Y_n}/A_0 \;=\; (1\;+\;g)^{Y_n}$$

$$A_{Y_n}/A_0 \;=\; (1 \;+\; g)^{Y_n}$$

$$\left(A_{Y_n}/A_0\right)^{1/Y_n} \;=\; (1 \;+\; g)$$

$$g \;=\; \left(A_{Y_n}/A_0\right)^{1/Y_n} \;-\; 1 \qquad (218)$$

B.6.4 Integral of Exponential Growth Equation (known initial and final conditions)

If the initial and final values of A(y) growing at an exponential rate g for Y_n years are known (A_0 and Ay_n, respectively), then substituting the expression for growth rate in Equation (218 in Equation (214 , the average of A(y) is:

$$AvgA(Y_n) \;=\; \frac{A_0}{Y_n}\,\frac{(1+g)^{Y_n} \;-\; 1}{ln(1+g)} \;=\; \frac{A_0}{Y_n}\,\frac{\left(\left(A_{Y_n}/A_0\right)^{1/Y_n}\right)^{Y_n} \;-\; 1}{ln\left(\left(A_{Y_n}/A_0\right)^{1/Y_n}\right)}$$

or, simplifying:

$$AvgA(Y_n) \;=\; \frac{A_0}{Y_n}\,\frac{A_{Y_n}/A_0 \;-\; 1}{1/Y_n\, ln\left(A_{Y_n}/A_0\right)} \;=\; A_0\,\frac{A_{Y_n}/A_0 \;-\; 1}{ln\left(A_{Y_n}/A_0\right)}$$

and then:

$$AvgA(Y_n) \;=\; \frac{A_{Y_n} - A_0}{ln\left(A_{Y_n}\right) \;-\; ln(A_0)} \qquad (219)$$

So, the sum of A(y) is then simply the product of the time interval and the average of A(y) over the interval:

$$SumA(Y_n) \;=\; Y_n\, AvgA(Y_n) \;=\; Y_n\,\frac{A_{Y_n} - A_0}{ln\left(A_{Y_n}\right) \;-\; ln(A_0)} \qquad (220)$$

Note that when the initial and final conditions for an exponential growing quantity A(y) are known, the sum and average over the interval are not a function of the growth rate or time interval, rather they are solely a function of these conditions.

Appendix C – Team Line Management Algorithm

This appendix describes a simple algorithm used by the DSO+T study for estimating the number and cost of line managers needed for supervising a team consisting of a given number of base team members. It does this based on the size of the team's base layer workers and their average salary, and a salary escalation factor that defines the escalating ratio of the salaries of each successive management layer to that of the previous layer. It then uses a hierarchical algorithm to estimate the number of management layers and cost of each layer of management associated with the team.

In the process it estimates the following dimensionless characteristics of a team:

- The ratio of total number of team members to the number of base-level team members
- The ratio of the total team cost to that of the base layer of the team
- The ratio of cost of the team leader to the average cost of the base layer team members
- The total number of layers in the team.

In the description of the algorithm that follows, the base (worker) layer of the team defined as Level 1 and each succeeding management layer is defined as a unit increment in level from that of previous layer.

The team's line management algorithm is calibrated to produce reasonable results for an entire utility organization with as many as 24,000 base-level employees, requiring up to six total layers. Calibration of the model involves defining the minimum and maximum number of direct reports for managers in each management layer and selecting a salary escalation factor that produces reasonable CEO and C-level executive salaries for utilities as a function of their size (number of customers) and, hence, their number of employees. Reasonable results were achieved by assuming a salary escalation factor of 1.3 as shown in Table 39.

Table 39. TEAMS model direct report assumptions and results.

Level	Max. Direct Reports	Min. Direct Reports	FTE	FTE Ratio to Previous Level	FTE Ratio to Level 1, Cum.	Salary Escalation Ratio to Previous Level	Salary Escalation Ratio to Level 1	Cost Ratio to Level 1, Cum.
1			24,000	-	-	-	1.00	1.00
2	10	5	2,400	0.10	1.10	1.30	1.30	1.13
3	8	5	300	0.13	1.11	1.69	2.20	1.16
4	8	5	38	0.13	1.11	2.20	4.83	1.17
5	8	5	5	0.13	1.11	2.86	13.79	1.17
6	6	5	1	0.20	1.11	3.71	51.19	1.17
Total			26,744		1.11			1.17

Note that the number of direct reports is assumed to decrease with level as organizations get very large.

The number of full-time equivalent (FTE) employees at any level in Table 39 is simply the number of FTEs at the previous level divided by the number of maximum direct reports:

$$FTE_N = FTE_{N-1} \,/\, MaxDirectReports_N \quad (221)$$

The FTE ratio between any two levels N and N-1 in Table 39 is simply the ratio of the FTEs at that level to that of the previous level:

$$FteRatio_N = FTE_N \, / \, FTE_{N-1} \tag{222}$$

The FTE ratio cumulative to level 1 at any level in Table 39 is simply the ratio of the FTEs at that level plus to all lower levels to that of Level 1:

$$FteRatioCum_N = \frac{1}{FTE_1} \sum_{n=1}^{N} FTE_n \tag{223}$$

The salary escalation ratio between any two levels N and N-1 in Table 39 is related to the salary escalation factor, as follows:

$$SalaryEscRatio_N = SalaryEscFactor^{N-1} \tag{224}$$

The salary escalation ratio between a level N and level 1 in Table 39 is then computed recursively from the salary escalation ratio of the previous level as follows:

$$SalaryEscRatio_{N\ to\ 1} = SalaryEscRatio_N \; SalaryEscRatio_{N-1\ to\ 1} \tag{225}$$

Finally, the cost ratio cumulative to level 1 at any level N is the ratio of the cumulative cost of the team up to that level to that of the base-level team in Table 39, i.e., the management overhead, is:

$$CostRatio_N = \frac{1}{FTE_1} \sum_{n=1}^{N} FTE_n \; SalaryEscRatio_{n\ to\ 1} \tag{226}$$

Appendix D – Calibrating the DSO Employee Model to Total Utility Employees

The DSO+T study developed a simple model of the total number of employees a utility has overall as the initial step in developing the DSO employees model it uses to estimate labor and workspace costs. As a basis for this, the number of employees in a sample of 11 utilities spanning the range of utility sizes in the U.S., nine of them from Texas, was tabulated along with the number of customers served and other characteristics as shown in Table 40. The number of employees a utility has is not readily available in any standard or centralized form, nor is it universally made available. It was gleaned from internet searches for utility summary overviews and quick facts, often posted in the form of flyers or presentations. The number of customers is sometimes expressed as number of members (in rural cooperatives) or number of meters, and in these cases were treated as equal to the number of customers.

From this data, the number of employees per thousand electricity customers (the employee ratio) was computed, also shown in Table 40. It is seen to vary across utilities by a factor of almost four, so using a simple average is not properly representative. Many of the utilities also sell natural gas, so clearly this must be taken into account. For example, this helps bring the employee ratio for CenterPoint in line with that of Oncor, but they are then both outliers at the very low end of the distribution of employee ratios. So, accounting for natural gas customers by itself is insufficient.

Other characteristics were then gathered that help explain the scope of a utility and hence its employee ratio, as shown in the rightmost columns in Table 40. The columns labeled AMR and AMI are the fractions of the utility's electricity customers that have automated meter reading (driveby meter readings) and fully AMI networks. In ERCOT, customers of investor-owned utilities have undergone retail deregulation that divests them of their retail functions aside from responsibility for metering. A value of one in the retail electricity column indicates this. The gas ratio is the fraction of the total customers that are also gas customers, and transmission ratio is the ratio of miles of transmission lines owned and operated to the miles of distribution lines.

To determine how these characteristics collectively drive the employee ratios, a sequence of multivariate linear regression models were developed and tested. Beginning by including all five of the variables defining the scope of a utility, variables with low explanatory power (T-statistics less than 2.0) were sequentially eliminated. Variables without sufficient explanatory power and therefore excluded were AMR, AMI, and the transmission ratio. The final employee ratio model is of the form

$$EmployeeRatio = b + m_1\, Retail + m_2\, GasRatio \qquad (227)$$

Table 40. Utility employees for various utilities.

Utility	Customers			Employees		Scope of Utility				
	Electricity	Gas	Total	Total	Per 1000 Electricity Customers	AMR	AMI	Retail Elec.	Gas Ratio	Trans. Ratio
Pacific Gas & Electric	5,400,000	4,300,000	9,700,000	24,000	4.44	0.00	1.00	1	0.44	0.15
Oncor	3,600,000		3,600,000	4,165	1.16	0.00	1.00	0	0.00	0.13
CenterPoint Energy	2,403,340	3,439,344	5,842,684	7,977	3.32	0.00	1.00	0	0.59	0.07
CPS Energy	840,750	352,585	1,193,335	3,100	3.69	0.33	0.54	1	0.30	0.10
Austin Energy	461,343		461,343	1,700	3.68	0.00	1.00	1	0.00	0.05
Entergy Texas	461,000		461,000	1,085	2.35	0.04	0.00	1	0.00	0.17
Perdenales Electric Co-op	332,261		332,261	857	2.58	1.00	0.00	1	0.00	0.00
Bluebonnet Electric Co-op	104,683		104,683	280	2.67	1.00	0.00	1	0.00	0.00
Benton PUD	54,136		54,136	149	2.75	0.00	1.00	1	0.00	0.05
Bandera Electric Co-op	35,452		35,452	110	3.10	0.00	1.00	1	0.00	0.00
Bailey County Electric Co-op	1,800		1,800	5	2.83	0.20	0.00	1	0.00	0.00

The final employee ratio model is described in Table 41. The statistics describing the results of the model, an r-squared of 0.84 and a standard error of the estimate of 0.38, indicate the model is a good predictor of the employee ratio. A plot of predicted vs. actual employee ratios is shown in Figure 14. Since the DSO's in the study are assumed to only supply electricity, the gas ratio term will be ignored.

Table 41. Employee ratio model: total utility employees per 1000 customers.

Variable	Coefficient		Std. Error	T-Statistic	r^2	Std. Error of Estimate
	Name	Value				
Constant	b	1.21	0.32	3.73	0.84	0.38
Retail	m_1	1.63	0.32	5.01		
GasRatio	m_2	3.50	0.61	5.78		

The model provides two important control total benchmarks for a more detailed breakdown of employees by job classification. First, the coefficient of the retail term (m_1) represents the number of employees associated with the retail operations of a DSO. Second, the value of the constant (b) represents the remainder of employees, associated with engineering operations. Both these control totals include their share of the general burdens of management and administration. For lack of better information, the valuation assumes they share these burdens equally in proportion to their number of employees. So, the retail functions are assumed to bear 57% of these costs. The breakdown of the number of employees by job classification that follows maintains strict adherence to these control totals.

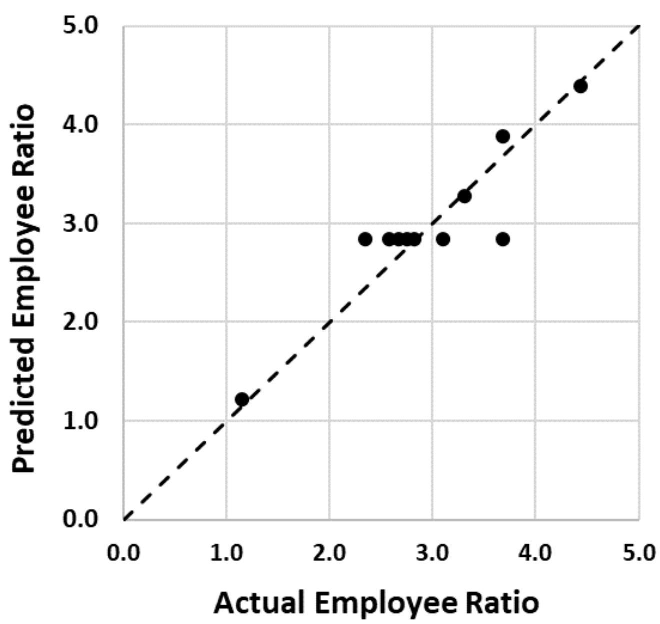

Figure 14. Predicted vs. Actual Employee Ratios

Even though there is significant uncertainty around the values of any of the individual team models, in aggregate they exactly match the control totals for engineering and retail operations developed by modeling the total number of employees in actual utilities as discussed above. This is demonstrated in Table 42, where the coefficients of the models for the teams are aggregated to form these control totals.

Table 42. Verification of employee model control totals for BAU case.

Organizational Level	Constant a	Per 1K Cust. b	(Per 1K Cust.)$^{1/2}$ c	Per Sub. d
Utility Total	3.1	2.836	0.000	0
Administration and Business Labor	1.1	0.072	2.054	0
Engineering Operations Labor (incl. COO)	2.0	1.177	-0.874	0
Retail Operations Labor (incl. CRO)	0.0	1.587	-1.180	0
Engineering Control Total	2.5	1.207	0.000	0
43% Engineering Ops. Share of Admin and Business	0.5	0.031	0.874	0
Engineering Operations Labor (incl. COO)	2.0	1.177	-0.874	0
Retail Control Total	0.6	1.628	0.000	0
57% Retail Operations Share of Admin and Business	0.6	0.041	1.179	0
Retail Operations Labor (incl. CRO)	0.0	1.587	-1.180	0

Note that since the coefficients represent the number of base-level employees on each sub-team, the coefficients (other than the constant) must be multiplied by their TeamFactors when aggregating:

$$AggregatedCoefficient_i = \sum_{t=1}^{T} Coefficent_i(t)\ TeamFactor \tag{228}$$

where: AggregatedCoefficient$_i$ ≡ aggregated coefficient i over a set of sub-teams

Coefficient$_i$ ≡ coefficient i of a sub-team's employee model

i ≡ coefficient being aggregated (i.e., from a column in Table 17)

t ≡ index indicating the sub-team

T ≡ number of sub-teams being aggregated

TeamFactor ≡ ratio of total team employees to base-level team employees

For the assumptions used in the DSO+T study, the TeamFactor is 1.11 for teams of a hundred or more employees. This value is used here as a constant for the purpose of calibrating the DSO employee model to the control totals.

Appendix E – Presumed Rate Design Policy for DSO+T

Ratemaking under a DSO+T strategy is presumably based on some fundamental assumptions about policy on the part of regulators as follows:

1. Adoption of the DSO+T strategy should be good for consumers on average: the DSO's net revenue requirements will decrease enough to offer slightly lower fixed-rate prices to nonparticipants and substantial reductions in participant electric bills that cover their flexible asset costs plus recompence for any inconvenience or costs caused by their responses.
2. The combined (sometimes conflicting) interests of fairness, simplicity, and transparency are best served by using dynamic rates and a retail market design, rather than pay-for-performance approaches, to reward valuable customer responses.
3. As in fixed-price ratemaking, DSO+T ratemaking must recover revenue via transactive customer bills that, combined with those from remaining fixed-price customers, is designed to equal the DSO's fixed and variable costs, including a regulated rate of return on capital infrastructure investments for investor-owned DSOs.
4. Customers who choose to migrate to transactive rates but do not participate by responding to them should pay no more (on average) on their electric bill than they would in the BAU case.
5. On aggregate, customers who choose not to migrate to transactive rates should pay no more on their bills than they would in the BAU case, and preferably slightly less (1% for example); see discussion below.
6. Customers on transactive rates should 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). This does not include expenditures for their DERs; that is examined by the study when overall cost-effectiveness is evaluated.
7. A desired outcome is that transactive ratemaking as embodied by the DSO's retail markets and transactive rates should result in a simpler, more transparent, and more accurate representation of actual DSO costs across customer classes.
8. All substations in a DSO should have the same rate design, whether congested or not, in order to maintain equity between customers on congested and uncongested substations while socializing needed and cost-effective distribution capacity investments across all DSO customers.

Policies 1 and 2 are the major drivers for the transactive rate structure. To a considerable extent, policies 3 through 8 reflect corollaries or implementation details driven by policies 1 and 2. Each of the policies are discussed in more detail, below.

Policy 1: Adoption of the DSO+T strategy should be good for consumers on average. The regulators that approved adoption of the DSO+T strategy were presumably convinced that it would be good for electricity customers in general, on average.[36] If this hypothesis is true, it implies that the DSO's revenue requirements will decrease enough, due to reduced need for capital infrastructure and reduced wholesale costs, to:

- Cover the DSO's increased costs for implementing transactive retail markets and communications systems. There is an implication here that a large fraction of customers switch from fixed-price to transactive rates. This is because these DSO+T implementation costs are, to a considerable degree, constant regardless of the number of participants. These investment hurdles would never be overcome by the resulting benefits if only a few customers adopted transactive rates and actively participated. In turn, this implies that the rewards for participation must be high enough to attract participants (see next bullet).
- Reward participating customers with savings on their bills that more than cover consumer costs for flexible asset implementation and provide acceptable recompence to consumers for any inconvenience caused. Sufficient savings for most customers to cover first and maintenance costs for batteries, plus a reasonable return on the invested capital, is required if the transactive battery case is to prove viable.[37] For flexible loads, in addition to return on investment for communicating controls, customers must also be rewarded for any inconvenience caused by shifting load, particularly any loss of comfort or amenity which is very difficult to measure. However, because customer response to transactive prices is entirely voluntary, it is reasonable to assume customers receive sufficient reward for any inconvenience, at least over the long run. Otherwise, they would simply stop responding and likely return to a fixed-price rate.
- Offer the same fixed-rate prices to nonparticipants than in the corresponding BAU case, or perhaps slightly lower rates as a reward for allowing the DSO+T policy to go forward. This is difficult to guarantee since the infrastructure that would have existed in the absence of the DSO+T strategy (i.e., the baseline infrastructure) can only be hypothesized analytically. A simple means of assuring this policy objective is met is to design fixed rates under the DSO+T strategy based on the actual infrastructure that exists, and not include costs for transactive retail markets and communications systems. The equity of such a policy vis a vis the transactive participants is a foundational question that will be examined by the DSO+T study. This is further articulated in policy 5.

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[36] It is difficult to guarantee that outcome for individual customers, however, since some have more advantageous (flatter) load shapes to begin with and will see some savings even without any response, while those that have "peakier" than average load shapes will see some increase in their bills even without response. Presumably, the latter group has more potential to save from providing flexibility, which tends to mitigate this issue. It also can be argued that this is in fact a fairer representation of their relative impacts on the system, i.e., that in the BAU case customers with inherently flatter load shapes are subsidizing those with peakier load shapes with today's fixed-price rates. However, any perceived risk on the part of potential participants will reduce penetration of transactive rates, so it may be desirable to address this issue in other ways. One approach can be a simple guarantee that participating customers whose bill would be less when computed based on a fixed-price rate will only be billed for that amount, at most. The DSO+T study will not implement this mechanism but will examine the issue instead.

[37] This cannot be guaranteed for individual customers, who may not recover their investment if they do not offer much response. The hypothesis is that most customers will more than recover these costs, far more than just 50% of customers (for example). The degree to which this is true and how it varies by the level of flexibility offered are a key focus of the study.

Testing the regulatory hypothesis and implications posed by Policy 1 is a fundamental reason for conducting the study.

Policy 2: Real-time prices with local retail markets are preferable to pay-for-performance approaches. Policy 2 states that, in the interests of fairness, simplicity, and transparency, the preferred approach used to implement the retail transactions in the DSO+T strategy is to use dynamic rates and a retail market design rather pay-for-performance approaches.

In principle, transactive mechanisms can be envisioned that pay directly for beneficial reductions in net load during times of congestion or high prices based on the actual local value of such reductions. For batteries or other flexible assets that produce or store energy and whose energy input and output can be metered as a function of time (at the cost of a separate meter), appropriate and fair credits and debits to a customer's bill for providing such services can be explicitly computed based on the relative value of the load reductions compared to the cost of additional consumption (if any) at other times.

Unfortunately, the same is not true for flexible loads in pay-for-performance approaches, since a reduction (or increase) in load at any point in time can only be inferred by comparing the actual (metered) consumption for the load to a hypothetical baseline of the time-series energy consumption that would have transpired if the load had not responded to transactively signaled opportunities (i.e., a customer's counterfactual). Several such methods have been used by wholesale market operators to pay aggregators for load reductions, for example. However, it is very difficult for such methods to be simultaneously accurate and transparent.

Simple methods suffer from inaccuracy under various conditions that result in over or under rewarding customers for response. These typically depend on the availability of data from long periods of time without any customer response. In a population of transactive customers fully engaged in maximizing their savings by providing flexibility in response to a number of asynchronous value streams, such quiescent periods with no response become increasingly rare. Over rewarding customer response taxes the benefits obtained by the DSO and is therefore unfair to nonparticipants (see policy 4). Under rewarding is unfair to participants (see policy 6) and may prevent them from recovering their investment in flexible, making the DSO+T strategy not cost effective (see policy 1).

More accurate methods can be developed and utilized, but these are technically complex since they need to control for the effects of weather, building usage schedule (time of day, day of week) and energy usage intensity for nonresponsive loads, specific physical characteristics and control strategies of the loads involved, and the sequence of recent responses. These typically depend on the availability of data from long periods of time without any response to make such adjustments based on developing a physical or quasi-physical model of the responsive load involved. In a population of transactive customers fully engaged in maximizing their savings by providing flexibility in response to multiple asynchronous value streams, such quiescent periods with no response become increasingly rare and certainly customer specific. Further, such methods require detailed information that is properly thought of by customers as sensitive, so maintaining customer privacy likely requires such methods to be executed within the customer premises. This complicates the ability of a DSO to offer and maintain such models, and to satisfactorily verify their degree of accuracy. Most importantly, such technically complex methods almost totally lack transparency to nonexpert customers. Policy 7 makes explicit the desire for transparency in the DSO+T rate structure.

The alternative and mechanism of choice for the DSO+T study is to design a real-time dynamic rate that has fidelity to actual costs of customer energy use at any given time and locale. Then the DSO is indifferent to how much customers respond and customers are free to maximize their savings considering constraints on comfort and amenity as they see fit and without the need to reveal how such decisions are made. No baseline consumption pattern or counterfactual is required. The ratemaking process involved requires knowledge of utility cost structures but is simpler than accurate baselining methods and can be completely transparent to regulators acting in customer interests.

Policy 3: DSO revenue must recover costs (and regulated rate of return on investment for investor-owned DSOs). This policy is assumed to be unchanged relative to current practice. It implies that the market operator and LSE functions of the DSO are indifferent to customer participation levels. The distribution system owner/operator's costs are also completely covered. However, the DSO (or an unbundled owner/operator) will presumably receive reduced return on capital investment payments in absolute terms, but not in terms of percentage rate of return (of their total capital investment), due to the reduced basis of capital investment in infrastructure resulting from the DSO+T strategy. This implies but does not require regulators authorizing implementation of a DSO+T strategy to simultaneously consider a transition to performance-based ratemaking in lieu of today's rate of return-based ratemaking, so that the DSO (or the owner/operator entity if the DSO is eventually unbundled) is similarly made indifferent to the DSO+T transformation. Note this is not an issue for public power suppliers such as municipal utilities or rural cooperatives who do not receive such a rate of return.

Policy 4: Revenue neutrality for transactive rates. The principle behind this policy is that the revenue recovered via the pool of transactive customer bills should be same as under a fixed rate, if the pool of customers who signed up for the transactive rate did not subsequently chose to respond to it. This requirement is referred to in the DSO+T study as revenue neutrality. If the transactive rate produced higher revenue, the DSO would have an immediate revenue windfall from the pool of fixed-price customers switching to transactive rates. From the point of view of the regulators, this would give the DSO a perverse incentive to get customers to switch, beyond customer self-interest. It also forms an immediate hurdle that customers must overcome before they begin to produce net savings on their bills by responding to transactive signals. Customers would be reluctant to switch to the transactive rate not knowing in advance how much valuable operational flexibility they will end up providing, and therefore how much savings would result on their bills.

The converse is equally problematic in that the DSO would immediately lose revenue as customers switch to the transactive rate, without any guarantee of commensurate savings in its costs without *a priori* knowledge of how much customers will respond.

In principle, policy 3 should also apply to each customer class—e.g., residential, commercial, and industrial—but also (for example) customers who use electric heat in the winter and receive a discount due to declining block rates in the BAU case. In practice, ensuring this may require a more sophisticated, iterative ratemaking process than implemented in the study. This could be the subject for future research based on simulation results. Nonetheless, the resulting impacts on customer classes and subclasses are a fundamental and important result of the study, and some effort may be applied in the course of the ratemaking analysis to achieve better results in this regard.

Policy 5: Equitable share of savings for fixed-price customers. The fundamental question around this policy is: what is an equitable share of the benefits from implanting the DSO+T strategy that should go to nonparticipating customers, if any, given that there was some risk that it would fail and their rates would then increase due to the increased costs of implementation? If that share is non-zero, then some of the impacts derived from the behavior of the transactive customers is diverted from them to the nonparticipants. In turn, the impact on the participants is a direct function of the relative size of the two groups of customers—the fewer nonparticipants there are, the less any sharing of impacts with nonparticipants by participants affects their bills. This may imply that an equitable solution involves some phased transition reducing the sharing over time, but that is complicated by the fact that, as the fraction of participants grows over time, the same time the risk associated with the transition to DSO+T is dropping.

Policy 6: Electric bill savings for transactive customers in proportion to the benefits each provides. That portion of the cost savings resulting from DSO+T implementation should be as close to 100% as possible consistent with meeting the constraint in policy 1 of recovering the DSO's required revenue and the need expressed in policy 5 to provide some small savings to fixed-price customers for their adoption risk and to cover any increased costs associated with implementing the DSO's retail markets. Assuming a reasonable adoption/participation rate, presumably the DSO will realize cost savings sufficient to implement transactive retail market operations and the associated communications network. To encourage large-scale customer participation, the remaining savings should be returned to the participants by the transactive rate design as implemented in the retail energy markets.

Further, the remainder of the cost impacts should be allocated equitably across customers in proportion to the relative impacts each customer's response provides. This, in turn, is highly dependent on the transactive rate structure, the retail market design, and the ratemaking process itself. It is particularly helpful if the rate structure and rate design reflect actual utility costs of serving a customer's load (see policy 7 discussion). Examining the equity of the rewards or losses each customer receives in the form of impacts on their bills is a fundamental goal of the study. While complete equity may not be achieved, the goal in this regard is to point out the key issues that need to be addressed by future transactive ratemaking processes.

Policy 7: Transactive rates should provide a simpler and more accurate representation of actual DSO costs than BAU. This is both a goal for DSO+T ratemaking and a testable hypothesis. Transactive retail markets and rates can be designed to reflect actual DSO costs imposed by customer behavior and consumption patterns, as the rate attempts to do. In principle, they may also provide a simpler representation of cost impacts for high-volume customers with electric space heat, for example. These customers should benefit from generally lower than average wholesale prices during winter, particularly in nighttime hours. This is simpler than defining a volumetric discount in the form of a declining block into a fixed-price rate and more accurately passes through the DSO's actual savings through to such customers.

The same may be true for the industrial customer class due to its flatter load shape because the dynamic transactive rate absorbs the BAU case's peak demand charge. This may be appropriate because the transactive prices are, in part, proportional to wholesale costs, so they provide an inherent price signal to customers that their demand during peak-load periods impute costs for infrastructure. This may be simpler and fairer than today's noncoincident peak demand charges, in which the timing of the customer's peak demand with respect to the DSO's or substation's peak load is not taken into account.

Policy 8: All substations in a DSO should have the same rate design, whether congested or not. Substations in a DSO should have the same rate design to maintain equity between customers while socializing needed distribution capacity investments across all DSO customers. A corollary to this policy is that all transactive customers in a DSO (customer class) should be subject to a uniform rate design, meaning there should not be separate designs for individual substations that, for example, vary with the substation's level of congestion. This is an important area for policy debate that requires some explanation of potential social policy directions.

The DSO's substations were not constructed in the same year nor subject to the same pattern of load growth. Some may have received capacity upgrades as a result of that growth so each substation will be at a different stage in its lifecycle, i.e., have different peak loads as a fraction of its rated capacity. In the BAU case simulations, this is assumed to always be less than 1.0, because otherwise an upgrade would have occurred. In the study's transactive cases, the gross peak load will have been allowed to continue to grow to some extent, since the transactive DERs can be motivated to reduce the net load on the substation during congested periods by 10% (for example). Eventually it becomes too expensive to continue to manage the congestion using the DERs and the substation is upgraded.

Thus, in a DSO executing a DSO+T strategy, some substations will be overloaded to varying degrees and others will not be overloaded. In the transactive retail markets and rate structure, retail prices are allowed to rise during local congestion events to the level needed to incentivize transactive DERs to provide the needed reduction in net load. However, in the absence of a compensatory mechanism, this implies that transactive customers on congested substations will see their electric bills go up relative to their peers on uncongested substations. Ironically, these are exactly the customers to whom the DSO needs to be the most responsive! This violates the revenue neutrality required by policy 3 by creating a savings hurdle that penalizes these participants.

Further, it implies that customers on congested substations will pay for the load growth on the substation, regardless of whether they contribute to it as it as individuals or it is caused by a big new customer or subdivision. Doing so would overturn the historical policy that the burdens (and benefits) of load growth should be borne by all customers on behalf of society as a whole.

One obvious way around this dilemma in the real world would be to have *a priori* knowledge of how many days and hours in an average year will be congested and to what degree, based on experience from previous years. The transactive ratemaking process would then account for this additional revenue collection and other components of the rate would be reduced accordingly to keep it revenue neutral in accordance with policy 4. However, this would result in a rate design that is specific to each individual substation and would have to be updated continually as load growth ensues.

Appendix F – Transactive Rate Retail Multiplier

This appendix describes how the retail multiplier is determined as part of the transactive ratemaking procedure, which provides the basis for Equations (45) through (51) in Section 4.3.2.2.

The first term of Equation (44) is intended to reflect the DSO's total wholesale energy costs, i.e., wholesale market costs and costs for reserves and losses, if it purchased all its energy in the day-ahead market. This is because, as stated above, the transactive rate is constructed using the wholesale day-ahead market costs as a benchmark for the variable costs other than the DSO's own congestion costs (which are represented in the second term). Note that this excludes capacity costs, which are intended to be represented by the second congestion-related term of Equation (44).

To facilitate development of an expression for the annual wholesale costs, define the study's simulated DSO total customer demand from the bulk power system for any hour of the year h as the sum of its industrial sector load plus the product of the DSO's weighting factor and the sum of the hourly loads consumed by each of its simulated customers (residential and commercial).[38]

$$Qdmd_h \equiv Qind_h + WF_{dso} \sum_{c=1}^{N_c} Qcust_h(c) \qquad (229)$$

where: $Qdmnd_h$ ≡ energy demand from DSO customers in hour of the year h

$Qind_h$ ≡ energy consumed by DSO industrial sector in hour of the year h

$Qcust_h(c)$ ≡ energy consumed by DSO customer c in hour h of the year

WF_{dso} ≡ the DSO's weighting factor scaling its simulated residential and commercial customers to the DSO's actual totals

(c) ≡ indicates value is for customer c

N_c ≡ number of DSO residential and commercial customers simulated

In addition, the total energy supplied to the DSO from the bulk power includes the energy losses in its distribution system:

$$Qdso_h = (1 + Fdloss_h)\, Qdmd_h \qquad (230)$$

where: $Qdso_h$ ≡ energy supplied to DSO by bulk power system in hour of the year h

$Fdloss_h$ ≡ distribution losses as a fraction of energy supplied in hour of year h

Losses are not a constant fraction of the total energy consumed, but for purposes of transactive ratemaking they can be reasonably approximated by the annual average fractional losses, so:

$$Qdso_h \cong (1 + \bar{F}dloss_A)\, Qdmd_h \qquad (231)$$

[38] This is because, the ratemaking process assumes all customers are assumed to be on the subject rate plan.

where: $\bar{F}dloss_A$ ≡ annual average distribution losses as a fraction of annual energy demand from customers

and substituting Equation (229 for the energy demand in Equation (230 :

$$Qdso_h \cong (1 + \bar{F}dloss_h)\left(Qind_h + WF_{dso}\sum_{c=1}^{N_c} Qcust_h(c)\right) \quad (232)$$

Then, for the purposes of transactive ratemaking, a DSO's annual wholesale energy costs are the sum of its wholesale energy market purchases and its costs for reserves, transmission losses, transmission access, and ISO fees over the course of the year:

$$WhslEnergyCost_A \equiv WhlsPurchCost_A + TransLossCost_A + TransFee_A + IsoFee_A + RegRsrvCost_A + SpinRsrvCost_A + NSpinRsrvCost_A \quad (233)$$

where $WhlsEnergyCost_A$ ≡ annual wholesale energy market cost of DSO customer demand

$WhlsPurchCost_A$ ≡ annual wholesale energy purchase cost of customer demand

$TransLossCost_A$ ≡ annual cost of DSO's share of transmission system losses

$TransFee_A$ ≡ annual cost of transmission access

$IsoFee_A$ ≡ annual cost of ISO fees

$RegRsrvCost_A$ ≡ annual of DSO's share of regulation reserves

$SpinRsrvCost_A$ ≡ annual of DSO's share of spinning reserves

$NSpinRsrvCost_A$ ≡ annual of DSO's share of nonspinning reserves

The energy purchased from the wholesale market is the energy supplied to the DSO less the energy purchased via the bilateral contract.

So, substituting Equations (9), (10), (13), (14), and (15) from Section 3.3.1 for the annual purchases via the bilateral contract, purchases from the wholesale market, transmission access fees, ISO fees, and cost of reserves, respectively, in Equation (233 :

$$
\begin{aligned}
WhslEnergyCost_A \equiv\ & \sum_{h=1}^{8760} LMP_h\,(Qdso_h - Qbi_h) && \text{; wholesale market} \\
& + \sum_{h=1}^{8760} Pbi_h\, Qbi_h && \text{; bilateral contract} \\
& + \bar{F}tloss_A \sum_{h=1}^{8760} LMP_h\, Qdso_h && \text{; transmission losses} \\
& + \bar{P}_T \sum_{h=1}^{8760} Qdso_h && \text{; transmission access fees}
\end{aligned}
$$

$$+ \bar{P}_I \sum_{h=1}^{8760} Qdso_h \qquad \text{; ISO fees}$$

$$+ f_{reg}\, \bar{P}_{reg} \sum_{h=1}^{8760} Qdso_h \qquad \text{; frequency regulation}$$

$$+ f_{spin}\, \bar{P}_{spin} \sum_{h=1}^{8760} Qdso_h \qquad \text{; spinning reserve}$$

$$+ f_{nspin}\, \bar{P}_{nspin} \sum_{h=1}^{8760} Qdso_h \qquad \text{; nonspinning reserve}$$

(234)

where: LMP_h ≡ wholesale day-ahead market clearing price in hour of the year h for the node serving the DSO

$\bar{F}tloss_A$ ≡ annual average transmission system losses as a fraction of annual energy supplied to DSOs = 2%

Note that, like distribution losses, annual transmission losses are approximated as an annual average fractional loss of 2% on top of the energy supplied to the DSO.[39]

To simplify Equation (234 define the following:

$$Qdso_A \equiv \sum_{h=1}^{8760} Qdso_h \tag{235}$$

$$Qbi_A \equiv \sum_{h=1}^{8760} Qbi_h \tag{236}$$

$$Fbi_A \equiv \frac{Qbi_A}{Qdso_A} \tag{237}$$

$$\overline{LMP}_A \equiv \left(\sum_{h=1}^{8760} LMP_h\, Qdso_h \right) \Big/ Qdso_A \tag{238}$$

$$\bar{P}bi_A \equiv \left(\sum_{h=1}^{8760} Pbi_h\, Qbi_h \right) \Big/ Qbi_A \tag{239}$$

$$\overline{LMPbi}_A \equiv \left(\sum_{h=1}^{8760} LMP_h\, Qbi_h \right) \Big/ Qbi_A \tag{240}$$

where: $Qdso_A$ ≡ the annual energy supplied to the DSO

Qbi_A ≡ the annual energy purchased by the DSO via the bilateral contract

[39] No transmission losses are available from the Study's simulation, so $Ftloss_A$ is assumed based on typical transmission system losses in the U.S.

Fbi_A ≡ the fraction of DSO's annual energy supply purchased via bilateral contract

$\overline{LMP}_A$ ≡ the weighted-average wholesale LMP of energy

$\overline{Pbi}_A$ ≡ the weighted-average bilateral contract energy price

$\overline{LMPbi}_A$ ≡ the weighted-average wholesale LMP of energy displaced by the bilateral contract purchases

Simplifying Equation (236 using Equations (237 through (242 and then factoring $Qdso_A$ out of each term, the annual energy supplied by the bulk power system to the DSO can be expressed as:

$$WhslEnergyCost_A \equiv \big(\overline{LMP}_A - Fbi_A\,\overline{LMPbi}_A + Fbi_A\,\overline{Pbi}_A + \bar{F}tloss_A\,\overline{LMP}_A + \bar{P}_T + \bar{P}_I + f_{reg}\,\bar{P}_{reg} + f_{spin}\,\bar{P}_{spin} + f_{nspin}\,\bar{P}_{nspin}\,\big)\,Qdso_A \tag{241}$$

From the transactive rate structure expressed in Equation (44), the DSO's wholesale energy cost recovered by the rate is defined as the first term in the equation, i.e., the sum over the hours of the year of the product of the retail multiplier, LMP of the transmission node serving the DSO, and DSO customers' energy demand from the bulk power system:

$$WhslEnergyCost_A \equiv A \sum_{h=1}^{8760} LMP_h\,Qdmd_h \tag{242}$$

where: A ≡ the retail multiplier

LMP_h ≡ locational marginal price of energy at node serving to DSO at hour of year h

Solving Equation (231 for the DSO's energy demand, substituting the result into Equation (244 , and then simplifying using Equation (237 :

$$WhslEnergyCost_A \equiv A \sum_{h=1}^{8760} \frac{LMP_h\,Qdso_h}{(1+\bar{F}dloss_A)} = A\,\frac{\overline{LMP}_A\,Qdso_A}{(1+\bar{F}dloss_A)} \tag{243}$$

Substituting Equation (243) for the wholesale energy cost in Equation (244) and then solving for the retail multiplier (A):

$$A \equiv \left(1 - Fbi_A\,\frac{\overline{LMPbi}_A}{\overline{LMP}_A} + Fbi_A\,\frac{\overline{Pbi}_A}{\overline{LMP}_A} + \bar{F}tloss_A + \frac{\bar{P}_T}{\overline{LMP}_A} + \frac{\bar{P}_I}{\overline{LMP}_A} + f_{reg}\,\frac{\bar{P}_{reg}}{\overline{LMP}_A} + f_{spin}\,\frac{\bar{P}_{spin}}{\overline{LMP}_A} + f_{nspin}\,\frac{\bar{P}_{nspin}}{\overline{LMP}_A}\right)(1+\bar{F}dloss_A) \tag{244}$$

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