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Valuation of Transactive Systems

Final Report

May 2016

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U.S. DEPARTMENT OF ENERGY

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Summary

This is a final report from a project funded by the U.S. Department of Energy to formulate and test a methodology for valuation of systems where transaction-based mechanisms coordinate the exchange of value between the system's actors. Today, the principal commodity being exchanged is electrical energy, and such mechanisms are called *transactive energy systems*. The authors strove to lay a foundation for meaningful valuations of transactive systems in general, and transactive energy systems as a special case. The report will be of interest to a range of technologist who are interested in transactive systems or valuation.

Here, *value* refers to a measure by which subsystems and components interact in a decentralized environment using transactive systems. Transactive systems enable coordinated decision-making through negotiation; the medium of exchange during negotiation is value. For many transactions, value may be expressed in cost. This report addresses more complex interactions, possibly with multiple players, where monetary costs may not adequately convey value. Value may be expressed monetarily, by non-monetary benefits, or by a comparison of alternatives relative to a baseline. Examples of non-monetary benefits are environmental quality, comfort, convenience, and health.[1]

The word *valuation* is used in many different ways. This report proposes a valuation methodology that is inclusive of many types of valuations. Many will be familiar with cost-benefit valuations, in which both costs and benefits are assessed to determine whether the assets are worth their cost. Another set of valuation methods attempt to optimize an outcome using available resources, as is the case with integrated resource planning. In the end, this report's methodology was most influenced by and most resembles the integrated-resource-planning approach. Regardless, we wish to enforce the premise that all valuations are comparative and should clearly specify a baseline scenario. A long, annotated list of prior valuation studies and valuation methodologies that influenced this report has been appended to this report.

Much research is being conducted today concerning transactive systems, but only a handful of transactive system mechanisms have been formulated and field tested. They are quite diverse, and the documentation of the various mechanisms is uneven in breadth and quality. It is therefore not adequate to simply assert that a valuation scenario includes a transactive system; certain characteristics and qualities of the chosen transactive system mechanism—eligible participants, the timing of its negotiations, the commodities that are exchanged, etc.—must be defined and stated. The report lists and discusses most of the known transactive system mechanisms (Section 3.0). It offers a set of questions that may be used to help specify important characteristics of the transactive system mechanisms, which should be conveyed along with other valuation results.

A valuation methodology is proposed. Some abstraction is necessarily retained so that the methodology may be applied for the many purposes of today's valuations and across grid, building, societal, and other domains. Valuation studies explore hypothetical futures that must be modeled and predicted. The report's methodology advocates separation of operational timescales from long-term growth timescales (Section 4.0). *Operational models* are defined as the models that inform impacts within

[1] This helpful paragraph was provided by reviewer Kenneth Wacks to introduce what will be a rather abstract treatment of *transactive systems* and *valuation*.

the relatively short, often yearlong, operational time periods. *Growth models* define how the scenarios evolve from one operational period to the next (e.g., from year to year). We believe the recommended methodology is a critical step toward collaborative community platforms, where analysts and decision makers alike could contribute and borrow content within their expertise.

The report then asks, what is unique about valuations when systems become coordinated by transactive systems? In answer, accurate valuations of transactive systems require careful representation of how (1) operational objectives (e.g., individual grid services) affect the transactive systems' representations of value (e.g., price signals), and (2) how the systems will, in turn, change their behaviors (e.g., consume, generate, or shift energy by location and time). When evaluating transactive systems, the representation of operational objectives' value and the corresponding transactive system responses must never be decoupled. Indeed, transactive systems facilitate this coupling. If the two valuation components are allowed to become disconnected, the valuation study cannot state what fraction of an operational objective will be accomplished or what fractions of the system's resources will become engaged. These fractions are always less than what might be calculated if the two valuation components are allowed to become decoupled.

After following the valuation methodology, the analyst possesses a series of periodic (usually yearly) costs and monetized benefits, plus a series of unmonetized benefits as well. Depending on the purposes of the valuation, the results are further aggregated to support decisions. Conventional economic treatments, like net present value, are well known and reduce the value of a scenario to a single monetary number. However, the methodology must also support decisions through selected weightings of unmonetized benefits and even through assessments of risk, if the valuation can support such decision making (Section 6.0).

The transactive system is treated as a platform for the exchange of value. As such, it introduces basic installation costs and recurring costs for the platform itself. But almost all of the benefits follow from the platform's facilitation of value exchange and not from the platform itself. The report offers a parametric model for the tracking of both installation and recurring platform costs. The analyst is advised to track such costs according to year, installation year, purchaser, owner, and system location.

The report advocates that several visual diagrams should be adopted by valuation practitioners to better reveal and make transparent the methods and assumptions of any valuation. The first, a Unified Modeling Language (UML) use-case diagram based on *e^3 value*™, clearly lays out the values that are transacted between the actors in a given scenario. The second takes advantage of UML activity diagrams to represent operational models, including the impact that is an output of the operational model and the data inputs that must be available if the impact is to be quantified using the operational model. These diagrams adhere to an accepted standard and concisely communicate important information about transactive systems and their value. Examples of these diagrams are offered.

The report next lists and describes many of the operational models that will be called upon for valuations of transactive systems. Because the list is long, they are categorized by their applicability to the grid, buildings, and societal domains. In the grid domain, the report was able to draw from numerous tested methods and reference materials. That was not as easily accomplished for buildings and non-energy applications. Here, the impacts were not as deterministic and, where any viable functional model could be found, could only be stated with great uncertainty. Many such functional models attempt to model human attitudes or behaviors, which have not been modeled with high accuracy. Future work is needed to define such models so that exploration may proceed in applying transactive systems in non-energy scenarios.

We then tested the proposed methodology in a building-to-grid scenario. The example used a responsive thermostat model and modeled the behavior of these thermostats on a prototypical feeder within the Midcontinent Independent System Operator, Inc., locational marginal pricing territory.

The methodology and recommended visualization diagrams should be further tested by diverse valuation scenarios. Most challenging among these will be to compare the performance of various transactive system mechanisms with one another under the same scenarios. The report recommends that its methodology be adopted and that online communities of analysts and regulators be fostered to continue these efforts to make valuation methods more openly available and to reveal methods and assumptions through standardized documentation.

Acknowledgments

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Two meetings were hosted by the GridWise Architecture Council (GWAC) to facilitate external collaboration and cross-fertilization of ideas in this important area of research. The first meeting was held during July 2015 at the PNNL campus, Richland, WA, and the second was hosted by the Electric Reliability Council of Texas (ERCOT) at its Taylor, TX facility at the end of September 2015. PNNL staff collaborated with GWAC to publish transactions for these meetings and capture the participants' valuable insights.

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- David Holmberg, National Institute of Science and Technology (NIST)
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- Lynne Kiesling, Department of Economics, Northwestern University
- Mark Knight, CGI Utility Solutions
- Virginia Lacy and James Sherwood, Rocky Mountain Institute (RMI)
- Kenneth Wacks, Management and Engineering Consultant

Acronyms and Abbreviations

AC	alternating current
AEP	American Electric Power, Ohio
AFUE	annual fuel utilization efficiency
ASHRAE	American Society of Heating, Refrigerating, and Air-Conditioning Engineers
BMI	Battelle Memorial Institute, Pacific Northwest Division
CAISO	California Independent System Operator
CBA	cost-benefit analysis
CC	combined cycle
CT	combustion turbine
DER	distributed energy resource
DG	distributed generation
DMS	distribution management system
DOE	U.S. Department of Energy
DRP	distribution resource plan
DSO	distribution system operator
EIA	Energy Information Administration
eMIX	OASIS Energy Market Information Exchange
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ESCO	energy service company
ESI	Energy Service Interface
GADS	NERC's Generating Availability Data System
GHG	greenhouse gas
HVAC	heating, ventilation, and air conditioning
ICE	internal combustion engine
IES	Illuminating Engineering Society
IRP	integrated resource planning
ISO	independent system operator; International Organization for Standardization
LBNL	Lawrence Berkeley National Laboratory
LMP	locational marginal price
LOLE	loss-of-load expectation
LOLP	loss-of-load probability
MISO	Midcontinent Independent Transmission System Operator, Inc.
MW	megawatt(s)
NAESCO	National Association of Energy Service Companies
NERC	North American Electric Reliability Council

NO_x	nitrogen oxides
NPV	net present value
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
OASIS	Organization for the Advancement of Structured Information Standards
PJM	Pennsylvania–New Jersey–Maryland Interconnection LLC
PMV	predicted mean vote
PNNL	Pacific Northwest National Laboratory
PNWSGD	Pacific Northwest Smart Grid Demonstration
PPD	predicted percentage dissatisfied
PUC	public utility commission
PV	photovoltaic
RMI	Rocky Mountain Institute
RTO	regional transmission organization
SO_x	sulfur oxides
ST	steam turbine
TE	transactive energy
TS	transactive system
TSO	transmission system operator
UML	Unified Modeling Language
var	volt-ampere(s) reactive
VPP	virtual power plant
WEAF	weighted equivalent availability factor

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1.0 Introduction

The U.S. Department of Energy (DOE), through a joint investment by both the Office of Energy Efficiency and Renewable Energy, Building Technologies Office, and the Office of Electricity Delivery and Energy Reliability, Power Systems Engineering, funded Pacific Northwest National Laboratory (PNNL) to formulate a methodology for valuations of systems that include transactive mechanisms—market-like mechanisms that coordinate the systems' operations. This document is the final report from that project. The report will be of interest to a range of technologist who are interested in transactive systems or valuation.

Two common types of cost and benefits assessments used in the energy domain are comparative cost-benefit analyses (CBAs) and integrated resource planning (IRP), previously referred to as least-cost planning. A CBA conducts a comparative analysis of a specified technology, policy or intervention, often resulting in a go/no-go technology decision. Conversely, an IRP steers the selection and growth of technologies to meet system needs into the future. The distinction between the two approaches is not definitive. The CBAs usually address both the costs and benefits of a single, well-defined scenario. IRPs, on the other hand, more strongly emphasize the rules by which resource growth and dispatch occur into the future based on load and price projections. The methodology recommended by this report was strongly influenced by both CBA and IRP methods, but it more closely resembles an IRP.

The word *methodology* has been used to refer to comprehensive valuation approaches that could be reapplied to address other similar scenarios. This report acknowledges and has been influenced by many excellent published methodologies in the energy domain. Among the most comprehensive methodologies are the Integrated Grid report by the Electric Power Research Institute (Forsten 2015) and the Smart Grid Computational Tool developed by Navigant Consulting for the DOE as a method for estimating many various smart grid impacts (DOE 2016a). Many methodologies more narrowly target the continuing growth of distributed energy resources (DERs) like the rapid growth in penetration of solar photovoltaic (PV) generation. These include a report by the National Renewable Energy Laboratory (NREL) concerning the value of DERs (Denholm et al. 2014), the Rocky Mountain Institute (RMI) Electricity Distribution Grid Evaluator (EDGE) model (RMI 2014), and the Minnesota Value of Solar study (Norris et al. 2014). The authors intend to build upon all this prior work.

The prior methodologies share similar approaches in their accounting of benefits, impacts, and costs. The above-listed methodologies are clearly focused on the energy domain and might not have the flexibility to be applied in other domains. They perhaps also differ in the rigor with which each tracks the allocation of benefits to various stakeholders. In formulating this report's methodology the authors asked, what other qualities of existing methodologies must be adopted or changed if we are to valuate transactive systems (TSs)? Valuations were found to differ based on for whom the valuation is being conducted and for what it will be used. Two seemingly similar valuations can use different assumptions, data, methodologies, and levels of detail. Valuations can also be carried out over different planning horizons and consider perspectives of different stakeholders. Levels of transparency can vary greatly between valuations.

Some valuations consider the value of a resource or set of resources as compared to some kind of baseline over a planning horizon. A comparison during a single, short time period (perhaps a year) assesses the system's operations. If the system's growth or evolution is also of interest, the changes that occur to the systems (both treatment and baseline) from one year to the next must also be modeled. The operational models modified by growth projections and executed in sequential years yield value projections through a planning time horizon. This report advocates that these two types of models (operational and growth) are needed but should be separated to facilitate a transparent treatment of temporal impacts, supplemented by improvements to both documentation and graphic representation.

The focus of this report will be to support valuations for scenarios that use TS coordination mechanisms. A valuation must compare a TS with a baseline that either employs traditional resource coordination mechanisms or uses an alternative TS mechanism. Many early formulations and demonstrations of TSs coordinate the consumption and generation of energy, especially electrical energy, and are therefore transactive energy (TE) systems. There are several TE system mechanisms that have been formulated, and several of these have been used in field trials. This report will provide an overview of each of these. This report will use the word *mechanism* to refer to the conceptual means by which a TS negotiates exchanges of value; the word *platform* is used in the report for the specific set of system components designed to support all the system's communications and control functions. For example, a TS platform has costs associated with it; its TS mechanism does not.

The report may at times use the shorthand "TS valuation" to refer to "the valuation of systems that use a TS for coordinating the exchange of value."

But why should the valuation of TSs differ from other valuations? A TS is not a typical asset to be purchased and used. It is not an energy resource. A TS is a resource coordination method for monetizing values and incentivizing assets to respond or not respond. A TE system, for example, offers a platform for negotiating the operating behavior of energy-related resources seeking to meet the multiple objectives of multiple entities, including owners, operators, end users, and still others. In this way, the valuation of a TS is different from valuing a discrete technology, policy or intervention.

There are different TS mechanisms that may be able to address similar operational objectives. A valuation methodology that helps compare different transactive mechanisms will inform researchers and decision makers about the mechanisms' strengths and weaknesses in this new hybrid field of engineering and economics. *The comparisons become not necessarily about the value of the assets, but whether one TS approach engages and coordinates the integration of assets better than another in achieving defined objectives.* A thesis of this report will be that such subtle distinctions cannot be achieved by simply adding another module to existing valuation methods. Instead, the interwoven dependencies between stakeholders' objectives and the systems' responses must be carefully laid out and the relationships must be functionally modeled. Furthermore, the valuation must be configured from the start to track the costs and impacts for each stakeholder.

Several trends have piqued interest in TE systems for electrical power systems. The growth of renewable energy resources and energy storage technologies has created new challenges that TE systems might mitigate. Emerging decentralized energy storage is customer owned and is sometimes even mobile. We have not yet defined the system and signals that will coordinate these resources and also respect all the stakeholders' perspectives. Wind and solar resources are inherently intermittent. Solar energy is available during sunny midday hours, but typical manufacturing and residential electrical loads remain heavy until late evening. As more renewable resource capacity becomes installed, the resources eventually threaten to displace base-load generation. These conditions are exemplified by the well-known "duck" load curve in California and the occasional need to curtail wind resources in the Pacific

Northwest. Electricity infrastructure, which constitutes two-thirds of the cost of electricity, is aging, and owners of power grids strive to delay the replacement of aged infrastructure. At the same time that growth in U.S. total electric energy consumption is slowing, the peak electrical load is growing (EIA 2014). Electric utility interest is not only growing for load curtailment (or equivalently, DER generation), but also for incentivizing load *increases* and *continuously* variable load responses.

This report has further attempted to lay the foundational groundwork for valuations in non-energy, non-grid domains. Nowhere has this interest been greater than in buildings applications. Energy is converted to qualities whose values are exchanged between buildings and other actors. Thorough TE system valuations require the inclusion of qualities like comfort levels and employee productivity, to name a few, within buildings. Somasundaram et al. (2014) list other interesting use cases for the buildings domain, including the exchange of diagnostic support and information.

The authors' working hypothesis is that TS valuations cannot be adequately completed by simply adding another module to existing energy-domain methodologies. That approach fails to represent the integrated nature of the coordination enabled by the TSs. This report will advocate that more rigor is needed if alternative TS mechanisms and their platforms are to be compared. What this means will be discussed further in Chapter 5.0.

Few analysts currently select the same metrics, use the same methods, or come to the same conclusions as they conduct energy valuations. Current valuation methods are unevenly documented and difficult to verify or compare. It is in this context that we introduce a methodology for the valuation of TSs. It is our hope that this effort will encourage consistency of energy valuations, fair assessments of alternative TSs, and altogether greater transparency of valuation methods and assumptions. The DOE has invested and continues to invest in TS research. Initial research and demonstration findings have been promising. Interest in TSs has been fueled by the need for more flexible energy systems in the face of growing penetration of intermittent renewable resources, vehicle electrification, changes in electric load growth, aging of energy infrastructure, and greater volatility in the environment and in fuel availability and prices. *Yet, after years of research and demonstration, definitive information about the cost-effectiveness of TSs has remained somewhat elusive. This report is a step toward more definitive valuations for TSs.*

1.1 Intended Use and Audience

The primary uses of this report are to (1) support the design and development of TS valuations, and (2) provide a tool for reviewing and comparing TS valuations. In a larger sense, the report presents a valuation methodology that can have broad applicability to electric system valuations in general and DER integration in particular. In this regard, it may offer foundational elements for developing a valuation analysis community with collaboration support, such as the creation of a repository for TS valuations with associated models, data, and tools.

This report's primary audience is the energy research community. Those researchers investigating the potential impacts of TS mechanisms are particularly targeted; however, other analysts studying the integration of DERs in the evolving electric system should also find the methodology proposed here of interest.

Others who may find this report useful include utility companies' planning and rates departments, public utility commission (PUC) staffs, staffs of other government agencies, advocacy groups participating in regulatory proceedings, third-party service providers, and product developers. The interests of these audience members perhaps lie toward the regulatory aspects of TSs or, in the case of third-party service providers, toward justification and marketing of their products. Some of these individuals may find this report's insights useful. They will certainly benefit from this report's recommendation of greater transparency in the valuation process. However, the outcomes of TS valuations will remain uniquely dependent on the choice of the TS mechanism, the local energy system topology, which objectives are incentivized, to which parties the incentives become revealed, which components are eligible and able to respond, and even the ultimate costs of installing a TS.

1.2 Organization of this Report

This report introduces and further defines its usage of the terms *valuation* and *TS* in Chapters 0 and 3.0. With that context, the authors present and recommended an abstracted valuation methodology in Chapter 4.0. The methodology is applicable to almost any valuation challenge, but it is particularly well suited to the valuation of TSs. It is argued that the methodology can support the modeling of rather subtle distinctions between different TS mechanisms and provides a framework within which analysts may collaborate and reveal their methods and assumptions.

Chapter 5.0 distinguishes the challenges of conducting conventional valuations from those of TS valuations. This chapter recommends that if one is to perform valuations of TSs, the interactions between the systems' responses and the incentivization of operational objectives must be modeled. If that connection is not captured, the valuation results in an envelope that shows the greatest possible system response (as opposed to what is likely) or the magnitude of the objectives that are being addressed (but not necessarily the practical extent to which the TS will fulfill them). Valuations that are based only on available system responses state an envelope of possible responsiveness, but may overstate the responses in light of multiple simultaneous (and potentially conflicting) objectives and objectives that are not, in fact, revealed through incentives. Valuations that are based only on system objectives state an envelope of desired mitigations, but may overstate the mitigations in light of unknown abilities to, in fact, obtain the needed responses from the system.

A valuation methodology supports decision making. Chapter 6.0 discusses how the recommended methodology supports decision making and further discusses decision making in the light of conventional economic metrics, incorporation of unmonetized impacts, and risk.

Chapter 7.0 recommends a model for the tracking of relatively static installation costs and some recurring costs from the installation of the TS platform. These relatively static costs may be modeled parametrically from numbers of assets that become or remain installed each growth period (e.g., each year). Other system costs and monetized benefits might be tracked using this same approach, but all costs and monetized benefits that might be dynamically changed—dependent variables—must be more richly modeled.

Chapter 8.0 advocates certain Unified Modeling Language (UML) visual models that should accompany valuations. These abstract modeling tools are standardized. One reveals the value objects being transacted and the actors who partake in the value exchange. The second reveals important aspects of operational models, including the definition of the impacts, needed input data, and assumptions.

Chapter 9.0 goes into greater detail about the implications of TS valuations in the buildings space, where non-energy applications of TS are becoming rapidly formulated. Sets of impacts are listed and discussed in Chapter 10.0 concerning the grid, buildings, and societal domains. The longest list is based on experiences gleaned from TE system field demonstrations in the grid domain. The chapter discusses impacts in the buildings and societal domain, too, but the principles behind the operational models in these domains were not found to be as fully formulated and available.

Chapter 11.0 discusses our experience upon exercising the recommended methodology in a building-to-grid simulated implementation, and Chapter 12.0 summarizes the report's finding and recommends follow-on research.

2.0 Valuation

The word *valuation* is used in this report for any analysis of a system that strives to apply monetary value, to weigh unmonetizable benefits, or to compare alternatives. Valuation methods currently differ by audience and intended purpose.

2.1 The Dimensionality of Valuations

An early draft of this report attempted to create context for the challenges that we face during valuation studies by introducing cost-benefit analysis (CBA) and integrated resource planning (IRP) methods, which together exemplify a large range of collective valuation studies. That attempt proved ineffective. Some reviewers objected that a complete taxonomy of valuations was not being provided. The detail that *was* provided was objected to by others who said that the treatment was uneven and incomplete and did not clearly set the context that we had sought. This section has been revised to now discuss, at a relatively high level, some of the dimensionality across which valuations work. The point is that prior valuations lie among the these dimensions in their treatments of time, location, stakeholders, and decision support; and this report's methodology, too, must address and be applicable across these same dimensions.

Let us begin with time dimensions. Figure 2.1 shows two time axes. The horizontal axis represents future time. Position on this axis represents the time duration over which impacts, benefits, or costs accumulate. This may be called a *planning horizon* where methods focus on system growth. IRPs, for example, strongly emphasize planning and may extrapolate 15–20 years into the future. The vertical dimension represents interval granularity or detail. Methods may use fine, granular intervals where dynamic impacts are being assessed or where high accuracy is needed. TS valuations will employ the future time dimension (horizontal axis). Some of the early field implementations of TSs used short (e.g., 5-minute) signal intervals, leading us to expect that many TS valuations may invoke relatively short intervals (i.e., fine granularity), too.

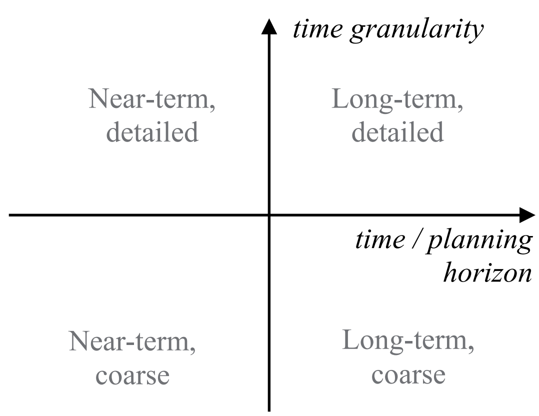

Figure 2.1. Time Dimensionality of Valuation Studies

Figure 2.2 suggests spatial dimensions that are addressed by valuations. The horizontal axis represents the geographical or physical scale of the scenarios' boundaries. This is important for TS valuations because we wish to explore the implications of TSs installed within individual homes (small-scale), as well as across an entire power grid (large-scale). The vertical dimension addresses the level of specificity or abstraction. Some valuations must be conducted with specificity, as is the case for a utility's planning, which, of course, must model that utility's circuits. Researchers, however, may wish to conduct general, representative valuation studies. Research into PV behavior, for example, may explore those behaviors on a representative, abstracted feeder instead of on a specific one.

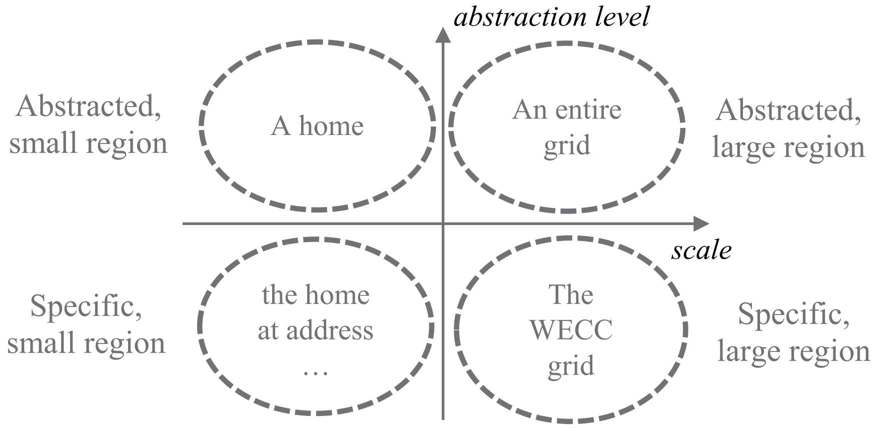

Figure 2.2. Spatial Dimensionality of Valuation Studies

Figure 2.3 addresses the tracking of valuation stakeholders using dimensionality similar to that which was suggested for location. Valuations must address a range of stakeholders from individual customers or building owners to society as a whole. The vertical dimension acknowledges that the stakeholders may be represented either in specific or in abstraction. For example, valuations may sum benefits for a specific utility, or for a prototypical utility. In electric grid studies, the business stakeholder categorizations for customer, distribution, transmission, and generation entities lie along the scale axis.

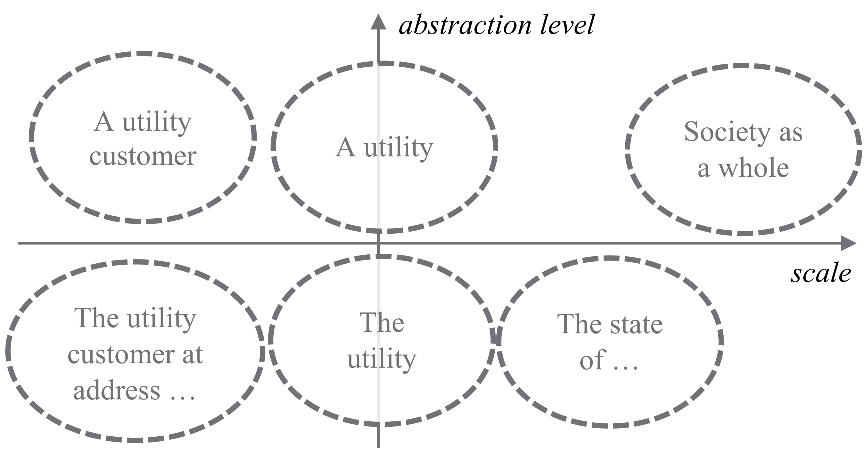

Figure 2.3. Stakeholder Dimensionality of Valuation Studies

Figure 2.4 suggests that the valuation studies' decision support has three dimensions. Where all costs and benefits can be monetized, as is often the case for CBAs, common cost measures (e.g., net present value) may be applied to justify decisions. Where benefits are unmonetized or cannot be monetized, then additional structure (e.g., decision trees) must be adopted to justifying the relative importance of the various unmonetized benefits that result from the valuation study. Risk is still another dimension that may capture the importance of uncertainty during the decision-making process. Indeed, risk aversion is an important driver for many decision makers.

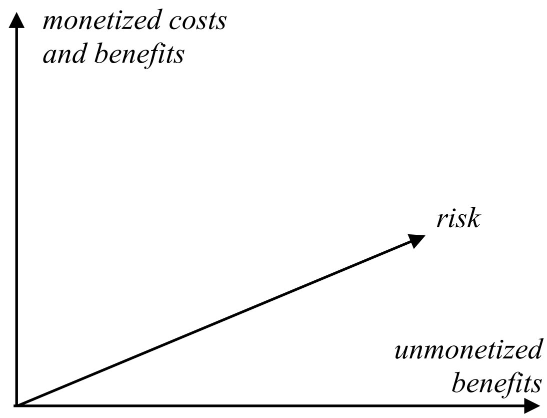

Figure 2.4. Decision Dimensionality for Valuation Studies

2.2 Valuations that Influenced this Report

The authors reviewed numerous valuations and valuation methods in preparation for this report. An annotated bibliography of these studies is located in Appendix B.

Given that this report's methodology was strongly influenced by IRPs, a good IRP example is presented. Figure 2.5 shows the modeling and risk analysis process developed by PacifiCorp for their 2013 Integrated Resource Plan (PacifiCorp 2013). In the PacifiCorp IRP process, core- and sensitivity-case definitions are first developed. Then price forecasts are developed for the planning period. The third phase entails using a computer model to develop resource portfolios based on the core and sensitivity cases. In many IRPs, this step is done manually by an analyst who simply selects a portfolio of resources that meet demand and operational requirements over the planning horizon. The PacifiCorp process in the 2013 IRP then checks that the resource portfolios meet renewable-portfolio-standard requirements.

Once a set of feasible portfolios are confirmed to meet resource needs over the 20-year planning horizon, production costs are calculated using Monte Carlo simulations. Top performing portfolios are selected, leading to the ultimate selection of the preferred portfolio.

The methodology presented in Chapter 4.0 will be recognized to treat the future planning dimension much like the example in this section.

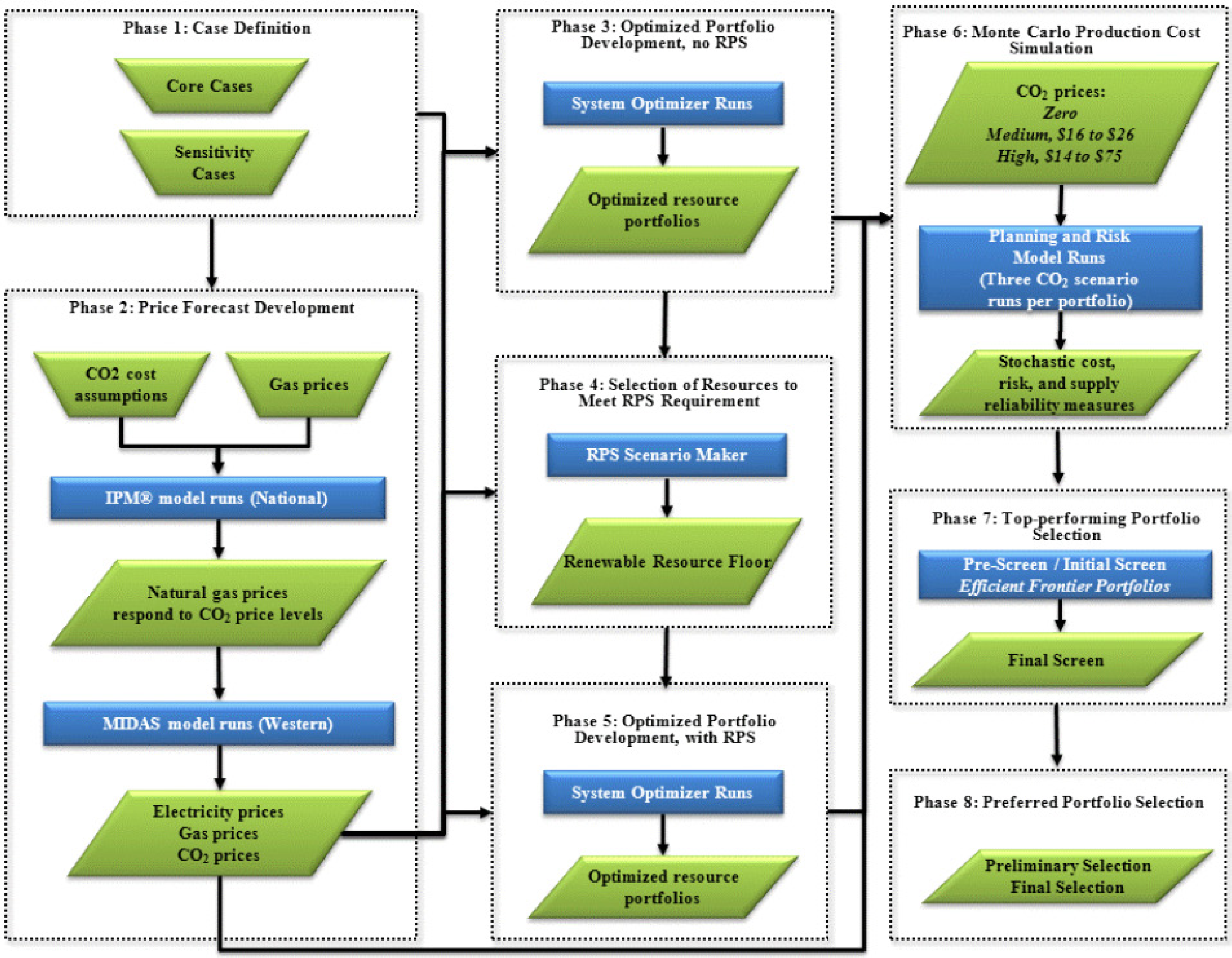

Figure 2.5. Flow of the PacifiCorp IRP Process (PacifiCorp 2013, p. 159, Figure 7.1)

2.3 The Reasons that Valuations Differ

The list below describes some of the numerous reasons that valuation methods can differ and why similar valuations may come to different conclusions:

- Clients and purposes – Valuation studies differ according to "for whom" and "for what" the studies are performed. Design and outcome depend on the target end user and purpose of the valuation. Valuations performed for utility planning have different methods and requirements from those used for setting rates.
- Assumptions – Different valuations use different forecasts and assumptions for foundational parameters—future penetration levels of DERs, cost and performance of resources, assumed return on investment, intertemporal changes and assumptions, stranded-cost considerations and baselines. Price assumptions, which can be location dependent, also vary.
- Data – Valuations use different data sources. Key considerations for data are data source reliability, repeatability, uncertainty, data cleaning process, subjective choices of data components, and subjective simplification or aggregation.
- Methodologies – Different valuations employ different methodologies, including physical and behavioral representations. *Methodology* refers to the overall approach taken and what is included and what is not included in the analysis.
- Model rigor and type – There are differences in the quality and rigor of computer models and tools used to conduct the methodology.
- Skill – The skill and backgrounds of those performing the analyses differ.
- Constraints – Different valuations use different constraints. For example, valuations may have differing constraints on spinning-reserve capacities. Some models may differ in their ability to represent operational or growth constraints.
- Spatial and temporal granularity – Valuations differ in the granularity with which location and time are represented.
- Time horizons – Valuations address different time horizons and deployment periods (decades, hours, or minutes).
- Stakeholders considered – Some valuations are focused on a single perspective (such as a utility's or the consumers' perspective), while others consider multiple perspectives.
- Transparency – Valuation reports have varying degrees of transparency. In this context, *transparency* refers to whether and to what extent underlying assumptions and methods are made clear. Some valuations performed internally for business reasons are, by design, not transparent. In some instances, there is transparency around certain aspects of a valuation but not others. When assumptions are not clearly documented, it is difficult to communicate results in a way that others can understand and trust.
- Different definitions of "value" – People do not agree on what the definition of "valuation" is. Different studies focus on different parts or value components. In addition, valuation methods are not well defined or categorized.

- Jurisdictional and regulatory environment – Valuations consider different jurisdictional and regulatory environments. Some valuations assume or anticipate market redesign or changes, while others assume status quo.

Which of the above differences should be allowed and disallowed? The first point to be made is that valuations would become more homogeneous if we were to emphasize *support* of decision makers and not decision making itself. Some of the most significant differences in the above list emerge from different perspectives on the decision-making process, which we argue should *follow* the valuation exercise. The remaining differences might then be categorized by their severity. Any difference that potentially hides or obfuscates deception must be eliminated. Lack of transparency fits this category. We should also be vigilant for differences that permit biases—intentional or not, which are sometimes observed as failures to consider viable alternatives. Another instance might arise when the allocation of benefits among stakeholders is not justified or realistic. Still another category simply hinders analysts from collaborating where, for example, operational models, software modules, or methods are not interoperable. Any remaining differences should be relatively innocuous. It is a great question whether *all* of the differences in the above list can be, or even should be, eliminated.

2.4 Attributes for Contrasting Valuations

While reviewing completed valuations and valuation methods, the authors devised a set of attributes and questions by which the scopes and methods of the valuations might be assessed, communicated, or compared. These attributes and questions are listed in Appendix C.

3.0 TSs

The GridWise Architecture Council (GWAC) developed a "GridWise Transactive Energy Framework" (GWAC 2015), which includes a formal definition of the term "transactive energy" as a "system of economic and control mechanisms that allows the dynamic balance of supply and demand across the entire electrical infrastructure using value as a key operational parameter." This definition is adopted, but it must be generalized still more for practitioners who extend the term *transactive* to non-energy transactions within buildings and elsewhere.

The distinction between existing markets and TSs is not crisp. Some apply the term TE system to existing energy markets and any point in a system were business value is exchanged. This report presents a methodology that can be applied to such valuations and is flexible enough to be extended to non-grid, non-energy services.

The next paragraphs discuss the qualities and characteristics shared by many TSs.

<u>They facilitate distributed, rather than centralized, control</u>. The control mechanism[1] in a TE system is fundamentally different from centralized, deterministic decision making; it includes distributed decision making and semi-autonomy. This decentralized decision making facilitates, but is different from, the distributed placement of energy resources (i.e., DERs) that has been occurring for many years. The distribution of decision making may reduce a system's vulnerability and may therefore improve the system's security and resiliency.

<u>A TS includes feedback</u>. TSs includes bidirectional communication. The response from a participant concerning a bid or incentive reveals the recipients' intentions to respond or not, where the responses are changes in the behaviors the participants would have otherwise exhibited.

<u>A TS can simultaneously address multiple objectives</u>. TSs often balance a plurality of objectives concurrently. For example, objectives for wind integration, peak management, frequency control, etc., can be simultaneously incentivized. The TS mechanisms address how the multiple objectives can be equitably weighted. The use of monetary units enforces an equitable weighting of the multiple objectives in a TS. TSs include a value discovery mechanism like that of a double-auction market, for example, in which the objectives may equitably compete.

Contrast this with multiple competing systems that strive to compel resources to respond to each's singular objective. If the resources do not overlap, each system and its objective have unfortunately limited the numbers of available resources. If, however, the resources receive all the various requests for the singular objectives, then they might respond to the "loudest" (i.e., best promoted, best funded, most threatening) objective, which might not be the one with the greatest utility or value. For example, if one of the objective owners tells the resource to turn up and another tells it to turn down, no response from the resource can satisfy the resource owner and both objective owners.

<u>TSs are scalable and sometimes multi-scaled</u>. The distributed decision-making characteristics of many TS systems allow them to be scaled to accommodate changing numbers of participants and system

[1] The use of "control" here does not necessarily connote automation.

growth. In time, fast dynamics or slow planning horizons can be managed. The word "multi-scaled" may be applied where a TS system operates simultaneously across a large number of spatial or temporal scales, especially where the implementation at one scale is self-similar to the implementation at other scales.

They leverage, but do not necessitate automation. Automated devices and agents are envisioned to support routine transactions in many TS mechanisms. An automation agent can be configured to represent its owner's objectives during individual transactions. The automation does not get tired or take breaks or vacations. Agents and automated devices can therefore participate at any time and in faster transactions than humans can. Still, the evolution to a world full of TSs will take time. In the meantime, even highly automated TSs must allow for human participants and all their inherent limitations.

The TS as a coordination platform**.** A TS will be treated in this report as a coordination platform that facilitates transactions. Open access is allowed to many players for their many purposes. Some would argue that there is, in fact, no other way to discover and reveal preferences and opportunity costs other than through market coordination like that facilitated by the platform. A TS facilitates the exchange of value, but the platform itself has modest value. Value streams pass through a TE system. This perspective will prove useful in Chapter 7.0, where the static costs of the system will be discussed. The perspective is also fundamental to the assertion in this report that additional rigor is needed if we are to compare different TS mechanisms that might not differ very much in the final outcome as to how the outcome is incentivized by the TS.

The topological scope of a TS can extend across an entire power grid or be complete within a single appliance or building. The Pacific Northwest Smart Grid Demonstration (PNWSGD) TS, for example (Hammerstrom et al. 2015), was implemented for multiple utilities in five northwestern states. On the smaller scale, there are activities underway for using transactive mechanisms to balance energy in buildings. A review of the opportunities for buildings and their devices to participate in TSs may be found in Somasundaram et al. (2014).

3.1 Attributes/Characteristics for Contrasting TSs

Multiple alternative TS mechanisms and platforms have emerged. This report makes a case that the value of a TS will depend on its ability to support exchanges of value, and the alternative TSs possess different characteristics that will either help them achieve, or will limit, their abilities to exchange those values—to supply services and respond to operational objectives. The authors drafted a set of 14 key questions to help analysts discern important characteristics of the TSs. While these are being stated for TE systems, the qualities may be easily extended to more general TS cases. These questions are the basis for comparisons of TE systems to be made in Table 3.1.

- What are the objectives of the TE system? What is the TE system *intended* to accomplish? What is the designer's concept for how the TE system will accomplish the desired objectives? What are the incentives (natural or imposed) and, summarily, how are actors expected to respond to the incentives?
- What time horizons can transactions represent? An important feature of any TS is the reach of the system in the time domain.

- How granular is the system with respect to its time intervals? It is essential to know how often the system updates its information and control signals. Some methods use the passage of time as a system feature, while others reference time as a data characteristic of a specific transaction.
- Is there modeling or simulation occurring on an ongoing basis, what can it accomplish, and how is it incorporated? Methods with modeling or simulation components have been demonstrated to provide greater value in a number of dimensions including, but not limited to, fault detection and diagnostics, improved system visibility and situational awareness, forecasting and planning, and finer-grained balancing.
- What services does the TE system provide or enable? As services and value are strongly coupled, it is important to note that every exchange of value—be it financial, goods and services, or information—may represent different utility according to the different actors in the system. Value from a given transaction may accrue to nonparticipants.
- How are the roles and relationships of system participants structured? This information relates to how information, goods, services, and financial transactions flow within the TE system. The creation and transfer of value (positive and negative) are strongly influenced by these flows. Structure may be considered hierarchical, or distributed, such as using agents, or a hybrid of the two.
- What information or signals are exchanged between participants? Information flow often defines the transactions. It can facilitate or hinder the creation of value. Information and information exchange are typically needed to determine the type and magnitude of value created or exchanged, as well as to monitor it. *In some cases, information itself is the valuable commodity being exchanged in a transaction.*
- How is data flow managed within the TE system? This information relates to the volume of data being transmitted and the network structure underlying data exchange. It is included to reveal the capability of the system and to provide insight as to whether the system manages data flow effectively and efficiently.
- What are the steps and/or mechanism for initiation of transactions and their subsequent negotiation? This information documents the actual transaction itself, which can be structured in many different ways. The structure of a transaction can have a significant impact on value, as it can affect factors such as price determination, the IT systems required by actors to process transactions, and the difficulty or simplicity of developing an effective business strategy.
- How are transactions cleared within the system? This information is important for understanding the nature of how value is assigned by the TE system mechanism—how a price is ultimately quantified, for example. Market clearing indicates the point at which the market establishes the price of goods reflected by balanced supply and demand, or the equilibrium price.
- How is control and coordination of the delivery of value objects structured and monitored? This refers to the operation of the physical system to deliver value streams such as energy, power and related ancillary services. The physical control and coordination system may include communication equipment, IT systems, and networks. If the system is automated, it will likely require significant effort, investment, and management of complexity. However, if the system contains no intrinsic control and coordination capability, then orchestrating the delivery of value objects is left entirely to the participants in the system, and the effort of joining and participating in a TE system is limited to following established "rules of engagement."

- How does the system keep track of items transacted, and what sort of reporting can it provide to participants? For participants to assess the effectiveness, return on investment, and value created and exchanged by participation in a TE system, they need to have an accurate accounting of their transactions. Examples include kWh of demand response sold last month, dollars earned, MWh of solar energy delivered, information acquired, and energy goods and services developed, delivered, and consumed. Provision of this information performs a function similar to evaluation, measurement, and verification in energy efficiency programs.
- How is delivery of value objects verified and enforced? Delivery verification is a crucial aspect of value exchange or creation; value streams that are not delivered in a timely fashion may not create the value for which the parties transacted. Poor performance and nonperformance may incur penalties.
- Does the system have an intrinsic means of valuing benefits? When evaluating systems that have built-in benefit valuation, the methodology and results of that built-in valuation should be understood and considered as part of the valuation process. Sound and well documented intrinsic valuation technology could save a great deal of effort for those doing the valuation. Even if an analyst chooses not to use the TE system's intrinsic valuation, the particular system's methodology should be very helpful as a starting point.

3.2 Example TE Systems

Although TSs are still new and examples of field tests of even TE systems are relatively limited, there are different types of TS mechanisms being proposed, each with distinct characteristics. Examples include double-auction distribution markets like those demonstrated by the GridWise Olympic Peninsula Project (Hammerstrom et al. 2008); the American Electric Power (AEP) gridSMART® Demonstration (Widergren et al. 2014a, 2014b), and PowerMatcher (Kok 2013), which operates similarly but bids entire demand curves. Many consider the Electric Power Research Institute (EPRI) concept "prices to devices" (EPRI 2006) as an example of a TE system, although it invites smart, end-use devices to respond to price signals without negotiation feedback. The control of demand response has also become quite mature in this respect, as evidenced by the ISO/IEC Standard 15067-3 (2012) "Model of a Demand-Response Energy Management System for Home Electronic System" that facilitates transmission of prices to home energy management agents. The TeMix platform (Barrager and Cazalet 2014) invites bilateral contracts (both future and spot) for energy and energy transfer between consumers and suppliers.

The PNWSGD formulated a system of distributed agents that helped suppliers predict and share their influence on an incentive signal and helped electrical loads predict and share their need for energy, including the impact of load elasticity. Information about the PNWSGD system's transactive signals and framework formulation may be found in (BMI 2013). Additional detail about the PNWSGD TE system framework and its toolkit functions that tie resource and load operations to the system's distributed incentives may be found in (BMI 2015). The field performance of the TE system is summarized in Chapter 4 of the project's technical performance report (Hammerstrom et al. 2015).

Table 3.1 below discusses representative TE systems and their important characteristics using the set of questions in Section 3.1 for guidance.

Table 3.1. Qualities of a Sample of TE Systems that May Affect Their Performances and Their Capabilities to Supply Services

	PNWSGD	TeMix	PowerMatcher	EnergyNet (Power Analytics 2016)	Olympic Peninsula Project
System objectives	To balance supply and demand through the use of a transactive market, with value signals exchanged concerning the next 72 hours exchanged between system participants that inform planning and operations decisions.	To balance supply and demand in an economically efficient manner, solely via bilateral market instruments including derivatives. Includes bids and offers for transport of the power.	To respond dynamically to changing supply and demand situations through a real-time market-based solution. Automates control and coordination operations from the consumer up to the network operator and wholesale markets.	To respond to system events, needs, and constraints. To provide optimal market and electrical grid performance.	Real-time price signals and demand bids in 5-minute intervals are intended to shift load in time, generating savings for a utility in terms of peak reduction and congestion management.
Time horizon	Value signals describe a forward horizon of operations extending up to 72 hours forward (~3 days).	Contracts may be traded for any period and length of time for which there is a market.	Seconds. Does not include future time horizon.	Seconds. Optimality search may run with real-time information from any data source. Does not itself incorporate a future time horizon.	Used 5-minute auction and market clearing. Did not use future time horizon.
Time granularity	Intervals are 5 minutes for the next hour, successively increasing to 15-minute, hourly, and eventually daylong intervals 3–4 days into the future.	Market instruments may take the form of any time granularity willing to be traded.	Event-based, with a ~1 second buffer to group events happening in rapid succession.	Control and transaction periods may be defined in the software based on SCADA[(a)] time granularity.	Five minutes.
Modeling or simulation inherent in the TE system mechanism	The method models a grid as a collection of nodes. Resources and incentives impact prices. Agents calculate and predict cost and demand. Price output from one node is blended with energy prices from each neighboring node to produce a network of local marginal prices.	No modeling or simulation is present in the method. Offers, quotes, tenders, and delivery are managed via communication between bilateral parties and traded via a defined market interface.	A system is modeled as a collection of nodes, and a simulation environment allows comparison of a business-as-usual scenario with a PowerMatcher scenario.	Design Base, a software suite of tools for modeling electric grids, allows for system-level modeling and simulation of power flow and grid economics.	Double auction: consumers submit bids for delivered energy and potential sellers submit their ask prices simultaneously to the TE system operator (e.g., RTO(b) or ISO(c), or balancing authority). The market clears where supply equals demand.(d)

Table 3.1. (contd)

	PNWSGD	TeMix	PowerMatcher	EnergyNet (Power Analytics)	Olympic Peninsula Project
Services addressed	Extensible service set. Production costs and demand-charge mitigation were demonstrated. New objectives may be defined if their impacts on delivered cost of energy can be modeled and predicted.	Energy and energy transport, along with financial derivatives of these two products.	Near-real-time balancing of the power system, plus congestion management.	Controls grids and facilitates market transactions.	Near-real-time balancing of the power system, plus congestion management.
Architecture of participants	Hierarchical, nodal network of agents. Only electrically connected neighbor nodes communicate. Agents represent nodes' respective owners and their objectives.[e]	Transactions occur at an Energy Services Interface, a market trading point that represents a single device or collection of devices. Any trading point can interact with any other trading point, and can facilitate transport, energy, or derivative financial products.	Agent-based system, with device agents sending information to concentrator agents, who aggregate the information and send it to the auctioneer agent.	Centralized dispatch of resources.	Hierarchical. A control system runtime environment is used for market clearing. Device agents submit bids and offers. The TE system market clears and sends the cleared market price back to participants.
Information exchanged between participants	Incentive and feedback signals. The incentive signal contains future price or value information; the feedback signal contains future load information. Downstream price information results in upstream forward load planning, and vice versa.	(1) Indications of Interest – non-binding requests for energy services or options; (2) tenders – published offers to buy or sell energy, or call or put options; (3) transactions – commitments to buy or sell energy at a specific location and for a specific period of time; and (4) metered delivery at each Energy Service Interface (ESI), or measured energy.	Bids contain a device's complete supply or demand curve and a bid number. The auctioneer returns a market price corresponding to the specific bid identifier. The Flexiblepower Alliance Network now facilitates PowerMatcher 2.0 with its framework (FAN 2015).	Scheduling requests for generation or curtailment, power flow information, power quality information, asset state, resource constraints. EnergyNet is a software system that engages the control system(s) of equipment assigned to the system.[g]	Clearing market price for each market (e.g., feeder), buy bids and sell bids per 5-minute period.

Table 3.1. (contd)

	PNWSGD	TeMix	PowerMatcher	EnergyNet (Power Analytics)	Olympic Peninsula Project
How data flow is managed	Price and feedback signal flows were demonstrated using a structured protocol developed specifically for the price and feedback signals and represented as Extensible Markup Language.	Data flow is managed using the TeMix profile on Energy Interoperation for products defined in OASIS eMIX, for financial energy transactions (open-source protocols).	Data from device agents is aggregated by concentrator agents. There can be multiple levels of concentrator agents in order to reduce the number of aggregated bids.	System energy use and optimal operation are centrally modeled and optimized.	A custom protocol, utilizing IBM's Internet Scale Control System, sends price signals and receives demand bids to the system.
Transaction initiation and negotiation	Transactions are defined by price and feedback signals between nodes. Load is summed at each node; unit price signals are blended, each component price weighted by the energy it represents. Negotiations occur every 5 minutes.[h] The forward price intervals facilitate a type of negotiation of future activity.	A counterpart will respond to an *indication of interest* with a tender offer. If accepted, the transaction becomes a binding commitment to buy and sell at the specific location and price.	Depending on a device's current status, it can change its bid at any time. Since the bid contains a device's complete supply or demand curve, no iterative negotiation is needed.	Transactions consist of control signals and data exchange to equipment, based on market interaction, and owner, operator, and electrical constraints.	Transactions occur at 5-minute intervals. The cleared price determines whether the bidder will act. Bids are submitted once, simultaneously, by suppliers and consumers.
Clearing mechanism	Uses a fully distributed price discovery mechanism at each node. No explicit market clearing event is defined. Responsive loads and generation are coordinated by agent settings that are unique to each device.	Transactions are bilateral agreements between buyers and sellers of services.	The auctioneer agent selects a market price at which supply equals demand, and communicates this price through the concentrator agents to the devices.	Contracted bilateral agreements between parties.	The TE system market coordinator agent clears a market price at which supply equals demand, and communicates this price through the market interface to the devices.

Table 3.1. (contd)

	PNWSGD	TeMix	PowerMatcher	EnergyNet (Power Analytics)	Olympic Peninsula Project
Control and coordination	Control may be implemented at a node to automatically operate based on the price signal and other factors. Responsive loads and generation are coordinated by control settings unique to each device. Coordination is accomplished by devices' elastic demand, which, in turn, affects system balance.	Each actor enters into and adheres to bilateral agreements using any resources or tools that are available. Supply and demand are balanced using financial instruments and willingness to participate in a forward market, hedge positions, and so forth.	Devices bid their demand curves. PowerMatcher distributes prices, which may result in a control action, depending on the settings of the device and the configuration set by each device owner or operator.	Software uses a security constrained economic dispatch / optimized power flow that accounts for scheduling constraints, fuel costs, operating costs, instantaneous operating rates, and other system resources, data, and constraints.	If a device's bid is successful in the double auction, it may operate. Coordination between the market coordinator and the transmission coordinator is assumed.
Transaction accounting	Meter readings at nodes' points of interconnection determine the energy delivered, generated, or consumed. The unit price of the energy is the price signal at the node from which the energy was supplied.	ESI meter readings for each metered delivery interval.	Comma-separated value logging, using a Kibana Logstash Elastic search stack for data visualization.	Automated Clearing House system accounting.	Transactions are accounted for as electronic signals and may be stored for verification and validation.
Verification	For each metered delivery interval, the associated meter reading may be used to determine the energy supplied or sold at that node.	For each metered delivery interval, the associated ESI meter reading is compared to the participant's net position in all forward transactions for the interval. Any difference is resolved by an automatic transaction accepting a tender from a balancing party.	Verification is implicit in the method. The response of each subsystem is verified as a function of the system interface.	SCADA data may be used to verify performance in near-real time. Market interactions may be logged and validated.	Verification of system performance is accomplished via smart meters.

Table 3.1. (contd)

	PNWSGD	TeMix	PowerMatcher	EnergyNet (Power Analytics)	Olympic Peninsula Project
Benefits valuation	The system's price incentive signals are based directly on energy costs, transport costs, and objective-based incentives. Agents record predicted changes in device load, which can be correlated to objectives and their impacts on the price signal.	TeMix does not have any existing implementations, but it supports transactive accounting should it be demonstrated.	A simulation environment compares business-as-usual to transactive implementations based on both user- and system-level perspectives.	The system performs a cash flow optimization each simulation run.	The system does not inherently perform a valuation over time, but the data may be used to assess system value.

(a) SCADA = supervisory control and data acquisition
(b) RTO = regional transmission organization
(c) ISO = independent system operator
(d) Notably, in order to simulate an actual market, the demonstration developed and used a shadow market.
(e) Nodes representing (1) regions of the transmission system and (2) distribution utilities have been demonstrated so far.
(f) OASIS = Organization for the Advancement of Structured Information Standards
(g) The exchange of data through EnergyNet is configured for the needs of each subsystem and the equipment being assigned.
(h) Event-initiated negotiations and iterative solutions are anticipated for future trials.

4.0 Recommended Valuation Method

The conceptual valuation method of Figure 4.1 is recommended by this report as most applicable and useful for general valuations and for those that include TSs. Its level of abstraction seems to capture and include the strengths of existing valuation methods. It provides useful guidance for those wishing to conduct valuations of energy systems.

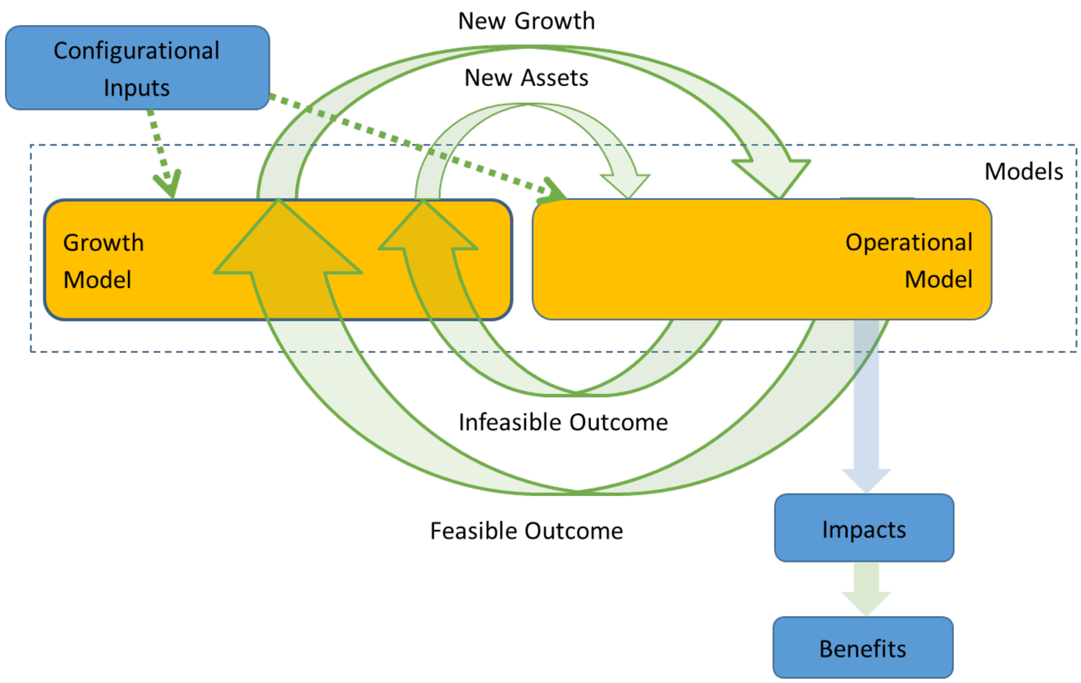

Figure 4.1. Recommended Conceptual Valuation Method

Two types of models are shown. The *operational model* models the performance of a system within a time interval, usually a year, within which policies, infrastructure, resources, and consumer population and behaviors are all relatively static. Very dynamic operations may be modeled, but the rules for the operations remain steady during the short time interval. Time domain simulation is one type of *operational model*, but models may include frequency domain, statistical treatments, or spreadsheet methods as well.

Regardless of the type of *operational model*, the model must be *configured*. That is, the model must be supplied with the circuit models, dispatch strategy, transactive properties, DERs, elastic behaviors, operational requirements, available resources, etc., that will be necessary to represent the energy systems' operations.

If the operations are shown to be feasible (i.e., do not violate operational requirements), the *operational models* inform the impacts and benefits that are being tracked. Installation costs, operational costs, and both monetized and unmonetized impacts and benefits should be attributed to the intervals within which the *operational models* are valid. If through the use of an *operational model* it is learned that an operational requirement is violated (e.g., reserve margin, quality of service, etc.), then the operational model must be reconfigured and retested.

The *growth model* in this conceptual method is the keeper of all of the system's anticipated growth and defines how operations will change from one year, in which an *operational model* is valid, to the next. There seem to be two types of growth. First, the system is challenged by natural, perhaps uncontrollable, changes in energy consumption, inflation, energy prices, and retirements of infrastructure after its useful life, and second, new technology is introduced. This iteration loop is labeled "new growth" in Figure 4.1. In this sense, growth challenges the energy system.

The *growth model* in this conceptual method is also the keeper of all the acceptable responses to the above challenges as well as the costs of such responses. While many prior valuations introduce new *hardware*, or *assets*, the responses may alternatively be in the form of new operational or regulatory policies. These responses are called into play when an *operational model* fails to produce a feasible outcome. The *growth model* supplies one or more responses from its set of acceptable responses, and these alternatives are again tested by the *operational models*.

If more than one response will resolve the operational challenge, then alternative evolutionary pathways are spawned by the *growth model*. Suppose an energy system can resolve an operational challenge by installing one asset "A," two asset "A"s, or an asset "B," or by changing operational policy "C." In this year, four alternative evolutionary pathways are created in the energy system's future. This multiplicity of outcomes may be objected to by practitioners because it makes the effort more computationally challenging. Some relatively sophisticated utilities and planning organizations use capacity expansion models that do look at a multiplicity of outcomes as described above, with the exception of policy solutions. However, far more utilities just manually select a discrete number of alternatives they believe will yield promising results. The problems with manually selecting alternatives are (1) planners may wish to explore alternative selection criteria, which opportunity is lost if alternative pathways are trimmed too early, and (2) the globally optimum pathway from one perspective is revealed only after it is permitted to show its performance over time. Because the components in the system are connected, there may be unexpected cascade effects that make a resource more or less preferable than initially anticipated. The alternatives should be coarsely discretized, and insight should be used to trim alternatives that have no chance of being optimal. Any assumptions used to simplify decisions in the growth model should be acknowledged and clearly stated.

The *growth model* must be *configured* in the sense that the natural growth patterns and sets of objectives and acceptable responses must be declared.

The output from the valuation method as it is described in Figure 4.1 is a series of yearly costs and benefits for each of the treatment and baseline scenarios. Economic treatments are often applied at this point to aggregate all the monetized costs and benefits into a single representation, like a net present cost or an equivalent amortized yearly net benefit. The sensitivity of the outcome may be further explored by perturbing various inputs to the *operational model*, *growth model*, or final economic aggregation. For example, the outcome may be rerun after incrementing or decrementing the expected load growth by 10% to state the valuation's sensitivity to load growth.

Because of the diversity of energy system valuations, it is difficult to prescribe the steps to be taken to conduct a valuation. In the valuation methodology proposed in this report, the structure and content of a valuation is determined by a set of hypotheses and the *benefits*, *impacts*, and models that would support each hypothesis. The basic abstracted method proceeds as follows:

1. Identify a treatment that is to be tested. This treatment is the principal difference between the initial *baseline* and *test scenarios* or how the two scenarios will evolve over time. The application of a TS is the main treatment of interest for this report.
2. Define assets and market conditions to be used in analyses of baseline and test scenarios. The analyst specifies the source of input data, whether it is through research, results of pilot projects, or assumptions.
3. Identify the *hypotheses* concerning how the *benefits* of the *baseline* and *test scenarios* and their evolutionary pathways will differ. The *hypotheses* specify stakeholder(s) who will be affected. Hypotheses should also be specified temporally and geographically to the extent possible.
4. List the metrics that will likely prove and quantify, or alternatively disprove, the listed hypotheses. These are *benefits*. *Benefits* should be monetized whenever possible and assigned to a certain stakeholder.
5. Map how these *benefits* will be derived from other *benefits*. This process stops with *benefits* that can be learned from *operational models*; such *benefits* are called *impacts*.
6. Specify the requirements for the *operational models* that will inform the *impacts*. A useful *operational model* will reveal the hypothesized differences between the *baseline* and *test scenarios* as they evolve over time and will achieve the geographical and temporal granularity desired.
7. Select the specific *operational models* that will satisfy the requirements from Item 6. Make clear where potential impacts are not included in the operational models and what assumptions, if any, are used instead.
8. Configure the *operational models* specific to the energy system under test and the treatment.
9. Configure the *growth model* specific to how a scenario will evolve/grow from time increment (typically a year) to the next, including demand growth and which new assets are available each year. The *baseline's* and *test scenario's* evolutionary pathways in the model might be different if that was the treatment (Item 1).
10. At this point, the valuation is entirely set up and ready to be executed by following these next steps:
11. Confirm that the initial *baseline* and *test scenarios* violate no operational requirements (e.g., line constraints, reserve margins, environmental impact limits) when they are tested by the *operational models* for Year 0.
12. Apply the growth predictions (i.e., load growth, annual equipment replacements, installed cost of DERs, inflation, etc.) within the *growth model* to both the *baseline* and *test scenario pathways.* Some growth predictions will cause assets to be implemented or replaced, which will introduce one-time costs for the new year.
13. Advance the growth model time increment (typically a year).
14. Test the new scenarios using the *operational models*.
15. Depending whether the new scenario violates one of the system's operational requirements,
    a. Violation case: Discard the scenario and formulate an alternative scenario by adding available asset(s) from those in the *growth model* to the *scenario* from which the violation case evolved. Return to Item 13. This step may be repeated if there are multiple reasonable alternative asset candidates. New assets mean that one-time costs are introduced by the new scenario.
    b. No-violation case: Continue.

16. Return to Item 11 until the desired time horizon has transpired, often 10–25 years.
17. Select baseline and test scenario pathways. These will often be the time series having minimum net present values.

The valuation's most important cumulative impact is generally the difference in net present values between the *baseline* and *test scenario* evolutionary pathways. Sensitivity analysis may be conducted by modifying the growth assumptions within the *growth model* and reevaluating. This could, for example, quantify the variability of the valuation under low, medium, and high load-growth rates or varying financial conditions.

The authors' reviews of prior valuation studies led to the following general recommendations for developing valuation methods that are robust and can be used to compare alternative TSs:

- Harmonize terminology – different valuation methods should use terminology similarly.
- Recognize that energy systems are systems of systems – the interactions of subsystems are important and rich and must be accurately represented. Valuations should consider simultaneous grid impacts on generation, transmission, and distribution, as well as end-user and other stakeholder impacts, such as buildings domain and societal impacts.
- Separate growth, operations, and decision-supporting treatments – if operational models are to be shared and reused, the functional interfaces to the models should be independent of growth assumptions.
- Value is broader than net present economic value alone. Representing value only as net present economic value may overlook insights into a complex situation. Decision making may instead be driven by indicators of reliability, resiliency, flexibility, economic risk exposure, etc.
- Many important benefits are difficult to monetize. Benefits of interest should be characterized to the extent possible so they can inform decision making, even if they cannot be monetized.
- Create clear baseline comparisons – every valuation is a comparison between alternatives.
- Allow for extensibility for new cases and value streams – valuation methods should be flexible to accommodate and model alternative TSs and innovative assets.
- Make methods and assumptions visible – valuations will be more trusted if both methods and their assumptions are visible.
- Track valuations using defined signal pathways – cause and effect require communication. Incentives and power are important signals between actors and components in TSs.
- Anticipate that valuations may require differing levels of abstraction or specificity, based on their scopes and data availability. Different levels of abstraction are necessary when detailed data is unavailable.
- Map benefits to an extensible set of stakeholders. Mapping positive and negative benefits to stakeholders allows decision makers to assess the sustainability and desirability of the scenario.
- Adopt standard ways to document valuations. Standardized methods, such as UML (UML 2016), have emerged and should be used to represent valuations.

5.0 Valuing TSs

The previous section introduced the words *benefit and impact.* Those words and *cost* are measures of aggregated value and describe products of valuation studies. This chapter introduces the words *objectives, incentives,* and *responses* to refer to the actions by the TSs to facilitate the exchange of value. As this chapter will more fully describe, an *objective* is what the system is trying to accomplish (a grid service, for example), an *incentive* is the evidence that the TS is responding to the *objective* (a change in price signals, for example), and the *response* is the action or actions that the TS *incentive* elicits that (we hope) addresses the *objective* favorably (a change in energy usage, for example). Other concepts from the last chapter, like *operational* and *growth modeling*, are parts of the valuation process that help us calculate how the TS systems' actions create benefits, impacts, and costs.

Two basic things happen—either implicitly or explicitly—in a TS. First, an *objective* (e.g., peak energy reduction) is valued and reflected in an *incentive* (e.g., an energy price) of the TS. Second, subsystems *respond* to the objectives within their abilities to provide such flexibility, to alter their energy (or other incentivized) behaviors. This report establishes a theoretical basis for valuation of TSs.

The word *incentive* is used here to represent that which either causes transacting entities to change their behaviors or coordinates those changes in behaviors. The connotations of *incentives* being intentional or manipulative in nature must be abandoned in this present usage. For example, incentive signals may be found to reflect the status of negotiations rather than directly elicit participants to change their behaviors.

The functional relationships between objectives and TS incentives may be difficult to define where the effect is implicit within the design of the TS. For example, suppose that an auction-based TE system disallows transport of power into a circuit as the transport infrastructure needed to carry that power becomes congested, as was demonstrated in the Olympic Peninsula study (Hammerstrom et al. 2008). As congestion occurs, increasingly expensive DERs win the right to participate, and the market clearing price (an example of a TS incentive) rises to coordinate the market participants' behaviors. The market price is not at all being manipulated to mitigate transport constraints, but the market design facilitates mitigation of the constraints, and changes in the market clearing price reflect the system's response to that objective.

The responses to the incentives probably require less discussion. Especially where the TS incentive has monetary units, its ability to influence behaviors and elicit responses is understandable.

What is argued by this report is that, if we are to compare the performance of alternative TS mechanisms and frameworks, both the incentivization of objectives and a system's responses to those incentives must be modeled. This is necessarily true because TSs facilitate connections between the objectives and responses. Therefore it is the facilitation or coordination itself that is critical for meaningful valuations of TSs.

Valuations that are based only on available system responses state an envelope of possible responsiveness, but may overstate the responses in light of multiple simultaneous (and potentially conflicting) objectives and objectives that are not, in fact, revealed through incentives. Valuations that are based only on system objectives state an envelope of desired mitigations, but may overstate the mitigations in light of unknown abilities to, in fact, obtain the needed responses from the system.

An example of an envelope evaluation has been appended to this report as Appendix A. The study estimates the total value of smart building control capabilities in the United States if the capabilities were to be applied toward four objectives—capacity displacement, reduction of energy production costs, supply regulation, and provision of contingency spinning reserves. The report's conclusion is that buildings could provide $22 billion worth of these services per year. The analysis methods are clever, but the evaluation does not enforce a strong linkage between the responses and incentivization of the four stated objectives. In fact, no claim is made concerning the mechanism that could engage the responses toward the stated objectives.

Table 5.1 lists some objectives that can be incorporated into TE systems. It also lists the corresponding technologies that would provide the service, participants in the transaction, the measurement or signal that could be used as the basis of a transaction, and a basis for monetization. This list is not exhaustive.

Table 5.1. Example Objectives Potentially Incentivized by TE Systems

Objective	Technologies that Could Provide the Service	Potential Participants in Transaction	Measurement or Signal that Is the Basis of Transaction	Basis for Monetization
Balance energy (at various time scales)	Bulk generation, building automation system, DERs, energy management system, inverter control	Building manager, DSO[b], ESCO[d], generator owners, ISO, prosumer, scheduler, TSO[c]	Energy, forecast errors, load magnitude and forecast, load variability, power, reactive power, reserve margin, resource availability, resource intermittency	Bilateral trades, cost savings, energy costs and tariffs, market clearing price, production costs, value of supplied energy
Reduce transport congestion – manage peak demand	Bulk generation, building automation system, DERs, energy efficiency, energy management system, inverter control, infrastructure upgrades	Building manager, DSO, ESCO, generator owners, ISO, prosumer, scheduler, TSO	Conversion efficiency, energy, forecast errors, load magnitude and forecast, load variability, numbers and severity of congestion events, outage count, outage duration, power, power factor, reactive power, reserve margin, resource availability, resource intermittency, SCADA, unserved load	Avoided cost, bilateral trades, cost savings, energy costs and tariffs, equipment replacement expense, lost revenues, market clearing price, peak demand charges, production costs, value of supplied energy
Provide spinning and contingency reserves	Bulk generation, building automation system, DERs, energy management system, inverter control	Building manager, DSO, ESCO, generator owners, ISO, prosumer, scheduler, TSO	AC frequency, energy, event notifications, forecast errors, load magnitude and forecast, load variability, outage count, outage duration, power, power factor, reactive power, reserve margin, resource availability, resource intermittency, reserve market price, SCADA, unserved load	Avoided cost, bilateral trades, cost savings, lost revenues, market clearing price, reserve product prices, value of supplied energy
Provide frequency support	Bulk generation, building automation system, DERs, energy management system, inverter control	Building manager, DSO, ESCO, generator owners, ISO, prosumer, scheduler, TSO	AC frequency, energy, forecast errors, load magnitude and forecast, load variability, power, reserve margin, resource availability, resource intermittency, reserve market price	Avoided cost, bilateral trades, cost savings, market clearing price, reserve product prices
Enable black start	Bulk generation, building automation system, DERs, energy management system, inverter control, infrastructure upgrades	Building manager, DSO, ESCO, field technician, generator owners, ISO, prosumer, TSO	AC frequency, energy, load magnitude and forecast, power, power factor, power surge at startup, reactive power, reserve margin, resource availability, resource intermittency, SCADA, unserved load, voltage	Cost of customer inconvenience, cost of lost productivity, cost savings, lost revenues, market clearing price, reserve product prices
Defer infrastructure investments	Building automation system, building diagnostics, DERs, energy efficiency, energy management system, infrastructure upgrades, industrial control system, inverter control	Building manager, DSO, ESCO, generator owners, ISO, prosumer, TSO	Conversion efficiency, energy, forecast errors, load magnitude and forecast, load variability, numbers and severity of congestion events, outage count, outage duration, power, power factor, reactive power, reserve margin, resource availability, resource intermittency, unserved load, voltage	Avoided cost, cost savings, deferred costs, equipment replacement expense, lost revenues, maintenance expenses, operating expenses, reserve product prices

Table 5.1. (contd)

Objective	Technologies that Could Provide the Service	Potential Participants in Transaction	Measurement or Signal that Is the Basis of Transaction	Basis for Monetization
Support voltage and var[a] / balance reactive power	Bulk generation, building automation system, building diagnostics, DERs, energy management system, infrastructure upgrades, industrial control system, inverter control	Building manager, DSO, ESCO, field technician, generator owners, ISO, prosumer, scheduler, TSO	Forecast errors, load magnitude and forecast, load variability, phase imbalance, power, power factor, reactive power, resource availability, resource intermittency, SCADA, voltage	Avoided cost, cost savings, market clearing price, peak demand charges, reserve product prices
Support ramping	Bulk generation, building automation system, DERs, energy management system, infrastructure upgrades, inverter control	Building manager, DSO, ESCO, generator owners, ISO, prosumer, scheduler, TSO	Energy, forecast errors, load magnitude and forecast, load variability, power, rate of power change, reactive power, reserve margin, resource availability, resource intermittency	Avoided cost, bilateral trades, cost savings, market clearing price, reserve product prices
Maintain comfort	Building automation system, building diagnostics, business practices / policy, infrastructure upgrades	Building manager, field technician, human resource dept., prosumer	Building system data, energy, forecast errors, sick days	Cost of customer inconvenience, cost of worker absenteeism, cost of lost productivity, output per work unit, value of supplied energy, value of lessee retention, value of worker retention
Maintain productivity – commercial and industrial	Building automation system, building diagnostics, business practices and policy, industrial control system, infrastructure upgrades	Building manager, human resource dept., prosumer	Building system data, energy, forecast errors, sick days, work hours, work output	Cost of worker absenteeism, cost of lost productivity, cost savings, deferred costs, lost revenues, output per work unit, value of supplied energy
Improve system operational efficiency	Building automation system, building diagnostics, business practices and policy, energy efficiency, energy management system, industrial control system, information management system, infrastructure upgrades	Building manager, DSO, ESCO, field technician, human resource dept., ISO, prosumer, sustainability officer	Building system data, energy, event notifications, forecast errors, resource availability, work output	Avoided cost, cost of customer inconvenience, cost of worker absenteeism, cost of lost productivity, cost savings, deferred costs, lost revenues, operating expenses, output per work unit

Table 5.1. (contd)

Objective	Technologies that Could Provide the Service	Potential Participants in Transaction	Measurement or Signal that Is the Basis of Transaction	Basis for Monetization
Maintain equipment and processes	Building automation system, building diagnostics, business practices and policy, energy management system, industrial control system, infrastructure upgrades	Building manager, DSO, ESCO, field technician, generator owners, ISO, prosumer, scheduler, TSO	Building system data, energy, event notifications, forecast errors, GHG emissions, power, reactive power, resource availability, SCADA, unserved load, work output	Avoided cost, cost of customer inconvenience, cost of lost productivity, cost savings, deferred costs, energy costs and tariffs, equipment replacement expense, GHG market prices, lost revenues, maintenance expenses, operating expenses, output per work unit, value of supplied energy
Maintain system reliability, resilience	Building automation system, building diagnostics, business practices and policy, energy efficiency, energy management system, industrial control system, infrastructure upgrades, inverter control	Building manager, DSO, ESCO, field technician, generator owners, ISO, prosumer, scheduler, TSO	AC frequency, building system data, event notifications, forecast errors, numbers and severity of congestion events, outage count, outage duration, reserve margin, resource availability, resource intermittency, reserve market price, SCADA, unserved load, voltage, work output	Avoided cost, cost of customer inconvenience, cost of lost productivity, cost savings, deferred costs, lost revenues
Reduce carbon footprint, improve environmental sustainability	Building automation system, building diagnostics, bulk generation, business practices and policy, DERs, energy efficiency, energy management system, industrial control system, infrastructure upgrades, inverter control	Building manager, DSO, ESCO, generator owners, ISO, prosumer, scheduler, sustainability officer, TSO	Building system data, conversion efficiency, energy, GHG emissions, load magnitude and forecast, resource intermittency	Cap-and-trade market value, GHG market prices, value of supplied energy, value of lessee retention, value of worker retention

(a) var = volt-ampere(s) reactive
(b) DSO = distribution system operator
(b) TSO = transmission system operator
(c) ESCO = energy service company

5.1 Price Discovery and Incentives in TSs

This section addresses the way that TS prices or incentives are determined, which, in turn, represents the way and degree to which objectives are incentivized in a given TS. To date, most examples have addressed transactions in the energy domain. The following three TS mechanisms represent most of the TE system frameworks that have been formulated or tested:

- Bilateral transaction –In much of the United States, wholesale energy is bought and sold today without auction markets. Bilateral transactions between sellers and buyers is the basis of TeMix (Barrager and Cazalet 2014). Proponents of this method point to its simplicity and its ability to address both forward- and spot-market energy exchanges for energy and transport services. As described by Barrager and Cazalet (2014), the energy supplier (or suppliers) states a cost for future hourly energy needs and the transport provider states a cost for the transport of that energy. These costs represent objectives for the energy provision and its transport, and these costs encourage or discourage installation of technologies by location.
- Double-auction market – The energy price is determined by a market clearing demand bids and supply offers at one or more points in the distribution system where power is naturally aggregated. The bids and offers include both quantity and price. This mechanism has been demonstrated in the GridWise Olympic Peninsula Project (Hammerstrom et al. 2008) and AEP GridSMART Project (Widergren et al. 2014a, 2014b). In both of these examples, the base price was determined by an "offer" from the transmission supply to the feeder node, and the price of this transmission supply was the locational marginal price, or LMP (for AEP), or a representation of the region's energy price based on the region's bilateral exchanges. Where an LMP is used in this way, the (marginal) price of energy, transmission congestion, and losses may be known from these price components in the LMP. A goal to avoid local transport congestion may be accomplished by including bids from local generation to clear the market when the system exceeds the supply offer from the transmission system. The resulting higher unit price of the locally generation disincentivizes consumption on the feeders while the congestion occurs. In principle, double auctions may be nested.

  A double-auction market can, in principle, be run on a forward basis, such as day-ahead, or hour-ahead. Such forward markets have not been demonstrated at the distribution level as yet.

  An interesting extension of the double auction is the bidding of devices' entire demand curve, as has been demonstrated by PowerMatcher (Kok 2013). Each device reveals the power that it will consume (or generate) at any given market price. This approach facilitates resolution of distribution system constraints and facilitates discovery of the market price without iteration in radial circuits.
- Nodal cost formulation – Still another method of price discovery was explored by the PNWSGD (BMI 2013 and BMI 2015). A TE system was formulated in which a computational agent represents a contiguous portion of a power grid circuit. Each agent is responsible to economically balance itself using energy that it either imports or generates locally. Each source of imported or locally generated energy has a corresponding unit cost, and a blended unit cost is calculated from those most economical resources that could balance the need for energy. An iterative solution was allowed for the calculation of cost both in the near term and for a series of future time intervals. End users modify their consumption based on the series of future costs that are revealed. In principle, incentives should be created much as for an LMP, but only the energy component was demonstrated in the field. Extensibility was built into the system to anticipate additional new objectives, or operational goals, to be incentivized.

5.2 Elasticity Discovery in TS

Value in a TE system is derived from the system's ability to change its behaviors according to the incentives that are being represented. The incentives work at multiple time scales. If, for example, a distribution line becomes constrained, TE system incentives might dynamically change the price to avoid exceeding the constraint. Over an extended period, however, the high prices that have been induced by the distribution constraint can reveal that a line upgrade might be cost effective. This long-term impact can assist with planning, and reveal where new technologies will be cost effective and not.

This section discusses methods that have been devised thus far to make assets responsive to incentive signals. As was emphasized early in this chapter, the change in behavior must be quantifiable in light of the changes in the incentive.

We start with the clever structure that was defined for agent representations of devices by PowerMatcher. A classification of DER controllability is stated (Kok 2013, p. 152). Table 5.2 shows these classes side by side with the set of agent strategies (Kok 2013, p. 165), plus the category of price-inflexible devices, to which DER devices can be mapped. For example, gas turbines are an example of "freely controllable devices" to which the strategy based fully on marginal cost should apply. Renewable generators happen to be "stochastic operation devices" that are generally "inflexible" to incentives.

Table 5.2. PowerMatcher Categorizations of DER Controllability and Agent Strategies that Can Be Mixed and Matched between the Two Columns (Kok 2013)

DER Controllability	Agent Strategies
Stochastic operation devices	Inflexible
Shiftable operation devices	Based fully on marginal cost
External resource buffering devices	Based fully on price history
Electricity storage devices	Intermediate strategies
Freely controllable devices	
User-action devices	

An advantage of this classification of devices' controllability and agent strategy in PowerMatcher is that software may be written for the device combinations and applied to existing and new device types as they become available to the system. The advantage for valuation is that the agent strategies are precisely the behaviors of the devices that reveal their demand bids as functions of incentive price.

Interestingly, the PNWSGD (Hammerstrom et al. 2015) came up with different categorization. This demonstration employed mostly aggregated, demand-responsive device systems of the type available and used in the United States. Direct demand-response strategies dominate commercially available demand-response systems today. Furthermore, time-of-use strategies contractually limit the number of times and durations that these systems can be applied. For instance, the challenge of selecting no more than five curtailment events per month requires that the device's agent must accurately predict and respond to the few monthly periods that have the highest price signals.

The demonstration therefore categorized its responsive opportunities according to the nature of events that were to be responded to, which then determined the timing of events. The PNWSGD employed a forward price signal, which meant that model-based predictions of device energy consumption were needed. The device models predicted the functional behavior of the devices, including the impact of incentive price on those behaviors. The demonstration's categorizations by event type and device model are shown in Table 5.3.

Table 5.3. Event Types and Device Models for which PNWSGD Load Functions Were Designed

Event Type	Device Models
Inelastic – no events	Water heaters
Event-driven – infrequent events	Thermostatic space conditioning
Daily events	Battery energy storage
Continuous events	Dynamic voltage management
	Smart appliances
	In-home displays / Web portals

The separation of event type and device model allowed some efficiency for code development. Nearly any pairing of event type and device model can be designed. As with PowerMatcher, these models can reveal the changes in modeled device behaviors under alternative pricing scenarios. Unlike for PowerMatcher, the devices' energy behaviors must be modeled to predict their future demand.

The GridWise Olympic Peninsula Project (Hammerstrom 2008) defined the price responsiveness of several device types, including thermostatic space conditioning, water heaters, backup generators, and a municipal water storage pumping facility. Backup generators bid their generation power and the price at which they would economically generate. The thermostats and municipal water pump functionally defined their monetary bids as a function of relative price, stated in standard deviation units. Water heaters' were allowed to heat water during a market interval if their bid was above the cleared market price.

So, what may be done to perform valuations in TE systems that have no explicit mechanism to functionally express the impact of elasticity on energy consumption? At this point, one must fall back to successively more abstract theory of interactions between willing sellers and willing buyers. Game theory might eventually offer such insights and model the behaviors of rational buyers and sellers, but more research is needed.

Humans' behavioral responses to price signals remains an art. The Brattle Group has been able to calibrate its Price Impact Simulation Model (PRISM) (Faruqui et al. 2009) that can predict a shift in consumption and load conservation based on several qualities of the energy system, responsive devices, historic load, and planned pricing signals. But customers' degree of participation naturally changes over time as the novelty wears off and priorities change. The dynamics of human participation is unpredictable, particularly when the human has the ability to override presets or opt into or out of programs and their events at will.

The magnitude of the challenge does not relieve analysts from modeling human behaviors. Much follow-on work is needed to adapt existing human behavior models or create new operational models that predict both humans' most likely actions and the distributions that represent the considerable uncertainty of those actions.

5.3 Survey of Stakeholders' Perceptions about TE Systems

A survey was conducted to assess the current level of understanding among potential stakeholders of TE systems and their value. A list of interviewees was developed to include respondents who both are key industry representatives and have a verified basic awareness (and some understanding) of TE system concepts. Fifteen stakeholders from the following categories and organizations were interviewed:

- investor-owned utilities (National Grid, Duke Energy, and Southern California Edison)
- an ISO (California ISO [CAISO])
- national laboratories (Argonne National Laboratory, Lawrence Berkeley National Laboratory)
- regulators and ex-regulators (one current state regulatory commissioner, and one former state commissioner who was also an active member of NARUC)
- service providers and aggregators (Nest Labs, Johnson Controls, and Enbala Power Networks)
- subject matter experts concerning various diverse electric power topics (four individuals from Navigant).

Interviews lasted 30–45 minutes. Time constraints limited the number of questions that could be asked. The mostly open-ended questions were structured to go from broad to narrow, and covered the following question areas:

- interviewee's understanding of, awareness of, and possible involvement in TE systems
- interviewee perspective on TE systems
- TE system valuation relative to other valuation efforts and approaches
- future development of TE systems (time permitting).

The questions most commonly asked were

- Are you or your company involved in TE systems?
- What is your current understanding of TE systems?
- What do you think is most valuable about TE systems?
- What do you think is least valuable (e.g., drawbacks and risks) about TE systems?
- In what way, if at all, do you see TE systems coming into play in your business or domain of activity? Alternatively, what pathway do you see as most likely for TE systems to come into play in the marketplace or energy ecosystem?
- In which of these do you see TE systems as being important, and in what way?
  - grid–customer (residential, commercial, industrial) interactions and relationships?
  - grid–DER interactions and relationships?
  - intra-building (also often asked about building-to-grid)
  - microgrids.
- Have you or your organization ever tried to put a value on the implementation of a TE system?
  - What aspects of value did/would you try to capture (e.g., monetary, operational, societal, sustainability benefits, reliability, resilience, grid stability, etc.)?
  - How did/would you measure the impact of TE systems in these various aspects?
  - How did/would you go about estimating value?

  - What tools did/would you use, if not already specified?
- How, if at all, do TE systems fit with respect to some of the ISO/RTO wholesale markets (e.g., as an extension of these markets down to the retail or distribution level)?
- How should TE system valuation relate to some of the other valuation methodologies used in electric system planning and operations (i.e., traditional utility cost tests, EPRI/NREL/DOE CBA methodology, value-of-solar type studies, traditional bilateral energy trade negotiations)?
- What factors, developments, and groups or organizations are most important for TE systems to be able to have an impact on the market or industry?

Copious notes were collected during the interviews, but only the high-level summary findings will be presented in the following sections of this report.

5.3.1 Stakeholders' Understandings and Definitions of TE Systems

The interviews make it evident that there is very limited understanding, or even awareness, of TE systems and TE system concepts across the industry. There is a good understanding of TE systems and the value they might bring to the industry and stakeholders within several key thought-leading groups and some vendors that are focused on TE-system-related products and services. But outside of these key groups awareness is very low. There is significant opportunity for education.

A wide variety of definitions of TE systems and perspectives on the concept was found among the stakeholders interviewed. Note that because a criterion of interviewee selection was having some prior understanding of TE system concepts, this is by no means a representative sample of the energy industry and its stakeholders.

Interviewees understood the TE system concept in significantly different ways, with the differences having major implications for the scope and nature of a TE system and the potential value that might be derived. Distinctions fell into three different categories:

- the types of items exchanged between actors that are considered to be part of TE system
- what constitutes a TE system transaction
- which portions of the energy ecosystem are open to transactions.

5.3.2 Stakeholders' Understandings of Types of Items that May Be Exchanged in a TE System

Some stakeholders considered the scope of items that could be exchanged in a TE system to be broader than others did:

- Narrow scope of exchange – Stakeholders whose organizations are strongly defined by the existing power industry tended to see TE systems as being limited to exchanges of energy, capacity, demand, load, and ancillary grid services. This includes the stakeholder categories of investor-owned utility, ISO, RTO, and regulator, plus Navigant subject matter experts who primarily work with these stakeholders.
- Broad scope of exchange – To stakeholders whose organizations are related to the power industry but have other areas of focus, TE systems tend to mean all of the above *plus* the exchange of potentially

many other services and goods. These other goods and services generally impact energy usage and grid functions in an indirect or nontraditional manner, such as increasing energy efficiency or negotiating which assets will provide demand responses. Typical parties possessing this view are research and development stakeholders and (some) service providers, plus Navigant subject matter experts who have significant exposure to this perspective.

The value that can be created and exchanged is very different for each of these perspectives. The broad-scope definition allows value to be created and exchanged for a much larger universe of goods and services than the narrow-scope definition.

In addition to being strongly connected to the dynamic smart-building-services space, the broad definition of TE systems has some overlap with the existing capabilities of building automation systems and emerging Internet of Things concepts and technologies. If the more inclusive view of TE systems is adopted, the momentum of such building-related vendors and emerging Internet of Things technologies might be leveraged to initialize these indirect parts of the TE system infrastructure and capture these receptive customers and other participants.

5.3.3 Stakeholder Perspectives on what Constitutes a TE System Transaction

Separate from the question of scope, respondents were further divided into those who see TE systems as a future scenario and those who believe that it already exists in the form of wholesale markets, demand-response opportunities, and grid-tied DERs. This derives from a difference in viewpoint regarding what kind of transaction is needed for a system to have a TE system nature. The two main points of view are as follows:

- <u>minimalist viewpoint</u> – Some advocate that the existence of a transaction—in the sense of a purchase and sale of a closed-ended quantity of items—is sufficient to be a TE system. To these parties, TE systems are already being implemented in the forms mentioned above.
- <u>greater-constraints viewpoint</u> – Others have additional constraints, such as (1) requiring a two-way characteristic, such as automated negotiation of a demand curve, or (2) the need for the signals exchanged to involve control information, financial information, or both.

The greater-constraints perspective, which views TE systems as a future phenomenon that may or may not come to pass, was more common among the respondents interviewed. Many of those interviewees did consider the existence of wholesale markets, demand response, and grid-tied DERs as important *steps* toward TE systems.

5.3.4 Stakeholders' Spheres of Participation

Finally, a third distinction within respondents' understanding of TE systems relates to the nature and extent of the desired or necessary sphere of transactions. Specifically, this means which actors and pieces of equipment can participate in TE systems. There were three viewpoints in this regard, summarized below:

- <u>Wholesale participation is sufficient.</u> – The minimalist viewpoint described above considers wholesale market systems to be TE systems, including both retailer and aggregator participation in these markets.

- Distribution participation is also required. – Some see TE systems as needing to involve transactions at the distribution level, but not extending to the involvement of equipment or devices. The lack of inclusion of the equipment sphere was a considered opinion of some of the interviewees, while for others it was due to the fact that they had not been aware of the concept of device participation. The belief that distribution participation is required for a system to be TE is the most common viewpoint.
- A TE system spans the range from wholesale markets to devices. – An important component for some is "prices to devices," that is, the ability of equipment or devices to participate directly in transactions, typically via automation and distributed control.

Due to the interview time constraints, questions about the value of TE systems to relationships between various parties (grid–customer, grid–DER, etc.) were not uniformly asked of interviewees. However, of those queried on this topic, the responses were consistent with their view of what TE systems are or should be. For example, the utility that was asked these questions downplayed (but did not entirely discount) TE systems in buildings, whereas service providers saw more value in TE systems for all combinations of parties. Responses from Navigant experts were also consistent with their individual viewpoint on the definition and scope of TE systems.

5.3.5 Stakeholders Observe Need for Regulation and "Rules of Engagement"

Across the board, interviewees from all stakeholder categories expressed that successful implementation of TE systems—and the associated creation and extraction of value—is critically dependent on having a well-designed and well-defined regulatory environment. Stakeholders also pointed to the additional need for a well-designed and well-defined market, whether as a part of a regulatory mandate or as a separate entity.

5.3.6 *Value Objects* and Their Value, as Identified by Stakeholders

Adopting the terminology used by e^3 value, a *value object* is the item exchanged by actors in a transaction. Most interviewees referred to these as simply *values* or *value streams*. In the context of TE systems, *value objects* include at a minimum energy and financial objects (money or other instruments). To those who adopt the broad definition of TE systems, *value objects* include goods, services, and information other than energy and financial objects. An important aspect of *value objects* is that the actual value assigned to them is often "in the eye of the beholder." In other words, each actor may value what is exchanged in a different way, though the object has some value to at least one of the actors.

Many of the *value objects* identified were mentioned by most of the stakeholders interviewed. These include the previously mentioned energy, capacity, demand, load, and typical ancillary grid services. Obviously, money was a *value object* for every interviewee.

Interviewees noted how having the prices of *value objects* to be exchanged allows the parties in a TE system to manage their assets, demand, and load to optimize their value. In particular, many consumers in the existing energy market currently lack the price of energy prior to purchasing it, which a large portion of the respondents interviewed see as disempowering them from capturing or creating value.

Less common, but not infrequently mentioned, was *services*, sometimes specified and sometimes not. A number of respondents referred to services in the context of something that utilities could—and will probably have to—offer to create revenue to compensate for a shrinking rate base.

Although there were many potential negative impacts and risks identified, it is not clear that there is a one-to-one correspondence between these effects and the exchange of a *value object*. In addition, quite a few of the benefits described by interviewees would not accrue directly from individual *value-object* exchanges or types of exchanges. Rather, they would result from multiple different exchanges, complex interactions of exchanges, coupled aspects of exchanges, the features and characteristics of the TE system itself, or combinations of these.

5.3.7 Interviewees' Notable Concerns

Most of the drawbacks and risks identified by interviewees would not be consequences of individual exchanges, but instead be related to the characteristics of the TE system implementation or even its architecture. Cyber security is a prominent example, potentially involving both architecture and implementation. As with benefits, common themes were also evident for negative value and risk. Themes included the following:

- system reliability (this was, perhaps, the most mentioned risk)
- high cost of implementing TE systems or failure to achieve payback of system cost outlays
- system security or privacy issues
- participants gaming the system
- the risk of failure of a TE system market to take hold or perform—on an overall level, for individual actors, or for a class of actors
- system complexity and the associated risks of breakdown, failure to work as intended, or difficulty to operate or manage. This was noted both at the overall system level and for end users, many of whom would likely reject such a system as too time consuming, user-unfriendly, or difficult to understand.
- having potential or likely losers in the ecosystem, in particular base-load generators and vertically integrated utilities.

As mentioned, a variety of the consequences mentioned by interviewees might result from inherent features of the underlying design and structure of the ecosystem, rather than aspects of its implementation. System complexity, security, and (initial) cost fall into this category. How the TE system is implemented can also contribute to complexity and security problems. Several other significant negative impacts, and risks, of this foundational sort were mentioned. Common ones included the following:

- unclear, incomplete, poorly designed, or impossible-to-enforce regulatory environments
- potential inability to either place a well-defined value on, or properly assign participants' contributions to, critical outcomes such as reliability, resilience, stability, and pollution reduction
- potential inability to properly allocate the responsibility for infrastructure or operational costs among multiple actors in the complex TE system ecosystem
- impacts of poor or inconsistent definitions of participants' roles.

On the positive side, interviewees cited many potential benefits that are either not simple functions of *value-object* exchanges or were brought up in the context of their overall societal impact. Oft-cited benefits of this type are listed below:

- deferral of large-scale power plant investment and distribution infrastructure upgrades (most-frequently mentioned)
- improvement in grid reliability, resilience, and stability; reduced congestion
- ability of a variety of parties to sell goods and services (e.g., its effect on the economy or its effect on the viability of current industry participants)
- ability of end users to weather macrogrid performance issues
- reduction in unused and underused resources (in terms of optimized economics)
- lower energy costs for customers
- additional options and services for customers (e.g., home automation that is affordable and requires little human interaction).

5.3.8 Stakeholders' Experience with Valuation of TE Systems

Not surprisingly, very few stakeholders had any experience with valuation related to TE systems. Several utilities have taken a cursory look at the costs and benefits of TE systems, though at a very high, scoping-type level. The lack of a regulatory framework or proven market designs makes doing valuation at any deeper level difficult and fraught with uncertainty.

Service providers have done some rudimentary valuation related to the worth of their product offerings to their customers, or as part of the accounting that takes place as they monitor and control customer assets.

Regulators noted some experience in evaluating costs of production and service, as well as avoided costs. Their decision-making process—which is strongly related to value, even if not in a simple way—is informed more by balances of a wide variety of stakeholder needs and interests than by grid model results and, as one regulator noted, is rife with arbitrariness.

On the other hand, the valuation done by the national laboratory respondent who cited valuation experience was performed with a sophisticated, agent-based model. However, it was limited to issues of integration of DERs and renewables in a standard market.

Finally, Navigant subject matter experts have performed some market-wide modeling and valuation related to demand response and virtual power plants. Their modeling did not include the costs of generation and energy storage, nor did it focus on a single grid at a time.

Of those asked, there was no consensus around which of the non-TE-system valuation methods currently in use would be of value. Each of the four types asked about (utility cost tests, CBA, value-of-solar type studies, and traditional bilateral trade negotiations) had proponents and opponents. In addition, several interviewees were simply unaware of these valuation methods.

When asked about how they would value TE systems, several interviewees pointed out that there is insufficient information upon which to base a valuation. There is no standard definition of a TE system, no regulatory context to consider, and no good prior experience to use as an analogy. Thus, the uncertainty about the outcome of a valuation is too high for their purposes, and they generally identified information needs rather than offering a valuation method.

On the other hand, Navigant experts do use various proxies for value (such as market prices for services), combined with informed assumptions, on a market-wide or region-wide basis. Also, several parties do calculate value to a certain extent but only within their own domain—e.g., metrics related to their products or services provided to their customers. The ISO and regulator interviewees do give significant thought to larger questions of valuation. The ISO respondent studies a variety of methodologies being developed, such as grid architecture and the "time and location" method of Paul De Martini (De Martini and Kristov 2015).

Regulator interviewees had a strong sense of the difficulties involved in valuation and little faith that it can be done accurately at this time. One indicated that models were helpful to him as "due diligence" rather than for direction in decision making.

6.0 Decision-Informing Treatment

Benefits cannot always be monetized, and most decisions involve risk. However, a robust valuation method must quantify monetized costs and benefits, unmonetized costs and benefits, and risks, too. The valuation methodology of Chapter 4.0 supports these purposes. It tracks a series of costs and benefits each growth period. A simple cost model for the TS platform and other simple asset costs will be established in Chapter 7.0, which costs may be compared with monetized benefits. No limitations have been placed on the selection of benefits, impacts, or operational models that would preclude tracking unmonetized benefits. It has perhaps not yet been made fully clear that the methodology supports sensitivity analyses and the propagation of uncertainty, but this chapter makes a case that it does.

Decision theory and multi-criteria decision-making approaches, like the Analytic Hierarchy Process (Wind 1987), might be useful here. Such methods account for the inherent uncertainty of forecasted outcomes and the risk preferences of the decision maker. This chapter discusses conventional economic treatments, methods for comparing unmonetized benefits, and the propagation and assessment of risks. The perspective of this report is that valuations should support various alternative decision-making criteria; the decision-making process should not itself be too closely integrated into the valuation methodology.

6.1 Conventional Economic Treatments

This section recognizes conventional economic treatments that can represent a rich series of costs and monetized benefits by a single number. The report's valuation methodology can set up the problem (i.e., a series of costs and benefits) well for such treatments. Most readers will be familiar with these methods, and this report does not claim to improve such methods. Therefore, only net present value will be summarized. Other conventional economic treatments could have included average amortized cash flow or an investment's calculated rate of return. Such conventional treatments lend strong support for decision makers if the net monetary impacts are most important.

An example of a conventional economic treatment is net present value (NPV). The NPV method includes the initial cost of an investment and also the net differences between benefits and costs for multiple future growth periods. One or more rates (e.g., discount, tax, inflation) modify costs and monetary benefits as they become translated through time to their present equivalent value. Although the NPV is a single value, cash flow is calculated on a yearly basis. The accumulated value minus the initial cost of an investment is the NPV. Equation 6.1 shows how the NPV is calculated.

$$\text{NPV} = \text{Initial cost of investment} + \sum_{n=1}^{N} \frac{\left(\text{Benefits}_n - \text{Costs}_n\right)}{(1+r)^n}, \tag{6.1}$$

where, r is a discount rate and $n \in \{1, 2, ..., N\}$ is the year (or some alternative growth period).

A limitation of this and other conventional economic treatments like NPV is that all benefits and costs must be monetized, which is difficult or impossible. Also, the value of money, as represented by the various rates r, changes over time. And what if the decision maker's objective is to select not the highest payback, but instead the time series that has the least likelihood of a negative payback? These potential limitations were among the authors' motivations to keep the costs and benefits separated by year in the report's valuation methodology. Furthermore, any of these treatments might be considered from each stakeholder's unique perspective.

6.2 Utility of Unmonetized Benefits

Environmental benefits (national scale and global impact) and occupant comfort (building scale and local impact) are two examples of unmonetized, sometimes unmonetizable, impacts that are the topic of this section. The first approach to be described in this section attempts to apply monetary values, even though no market is available to discover such monetary value. A second approach is necessary when it is deemed unsuitable to monetize the utility[1] of a benefit.

Value may be measured in terms of consumers' *willingness to pay* or their *willingness to accept*. These concepts sometimes allow assignment of monetary value where monetary value is not commonly assigned or where no market is available to establish monetary value. Using the concept of *willingness to accept*, economists assess the value of an asset as what a consumer would be willing to pay to use or enjoy its benefits. The value of a public asset—clean air, for example—is the total amount the public would be willing to pay for the asset if they truly had to pay for it directly. Measuring what consumers are willing to pay or accept while they do not really have to pay for it directly is challenging. Different methods have emerged to estimate the value or utility of unmonetized benefits.

Direct methods *directly* survey people about their *willingness to pay* or *willingness to accept*. Conducting a *direct* method is time consuming. It is expensive to interview people and to conduct surveys. More importantly, respondents may not possess a good sense of how much they are, in fact, willing to pay or accept for a good or service. Respondents may not yet know how the good would impact their lives. The reliability and accuracy of a *direct* method can therefore depend on how familiar the respondents are with the goods and with related topical information, like environmental issues, for example, that might affect the respondents' answers (Baker and Ruting 2014).

In *indirect* methods, people's *willingness to pay* or *willingness to accept* are estimated based on their payments for assets that they are, in fact, paying for. The method asks what the consumer already pays for the equivalent utility that would be available from or supplied by the alternative good. The advantage of the *indirect* method is that it represents peoples' actual behavior.

Although its direct and indirect data collection approaches may be similar to those above, multi-attribute utility theory places less emphasis on equivalent monetary value. It instead lays a foundation for the ranking or weighting of a good's or service's many attributes. To support multi-attribute utility theory, the analyst should identify (1) the stakeholders whose utilities are to be maximized, (2) decision objectives or attributes, (3) alternatives to be evaluated, and (4) the relevant dimensions or levels of attributes for evaluating alternatives.

In the example given in Figure 6.1, some stakeholders' decision objectives are stated in terms of the utility of unmonetized benefits. There might be different stakeholders involved in the valuation of unmonetized benefits for TE systems; however, the objectives involved might be similar to those shown here.

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[1] The word "utility" in this section will almost always refer to the suitability of an item for its purposes, not an electrical utility.

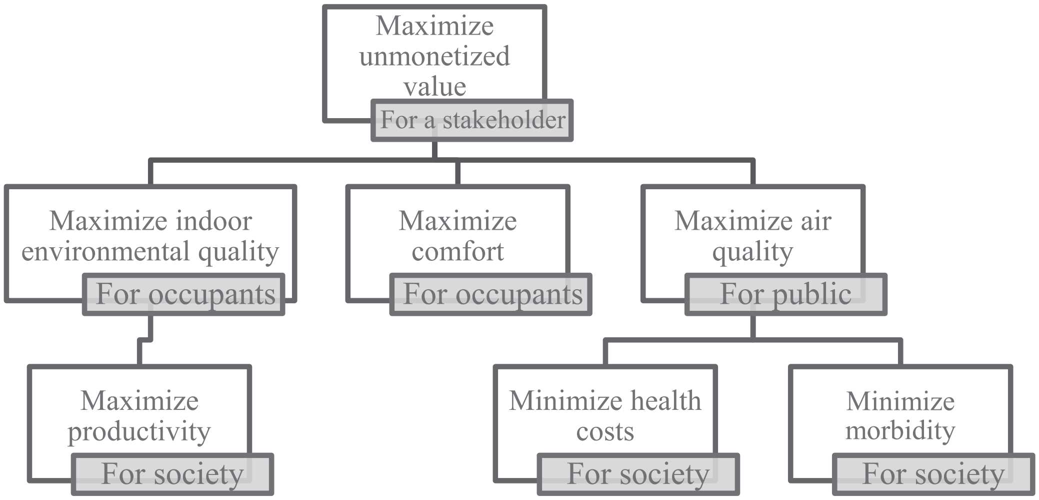

Figure 6.1. Example Hierarchy of Objectives to Consider for Valuation of Unmonetized Benefits

Multi-attribute utility theory is a method to weigh all of the attributes and to scale them by the level of importance to the stakeholder (or decision maker). An *attribute* is a measurable quantity defined based on an objective and measured using summary statistics of data collected. An attribute is considered quantifiable if it is possible to (1) obtain a probability distribution for each alternative over the possible scales of the attribute and (2) assign levels or ranks for decision makers' preferences. Equation 6.2 represents the utility functions based on multi-attribute utility theory. In this function, $U(v)$ is the overall utility of an alternative, $a(i)$ is the magnitude of the alternative being evaluated for the i^{th} attribute, $u(i)$ is the value of the i^{th} attribute, and n is the number of attributes identified. That is, the overall utility of an alternative is simply the weighted sum of its attributes.

$$U(v) = \sum_{i=1}^{n} a(i)u(i) \tag{6.2}$$

6.3 Treatment of Risk

In any valuation, the decision maker has to make a choice among potentially risky alternatives. Choices are risky because of the uncertainty involved. If risk aversion plays any role in decision making, then the distributions of outcomes must be propagated and used during valuations. The previous two sections have been focused primarily on the most likely impacts that can be identified by a valuation study, whether they can be monetized or not. However, a valuation methodology must also anticipate risk aversion as a potential decision maker's criterion. Standard ISO 31000 (2009) concisely defines risk as the "effect of uncertainty on objectives." The sources of these uncertainties during a valuation are model inaccuracy, natural variability, and uncertainty. This section looks at necessary qualities of a valuation methodology if it is to support making risk-informed decisions.

Modeling inaccuracy. This report has made a case that the valuation of TSs requires enforcement of the linkages between the system's responses and the incentivization of operational objectives that occurs through the TS. Because many TS platforms are relatively new, there remains considerable discretion for analysts concerning how they model the workings of the TS. Admittedly, system models also differ in the rigor with which the systems are modeled. This source of risk is somewhat unavoidable. Honest disagreements will persist about system models and modeling methods.

This report has addressed this risk by advocating for the transparency of models and methods. Specifically, Chapter 8.0 *will advocate that valuation studies be accompanied by UML diagrams that make transparent assumptions about the TS that is being investigated and the operational models that are being used to quantify its impacts.*

Natural variability affects risk. Buildings, for example, differ by size, thermal mass, and thermal insulation quality, among other things. A population of buildings will therefore produce a distribution of energy usage, and the comfort levels of the buildings' occupants will also lie on a distribution.

This natural variability may not have been especially important in a conventional valuation study, where, from the perspective of the distribution utility, the aggregate load is all that is important. In TSs, however, the distributions may represent the natural variability in transacted values that are of interest. In the light of baselining, baseline distributions must be subtracted from those of the test group, and the distributions should be propagated until the distributions of important impacts are learned. Among the population of stakeholders, there may be both winners and losers concerning the buildings' energy performances and occupant satisfaction. It is inadequate, from a risk perspective, to rely solely on the average, most likely aggregate outcome.

This report therefore advocates that the natural variability of data should be included and propagated to the impacts that will guide decision makers. Continuing with the building domain example, the decision maker could now review the distributions of building outcomes and accept a scenario based on the numbers of "losing" buildings in the population or in the bottom quartile of impacts, for example.

Other places where natural variability may be relevant include weather, human responses, and coincidence of especially short-lived events.

Uncertainty. There are also numerous sources of uncertainty that could affect the outcome of a valuation. The distributions discussed in the preceding paragraph may possess uncertainty in both their expected values and in their distributions. Those conditions that drive system growth—load growth, technology penetration rates, and equipment lifetimes—are also uncertain. Economic rates (discount rate, interest, tax) and regulatory policies may change.

The conventional method for addressing uncertainty is sensitivity analysis, which can be applied with this report's recommended methodology. An uncertainty boundary is created around an uncertain parameter. For example, the load growth rate might be perturbed by first adding, then subtracting, 10% of its value. The methodology is rerun for each extreme to test the sensitivity of the valuation in this range. It is theoretically possible, but will usually be impracticable, to test all possible permutations of multiple uncertain parameters. Sensitivity analysis is usually conducted for one parameter at a time.

Conventional sources of uncertainty are well addressed by existing sensitivity analysis techniques. This report recommends that inputs should be varied about their nominal values to explore and report the results that such variations would have on the valuation study.

7.0 Model for TE System Platform and Other Costs

This report treats a TS as a communication and control layer, or platform. Depending on the specific TS that is the subject of the valuation, the TS will require installation of various distributed and centralized components. A scenario may also include responsive assets that interact with the TS in addition to the communication platform itself. The growth model may include conditions for aging and replacement of aged equipment, including the components of the TS platform. This section recommends how these cost components can be modeled so that the costs are objectively estimated as the system grows or ages.

The approach described in this section is a special instance of a more general approach for quantifying static costs and static benefits, both of which are trivially calculable based on numbers of new and existing unit installations and corresponding unit and yearly costs. Trivial operational models could be implemented to quantify these static costs and monetized benefits, but most analysts will probably forgo that formalization. The formalization is necessary, however, whenever costs and monetized benefits might be dynamically affected by a scenario's transactions. Then, the operational models could be augmented to include functional relationships with weather or whatever inputs might be important to the quantification of the cost or benefit in light of anticipated transactions.

The following is a list of possible static costs and monetized benefits. The cost of a TS platform is included in this list ("communication platform costs"), but many other examples are listed as well. As was discussed above, scenarios exist under which each listed cost or monetary benefit must be alternatively formulated more richly as a dynamic cost or benefit.

accelerated depreciation
ancillary service costs
ancillary service payments
asset capital costs (purchases)
asset resale value
capital costs
communication platform costs
customer billing expense
customer incentives
cyber security costs
data storage and management expense
distribution management system (DMS) software
DMS operations and maintenance costs
entitlement-related benefits
environmental compliance costs
finance of debt
grants
insurance costs and benefits
integration costs
meter reading expense
mortgage premiums
operations and maintenance costs
production tax credit
program/project administration costs
program/project evaluation costs
program/project marketing
property tax
rebates
rent/lease costs
sales tax exemption
sales tax expense
service disconnection/reconnection costs
software expenses
staff labor expenses
subsidized lending
tax credits and incentives
tax credits to participants
transaction costs[1]
verification and validation expenses

[1] Transaction costs could be so regularly incurred that they are predictable and need not be calculated with an operational model.

7.1 Parametric Cost Model for a TS Platform

This section lays out an approach for the calculation of the static costs of a TS. This model might be thought of as a trivial operational model, using this report's terminology. We assume that the TS may be treated as a communication (or control) platform. The costs will be defined parametrically—in terms of a set of defined variables. The costs are ultimately stated each year based on an inference of the numbers of devices that are newly installed in a year and those that exist during the year. This approach is useful if the cost of a system is to objectively be hypothesized as the TS matures and as its penetration increases.

We assert the following assumptions that are applicable to not only the costs of a TS platform, but all static costs:

- Equipment and system components are replaced, as needed, by the same equipment and components.
- By default, equipment is purchased and maintained by the owner of the location at which the equipment becomes installed. Today, however, much smart grid equipment is being purchased by utilities.
- All costs are based on Year 0 dollars, regardless of when equipment is, in fact, installed.
- New equipment is not installed unless triggered by the growth model.
- The following are reasonable default equipment lifetimes that may be modified by analyst:
  - Appliances – 20 years
  - Electronic and communication equipment – 5 years.
- If data storage is specified for the TS mechanism or platform, all TS data is stored by the distribution utility or utilities.
- Data storage equipment needs are triggered by transaction volume and numbers of business entity participants.
- Utilities, regulators, and market operators require the equivalent of one or more servers to participate in the TS. The numbers of servers should be stated proportional to peak calculation requirements (e.g., servers/peak gigaflops) and communication bandwidth (e.g., servers / MBps) at the system locations, rounding up to the next whole number of servers.[2]
- Customer premises and other sites require the equivalent of a personal computer to participate in TSs.[2]
- Devices require the equivalent of a microprocessor to participate in a TS.[2]
- We propose that the cost of a TS platform is functionally relatable to the following parameters:
  - y – one of multiple years in a valuation period[3]
  - y^* – the year of installation

[2] If computational platforms like servers, computers, or microprocessors already exist, some or all of the costs of these hardware platforms may be defrayed and represented by software and firmware costs instead.
[3] We will presume a growth period is one year in duration for this formulation. Other periods are allowable.

- l – location, using an enumeration of locations that are relevant to the valuation (e.g., residential homes, residences on a feeder phase, a specific feeder, substations, a specific substation, transmission system, a specific transmission circuit, generator sites, wind generator sites, a specific wind generator site)
- b – buyer, using an enumeration of stakeholders that are relevant to the valuation. The buyer is the entity that pays the installed cost of the item for accounting purposes.
- o – owner, using an enumeration of owner-stakeholders that are relevant to the valuation (e.g., residential customers, distribution utilities, a particular distribution utility, generating companies, the owner of a particular wind farm). The owner owns the device and has the right to transfer, remove, or sell it. An owner might have residual monetary value in a device at the conclusion of a valuation period.
- d – device, using an enumeration of all the devices that are relevant to the valuation (e.g., thermostat, water heater, DMS, lighting, clothes washer, in-home display, web portal, mobile device). The word "device" should not imply physical infrastructure here, as it may be used to track software, a system of devices, labor units, or even intellectual property costs.
- $F^*_D(d, y, y^*, b, o, l)$ – fraction (%) of installed cost of device d to buyer b that should be incurred in the present valuation in year $y = y^*$. The default value is 100%. This term affects only installation costs to the buyer; ownership is unaffected.
- $F_D(d, y, \text{-}, b, \text{-}, l)$ – fraction (%) of recurring cost of device d to buyer b that should be incurred in the present valuation in year $y \geq y^*$. The default fractional value should be the same as $F^*_D(d, y, y^*, b, o, l)$. This term affects only recurring costs to the buyer. Ownership and year of installation are irrelevant and are therefore represented by dashes (i.e., "-").
- $N^*_D(d, y, y^*, b, o, l)$ – number of devices d installed in year $y = y^*$. The number of these devices installed and useful in years $y > y^*$ may also be represented in this way.
- $C^*_D(d, y, y^*, b, o, l)$ – installed unit cost ($/unit) of device d installed in year $y = y^*$. The residual value of the device to an owner o may be also represented this way in any year $y > y^*$.
- $C_D(d, y, \text{-}, b, \text{-}, l)$ – total recurring cost ($/yr/device) attributed to device d in year y. Buyer b is the entity that pays the recurring cost. The year of installation is irrelevant. This is a sunk cost, so the owner is irrelevant.

The general strategies for keeping track of static costs like those for the TS platform are described next. *New rigor has been introduced in this section to allow costs to be tracked by device, year, buyer, owner, and system location.*

<u>Installed costs of devices.</u> The total installed cost of the devices d installed in year y, which happens to be the year y^*, by buyer b and owner o at location l is simply the product of the number of each type of device and the unit cost of the device. In some cases, only a fraction of a device's cost will be allocated to the valuation for the purposes of a cost-benefit assessment.[4] The lists of parameters for devices, years, buyers, owners, and locations remind us that costs (and benefits) might be unique to these sets. If the

[4] In some cases, a fraction of the cost of an asset may be omitted from the valuation if the asset's usage, and therefore its costs, are to be divided among the scope of the valuation and other scope that is not part of the valuation. The device might have already been installed—for example, for an earlier purpose.

devices, years, buyers, owners, or locations do not need to be tracked, sums may be conducted over all, or subsets of, the parameter enumerations.

$$F_D^*(d, y = y^*, y^*, b, o, l) \cdot N_D^*(d, y = y^*, y^*, b, o, l) \cdot C_D^*(d, y = y^*, y^*, b, o, l) \qquad (7.1)$$

It is a good practice to make sure that all costs of a device are accounted for.

This method is flexible enough for situations when buyer *b* is not the same as owner *o*, as happens often. A utility sometimes invests early in innovative smart grid equipment by providing much of the device's purchase price, but the recipient owns the device either immediately or after a defined waiting period.

All static one-time costs that can be attributed to the installation of a device should be addressed using this practice. The costs may be lumped together if they apply to the same subset of devices, buyers, owners, and locations that are to be tracked during the valuation, but they may also be tracked separately. For example, an inspection fee was applied for the installation of modified devices at residences. Because the cost could be specified by the number of installations, the additional cost could be lumped together with the rest of the device's installed costs. But it may also be defensible to track the additional cost separately because the modification cost might be avoided if the modification later becomes available in commercial off-the-shelf devices. The separate accounting can be accomplished simply by defining a new "device" whose installation perfectly correlates with that of the device that triggers the additional installation cost.

Most TS platforms will be found to include some form of intelligent agent. An intelligent agent should be treated as a special class of device, the quantity of which should be a function of numbers of participants and locations in the system. TSs that do not use agents for the control of system assets will still possess communication infrastructure that should be accounted for similarly.

Some static costs are triggered not by individual devices but by a system or grouping of the devices. An example is an integration cost. The integration cost is incurred as the buyer learns how to use a new device or new pairings of devices. The suggested method can readily accommodate this type of cost by defining a device *system* or other superset.

The method can also accommodate static monetary benefits. Suppose that the installation of a TS is accompanied by a grant, energy efficiency rebate, tax deferral, or other positive outcome that will affect the net TS cost. The method is readily extended to account for this monetary benefit. The rigor of the method should facilitate the accurate representation of stakeholders (e.g., as buyers and owners) like grant providers, states, and taxpayers, who are sometimes glossed over in valuations.

<u>Recurring costs for devices</u>. The following expression calculates the total recurring device costs borne by buyer *b* at location *l* toward maintaining device *d* in years *y* of the valuation period. If the valuation will not be separately assessed for devices, locations, or buyers, the expression may be summed over these sets.

$$F_D(d, y, -, b, -, l) \cdot C_D(d, y, -, b, -, l) \cdot \sum_{y^* \le y}^{y} N_D^*(d, y, y^*, b, -, l) \qquad (7.2)$$

The main difference between this calculation and the one advised for static installation costs is that the number of devices must be summed from the numbers of devices installed in prior years. In the simplest case, all installed devices installed in prior years are assumed to still exist in year y. However, more sophisticated valuations will require that the remaining numbers of devices are modified by the growth model. Devices may fail. Customers move away, taking their devices with them. Devices, especially electronic devices, might need to be periodically replaced.[5]

7.2 Role of the Growth Model in Static Costs

The growth model has some implications for the treatment of static costs and static monetized benefits like those from the TS platform. First, if the system is to be installed incrementally, the growth model must specify how many of each device are to be installed each year. Conversely, if the devices must be periodically replaced, or if the likelihood of device failures can be predicted, then the growth model must state these replacements or must predict the numbers of failures.

The growth model must trigger recurring costs and recurring monetary benefits, too, each year of the valuation period.

[5] If all devices are to be replaced by the same device, the treatment may be simplified. However, the general method allows for changes in device installation costs over time as the technology matures, in which case the device lifetimes and replacement and failure rates are important.

8.0 Standardized Modeling of Business Value and Value Activities for TSs

One overriding challenge of recommending a TS valuation methodology has been to retain the flexibility needed to accommodate many diverse valuation purposes and many diverse TSs. A level of abstraction must be maintained that will allow extension of the methodology to diverse scenarios. Table 8.1, for example, explores whether such abstraction can be facilitated through requirement definition. The structural characteristics of TE systems—ownership and extension across spatial and temporal boundaries—might be accommodated by defining abstracted feature requirements.

Table 8.1. High-Level Structural Characteristics and Abstraction Feature Requirements

TE System Structural Characteristic	TE System Abstraction Feature Requirement
Transactive resources are distributed across ownership boundaries	Need to define layers of ownership and value abstraction; resources associated by ownership as a property of a resource
People and TSs may be interacting with each other, also across ownership boundaries	Need to define the exchange of value between system elements, grouped by ownership properties
Security, management, and governance are distributed across ownership boundaries	Need to accommodate the value of such services separately as system elements
Interaction between people and systems is primarily through the exchange of messages or data with reliability that is appropriate for the intended uses and purposes	The exchange of information may be used as a proxy or signal that represents one exchange and flow of value in the system

Object-oriented methods might also help define the problem at the right level of abstraction. UML (2016), for example, was originally intended to standardize the representation and development of software designs, but it has been extended to design non-software systems and to represent business practices. UML supports seven types of structural diagrams (e.g., class structure diagrams) that show the relationships between objects. It also supports seven types of behavioral diagrams (e.g., use-case diagrams) that specify processes and behaviors of objects and systems. This chapter will recommend two specific usages of UML for organizing and documenting TS valuations. Section 8.1 introduces e^3-value modeling that can be represented as UML use cases. The graphical model should help define and document the exchange of business value as we evaluate transactive mechanisms. UML is also strong for documenting process activities, and is recommended to represent operational models in the valuation process in Chapter 4.0.

8.1 Modeling Business Value

Modeling business value is different from modeling business process. Jaap Gordijn and Hans Akkermans developed a compelling conceptual business modeling approach called "e^3 value" (Gordijn and Akkermans 2001). The approach was originally developed for e-business, but examples have now been formulated in other domains. Perhaps the most relevant prior work is documented thoroughly by BUSMOD, a consortium promoting DG (Kartseva et al. 2004). The purpose of that report was to develop and test business cases for DG in electrical power systems. However, the report is also found to include tutorial sections how e^3-value diagrams ought to be constructed. One of the most comprehensive examples of an e^3-value diagram from Kartseva et al. (2004) is shown here as Figure 8.1.

At one point in Kartseva et al. (2004), the process of developing an e^3-value model is referred to as a methodology. Indeed, the following steps (p. 99) are shown to document a business case and provide the context with which the financial positions of the business case's actors may be evaluated:

1. concise statement of the business idea
2. identification of the strategic and operational goals of the business case
3. identification of possible technological solutions
4. building the (graphical) value model
5. building the financial model (stakeholder profitability calculations)
6. performing sensitivity analysis.

The above steps emphasize the creation of, and testing of, a business case (in this case, for DG), but the principles are pertinent to the valuation of TSs. Step 4 results in lists of the business case's *value activities*, through which at least one stakeholder (actor) might profit. The *value activities* are argued to follow from the business case's long-term strategic goals and nearer-term operational goals. They are the activities through which the operational goals of the business case may be achieved. For example, a building consumes energy (a *value activity*) to keep its residents comfortable (an operational goal). The value activities are then allocated among the stakeholders, who may be further aggregated into *sectors* if they share the same business value propositions. For example, the sector "electricity consumer" might be used if all such entities have similar operational goals.

The *value activities* reveal exchanges of *value objects* that are represented in the diagrams by labeled arrows. The exchanges of the *value objects* are formalized through interfaces, which conceptually bind the necessary pairings of the *value objects* with their respective *value activities*. A common pairing in electrical energy applications, for example, is the exchange of monetary payments for supplied energy. These two *value objects* are not separable. If one happens, the other also must.

One or more *scenario paths* (red lines in Figure 8.1) are overlaid on the diagram to indicate precisely which *value interfaces* are relevant to a scenario, without necessarily prescribing process order. The *scenario path* preferentially begins with the ultimate consumer in the value chain and terminates at the supplier or suppliers of the value chain. The *scenario paths* can split and rejoin to represent either parallel segments (an AND fork) or alternative segments (an OR fork) of the *scenario path*.

A strength of e3 value is that it rigorously defines and tracks the exchange of value in respect to stakeholders, which is also critical for TS valuations. Once the e3-value graphical model has been completed, the financial position of each stakeholder (or sector) in the business case may be calculated as the net sum of monetary value objects that enter and leave the stakeholder's box in the graphical model. An intrinsic assumption of the corresponding financial model (step 5) is that no business case can be long-term viable if any of its stakeholders loses money. This is a strong guiding principle for business modeling and forces analysts to consider not only the global benefit, but also the stakeholders' individual benefits.

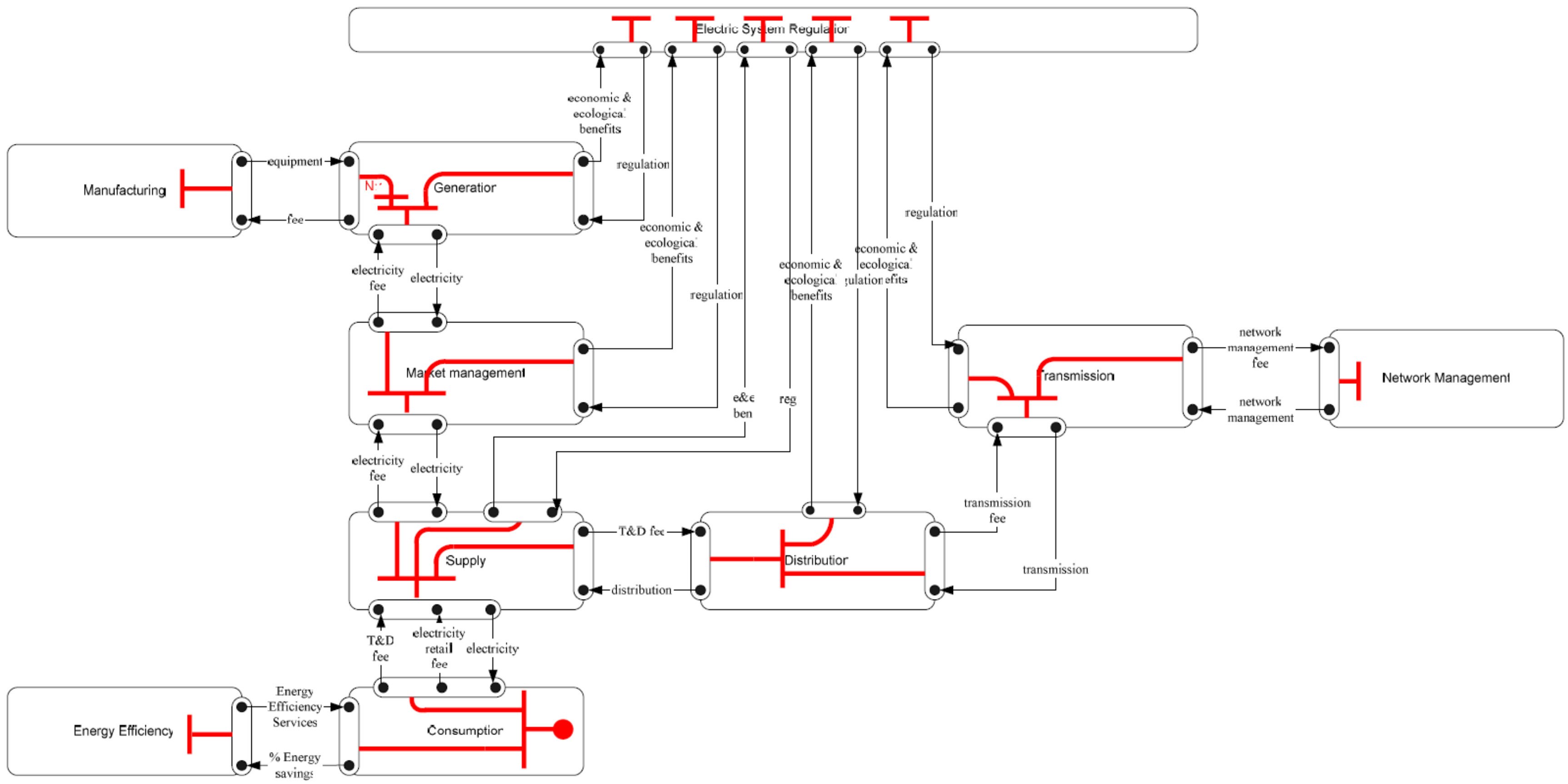

Figure 8.1. Example e[3]-Value Diagram Concerning a DG Business Case with Regulation Services (Kartseva et al. 2004, Figure 29) (Permission Free University of Amsterdam)

Step 6 extends the financial model by investigating the sensitivity of the financial model to perturbations. The results of the sensitivity analysis reveal directions in which the business case could be adjusted to make it viable for all its stakeholders, if it was not already.

The following common mistakes are listed in Kartseva et al. (2004), and the authors of this report confirm that these mistakes are very hard to avoid:

- modeling physical processes, not business value
- modeling information exchange[1]
- modeling investments (which should not come into play until the last steps of the business modeling process)
- excluding important alternatives.

The first two mistakes remind us that business value is not the same as business process. This warning has important implications for the representation of TSs. The TS transaction mechanisms and the things actually being transacted by a TS have to do with process and signal information. That is, a TS transaction and its signals are not necessarily e^3-value *value objects*. The TS mechanisms and platforms instead define processes by which *value objects* can accomplish the system's operational goals. While the TS transactions are not necessarily *value objects*, the accounting of *value objects* for the purposes of completing the financial model (e^3 value step 5) must reflect the way a TS might affect accumulation of *value objects* in the financial model. Two scenarios having different TS mechanisms or platforms could be used to manage the same set of *value objects*.

Suppose, for example, that a distribution utility incurs demand charges from its energy supplier, and the charges are based on the single peak hour each month. Such demand charges can and have been incorporated as an incentive into a TE system. The energy supplier today implements the charges as part of a rate structure, not a TE system, to account for the impact of, if not mitigate, peak demand. The distribution utility may partake in a TE system to mitigate and flatten its peak demand and thereby offset its demand charges. This is an objective. The distribution utility should declare that demand charges and monthly peak demand are its value objects that can account for its success toward its objective. The TS incentivizes the objective by somehow disincentivizing demand during hours that might coincide with the monthly peak, perhaps by increasing an energy price signal. The signal, however, is much about information and process and does not itself necessarily state business value. The utility customer does not need to know the utility's objectives or business values and vice versa. From the customers' perspective, they may be willing to exchange demand flexibility (a value object) for bill reduction (another value object). The demand flexibility might be additionally connected to thermal comfort or other of the customer's valued objects and objectives. This example was offered to differentiate business value from processes and information.

Chapter 5.0 of this report advocated that operational models must enforce the linkage between operational objectives and the system's responses. If two alternative TSs are to be compared, these observations imply that a single e^3-value diagram must be developed, and the two TS scenarios (1) might

[1] Although in (Kartseva, Gordijn and Tan 2004), a value object is further defined as services, products, money, or even consumer experiences.

follow different *scenario paths* through the diagram, and (2) must necessarily model enough of the TS processes to differently affect the accumulations of various *value objects*.

In Huemer et al. (2008), the e^3-value diagraming process is mapped to UML. The conclusion of that paper is that UML use-case diagrams are suitable for representation of e^3 value. Only minor limitations are encountered if *value activities* are modeled as use cases and *value-object* exchanges as UML information flows. The diagrams' similarities are even greater when UML use-case actors (sectors) are shown using block representations instead of stick figures. This mapping is important because of the wide acceptance and standardization offered by UML. UML diagrams offer an engineering formalism that could elevate the practice of valuation studies and perhaps enhance the standing of valuation studies' results with their audiences.

Consider this additional insight concerning how business value modeling can help TS valuation. Chapter 5.0 insisted that a TS valuation represent the coupling between the incentivization of operational objectives and the system's responses in light of that incentivization. That advice can now be further cast in light of this chapter's discussion of business value. The *operational objectives* discussed in Chapter 4.0 refer to *operational goals* on the initiation side of a *scenario path*, and the system responses refer to a *value object* at the termination end of that *scenario path*. *In this context, scenario paths precisely represent the coupling between a system's operational objectives and its responses via the TS.*

8.2 Example Business Value Use-Case Diagram

This section offers an additional example of the application of e^3-value principles and UML use cases to the valuation a TE system. The purpose of this chapter has been to make a case for the power of UML and e^3-value modeling for TS valuation, and in the practice of valuation more generally. The example demonstrates some of the power of business modeling, but it is known to have violated some of the principles taught in Kartseva et al. (2004), primarily by its not representing *scenario paths*.

Figure 8.2 is meant to represent business values that are exchanged by stakeholders in the Olympic Peninsula field demonstration (Hammerstrom et al. 2008), in which a double-auction market was operated to coordinate distribution-customer demand management and DG. The system emulated the impacts of market transactions for procuring bulk energy, and the double-auction market price was allowed to rise at times the feeder became congested.[2] Therefore, important operational goals in this scenario were to (1) help mitigate the causes that elevate bulk energy prices[3] and (2) avoid feeder congestion.

[2] The power carrying capacity of the feeder was artificially reduced to prove the concept in this field demonstration. The dynamic price was necessarily emulated because the impacts of bilateral transactions for bulk power could not be known until at least a day after the transactions.

[3] Unfortunately, the specific causes for price fluctuations where prices are determined by bilateral agreements cannot be explicitly known. We might infer that the energy prices change due to production costs, load, transmission congestion, system losses, etc., but these goals are not made transparent. The impact of feeder congestion, in this case, is estimable from its observable impacts on the double-auction market price.

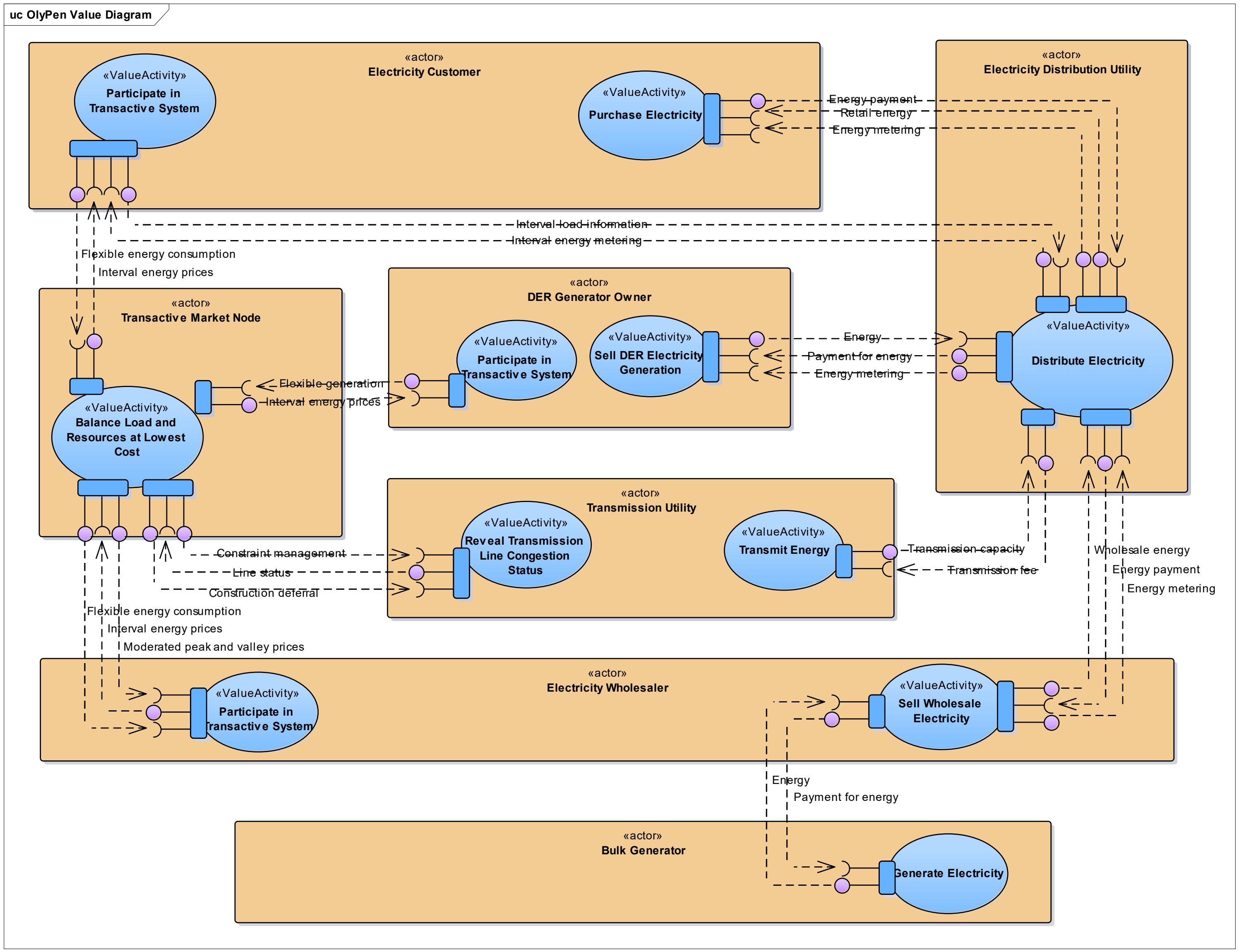

Figure 8.2. UML Use-Case Diagram Example of the Olympic Peninsula Project's (Hammerstrom et al. 2008) TE System based on the Principles of e^3-value Diagrams (Kartseva et al. 2004)

At least seven unique stakeholders are relevant to business value for this scenario.[1] The right-hand side of the figure addresses the provision of electrical energy. While not shown, a *scenario path* for the provision of energy would initiate at the electricity customer and end at bulk generation. The path forks (an AND fork) to also terminate with the transmission utility that must supply the transport service for the energy. An alternative of this *scenario path* terminates with the DER generator owner, who can provide local electricity when congestion limits the import of bulk generation through the transmission system.

The left-hand side of the figure addresses the values that potentially can be provided by the demand flexibility of the electricity customers. There exist several *scenario paths* (not shown) through those *value activities*. One of the *scenario paths* initiates at the electricity wholesaler, then forks, and terminates with both the electricity customer and the DER generator owner. The electricity wholesaler is the "consumer" of the demand-side flexibility that the electricity customer, DER generation owner, or both, can supply.

Another *scenario path* would initiate with the transmission utility, then fork, and terminate at both the electricity customer and the DER generator owner. The transmission utility, as the owner of energy transport, "consumes" demand-side flexibility that can relieve transport congestion. Either the electricity customer or the DER generator owner can potentially supply this flexibility.

8.3 Activity Diagrams to Represent Operational and Growth Models

Recall that the operational model construct was introduced in Chapter 4.0. It quantifies or otherwise informs an impact or benefit. In the context of this chapter and its discussion of business value, these *impacts* can now be understood as measures of *value objects*.

A second type of UML is recommended in this chapter for the representation of the operational models. UML activity diagrams should be used to document the operational models, and potentially also the growth models, that are used during valuation. These diagrams are classified as behavioral diagrams in UML terminology because they represent a process.

Figure 8.3 is a UML activity diagram. At this level, it looks a lot like any other block diagram. This example happens to represent one of about five different operational models that were reconstructed from the Minnesota Value of Solar study (Norris et al. 2014). This one calculated the avoided generator fuel cost for a year—the model's output shown at the right side of the activity block. A name has been applied to the operational model that indicates its output and an operational goal that is represented by the operational model. The UML activity diagram is annotated, which is not required.

The required inputs to the model are revealed on the left of the activity block. In this case, four inputs are required. Some of the inputs are simple constants. Note that the activity diagram makes transparent the inputs that were needed to use the model, but specific details of the calculation can be rolled up if these details are unimportant or not yet defined. This latter feature is structurally important because it supports abstracted modeling until the details can be worked out.

[1] Admittedly, some of the biggest actors in this scenario were not truly engaged due to the small scale of the demonstration. Regardless, we attempt to accurately represent their goals and activities in this scenario.

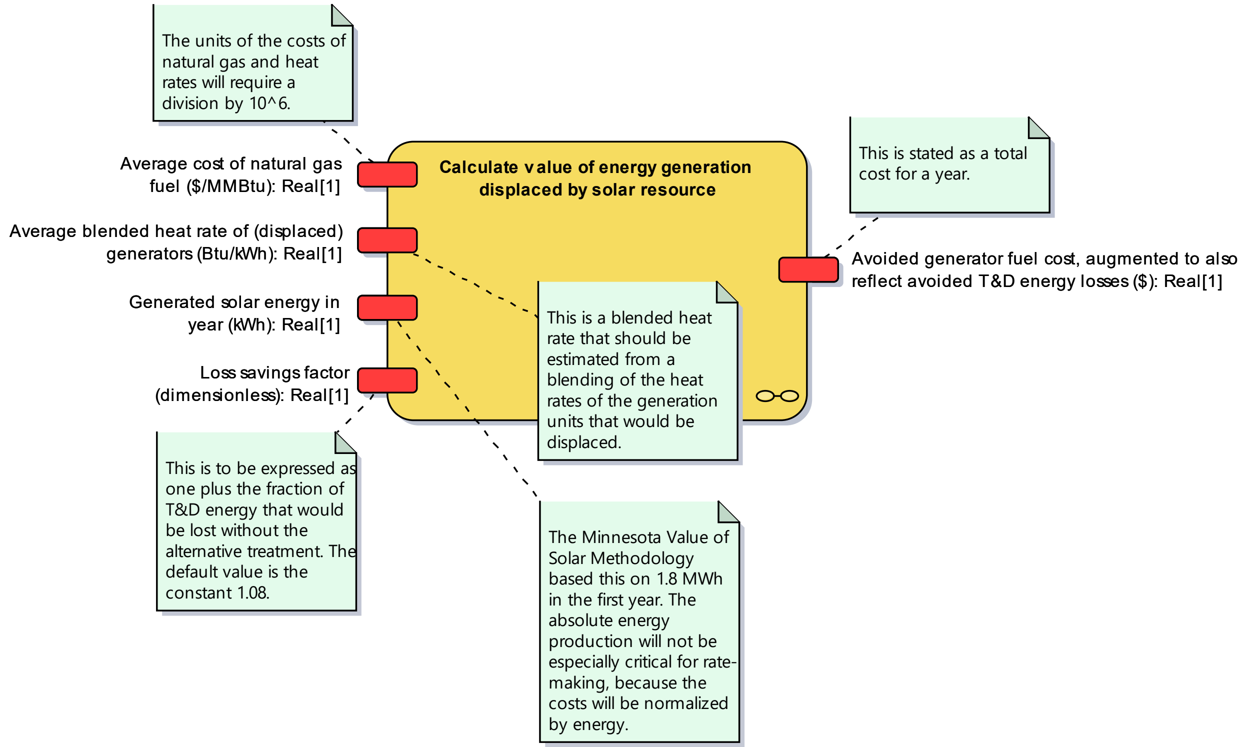

Figure 8.3. Example UML Activity Diagram Representation of an Operational Model and its Inputs

Another advantage of UML is that multiple software environments have been developed to facilitate the construction of these activity diagrams. Figure 8.4 is the result of double-clicking on the activity diagram of Figure 8.3, which expands the activity block into all its individual *actions*, further defining how the activity's inputs are used to calculate the activity's output (an impact). In this case, four relatively simple calculations entirely define the operational model.

Incidentally, the model on which this activity diagram is based was in the form of a spreadsheet. The interim calculations and ultimate output (the impact) were in columns, and successive years were represented by successive rows. The operational model and its UML activity are an abstraction for the calculation a single row of the spreadsheet on which the example was based.

The activity diagram, in our opinion, can be interpreted much more rapidly than the spreadsheet and therefore enhances the transparency of the method. Access to a UML activity diagram is ensured by its status as a standard, so the method's reviewer does not needs to purchase or possess the precise sets of analysis software tools into which the method was originally embedded. Furthermore, the activity diagram expresses the method properly as a function and may therefore facilitate interoperable software implementations of the method.

Relatively simple activity diagrams could be constructed to show the growth model. The growth model would necessarily show the evolution of the four listed inputs from year to year—from one row of the spreadsheet to the next. For example, one input is the amount of solar energy generated in the year, which number could be defined to grow by a given amount or given rate each year.

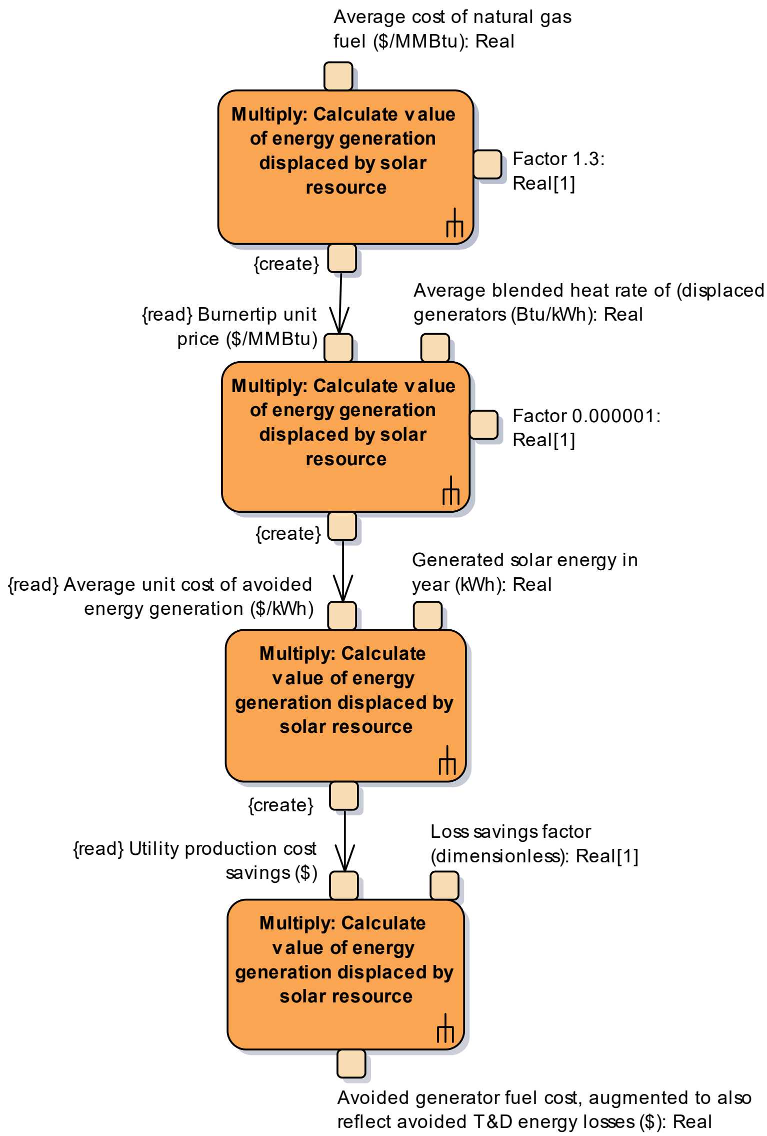

Figure 8.4. Four Actions that are Revealed upon Expanding the Activity that was Shown in Figure 8.3

8.4 Other Potentially Useful UML Diagrams

The authors explored other possible UML representations, but none had the clear value that was demonstrated by the two that have been chosen and discussed in this chapter already. These additional diagrammatic representations may have value:

- Structural signal connectivity diagrams – given the importance of information and signals to many of the alternative TS mechanisms and platforms, it might be useful to include structural UML diagrams that show the signals and the actors who receive and generate those signals.
- Structural packet diagrams – these structural diagrams are much like class diagrams, but they are highly abstracted and could potentially provide analysts the structure needed to organize all the many different operational models. This would be especially important in a collaborative environment where the models could be located, used, or modified by many persons and organizations.

9.0 Application of the Suggested Valuation Principles in the Buildings Domain

This chapter discusses the application of the report's TS valuation methodology to the buildings domain. Most examples of TSs in the buildings domain have focused on the purchase of electrical power given a dynamic price incentive. However, other examples exist and still more are emerging over time.

9.1 TE Building Systems

Building energy systems, including space conditioning, ventilation, hot water, refrigeration, and lighting systems, link buildings, building owners, and building occupants to the electricity, water and natural gas systems that serve them. Nationally, the electricity used by building systems dominates total electricity consumption and therefore represents the largest opportunity for TSs to provide grid services. Recognition of this fact has resulted in a "buildings-to-grid" perspective that has defined TS demonstrations to date. However, the potential value of TE building systems extend beyond services provided to the electricity grid. TE building systems have the potential to support a wider variety of transactions, provide new services, expose additional value, and create business opportunities[1] independent of the electric grid.

9.2 Classifying Building Domain Transactions

Transactions in and between buildings may take many forms, transact many different commodities, and occur at a variety of timescales. The *Transaction-Based Building Controls Framework, Volume 1: Reference Guide* (Somasundaram et al. 2014) provides a set of examples that illustrate a number of possible buildings-based TS use cases. The document classifies transactions according to transacting parties. For the purposes of this report, we adopt a subset of those established by that document, which classifies the transactions as intra-building, building-to-building, building-to-grid, service-provider-to-service-provider, customer-to-customer, and building-to-other. Four of these classifications are adopted for this this report as follows:

<u>Building-to-grid</u> transactions occur between a building and utility entity (generation, transmission, or distribution). These transactions are the type most commonly associated with building energy systems today and include those that enable buildings to provide ancillary services.

<u>Building-to-other</u> transactions occur between a building and a third-party service provider, e.g., an ESCO, energy retailer, or demand aggregator. These transactions may be motivated by shared energy savings that is realized through information exchange and improves building performance.

<u>Building-to-building</u> transactions occur between buildings or building communities. Communities may be fixed, dynamic, formally defined, or ad hoc. These transactions may be motivated by a shared need to limit aggregate demand or to balance local DERs.

[1] Identifying opportunities that transactions expose justifies TS investments and points to potential markets for commercialization.

Intra-building transactions occur between devices within a building. The motivation for the transaction is purely building-centric. For example, equipment in buildings may compete for limited resources, leading to reduced energy consumption or improved occupant comfort. Intra-building transactions also include those related to smart manufacturing.

Figure 9.1 depicts a transaction connectivity layer for entities in the buildings domain, where the arrows represent various transactions that might be designed within buildings, between buildings, with third-party service providers, and between buildings and grid entities.

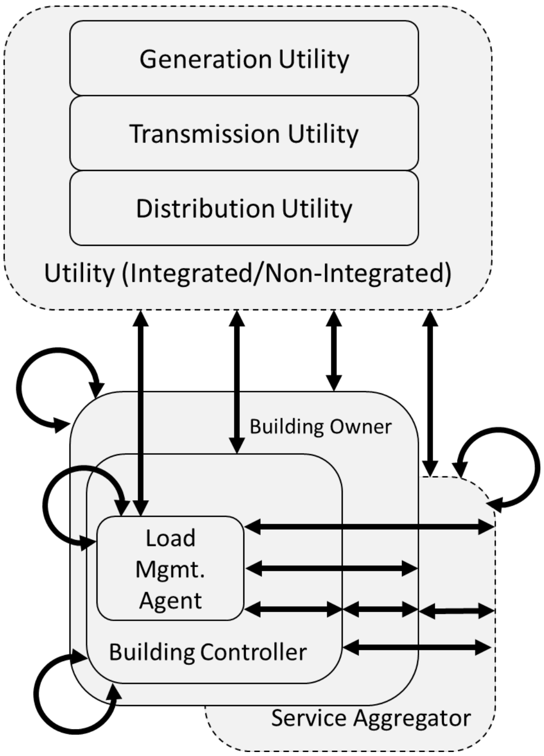

Figure 9.1. Transaction Signal Diagram Showing Feasible Transactions among the Building-Related Domains

9.3 Intra-Building Transactions

Transactions occur between devices within a building. Motivation for these transactions is purely building-centric. For example, equipment in buildings may compete for resources, leading to reduced energy consumption or improved occupant comfort. Implications for smart manufacturing are discussed in this section as well as two use cases from Somasundaram et al. (2014).

9.3.1 Smart Manufacturing

Components of a manufacturing system can inform other parts of the system about their statuses, and each can react to the incoming information. Each component can communicate data that enables other components to react to situational changes, such as energy or feedstock price spikes or an unexpected process disruption. The impacts of these types of transactions can help a manufacturer achieve its operational and corporate objectives as well as energy and sustainability goals and objectives. This use case is similar to the concepts of “industrial internet” and “internet of things” (Rogers et al. 2013).

TSs might facilitate machine-matching optimization in smart manufacturing processes. TSs might be integrated during initial product development and design as well as during the development of integrated facility and process operations. Intelligent systems can drive capital projects and investments, and allow for system-level efficiencies (Rogers et al. 2013).

9.3.2 Tenant Contracts with a Building Owner for Energy (Use Case 4.3)

A building or facility owner or operator either (1) passes through energy costs (including dynamic rates), peak demand charges, etc. to building occupants, or (2) gives occupants a monthly allowance for energy consumption that is covered in the tenant’s monthly rent. In the case of (2), if the tenant exceeds its monthly allowance, the tenant incurs a penalty. If the tenant uses less than the allowance, the tenant receives a rebate. Tenants may be allowed to trade surplus allowances with other tenants who anticipate exceeding their allowances.

This engages tenants in energy conservation, managing peak loads, and responding to dynamic rates by co-optimizing comfort or quality of service for the costs of receiving them.

9.3.3 Transactive Control for Large Commercial Building HVAC Systems (Use Case 4.4)

A customer or building operator uses a TS in a hierarchical fashion for a multi-zone commercial building heating, ventilation, and air conditioning (HVAC) system comprising chillers, cooling towers, air-handling units, etc. Devices within the building can transact

- energy in order to achieve greater system energy efficiency (Use Case 4.4)
- information that assists other devices in their operation, perhaps resulting in improved lighting, comfort, or safety for building occupants
- information with the building manager, assisting him/her in day-to-day operations.

9.4 Building-to-Building Transactions

Transactions occur between any two or more buildings. For example, buildings might negotiate operation schedules in order to minimize demand charges. Transactions may include communities of buildings. Communities may be fixed, dynamic, formally defined, or ad hoc. These transactions may be motivated by a shared need to limit aggregate demand or best utilize local DERs. One such use case was listed in Somasundaram et al. (2014).

9.4.1 Microgrid Coordinating Demand Response, DG, and Storage (Use Case 4.7)

Electricity consumers sign up to participate in a TE system market within a microgrid. The microgrid’s objective is to balance its resources and loads when operating in islanded mode and to ensure reliable electricity service. In this example, all resources are independently owned by building owners, including DG and storage. The microgrid use case is built upon Use Case 6.2, "Transactive Retail Energy Market." Only the differences or additions will be highlighted here. The buildings transact with one another to

- keep total site demand below a set amount using DER output to minimize capacity charges
- maximize utilization of site-generated renewable resources and minimize emissions
- meet other facility goals associated with resilience, resource use, and emissions.

9.5 Building-to-Other Transactions

Transactions occur between a building and a third-party service provider, e.g., an ESCO, energy retailer, or demand aggregator. These transactions may, for example, be motivated by shared energy savings and realized through information exchange, which ultimately improves building performance. Three use cases of this type are listed in Somasundaram et al. (2014).

9.5.1 Third-Party Energy Provider (Use Case 4.1)

An electricity customer (typically a commercial building owner) contracts with a vendor that installs, operates, and maintains equipment at its expense, such as a building combined heat and power (CHP) system, a thermal or battery energy storage system, or a conventional generator. The vendor then bills the customer for the energy services provided to the building and shares with the electricity customer the proceeds from services that are provided to the electric power grid (e.g., net reduction in demand, ancillary services, etc.).

9.5.2 Shared Efficiency Savings (Use Case 4.2)

An electricity customer (typically a commercial building owner) signs up with an ESCO who provides energy efficiency retrofits and services in exchange for a shared savings contract. The existing ESCO model is an example of a transaction between a building owner and a third party that results in beneficial impacts to buildings and the grid without sacrificing occupant and customer comfort. A third-party service provider examines an organization's current energy use, including the performance of all aspects of its buildings and facilities. The third party then determines the financial savings that could be achieved through energy efficiency measures and upgrades. The third party often requires no up-front capital outlay from the building owner. The investment is recouped over an agreed payback period, through energy savings (Anesco Ltd. 2016).

Benefits of the ESCO model include upgraded buildings, reduced GHG emissions, improved efficiency of corporate buildings, and replacement of end-of-life assets. Utility or state incentives can be applied to an ESCO transaction, where the utility, state, or PUC deems it is in the best interest of the utility or state to save energy rather than increase supply or upgrade transmission or distribution infrastructure. In these cases, the cost of the upgrades is shared between the ESCO, customer, and utility or state, just as the beneficial impacts are also shared.

9.5.3 Diagnostic and Automated Commissioning Services (Use Case 4.5)

An electricity customer (typically a commercial building operator or owner) signs up with a service provider for remote diagnostic services or automated commissioning services. In exchange for money, the customer receives diagnostic information or maintenance and repair services. The investment in diagnosis and repair should pay for itself in benefits such as avoiding costly catastrophic equipment failures, retaining tenants, and improving occupant satisfaction and productivity.

9.6 Building-to-Grid Transactions

Transactions occur between a building and a utility entity (generation, transmission, or distribution). These transactions are commonly associated with building energy systems, and include those that enable buildings to provide ancillary services. This section lists three use cases of this type from Somasundaram et al. (2014).

9.6.1 Dynamic Rates (Use Case 5.1)

An electricity customer signs up with a retail electric utility or retail service provider for a dynamic (time-varying) rate program such as (1) time-of-use, (2) critical-peak price, or (3) real-time price. The technical solutions implemented for this scenario are also relevant for Use Case 7.1, "Emergency Power Rationing."

9.6.2 TE System Market Exchange (Use Case 5.4)

An electricity customer purchases electric energy and delivery services from generation, transmission, and distribution suppliers in an asynchronous, bilateral, stock-market–like transaction. Separate forward contracts can be purchased at various timescales. The customer can resell contracts for unneeded energy and delivery back to the market.

9.6.3 Transactive Retail Energy Market (Use Case 6.2)

An electricity customer signs up with its retail electric utility or retail service provider for a transactive control and coordination program, involving a real-time price determined by customers' bids for electricity demand from a short-term (~5-minute) retail price-discovery process (e.g., a market).

9.7 Assigning Impacts to Benefits and Costs

Identifying and assigning impacts to relevant stakeholders enables allocation of benefits. Impacts may be first order (primary), or second order and higher (secondary) impacts, and may affect stakeholders in different ways. For example, a primary impact of a TS may be a change in HVAC operation. This may result in reductions in electricity use and increased compressor cycling, both of which are secondary impacts of the TS. Furthermore, each of these impacts may in turn affect equipment lifetime or a customer bill—secondary impacts dependent on the preceding impacts in this chain.

Many of the impacts revealed through the assignment process may not be directly related to energy use or cost, whether or not the primary motivations for transactions are energy related. See Figure 9.2. These impacts are extremely important to consider in a complete valuation, as non-energy costs dominate most business and personal expenses, and are often missing from grid-centric valuations. Non-energy impacts include water usage, equipment maintenance, worker retention, property value, and insurance premiums. Works published by the National Association of Energy Service Companies (NAESCO) (Birr and Singer 2008), RMI (Bendewald et al. 2014), Lawrence Berkeley National Laboratory (LBNL) (2016) and others have revealed many of these non-energy impacts and their associated value to buildings, building owners, building occupants, and society. These works provide guidance for the assignment process and the quantification of impacts on multiple stakeholders. Much further work is needed to define use cases and value objects in the buildings domain, consistent with the practices recommended in Section 8.2.

It is important that those evaluating TSs have a strong understanding of the relationships between impacts. In some cases, impacts may be deeply nested, or feedback loops between impacts may exist. In these cases, an analyst must take extra precaution to prevent double counting such impacts. The evaluator must apply expert knowledge in order to determine how far down the chain of impacts one must travel when assigning these relationships.

Assigning impact relationships helps the evaluator understand how the system benefits all of the various stakeholders. By examining the impacts of the TS, we are able to understand and correctly assign impacts to a chain of secondary impacts, revealing their relationships to their respective stakeholders. These relationships are critical to producing an accurate and meaningful valuation, and only through this process are the full implications of a TS understood.

We stipulate that some of these impacts are constrained by operational requirements. For example, any transaction that sacrifices occupant health or safety, without means to address the violation, should trigger an automatic exception, excluding the transaction from the valuation. This process places restrictions on the feasible universe of transactions and provides some guidance for TS design. While this seems a rather obvious point to make, a transaction may have unintended consequences not immediately apparent in the system design until exercised in operation. A far-fetched example may be a demand-response transaction that temporarily reduces outdoor airflow to a hospital operating theater. In practice, this is difficult to determine a priori without exhaustively checking all possible constraints, however unlikely they may be.

9.8 Quantification of Costs and Benefits

Benefits and costs derived from TE building systems are most easily understood and compared in monetary terms. However, for many anticipated impacts, a method of monetization may not be practical or well established. Not all impacts can be monetized. They should, where possible, be evaluated quantitatively using standardized methods.

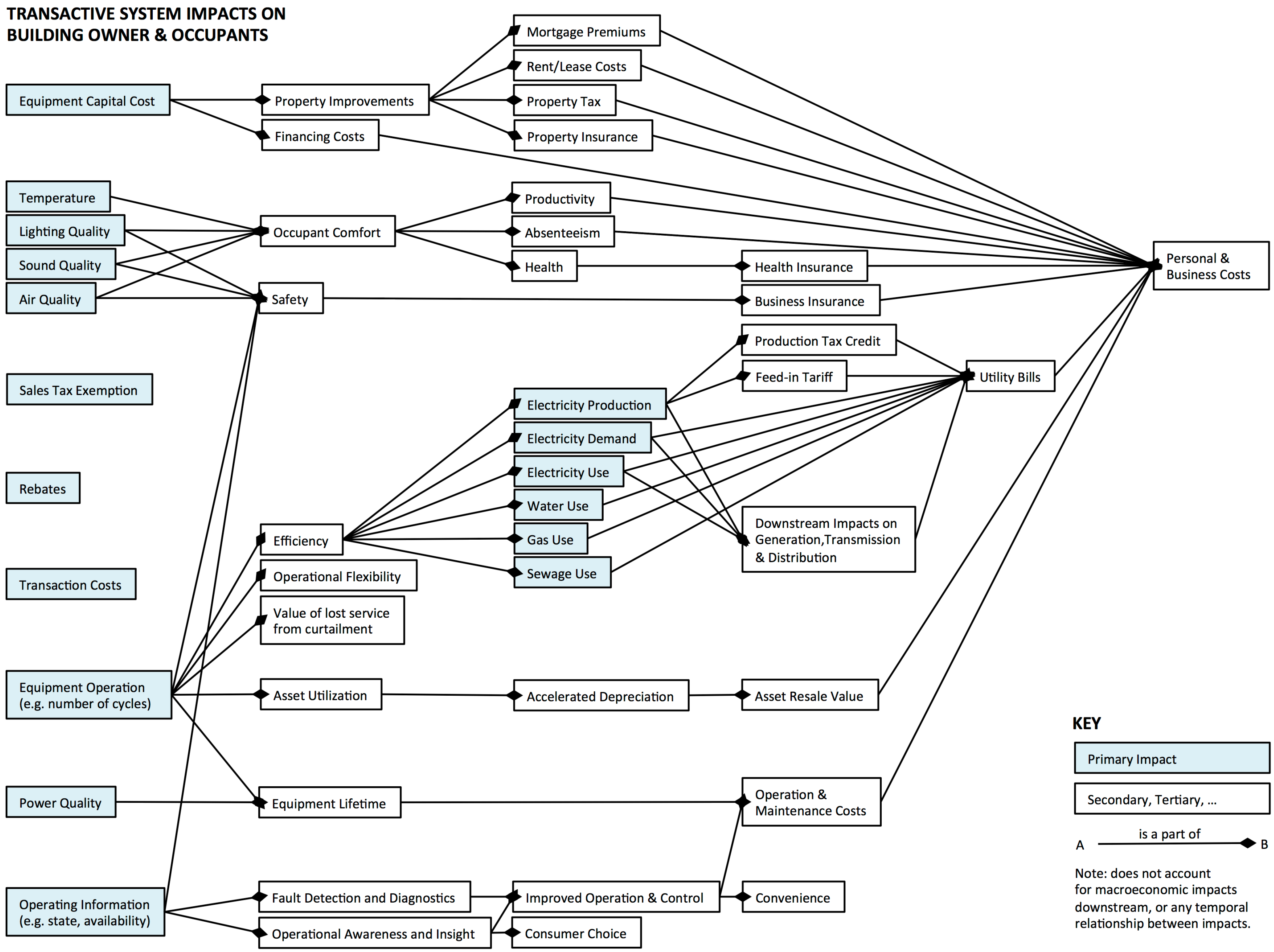

Figure 9.2. Relationships between Potential Impacts Realized in TE Building Systems

Consider a building-to-grid TE system that affects lighting levels within the building. With an appropriately detailed model, it is easy to quantify the primary impact in terms of power measured at the utility interface, and the lighting intensity falling on work surfaces measured in lux. Secondary impacts from changes in lighting intensity extend to occupants in terms of visual comfort, and may ultimately affect worker productivity. The value of worker productivity is itself a complex problem with a large body of literature devoted to the subject. A method of monetization may not be clear in this case. However, even if impacts cannot be easily monetized, the benefit (or likely cost in this example) must still be captured and quantified in order to provide a means of comparison. The identification and selection of models that monetize or otherwise quantify non-monetizable impacts is therefore a critically important aspect of a valuation effort.

Complications occur when TSs provide multiple services, such as peak load reduction and spinning reserve. In some cases, these services cannot be provided concurrently. Calculating costs and benefits without addressing concurrency can lead to overestimation.

9.9 Building-Specific Considerations for Growth Modeling

This section discusses some building-specific considerations for the modeling of growth in a TS. Specific growth drivers and mitigations may differ by use case and scenario.

Assessing the long-term value of TE building systems requires consideration of how buildings evolve. Building characteristics are not static. They change irrespective of the needs of an electric power grid. This evolution may result from equipment degradation and replacement, from changes in occupancy and space usage, or from changes in regulations, building codes, and policy. Some evolution may be driven by the deployment of TS, too, and may represent an opportunity for co-investment. For example, the option to install a grid-responsive version of a subsystem that is to be replaced may enable grid-related transactions at a small incremental cost shared between the building owner and utility.

Assumptions regarding costs, equipment replacement intervals (these may be planned, or result from equipment failure), and retrofit schedule (regulations may dictate schedule or events that trigger building retrofits, e.g., change in occupancy) must be defined. In some cases, these costs represent co-investment opportunities, especially when they enable transactions that were not available in previous years. In practice, modeling the evolution of a building over the valuation periods is difficult and requires the analyst to make many assumptions about future regulatory conditions, building usage, and equipment service life.

10.0 Impacts and their Corresponding Operational and Growth Models

This chapter addresses many operational and growth models that are needed to conduct valuations for systems that employ a TS. Where possible, discussions of impacts and operational models will be accompanied by e3-value-style diagrams that show value interfaces, value activities, and value flows. This practice builds on a "Value Interface Library" found as an appendix of Kartseva et al. (2004). In many cases, such diagrams are helpful toward defining the point in the business model where impacts and their operational model(s) are most relevant.

When operational models are lacking, or when inadequate data exists today to support the ideal operational model, alternative simplified models are listed. This practice is adopted from Denholm et al. (2014) that consistently listed alternative methods (*operational models* in this report) for valuation of each of its listed impacts. Having alternative methods available allows an analyst to proceed with limited data and with time-saving alternative levels of analysis vigor. When the simpler methods (*operational models*) must be chosen from among the alternatives, limitations and inherent assumptions follow, and these limitations and assumptions should be stated.

The discussion in this chapter has been divided into three major classes of operational models—those that are mostly relevant to grid impacts (Section 10.1), building impacts (Section 10.2), and overall societal impacts (Section 10.3). The sections are organized by classes of impacts instead of by operational models. Several impacts may share a single operational model—a time simulation, for example. Impacts were found to be the preferred basis for categorization. Impacts have their own theoretical foundations and imply requirements for the operational models, regardless whether such models are distinct.

10.1 Grid Impacts and Operational Models

This section addresses impacts and operational models having to do especially with electrical power grid systems. There has been great interest in recent years in costs and benefits of DERs, so example valuation methods are readily found in the electric power space. This report has recommended methodological and structural improvements. We do not intend to reinvent or even list *all* the impacts and operational models and methods in the grid space. Instead, the methods will be described and related to TSs, and discussion will point to especially informative treatments of the methods from literature.

10.1.1 Electrical Load Model

An electric load model quantifies the electrical power and energy used by electricity customers and the system. It should further capture impacts of DER operation, demand response, and any other TS actions that can shift, defer, or otherwise alter the quantity or timing of electrical energy consumption in the system. Some relevant example e^3-value activities, interfaces, and value flows are suggested in Figure 10.1. The operational load model points to the consumed (or DER-exchanged) electrical energy that is directly informed by the load model.

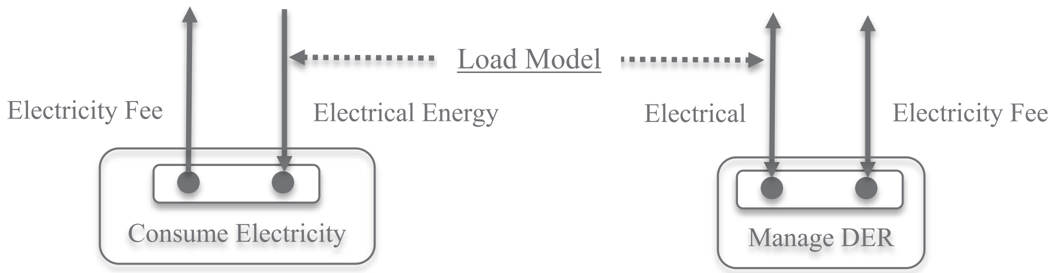

Figure 10.1. A Load Model Represents the End-Use Consumption and Both Energy Consumption and Supply by DERs

The value flows that share an e^3-value interface are linked (*atomic*) and must accompany one another. Therefore, the load model also indirectly quantifies customer bills and DER owners' energy payments.[1]

Electric load is an input to and drives other important operational models in the electric grid domain. Total energy generation must be equal to total energy consumption, plus a little more for the lossy transmission and distribution systems. Demand during short intervals drives assessments of generation, transmission, and distribution system adequacy and the consequent statistical reliability of these subsystems. Dispatch of energy resources is necessarily affected by electric load both spatially and temporally. In regions having energy markets, load and demand drive the quantities of energy that must be traded, and demand and consumed energy thereby indirectly estimate wholesale energy prices.

The following are used to represent electric load:

- Complete time-series load pattern. A complete time series of power consumption is determined for devices, customers, feeders, utilities, regions, or grids. This might be based on available historical data, but it is preferably predicted by time simulation. Most load is determined by end users in a distribution system, so the behaviors must be emulated either individually within a modeled distribution circuit, or in bulk at the load-serving buses of a transmission model.
- Time-series load patterns for representative days. Given the great computational challenge of determining complete time-series electrical load in a system, it is tempting and sometimes acceptable to define representative days and extrapolate load behaviors from the representative days to longer periods like months and years. Example days may be typical for their respective month or season, and in whether they represent week days, weekend days, specific days of the week, peak days, non-peak days, or holidays.
- Demand curves. If the temporal behavior of load is unimportant, a demand curve may be used to characterize load magnitudes. In principle, this representation could be made for individual devices or customers, but these are usually made to represent entire feeders, utilities, regions, or grids over prolonged periods like months, seasons, and years. They usually are arranged by monotonically decreasing average load magnitudes for all the hours in a given period.[2]

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[1] As a reminder, this report has reserved the word *impact* for the direct outputs of operational models. We prefer the more general word *benefits* for things that may be trivially calculated from impacts. These definitions are narrower than those conventionally applied, but the authors find the distinction somewhat useful in this more structured discussion of valuation methodology.

[2] Of course, the demand curve may be normalized instead to show fractional time.

- Average demand. If dynamic system behavior is not particularly important, system load(s) might be represented by average demand on a daily, weekly, monthly, seasonal, or yearly basis. Averages for heavy-load hours or light-load hours during these periods might fall into this category, too.
- Peak demand. Especially where only system capacity is in question, system loads might be represented by peak demands. Peak hourly demand by month aligns with many utilities' demand management practices and consequent demand charges.

Most TSs will modify dynamic system load and further modify total load. Therefore, the selected operational load model must employ inputs that are dynamically responsive to the TSs. Only then can the impact of the TSs on total load and the consequent other benefits be predicted. The following input information will often be important for valuation studies involving TSs:

- Elastic behavior. Most importantly, the load model must accurately capture the influences of at TS's incentivization on load behaviors. This is relatively straightforward where the behavior has been defined and automated. Models of human behavior must exist where human volition and nonautomated decisions are important to the performance of the TS.
- Numbers of buildings and customer types, if not numbers of devices. Load and load patterns scale with the numbers of end-use customers and devices. In some cases, the load of a representative number of fully modeled devices, customers, buildings, feeders, or utilities may be scaled to represent many more such elements.
- Locational information (e.g., circuit topology). Topology and locational detail is needed if the behaviors of the TS are locationally relevant. In some cases, topologies may be simplified without greatly changing the impacts that are to be observed.
- Independent load patterns. If load patterns will not be affected by the TS, they may be statically modeled and scaled according to numbers of devices, customers, etc.
- Weather. If, however, a load pattern may be affected by humidity, solar intensity, or outdoor temperature, and these influences can affect the performance of the TS, these weather influences should be modeled.

10.1.2 Electrical Energy Resource Dispatch Model

The resource dispatch model selects from among available resources those that are needed to supply electrical demand. The selection is usually based on a minimization of production costs. The dispatch solution may be further constrained to account for transport limitations, market processes, system efficiency, policies, or operational capabilities of the various resources.[3] Simplifications to the dispatch

[3] Some examples of these constraints and their effects might be useful:

- An otherwise optimal dispatch may be disallowed if it is found to violate one or more transmission lines' capacity limits, in which case successively suboptimal dispatches must be considered until one is found that violates none of the limits.
- Market processes require that generators become committed before they can become dispatched. In a balancing reserve market, generators must become accepted as reserve resources before they can be dispatched.
- A region's policies may require it to accept energy from certain renewable resources regardless of the economics of doing so.
- Finally, dispatch order can be influenced by generators' startup rates or ramping rates.

model are possible if any of these various constraints can be ignored. Figure 10.2 shows that the dispatch model ultimately determines the electrical energy that is obtained from each generator or from each generator type.

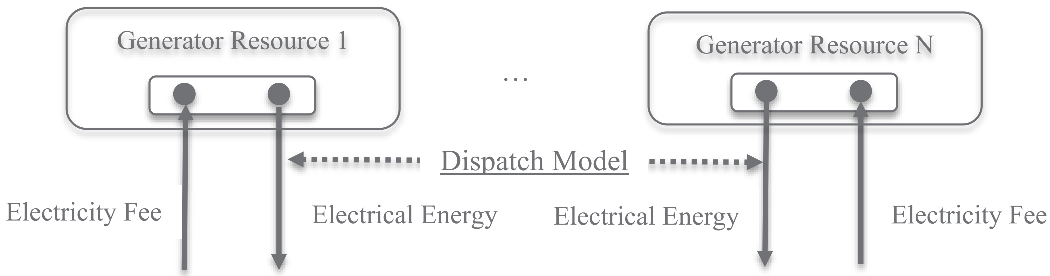


Figure 10.2. The Dispatch Model Represents the Means by which Generators or Generator Types are Engaged to Supply Electricity

The energy fees for supplied energy can be determined from the dispatched electrical energy. As shown in Figure 10.2, the fees and supplied electrical energy are necessarily coupled.

Fuel consumption also follows quite directly from knowledge of the dispatched generators and their fuel types. Heat rates of different generation technologies affect the efficiency as each converts its fuels into electrical energy. Furthermore, generator efficiency can be a function of generator loading, should the dispatch model be able to model fractional loading of the generators. If unit fuel costs are modeled, total fuel costs can then be calculated.

- Constrained production cost model. The most rigorous approach is to try to recreate the entire production cost model to emulate the dispatch practices of the utilities or region. This model presumes that all generators are known and characterized and that the model's feasible dispatch solution is the same one the actual system would likely select. Power flow, market behaviors, and policy implications must be emulated to reconstruct and predict dispatch practices. This vigor is required where a TS's performance is anticipated to be locationally dependent.

  Successive simplifications are achievable for each constraint that can be ignored, but the many permutations of such simplifications will not be listed here.

- Unconstrained dispatch optimization. This model presumes that all generators are known and characterized, but it does not test for the feasibility of the chosen solutions and does not constrain or modify the optimal dispatch solution. Location-specific impacts are lost given that transport constraints are being ignored.

- Ordered dispatch stack, based on inferred dispatch practices. A spreadsheet model may suffice where the relative production from each generator type is known and where the production costs of these generators can be estimated. An ordered dispatch stack may then be created, making the mix of dispatched generators a relatively simple function of total system load. Resource location is irrelevant when using this modeling approach.

Operational dispatch models are relevant to TSs because many of the TSs will be shown to modify the dispatch of resources by flattening load shapes, reducing system peak loading, inviting active participation of DERs, or altogether reducing energy consumption, all of which affect the dispatch of generation resources. In a few cases, the TSs may more directly affect the dispatch of generation resources, too.

The following input data is essential for the operational dispatch models:

- Lists of dispatchable resources. Ideally, all the dispatchable resources and their circuit locations will be known and characterized by their type and fuel. The generators' operational capabilities, such as startup time and ramping capabilities, must be known, too, if these capabilities can affect the dispatch outcome. Alternatively, the fractional composition of resource mix by type and fuel may suffice.
- Fuel heat content. Heat content is the theoretical energy that can be released per unit of fuel. This is an inherent physical property for each fuel. (A table of some fuel heat contents will be presented in the next chapter as Table 11.2.)
- Heat rates for dispatchable resources. The heat rates define the conversion efficiencies with which the generators convert the heat in fuel into electrical energy. The conversion efficiency may additionally be stated as a function of generator loading. Alternatively and more simply, heat rates may be defined as constants and by generator type. (Example heat rates will be presented in the next chapter as Table 11.3.)
- Unit fuel costs. The costs of fuel must be stated, as these affect dispatch order, production costs, and the calculated total costs of fuels and consequent total energy costs in the system.
- Total system load. The dispatch process is ultimately driven by the need to satisfy system demand.
- Circuit models. Detailed circuit models may be required if capacity-constrained dispatch is used.

10.1.3 LMP

An LMP model is perhaps a special case of the resource dispatch model that was described in Section 10.1.2. The main difference is that an LMP reveals the calculated marginal price and thereby provides a means for distributed, small resources like DERs to partake in a region's balancing process. In contrast, the general dispatch process of Section 10.1.2 may be used for selecting resources without necessarily revealing the basis for any of the dispatch decisions. The methods are otherwise quite similar. An LMP model uses spatial price differentiation to accomplish the location-dependent outcomes that are similar to those that would result from conventional constrained dispatch solutions.

An LMP model prescribes, but does not necessarily dictate, control of electrical energy at the DER demand-side locations (see right side of Figure 10.1) as well as at the system's interface with its generators (Figure 10.2). In this respect, it shares similarities with TE systems in that it includes a signal that is intended to incentivize the needed system responses.

These methods are considered, in order from most vigorous to least:

- Recreate the region's entire LMP calculation. This model is probably identical to the full constrained production model of 10.1.2, but it outputs the LMP instead of the dispatched resources. The purpose of this vigorous approach is to perfectly reproduce the region's LMP formulation. As for the dispatch model, this model may be simplified by eliminating its responses to constraints, providing the omitted constraints are not important to the scenario being evaluated.

- Use parametric LMPs from regression analysis. We propose that a parametric model of LMPs may be possible using regression analysis if sufficient historical LMP and system data is available. The greater challenge for this approach is probably in finding the candidate causal variables that might be correlated with the historical LMPs.
- Use historical LMP prices as static scripts. Historical published LMPs are available for some U.S. ISO regions. The scenario must be presumed to not have changed the LMP, which is unlikely to be true for most interesting scenarios and those having region-wide impacts.

LMPs are relevant to TSs in two respects. First, some TE systems—those that are built upon LMP pricing that represents the generation and transmission system domains—require that the LMP process be modeled. Second, even those TSs that do not explicitly use any LMP may affect the LMPs at scale. Just as TSs were described to have affected dispatch of resources by modifying load, these TSs must similarly affect the LMPs that are intended to induce similar dispatch outcomes.

The LMP model is similar to the resource dispatch model and should be expected to require the same inputs as those discussed in Section 10.1.2. New DERs may come into play during the LMP calculation, and resources' locations are more important in an LMP model if the locational relevance of an LMP must be accurately emulated.

10.1.4 Volt/Var Management Models

Voltage management and reactive power management are often inseparable and will be addressed together in this section.

Voltage is a characteristic of electric power. The voltage level of delivered electricity is required to remain within 95–105% of the nominal voltage. Electric loads are expected to operate satisfactorily within this range, and many devices can tolerate significant excursions outside this range for at least short durations. While the statistics of voltage can be metered (e.g., average voltage, extreme voltages, variance, and the distribution of voltages), the important impacts for voltage are typically measures of potentially poor electric service quality, as occurs when voltage lies outside the normal voltage range. The impacts' measures may be numbers of excursions outside progressively larger voltage ranges and durations of service time outside these voltage bands.

Voltage level is managed by excitation from generators, capacitors, switched reactors, and active control devices in the system. Electric demand types can affect voltage, too. Induction motors, for example, are well known to play a role in prolonging low-voltage events.

Depending on the load device, power consumption by the device may be proportional to the voltage or squared voltage. The efficiency of power generation and transport is therefore related to voltage level. Additionally, many devices' standby power losses are proportional to the square of voltage. Regulators' switching events may change with voltage management practices, thereby changing their remaining life spans and anticipated replacement costs.

Related impacts may derive from voltage oscillations. High-order harmonic frequencies may become injected during power conversion and become reflected in the system voltage. This harmonic pollution may affect neighboring loads and may cause transport equipment to overheat. Slower, subharmonic frequencies may develop as large masses in the electric power system exchange inertial energy, as measures of potential dynamic instability for the system.

Vars, on the other hand, are a measure of reactive power exchange in an alternating current (AC) power system. The transport of vars requires that electrical current magnitude is increased beyond the current that would be needed to transport real power alone. In the classical sense, reactive power exists when the electrical current's sinusoidal waveform is permitted to either advance or lag in respect to the voltage waveform. Power electronic converters can also affect reactive power levels if they introduce harmonics into the power system. The exchange of vars is indirectly regulated through mandatory power factors, but this modest criterion has not greatly affected daily operations. The statistics of vars (or, equivalently, power factors) at various system locations are the impact of interest.

Load devices, including conductors, generate or consume a specific amount of reactive power just as they generate or consume a specific amount of real power. The management of reactive power in a system uses many of the same devices as were listed for voltage, which is the reason the management of voltage and vars is inseparable.

The transport of reactive power introduces energy losses. Where power factor on a circuit is less than unity, electrical conduction losses increase.[4] Distribution systems will often have power factors near 0.85, which means that distribution system conduction losses will be 38% higher than had only real-power transfer been used to estimate conduction losses. Power factor must be accounted for in scenarios that will actively or passively change reactive-power transfer in transmission and/or distribution systems.

Var management has a fairly direct effect on AC system voltage management as well. Management practices may use up the limited numbers of switching events available to capacitor banks and other devices, thereby affecting the life spans and replacement costs of such equipment.

Figure 10.3 suggests that voltage and var operational models must inform the voltage level and vars that are being exchanged at circuit locations, as these quantities are affected by end-use consumption and by a large number of controllable devices like synchronous generators, switched capacitor banks, switched reactors, and active devices like flexible AC transmission systems. End users receive adequate load performance in exchange for the management of voltage and reactive power. Those who conduct active management of voltage and reactive power may reduce their energy losses and satisfy accepted practices and regulatory requirements placed on them.

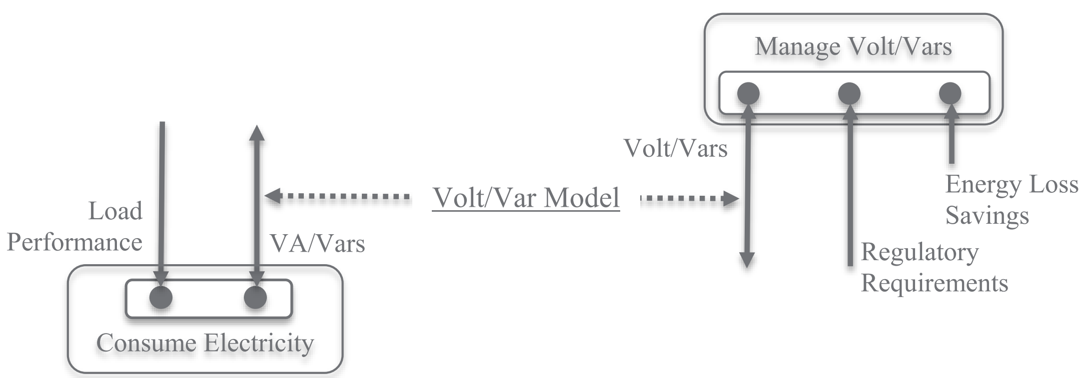


Figure 10.3. The Volt/Var Model Calculates Voltage and Reactive Power Flow as a Function of Loads, Volt/Var Management Efforts, and Circuit Characteristics

[4] Specifically, the conduction losses are $(P / (3V_p (pf))^2 R_c$, where P is the three-phase power transfer, V_p is phase voltage, pf is power factor, and R_c is the equipment's characteristic conduction resistance.

Operational models that reveal voltage and var impacts are similar to those used to model electrical load.

- Full time-series system simulation. Whereas power balance was adequate to model the consumption and supply of real power in time, additional rigor is needed here, including complex (in the mathematical sense) phasor representations of voltage and power in time. Multiple tools exist for revealing voltage and reactive power flow in transmission systems if the interfaces to distribution systems can be specified. Similarly, distribution feeders can be modeled in detail if the transmission boundary is relatively static. Emerging technical tools will aim toward meaningful co-simulation of both transmission and distribution systems.
- Reactive load curve. The authors have not observed applications of this type of model, but simple TS challenges might be adequately served by the distributions of reactive power in a manner similar to the way load curves are used. This would perhaps be applicable for limited-scale distribution system models. Unfortunately, the management of reactive power and voltage is usually inseparable from the management of real power load and supply, making this method of limited applicability.

The first TE systems have incentivized real power rather than reactive power and voltage. Voltage and reactive power impacts could be incentivized, however, and systems indirectly invite voltage and var management if energy losses are penalized and as AC power flow is optimized. The following inputs are needed to drive the volt/var model:

- Transmission and/or distribution circuit models. Voltage and reactive power are modified as power flows through circuit elements. The reactance and capacitance of the elements are important here, but skilled modelers may be able to simplify their simulations by eliminating elements' resistances, which are often small or irrelevant to a scenario.
- Load characterization by circuit location. The locations of loads should be known on the circuits. The loads should further be characterized by type, as these load types help define the parametric voltage and vars by location in the circuit.
- Parametric load models. Both the real and reactive load consumption at devices should be modeled as parametric functions of voltage and other input variables (weather, occupancy, etc.). For example, the reactive power consumption of induction motors running HVAC compressors is strongly affected by supply voltage. The load models may sometimes be simplified, reducing dynamic parameters that will not be important to a scenario. The modeling of aggregate loads up to building, feeder, utility, or region levels also may be acceptable where the load behaviors of individual devices, buildings, feeders, or utilities are irrelevant.
- Location and characterization of volt/var management equipment. The locations and capabilities of tools available to the system for the management of voltage and vars must also be known in the circuit. Examples of these tools include voltage regulators, switched capacitor banks and reactor banks, synchronous machines, and active devices like flexible AC transmission systems.
- Policies and practices for volt/var management. Finally, the rules and practices for volt/var management must be specified. These policies and practices guide how the volt/var management equipment will be controlled.

10.1.5 Losses / Efficiency Models

A system's energy losses might be characterized as *load losses* and *no-load losses*. Load losses may be calculated as the product of a characteristic electrical resistance and the square of electrical current. Magnetic core losses are important no-load losses for electrical transformers and motors and may be estimated by the square of the voltage divided by a characteristic magnetic core resistance. Electronic loads may include other no-load losses—"vampire" loads—even while the load appears to be off. All these are sources of energy that is lost by the system, thus decreasing a system's overall efficiency. The purpose of this section is to discuss the quantification of such losses.

The inefficiency of bulk generation is not addressed in this section. The electrical efficiency of large generators is usually rolled into the much greater energy conversion losses that state electrical output as functions of fuel consumption.

The measurement impacts for system energy losses differ mostly by their granularity in time and circuit location at which the impacts are reported. In principle, the losses at every device or system component could be calculated. However, the losses are often aggregated by classes of devices at the building, feeder, utility, or regional levels. Similarly, losses may be determined for each data interval, but aggregate losses are often summed by hour, day, month, season, and year.

Depending on where the energy losses occur in a system, the losses represent money that cannot be recovered, from sales to retail and wholesale customers. This is a direct monetary consequence of such losses.

Energy losses cause generation, transmission, and distribution system capacities to be necessarily oversized, which also has a monetary impact. Therefore, a system's energy losses have implications for system growth and infrastructure.

Poorly balanced three-phase lines may also affect conduction losses, especially in distribution systems. Ideally, each phase of a three-phase system carries the same current, but the phases may instead be badly imbalanced, especially in remote distribution systems. If a scenario alters or corrects the balance of electrical current between the phases of a three-phase system, the imbalance of phase currents must be modeled. For example, in a three-phase system where one of the phases carries twice the average load on all three phases, equipment conduction losses would be 12.5% greater than for the perfectly balanced system.

The following operational models are relevant to the assessment of energy losses in the system:

- <u>Calculate device load losses from time-series electrical currents and characteristic resistances</u>. Perform detailed calculations of individual component losses as functions of the components' loading over time. No-load losses may be estimated similarly if supply voltages and characteristic magnetic core resistances are known for devices.
- <u>Use current duration curves</u>. If time-series analysis is not relevant for a scenario, the distribution of devices' load currents ordered by their magnitudes may be used along with characteristic resistances to estimate component losses as functions of component loading. A similar argument can be made for calculating no-load losses from a distribution of supply voltages.

- Estimate dynamic load losses from estimated total losses. For transmission or distribution circuits, dynamic load losses may be estimated without detailed data about the individual conductors. Suppose that total losses in a circuit are known as a percentage of total energy transport on the circuit. This knowledge and the fact that load losses are a function of the square of load current may be used to estimate dynamic losses in the transmission or distribution circuits. An implicit assumption is that the circuit's voltage and power factor is relatively constant. Figure 10.4 demonstrates this approach. The dotted line represents a total load duration curve for a transmission system. The solid line was calculated as the power loss as a function of total load, given the squared load-to-loss relationship, assumptions about steady voltage and power factor, and knowledge that total losses over a year are a known fraction of total supplied load.
- Losses as a constant fraction of peak or average load. Where system dynamics are unimportant, or where losses need be estimated only crudely during peak demand hours, the transmission and distribution system losses may be estimated as a constant fraction of the peak or average system loading.

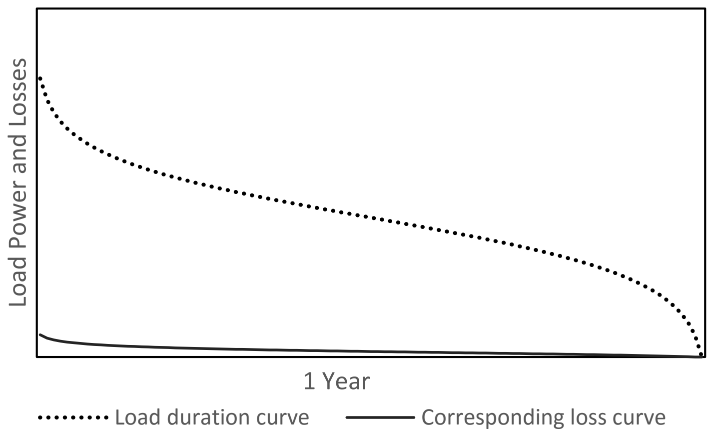


Figure 10.4. Conceptual Load Curve and Corresponding Loss Curve

Operational models concerning system losses are relevant to TSs because TSs may reduce local and system demand peaks and shift demand, which affect conduction losses. This is accomplished, for example, in TE systems that are responsive to LMPs that include marginal loss components. To the degree that a TS facilitates distributed renewable generation, the TS changes the net and relative energy quantities that must be supplied by transmission and distribution systems, which also changes the system's load losses.

10.1.6 Infrastructure Capacity Models

Figure 10.5 suggests (1) the relationships between the capacities of generation, transmission, and distribution subsystems; (2) the implications of these systems toward supplying reliable power; and (3) the operational models that inform capacity and reliability decisions. An underlying principle of the relationships in Figure 10.5 is that maintaining electricity supply to end users is the fundamental driver for decisions about the adequacy of system infrastructure. Decisions to construct new and replacement infrastructure are initiated by any inadequacy of the infrastructure. Infrastructure is purchased and installed to restore or exceed an acceptable level of service reliability. The methods for assessing inadequacy differ somewhat between generation, transmission, and distribution, so separate operational models are needed for each of these subsystems.

The criteria stating *inadequate* levels of reliability are important to valuation. These assumptions are not explicit in many valuation studies. In others, a presumption is stated that an existing level of reliability must be maintained.

Another implication of Figure 10.5 is that resiliency (as a valuation objective) is simply a special case of reliability. The impact of resiliency on system infrastructure inadequacy should be measured using the same criteria—namely maintenance of service to end users—as for reliability. The difference is that *resiliency* events are typically initiated by infrequent causal events like extreme weather conditions or intentional attacks on the system, whereas reliability is typically associated with normal degradation and unanticipated equipment failures. The business value for resiliency is otherwise the same as for reliability. Most of the value of resiliency should still derive from its impacts on the frequency and durations of customer outages. This understanding of resiliency, we advise, helps disentangle issues concerning the value of resiliency to a system.

This is not to say that separate metrics cannot be stated for a system's resiliency and flexibility. It is still useful to track the abilities of a system to ride through and recover quickly from hypothetical extreme events. But these capabilities are not valuable except in light of the likelihoods of those extreme events.

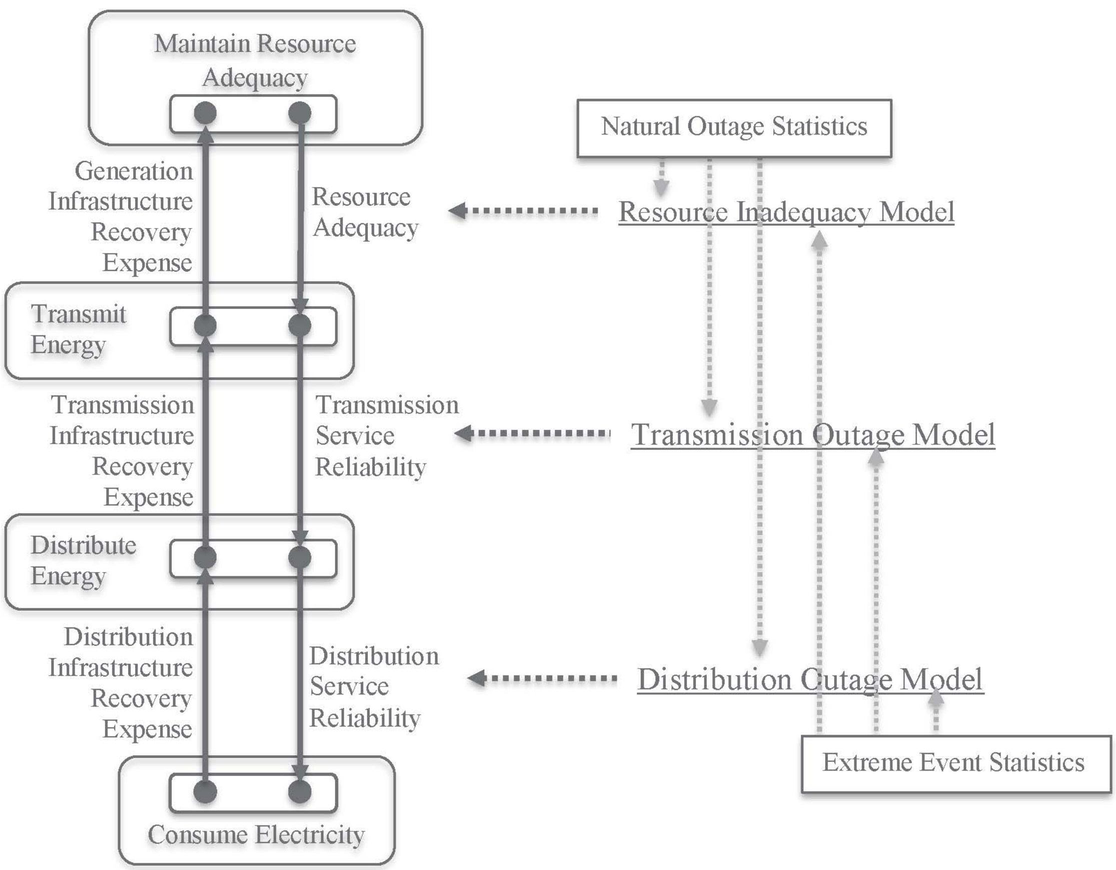


Figure 10.5. Resource Adequacy and Transmission and Distribution Outage Models Both Predict Service Outages and Determine the Needs for New Infrastructure Investments

The next subsections will address the three operational models that statistically predict the adequacy of the generation fleet and the likelihoods of outages in the transmission and distribution systems. It would be ideal to integrate these operational models, but they are usually addressed separately today. Addressing the models separately introduces small errors to the degree that the statistics of the three types of service outages might be correlated. This separation is probably acceptable in the United States, which has a high level of reliability in its electric power grids, but the effects of the separation should be reassessed for smaller and less reliable power grids.

10.1.7 Generation Resource Inadequacy Model

Generation inadequacy is measured by the likelihood that a system's electrical load might be unserved by the existing fleet of generation resources that are available to the system at any given time. These likelihoods are stated as loss-of-load probability (LOLP) or its integral, loss-of-load expectation (LOLE). More concretely, these impacts may be converted to their implications for the numbers of outage events in a period (e.g., a year), the load (or fraction of load) that is unserved during outages, and the individual and total durations of the events.

Individual generation units become unavailable when they become removed from service for maintenance. They also become unavailable when they break down and while remedial actions are being taken to return the units to service. On average, most utility-scale, conventional generators are available about 80–90% of the time. A generation unit's *availability* is greater than the fraction of time that it actually generates, which is the basis for the calculation of *capacity factors*. More generation units are typically *available* than are among the *reserve* generators that energy suppliers contract to be ready to quickly ramp up and operate when dispatched to do so.

Wind and solar renewable generation units must be treated somewhat differently due to their intermittency arising from their reliance on wind and sunshine. One common method is to treat these renewable resources as negative electrical load; however, this trick does not relieve the analysts from addressing the variability and diurnal patterns of the wind or solar power. The availability of conventional generators is adequately addressed by the likelihood that the generators will be in one of two binary states—available or unavailable. The joint availabilities of multiple conventional generators have increasingly more possible states due to all the permutations of the individual generators' on and off states. We propose that the joint availability of multiple conventional generators is perfectly analogous to the distribution of power generation from one or a set of solar PV or wind generators. The main difference is that the renewable generators rely on solar and wind energy, which causes their output to be correlated by season and hour. Such distributions (i.e., the distribution of power production by hour of day) may be obtained from the renewable generators' historical performance.

The impact of generation resource inadequacy must be reflected in conventional reliability customer impacts like System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and CAIDI.

Generation resource adequacy itself is an important impact for valuation, but a theme of this section is that it is a required level of resource adequacy that should drive decisions to procure or construct new generation infrastructure. The acceptable level of resource adequacy is the criterion by which the methodology's growth model determines whether new tools—perhaps, but not necessarily new generation resources—must be procured and installed.

Resource inadequacy trumps transmission and distribution system reliability; the condition of transmission and distribution systems probably does not matter while generation resources are inadequate.

The modeling of generator resource inadequacy may be conducted with various levels of rigor:

- Time-series simulation of LOLP and LOLE. The most rigorous calculations will assess generator resource availability and load every hour in a year to account for seasonal and diurnal generation and load patterns. This is the only way to make sure that the coincidence of heavy load and resource availability is fully addressed. This rigor is necessary if both the spatial and temporal effects of generation inadequacy are to be addressed or if the impacts of generator inadequacy are to be co-simulated with the impacts of transmission or distribution system reliability.
- This level of rigor also naturally addresses intermittent renewable generation if the statistics of the intermittent generation are known. Some generator maintenance outages may be scheduled to coincide with low-load seasons and hours, meaning that the *planned* outages are less risky than might otherwise be calculated if the generator outages are all assumed to be random. This improved treatment of planned outages, however, introduces new challenges in that the planning for maintenance outages must be emulated by the simulation.
- Statistical estimation of LOLP and LOLE during critical, representative hours. The rigor of the modeling may be significantly reduced if a subset of critical time periods can be addressed without having to simulate every hour of the year. Representative periods might be selected to represent a sample of daily hours, weekdays, months, or seasons. The peak demand periods of winter and summer seasons are most important because insufficient generation is more likely to occur during those times.
- Fully statistical treatment. If the availability of generators can be assumed to be uncorrelated among the generators and load patterns, then a fully statistical treatment might suffice. This method ignores the topological locations of generators within the circuit. The likelihoods of generator availability and the load duration curve are adequate to estimate LOLP and LOLE in this case. This approach is used often. It should probably not be used if the penetration of intermittent renewable resources has become large.

Generator resource inadequacy models are relevant to TSs because the TSs may alter peak demands, facilitate DERs, incentivize load curtailment when resource inadequacy might otherwise cause outages, or affect the dispatched generation resource mix, all of which can affect the LOLP and LOLE. These actions by the TSs could thereby affect customer service reliability and could alter future investments in alternative generation resources.

The following inputs are necessary for the operational model that determines generator resource adequacy:

- Lists of generator resources. The circuit locations and generating capacities of the region's generators should be known.
- Generator availability. If great rigor is being applied to the modeling of generator resource adequacy, both the planned outages and unplanned outages must be modeled for each system generator. This means that the practices for unplanned outages must be emulated by the simulation. However, the likelihood of generator availability is usually based on the historical availabilities of the generators alone. If specific historical generator availability is unknown, the likelihood of generator availability may be based on North American Reliability Council (NERC) Generating Availability Data System (GADS) data that has been reported for a number of generator types (NERC 2014).

- Electrical load. If great rigor is being applied to the modeling of generator resource adequacy, the system's dynamic electrical load must be accurately modeled. Simplifications are possible, commensurate with the rigor of the operational model, if spatial and temporal impacts can be ignored.
- Resource inadequacy criterion. If resource adequacy plays a role in triggering new investments, the threshold for the trigger must be stated. This is usually defined as a specific LOLE, but it could be a requisite number of outages, power outage magnitude, or likely outage time duration.

The success of a generator resource adequacy model hinges on the accuracy with which planned and unplanned outages can be predicted and emulated. Our ability to make these predictions is limited. Suppose that a TS were able to take actions that would reduce the likelihood of generators' unplanned outages or decrease their needs for planned ones. Only a couple of literature examples were found that might eventually help define generator outages parametrically in ways that such TS behaviors and benefits might be tested. Both examples are based on correlation studies using real generator outage data.

A long list of parameters, including the generator's capacity factor, equivalent forced outage rate or hours, loading, maintenance cycle, availability of spare parts, number of start-ups, operations and maintenance spending levels, operating and design duty cycles, planned outage hours, quality of operator training, quality of preventive maintenance program, and service factor were all found to affect conventional generator availability in Binder et al. (1991, Appendix C, p. 26). This paper suggested that generator availability could be correlated to these factors, which might allow a utility to better predict and continually improve generator availability.

Welton C. Simpson, Jr. and Harry G. Stoll offer a specific functional relationship between three causes of unplanned generator outages—annual service hours, service hours per start, and number of starts—and their likelihood in an article in Binder et al. (1991), "The Influence of Maintenance Spending and Upgrading on Generating Unit Availability Performance," p. 10. Based on correlation studies using NERC GADS data for the period 1978–1987, the relationship shown in Equation 10.1 was posed by these authors:

$$Failures/Year = a \cdot N + b \cdot H + \frac{b \cdot c \cdot H^2}{2 \cdot N} + \frac{b \cdot c^2 \cdot H^3}{6 \cdot N^2} + \ldots \tag{10.1}$$

where N is the number of starts; H is the total number of service hours; and a, b, and c are parameters that may be found by least-squares regression methods. The ratio H/N is the ratio of service hours per start. This result could then be combined with a model of repair times and scheduled outage hours to yield an equivalent availability factor for each generator. The resulting model would have predictive value and would be responsive to changes in service hours and starts.

Access to specific lists of generators and their historical or parametric availabilities is challenging. Table 10.1 is a compilation of useful data for the entire United States. While such data represents no one specific utility or region, it may be used for research purposes to model typical generator availability in the United States. This table reports the weighted[5] equivalent availability factors (WEAFs) for the various fuel types. It uses the total U.S. generation and stated capacity factors by fuel type to estimate the total

[5] The *weighting* is done by resource capacity. This is appropriate when availability factors are being stated for a composites of multiple individual generators or generator types.

generation capacity in the United States by fuel type and the typical capacities and numbers of these units. This is adequate information to generate the joint unavailability for all these generators.

Table 10.1 yields another valuable piece of information. The average system load in the United States is about 29.4% of the sum resource capacity. This is a useful rule of thumb that may be used to position the aggregate capacity of a poorly defined set of generators with respect to total system load, which is typically better known.

Table 10.1. Total U.S. Generation, Average Annual Capacity Factors, and Weighted Equivalent Availabilities of U.S. Generation by Major Generation Resources

	U.S. Gen.[a] (TWh)	Annual Capacity Factor[b] (%)	Maximum Energy Capacity[d] (TWh)	Capacity[e] (%)	Fleet Capacity[f] (GW)	Typical Unit Capacity[g] (MW)	Units[i] (No.)	WEAF[j] (%)
Coal	1,624	67.3	1,396	17.2	159	320.0	497	83.21
Natural Gas	1,124	12.5	5,187	64.0	592	232.0	2550	84.18
Nuclear	791	89.5	511	6.3	58	981.0	59	88.98
Hydro	250	41.1	352	4.3	40	56.0	716	85.36
Biomass	71	63.9[c]	64	0.8	7	2.0[h]	3655	84.18[k]
Geothermal	17	94.8	10	0.1	1	33.0	35	97.27
Solar	17	25.9[c]	37	0.5	4	15.3[h]	277	99[k]
Wind	183	32.4[c]	327	4.0	37	1.5[h]	24879	32.4[k]
Petroleum	42	10.8	222	2.7	25	263.0	96	80.71
	4,119	29.4%	8,106	100.0%	925			

(a) The numbers in this column are based on the 2014 U.S. electricity generation mix found in (NERC 2014) and the total 2014 U.S. energy generation by utility-scale generators, plus all solar, stated in (EIA 2016a, Table 3.1.A).
(b) These annual capacity factors are average net capacity factors for the years 2007–2011 from (NERC 2014).
(c) The annual capacity factor for biomass was averaged from (EIA 2016b, Table 6.7.B) capacity values stated for "Landfill Gas and Municipal Solid Waste" (68.9%) and "Other Biomass Including Wood" (58.9%). This reference was also the source of the annual capacity factors for solar and wind renewable resources.
(d) Annual Capacity estimates the maximum available energy from each resource. This is estimated by dividing the total generated energy by the annual capacity factor.
(e) This column states the maximum energy capacity for each resource type as a fraction of the sum maximum energy capacity, about 8,106 TWh.
(f) Fleet capacity was calculated by dividing the maximum energy capacity for each resource type by 8766 hours.
(g) Typical unit capacity was available from the NERC GADS data (NERC 2014) as net maximum capacity.
(h) The typical unit capacities for wind turbines was crudely estimated at 1.5 MW. Individual turbines seem to be the right units for assessing availability for wind resources. The scale of biomass plants was also crudely estimated. The typical scale of utility-scale solar PV was calculated from information in (NREL 2015) that attributes 2.035 GW total utility-scale solar PV capacity to 133 sites.
(i) The number of units is estimated by dividing the fleet capacity by the typical unit capacity and rounding down.
(j) WEAFs were found in in (NERC 2014).
(k) The WEAF of biomass generation was assumed to be the same as that for natural gas. The WEAF of wind power is represented here by its annual capacity factor. Seasonal and hourly correlations are ignored for wind, for now. The WEAF for solar PV is very high, but overall availability is also correlated to both season and hour of day. The U.S. penetration of solar power is currently low, but as solar penetration grows, availability should be assessed by both season and hour.

10.1.8 Transmission Capacity Impacts

This section addresses three operational models and their impacts that help quantify the adequacy of transmission infrastructure. In Section 10.1.8.1, the day-to-day cost impacts of transmission congestion are assessed, based on the way that transmission congestion constrains optimal dispatch of a region's resources. Section 10.1.8.2 values transmission congestion events based on the transmission system's modeled marginal capacity, and Section 10.1.8.3 addresses transmission congestion events' effects on customers' electrical service, as was introduced in Section 10.1.6 and for Figure 10.5.

10.1.8.1 Additional Costs for Generation Resources Due to Transmission Constraints

One impact that reveals the status of transmission system adequacy is the suboptimal-resource expenses that must be accepted to avoid transmission constraints. The dispatch of generation resources must sometimes be altered spatially to avoid transmission congestion. The unconstrained, optimal, least-cost option must be discarded. The alternative dispatched resources are more costly than those unconstrained by congestion, thus increasing energy costs. These suboptimal costs must be weighed against the alternative—the cost of transmission upgrades that would relieve the system from making so many suboptimal dispatches of generation resources.

- Locations having an LMP. In locations having an LMP, this cost impact is revealed by the marginal congestion component of an LMP. The sum of the differences between the energy-weighted marginal constraint costs for the treatment and baseline scenarios reveal the degree to which the treatment mitigates the suboptimality that is caused by transmission constraints.
- Locations not having an LMP. Where there is no LMP, this impact is harder to assess. The incremental costs must be derived from the dispatch or market practices of the region. Regardless, the impact still should be defined as the additional costs incurred as lower cost generation options must be disallowed due to transmission system congestion.

This impact is relevant to TSs because many TSs' incentives are based on LMPs. Still others may affect peak demand and resource dispatch decisions. The TSs' responses should be expected to be stronger where the TSs directly incentivize an objective to avoid transmission congestion.

The inputs to this operational model obviously include the modeled marginal constraint cost component of an LMP. Alternatively, the costs of avoiding transmission constraints must be derived from a region's dispatch or market practices. This impact is heavily reliant on an analyst's ability to accurately reproduce or emulate the resource dispatch processes in a region. This impact will not be accurate and meaningful if the dynamic dispatch process is poorly defined or too crudely modeled.

Section 10.1.6 advocates that decisions to upgrade transmission infrastructure should be predicated on maintaining the reliability of customers' electric service. The impact in this subsection provides an alternative threshold criterion for making such decisions: investments should be made in new transmission infrastructure if doing so is predicted to be more cost effective than continuing to accept suboptimal resource dispatch that might be avoided by making the investment. It seems both the criteria could be applied simultaneously to maintain both reliability and economic performance of the transmission system.

10.1.8.2 Measures of Transmission Margins

Other potential impacts that reveal transmission adequacy are measures of transmission system transport margins. These include measures of the remaining available transport capacities of transmission lines over time and the numbers of times and durations that transmission system capacity limits are anticipated to be approached or exceeded.

These impacts are informed by detailed transmission circuit models and must include accurate reproduction of resource dispatch practices and load patterns within the transmission system. Time-series simulation must be used. The impacts are therefore sensitive to the accuracies of these circuit models and the modeled load and dispatch patterns and practices.

If the resulting impacts are deemed to be meaningful, they can be used to trigger upgrade decisions for specific transmission circuits. For example, a line's exceeding its capacity for more than 1 continuous hour in a year might be a decision threshold. Again, these criteria for upgrading transmission infrastructure may be considered simultaneously with other economic and reliability thresholds.

Compared to the other threshold criteria that trigger investment in new transmission infrastructure, these impacts and thresholds are relatively unfounded. One approach to creating a stronger foundation for investment decisions based on these impacts would be to formulate a parametric model of their effect on transmission infrastructure life span. If this can be accomplished, a stronger argument may then be made for the trade-off between equipment lifetime and upgrade costs.

10.1.8.3 Predicting Transmission Outages and Corresponding Customer Outages

As was suggested in Section 10.1.6, transmission outages and their corresponding impacts on customer service outages are strong measures of the adequacy of transmission infrastructure. Suggested impacts measure numbers of outages, numbers of customers affected by the outages, and durations of the outages. This operational model is then the basis for stating threshold criteria that trigger transmission investments. (This model also helps inform customer service reliability impacts.)

This impact is usually addressed through contingency analysis. Skilled system analysts use their insights to select the outage contingencies that threaten to induce the worst customer outages. Cascading outages may be considered and modeled. This approach seems well suited to planning, but it is not a basis for a consistent criterion, as is needed for valuation studies.

Each transmission line has a statistical likelihood that it will become unavailable. We will usually assume that the likelihood of an outage for each line is uncorrelated to the outages of other transmission lines. The likelihood of a transmission outage may be further parametrically affected by things like electrical loading, maintenance practices, and weather events and conditions, which can introduce correlations between different lines' outage statistics. Additionally, the lines have some likelihood of being out for routine service. If a transmission line is the sole supply of electricity to a customer (unusual), then its outage will have direct implications for those customers' service outages. More commonly, the transmission network is meshed, and redundant transmission pathways exist to serve most customers even after a transmission outage event.

If, however, the alternative transmission pathways that come into play after an outage are inadequate to supply demand, the newly overloaded lines protect themselves by opening their circuits. This occurs until all remaining customers can be served by the remaining intact transmission network. This is a basis for modeling cascading outages.

After a transmission outage has been modeled to occur, another related model must then predict the timing of service restoration. The modeling of outage service recovery is challenging because it requires the modeling of outage detection, circuit restoration actions, human operator decisions, linemen practices and skill, and other parametric effects that may be poorly defined or unavailable to the analyst. There may be costs associated with these restoration actions, including service truck rolls, linemen wages, etc.

Operational models requiring differing levels of rigor may be selected to inform these impacts:

- Time-series simulation. Especially where the likelihoods of transmission line outages can be stated as functions of line loading, time-series simulation should be used to accurately reproduce temporal loading at each circuit location. The temporal loading also helps determine the magnitude of unserved load each interval. The likelihood of transmission outages and their impacts are summed for all simulated intervals (e.g., hourly) throughout the simulated year.
- Conditions during representative time periods. If a scenario requires only modest temporal accuracy, the likelihoods of outages may instead be calculated during representative time periods, and those impacts can be extrapolated to the inclusive time periods. For example, sample hours, weekdays, months, or seasons may be chosen as representative of entire years. Peak demand hours might be good candidates where outages and their impacts are modeled as functions of load.
- Statistical treatment using transmission circuits and load curves. If temporal effects are relatively unimportant for a scenario, the statistical loading of transmission circuits (e.g., load curves) may be used along with the transmission circuit model. Transmission outage likelihood may still be stated as a function of load level. Representative load levels are used in place of representative time periods. Given that circuit models may be unavailable, prototypical transmission circuits might be derived from actual ones to simplify calculations.
- Recovery models. A separate model is necessary to represent outage responses and the timing of outage recovery efforts. There may be costs associated with these restoration actions, and other benefits and impacts to be learned from this model, including service truck rolls, linemen wages, etc.

This operational model and impact are relevant to TSs because TSs may reduce peak demand and thereby reduce the likelihood of a transmission outage. After an outage occurs, TSs may take actions to reduce load so that service can be supplied or restored to more customers more rapidly.

The following inputs may be necessary to drive the operational models:

- Transmission model. The detailed transmission system model relates transmission load to outage likelihoods and to customers who will be affected by transmission outages. Reduced-order, prototypical transmission system models might be derived to yield similar impacts with less computational vigor.
- Transmission line outage probabilities. A model of transmission line outage likelihood must be available. These likelihoods may be derived from historical data for the system being modeled or

from representative nationwide data. Ideally, this data should be stated as parametric functions of load, maintenance, equipment age, and weather conditions.

- Transmission line capacities. If cascading events are to be included, line capacities must be modeled. This should be stated as the capacity at which a breaker will open to protect the line.
- Recovery practices and trends. The recovery time must be parametrically defined as a function of available restoration actions and historical trends. If these specific parameters are unknown or are unavailable, a typical recovery curve may be used, based on an assumed rate that customer service is typically recovered.

10.1.9 Distribution Capacity Impacts

The impacts to be discussed in this section are those that help establish criteria for distribution system adequacy. This discussion should closely parallel the discussion in Section 10.1.8 concerning transmission system capacity. Two impacts are offered. Section 10.1.9.1 recommends the tracking of distribution equipment capacity margins and overload conditions. Section 10.1.9.2 recommends a statistical treatment of distribution equipment outages. The main differences between these impacts and models and those used for transmission capacity are that failures of distribution equipment are less costly than failures of transmission systems, distribution networks are less meshed than transmission networks, and fewer customers will be inconvenienced by distribution equipment outages.

10.1.9.1 Measures of Distribution Equipment Margins

The impact metrics for distribution equipment margins should closely track those put forth for transmission line margins in Section 10.1.8.2. Discussion will be abbreviated due to these similarities.

The principle is that electric load on a distribution circuit may at some time approach or even exceed the equipment's design capacity. These occurrences may be quantified by event counts or by time durations. A criterion is then stated that will trigger the replacement or upgrade of the equipment. Distribution equipment is usually overbuilt, and the criteria that trigger upgrades will often be conservative to make sure that rapid load growth cannot overcome the system's capabilities. Also, few options may exist for restoring customers upon the loss of critical distribution equipment.

Distribution circuits and their loads must be accurately modeled if distribution equipment capacity margins are to be predicted. Time-series simulation is required.

As was suggested in the discussion of transmission infrastructure margins, the decision criteria that trigger investments in distribution infrastructure will be more defensible if distribution equipment life span (and consequently replacement cost impacts) can be modeled as functions of time and electrical load. The threshold could then be defended based on the trade-off between changes in equipment life span and investments in distribution equipment. Changes in equipment life span and consequent maintenance or replacement expenses are themselves quantifiable impacts in a valuation.

10.1.9.2 Predicting Distribution Outages and Corresponding Customer Outages

This section recommends that distribution equipment outages and their effects on customer outages are metrics for making distribution system upgrade decisions. The argument should closely parallel the discussion that was presented in Section 10.1.8.3 concerning transmission systems outages. Therefore this section will be abbreviated. Please refer to Section 10.1.8.3 and mentally insert the word “distribution” for “transmission.” The purposes of the operational models are similar, although in practice, different tools have emerged to simulate power flow in transmission and distribution systems.

10.1.10 Resiliency Impacts

The stance taken in this report is that reliability and resiliency are very closely related system characteristics. The valuation community has perhaps conflated the simple impact of customer service outages to be assessed differently in scenarios where the system has, or lacks, an ability or flexibility to respond and mitigate or prevent customer outages; where outages are event-caused rather than natural; or where customer service outages are future hypothetical, not historical. These distinctions confound valuation efforts.

Clarity should result if resiliency impacts can be divided into the following simple elements, each of which may be captured as a separate impact:

- the likelihood of each of a set of extreme events, by location, against which the system is hoped to prove itself resilient
- for each extreme event, the likelihood that the event will initiate an outage for each of the generation, transmission, or distribution components
- assigning of equipment outages in the generation, transmission, and distribution domains to the resultant unsupplied load and to the customers who will incur consequent outages
- a model of the rate at which affected components and customer service would be restored.

With this understanding, the joint probability of extreme-event equipment outages is the product of the first two bullets’ probabilities, which yields the overall statistical likelihoods that each piece of generation, transmission, or distribution equipment will fall out of service as a result of an infrequent, extreme event. Once a piece of equipment falls out of service, it is assigned to its effect on unserved load and the number of customers who lose electric service. (This assignment is identical to that which was described in Section 10.1.6 and shown in Figure 10.5 for system reliability and its impact on capacity.) Modeling the rate of equipment and service restoration is also very similar to that which was already discussed, but there may be exceptional circumstances for the modeling of unusually large outages that stretch restoration resources and for weather events that hinder restoration efforts for prolonged time periods (e.g., big, long-lived snowstorms).

Resiliency impacts are important to TSs because the TSs might prepare the system for extreme events, thus diminishing the amount of equipment harmed and the number of customers inconvenienced. If the event must occur and cause outages, then a TS might facilitate rapid recovery from the event. Consequently, fewer customers might be inconvenienced and for shorter durations.

An interesting source of data about historical outages and their causes has been assembled by Eaton Corporation (2016).

10.1.11 Other Ancillary Services

This report has already discussed valuable impacts that touch upon various ancillary grid services, including its treatment of dispatch practices, voltage management, reactive power management, and energy losses. System protection, too, is addressed to the degree that it affects the resiliency of a power system, which has been discussed. The treatment of dispatch practices and markets in this report arguably addressed load following and other of the grid's balancing responsibilities, as well.

Other possible ancillary services perhaps remain unaddressed, including

- a grid's fast balancing and frequency management responsibilities
- ramping responsibilities
- spinning and non-spinning reserves that are not procured through a market
- system inertia management.

This section introduces structural considerations and cautions concerning the valuation of ancillary services, but it does not offer a comprehensive prescription of operational models for the many ancillary services and the impact metrics with which the services may be quantified.

Ancillary services themselves are weak bases for conducting valuation. The ancillary services are defined differently in different locations of the United States, and the services' objectives are not completely independent. That is, an actor's performance toward one ancillary service may limit its ability to perform, or change the outcome of its performance, toward another.

Some ancillary services are incentivized by markets in one region but not in another.

The methodology of this report still holds. However, we recommend that impact metrics should be selected to quantify the underlying objective or objectives of each ancillary service. Metrics of the ancillary service or its market may be reported as well, but these impacts may be weak for the reasons mentioned in the prior paragraphs.

If a new operational model and impact should become defined for another ancillary service and its objectives, our guidance is to make sure that an operational model quantifies the impacts and also has inputs that are parametrically defined in a way that will be accurately responsive to the actions taken by the TSs that are to be tested. The operational model must also accurately reflect the features and limitations of the region's ancillary service market or program.

NERC's Essential Services Reliability Task Force analyzed and assessed current system behavior as well as future services critical to the reliability of the bulk power system (NERC 2015). This list addresses many of the underlying objectives for which ancillary services are implemented. Table 10.2 lists a combination of measures and industry practices that can be used to characterize trends and impacts of a changing resource mix. These measures and practices nicely represent objectives and impacts for the valuation of ancillary services.

Table 10.2. Measures and Industry Practices that Can Be Used to Characterize Trends and Impacts of a Changing Resource Mix (NERC 2015)

Measure	Brief Description	Level
Synchronous Inertial Response at Interconnection Level	Measure of kinetic energy. Historical and future (3 years out).	Interconnection
Initial Frequency Deviation Following Largest Contingency	At minimum inertial response, determine the frequency deviation within the first 0.5 seconds following the largest contingency.	Interconnection
Synchronous Inertial Response at Balancing Area Level	Measure of kinetic energy. Historical and future (3 years out).	Balancing Area
Frequency Response	Comprehensive set of frequency response measures at all relevant time frames as well as time-based measures capturing speed of frequency response and response withdrawal.	Interconnection
Real-Time Inertial Model	Industry practice: real-time model of inertia, including voltage stability limits and transmission overload criteria.	Balancing Area
Net Demand Ramping Variability	Measure of net demand ramping variability. Historical and future (3-years-out) view.	Balancing Area
Reactive Capability on the System	Measure: at critical load levels, measure static and dynamic reactive capability per total MW on the transmission system and track load power factor for distribution at low side of transmission buses.	Balancing Area
Voltage Performance of the System	Measure to track the number of voltage exceedances that were incurred in real-time operations.	No Further Action
Overall System Reactive Performance	Industry practice: measure to determine reliability risk following event related to reactive capability and voltage performance. Evaluate adequate reactive margin and voltage performance (planning, seasonal, real-time horizons).	Balancing Area
System Strength	Industry practice: measure to determine reliability risk due to low system strength based on short circuit contribution. Calculate short circuit ratios to identify areas that may require monitoring/further study.	Planning Coordinator

10.1.12 Growth Drivers

This report's methodology recommends a separation of operational and growth models during valuations. This and the following section address treatment of growth during a valuation. This section discusses growth drivers, and the next will discuss growth responses.

Growth drivers should be thought of as emerging stimuli that challenge an energy system. Planners usually have little control over such stimuli. The stimuli create outcomes that must be managed or mitigated. For example, rapid growth in the penetration of customer-owned PV generation on a feeder might challenge the feeder's ability to stay within acceptable voltage limits.

One of the most common growth drivers is electrical load growth. Electrical load growth challenges all parts of an energy system. Distribution and transmission systems are challenged to transport the new load. Generators are challenged to supply the new load. Load growth may be stated in terms of real power growth or as a fraction of the previous year's average or peak load. The fractions of new load that are residential, commercial, and industrial should also be predicted. Furthermore, at least the typical diurnal load patterns for each category of new load should be defined. Location may be relevant if adequate detail about growth patterns is available to predict differences in load growth on specific feeders or at specific sites.

Equipment degradation may be treated as a growth (in this case, *decay*) driver. If system equipment life spans can be stated as simple functions of time, new replacement costs are then incurred each year as the equipment is modeled to need replacement. If, however, equipment life spans are more richly defined as functions of other events and conditions, then the additional events and conditions, too, must be predicted (modeled), and the replacement costs are affected by each year's events and conditions.

If a new policy is anticipated in a future year, the new policy may be a driver in the growth model. The system must respond to the new policy just as it must respond to load growth and other potential drivers.

If the growth of a TE system penetration is presumed to be imminent over future years, the growing penetration of the TE system is itself a growth driver. Certain stakeholder groups might pay for new system equipment. Other stakeholders might benefit from the increased scale of impacts in following years.

10.1.13 Growth Responses

Growth responses arise from sets of tools—new assets, new products, new or modified policies and practices, etc.—that a scenario's actors have at their disposal to respond to system conditions, many of which will have followed from the growth drivers that were described in the previous section. The need for a response emerges when an operational model has failed to satisfy one or more of the system's operational requirements. When this happens, tools should be selected and tried until the operational requirements are satisfied.

Two or more of the tools might successfully mitigate the violations of operational requirements. It is difficult, if not impossible, to definitively select the single best tool at this point in the valuation because the interpretation of "best" might only be revealed by the long-term performance of tools in the system. Furthermore, the interpretation of "best" might differ at the end of a valuation if the decision criteria are uncertain or if multiple decision criteria are to be considered—least expensive alternative versus environmentally "greenest" versus least risky, etc. Furthermore, not all of the impacts will have been found to have been monetizable in a way that facilitates comparison, thus inviting debatable weighting of the many monetizable and unmonetizable impacts.

The installed cost of the new tools must be noted each growth year for later economic treatment. Some of these tools will further affect the configurations of and the behaviors of the valuation's operational models.

10.1.14 Modeling Energy Markets

This report addresses how TE systems affect valuation. Some TE system frameworks are market-like, but there may be other existing energy markets that will be impacted by the performance of a TE system as well. This section introduces how such markets may be modeled. Impacts for these markets should be defined in terms of the amounts of energy that become traded in each market (e.g., average, total, maximum, etc.) and the fees that are paid and received for that energy (e.g., price, average price, total price, etc.).

Figure 10.6 depicts an e^3-value activity for the trades that take place in an energy market. In a complete e^3-value diagram, the trade activity would be encompassed by the market-operator business entity that runs the market. A market model emulates the energy quantities and fees (*value flows*) that are exchanged by the market.

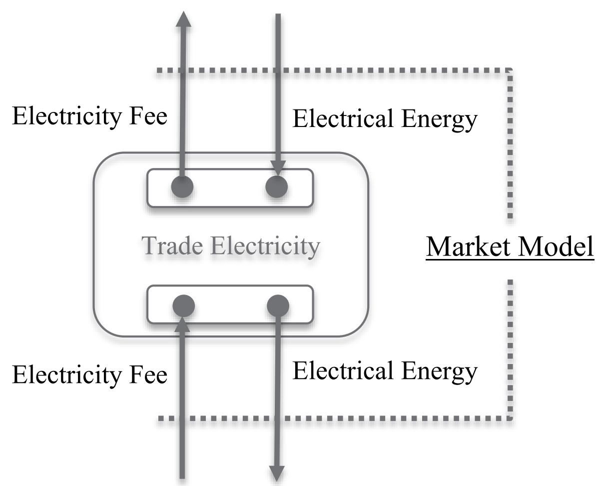


Figure 10.6. A Market Model must Represent the Effects of an Energy Trading Activity in the System, Including its Effects on Traded Energy and the Fees that are Paid for that Energy

A market model may rely on and should be consistent with the valuation dispatch model. The dispatch model is one possible foundation for a market's energy prices. These energy prices must be functionally stated within the market model.

The market model also relies on the load model. The amounts of energy exchanged in a given market must be functionally stated based on predictions, or forecasts, of the final electric load. The load model derives the final electrical load. The remaining responsibility is to, based on the actual modeled load time series, state the statistics of forecast errors, which can then be used to emulate the inaccuracy of the various load predictions at the time the respective markets clear. The forecast errors can probably be stated as functions of time, prediction time horizon, and level of aggregation being represented in the system.

Models may be needed for the following common energy markets, although their definitions, names, and rules may differ by region:

- <u>Long-term futures energy markets, including load following</u>. Relatively large and relatively constant blocks of energy are bought and sold well in advance of the times they are to be supplied and consumed. Prices are usually among the lowest for eligible energy consumers in this market. Suppliers benefit from predictable, guaranteed sales that may become a basis for investments on their part.
- <u>Day-ahead energy market</u>. Trades of hourly blocks of energy for the next day, or so. The opportunity to participate ends at a specific time prior to those hours.

- Hour-ahead energy market. Trades of hourly blocks of energy that may be made up until nearly the hour in which the energy is to be consumed and supplied.
- Intra-hour energy market. Refinements of hour-ahead outcomes using half-hour, 15-minute, or shorter time intervals.
- Spot market. One of the final opportunities to procure and sell energy in a market. High, premium prices are usually required to purchase energy on the spot market. Participants may become active after encountering unforeseen conditions.

One challenge in analysis of market impacts is that the markets are not independent. Purchases and offers in one market might have been alternatively made in another. The buyers and sellers' behaviors are strategic and self-serving and are not necessarily public information. The individual market participants' actions cannot be emulated without knowledge of participants' strategies and status. Valuation analysis must simplify market processes. Analysts must suppress much of the complexity of the markets while still capturing reasonable, meaningful dynamics of the participants' aggregate exchanges in the market.

The overall recommended valuation strategy is to presume that market participants will make reasonable load forecasts in the available markets, based on the information that the buyers might have at the time bidding ends in the given market. If individual energy markets are presumed to be sequential, each successive market should be presumed to possess a superior prediction of actual load compared to its predecessor. That prediction accuracy must be modeled. Each market clears the difference in energy between the improved, market-cleared load and prior cleared energies.

In light of an improving load forecast, market participants buy and sell quantities that, in some sense, optimize their performance in the markets. Buyers buy as much energy as they can at the lowest prices available, while accounting for possibilities that they may be unable to later resell it or may be forced to sell it at a loss. Sellers, on the other hand, sell at the highest price possible, while accounting for the possibilities that energy may remain unsold or must later be sold at a considerably lower price. The energy market models strive to emulate bulk market behaviors in a way that is true to the participants' strategies.

The model must derive energy price and price stability advantages and disadvantages, which emulate the impetuses for market participants to, for example, participate in long-term future markets rather than wait and buy energy on the spot market instead. Ideally, the prices are modeled as functions of the region's dispatchable resources consistent with the dispatch model (Section 10.1.2). This general modeling strategy might reasonably predict aggregate market performance without having to address how each participant's performance should be optimized according to unknown participant strategies and other unknown or unobservable market information.

Figure 10.7 helps demonstrate the modeling strategy. It represents five successive energy markets for procuring energy supply for a specific 24-hour period. A constant base-load supply is presumed to have been procured for supplying the minimum load on this day. In this case, the base-load magnitude was formulated as a fraction of the day's average load. Other formulations are, of course, possible. The price of this base load might be functionally based on production cost of the least expensive resources that can supply this amount of energy. This simple price model gives base-load energy purchases a clear advantage over quantities that would later need to be purchased at higher marginal prices.

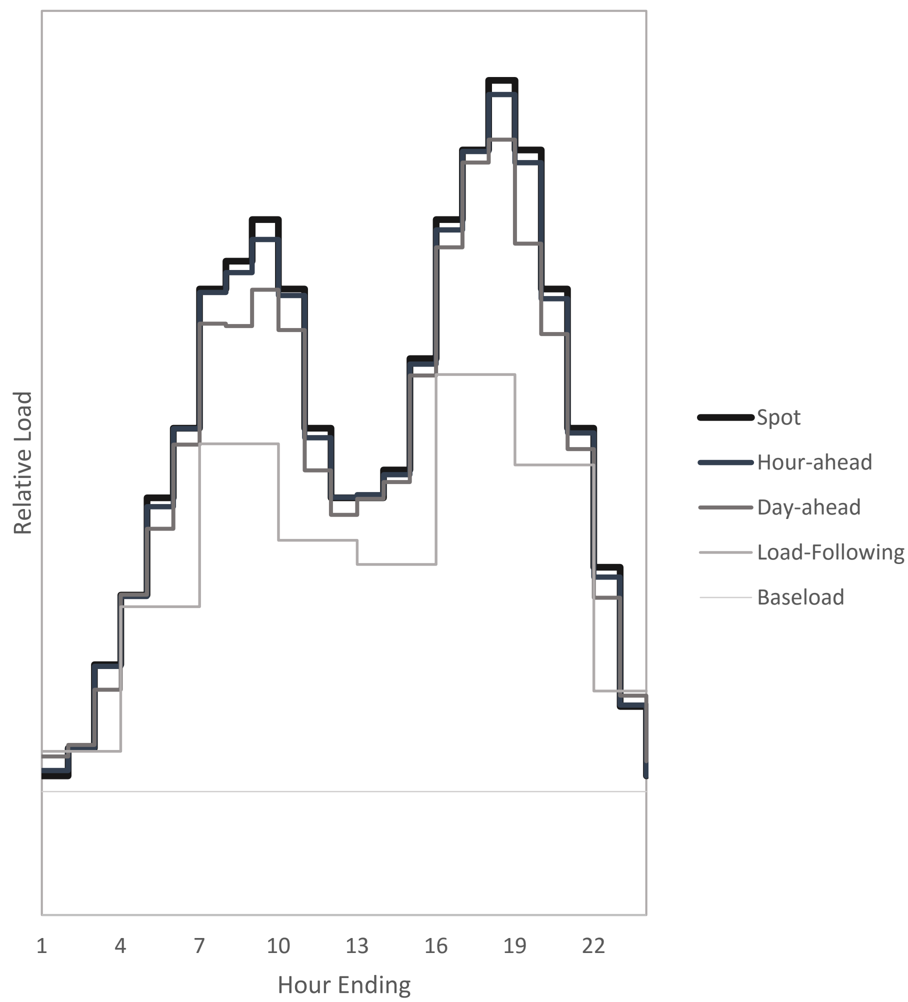


Figure 10.7. Successive Energy Market Models that Yield Increasingly Accurate Predictions of the Actual Load

A load-following market further refines the base-load prediction. The example model does so in 3-hour blocks. A bias was included in this model as would be used if a market tends to underestimate future load. Perhaps the buyers in this market prefer not to later resell energy. The amount of energy cleared in the market on this day is the difference between the areas under the base-load and load-following curves. The dispatch model could be used, as for base load, to determine an advantageous price that is greater than that for base load but is less expensive than, and more predictable than, energy that will eventually become available on the spot market.

Day-ahead and hour-ahead markets are shown in Figure 10.7 to refine the load predictions still more. The spot market, in this case, happens to represent the final difference between final modeled load and the total predicted load after the hour-ahead market. Spot market prices are probably to be modeled identically to marginal resource prices.

The market models and market impacts may be relevant to TSs because the TSs can change load peaks and patterns, which will likely move trading among, into, or out of the various markets. Many TSs share operational objectives with and might compete with hour-ahead, day-ahead, and spot markets. TeMix, in particular (Barrager and Cazalet 2014), strives to extend participation in futures markets—historically available only to very large customers and the bulk transmission and generation system—to new distribution-level and DER participants.

The following inputs are likely needed to drive market models:

- Market rules. Because the existence of markets and their definitions differ across the United States, the scenario must be configured for relevant markets and their rules and practices.
- Electric load. Electric load magnitude is the target for load forecasts and helps derive energy production costs.
- Resource production costs or other functional energy pricing formulation. Market prices may be derived from production costs in a way that is self-consistent across the valuation. The price's dynamics come from the interaction of the dispatch model with system load. Additional dynamics may occur if energy prices are stated as functions of fuel costs and other potentially dynamic inputs.
- Statistics of load prediction errors. The accuracy of load predictions should affect bid energy quantities. The inaccuracies cause bidders to later either need to buy still more energy or to resell energy. The inaccuracy of load forecasts therefore has monetary impacts.
- Historical market performance. Historical market data is useful to calibrate market models and make them better emulate actual market behaviors.

10.2 Buildings Impacts and Operational and Growth Models

The primary function of buildings has historically been to support the buildings' business purposes and provide safe and comfortable shelter for their occupants. The need for building energy modeling and simulation techniques emerged as energy and sustainability concerns increased. However, these building models have not typically been used for load modeling for power management and planning. Buildings diagnostics and controls are becoming increasingly sophisticated and prevalent, particularly in the commercial building sector. Highly optimized controls can continuously monitor and increase building efficiency while improving resource allocation and minimizing cost (Somasundaram et al. 2014).

Figure 10.8 suggests eight e^3-value activities and their value flows that might be used to formulate business cases in the buildings domain.[6] These are uniformly presented from the perspective of a building owner or operator. Counterparts to these value activities and flows would also exist from the perspectives of occupants, load aggregators, service providers, energy suppliers, and others who interact with the building owners and operators. Most of these value activities inform value flows that are either directly related to or in support of buildings' interactions with electric power systems. We anticipate still more and new value activities may be defined as business cases become defined apart from TE system applications.

[6] This report's recommendation for the use of e^3 value in the buildings domain is so new that these value activities are truly suggestions. They should be scrutinized for their use in complete e^3-value diagrams, and they may require further revision thereafter for specific business cases.

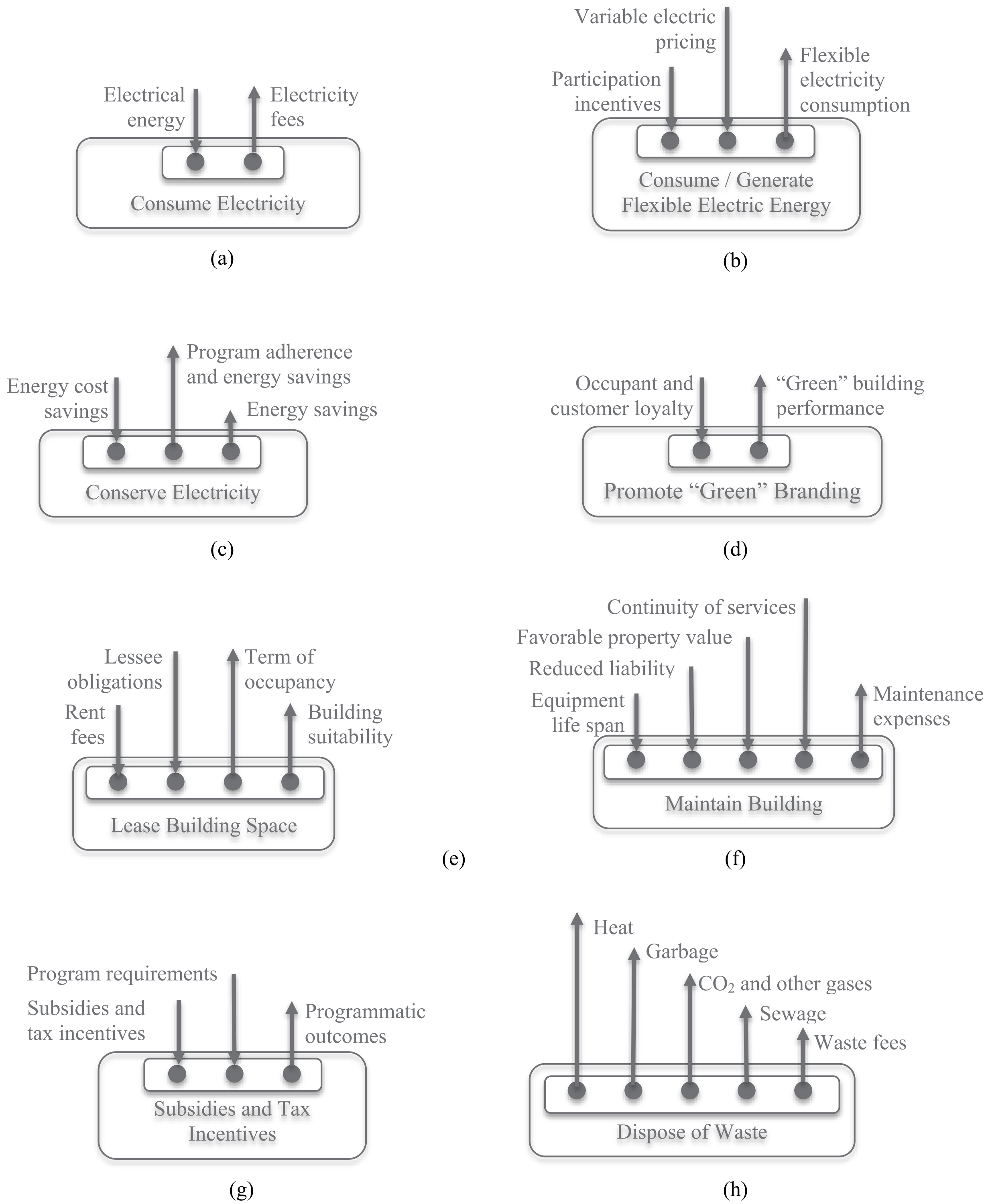


Figure 10.8. Business Value Activities from the Perspective of the Building Owner or Operator

We offer the eight example value activities (Figure 10.8) as context for discussion of the operational models and the impacts that should be quantified in the buildings domain.

- Consume electricity (Figure 10.8a). The principal interaction between a building and its electric power supplier is the consumption and provision of electricity. Buildings receive electrical energy in exchange for a fee. This particular value activity is intended to address the normal consumption of energy at buildings, not dynamic changes in building load that can be attributed to incentives (see Figure 10.8b) or conservation efforts (see Figure 10.8c). Impacts and operational models may still incorporate weather and other conditions. Simplifications are possible where such sophistication is unlikely to significantly affect the outcome.

  From the building owners' perspectives, the consumption of electricity has a straightforward implication for their electricity bills.

  Because buildings are diverse, electricity consumption may need to be modeled for unique manufacturing and other building processes. This report addresses only the most common models concerning building space thermal management (Section 10.2.2); building lighting management (Section 10.2.5); and building air quality, which has implications for building ventilation (Section 10.2.3).

- Consume / generate flexible electric energy (Figure 10.8b). This is a special case of the value activity of Figure 10.8a, "Consume Electricity," where load models (Section 10.1.1) must be made sufficiently dynamic and responsive to system incentives (e.g., a TS, traditional demand response, etc.) that the impacts of TSs and other dynamic incentives may be investigated. The responses of buildings might include contingencies to engage not only loads, but also site generators. This value activity provides the context under which many of the electricity grid's services may be revealed as incentives, and the consumer, in return, provides a degree of load (or generation) flexibility.

- Conserve electricity (Figure 10.8c). This is still another special case of the value activity of Figure 10.8a, "Consume Electricity." It is similar to the value activity of Figure 10.8b, "Consume / Generate Flexible Electric Energy," except that the flexibility being offered for energy conservation usually results from prolonged insertion of new technologies or policies, not the impacts of short-term incentives. This elevates the importance of the valuation growth model for the business cases that address conservation.

- Promote "green" branding (Figure 10.8d). This report has challenged the technical community to valuate elective, and even non-energy, impacts. Businesses' "green" images will be discussed in Section 10.2.10, "Green Image Impacts Model." By conducting and branding these green activities, the building owner may favorably impact building occupants' and their customers' loyalties.

- Lease building space (Figure 10.8e). Electrical energy is only a small fraction of most businesses' total expenses. The short Section 10.2.4 introduces the concepts for modeling the retention and loyalty of business space occupants, for example. Businesses tenants remain loyal, paying building owners in exchange for a stable term of occupancy and suitable building conditions.

- Maintain building (Figure 10.8f). A building's maintenance has indirect effects on electricity consumption and suitability, and it is a significant expense for many building owners. This value activity might also model sources of risk for the building owner, including liabilities for any harm that malfunctioning equipment might cause to businesses and building occupants. The short Section 10.2.8, "Building Maintenance Model," introduces some of these modeling concepts.

- Subsidies and tax incentives (Figure 10.8g). Buildings or building occupants may become affected by subsidies and tax incentives, as will be introduced in Section 10.2.11.

- <u>Dispose of waste</u> (Figure 10.8h). The management of waste streams is another soft activity and impact that might affect business cases in the buildings domain. This value activity was introduced by Gordijn and Akkermans (2001) and will not be further discussed, other than here, in this report.

Figure 9.2 (Chapter 9.0) was a relational structure diagram between various valuation impacts in the buildings domain. Figure 10.9 has a similar purpose, but the blocks in this figure are simplified representations of classes of operational models with which the impacts should be calculated. Not all inputs and outputs are explicitly shown for the operational models in this figure, but the arrows that are shown represent important types of impacts (as outputs of the operational models) and inputs.

The following sections will address three groupings of operational models, concerning building thermal space management (Section 10.2.2), building air quality (Section 10.2.3), energy usage by appliances (Section 10.2.4), and building lighting management (Section 10.2.5). The interrelationships between operational models for these three groups appear similar, as shown in Figure 10.9. Each one possesses measures of occupant comfort, based on building conditions that further affect the occupants' behaviors. This means that the occupants interact with their building based on their comfort satisfaction and other conditions. For example, dynamic electricity rates are suggested in Figure 10.9 to potentially affect occupant behaviors. Building operators and occupants, in turn, interact with the physical building to hopefully keep the building occupants comfortable. The building model generates both the measures of the physical variables like temperature, lighting, and ventilation impacts, but also calculates the amounts of energy that the building would need based on these conditions. The consumed energy and energy rates help predict an electricity bill. A complete treatment would require similar discussions and models for all other building energy sources (e.g., natural gas) and commodities (e.g., water), but this report will continue to focus on electrical energy impacts to demonstrate basic principles.

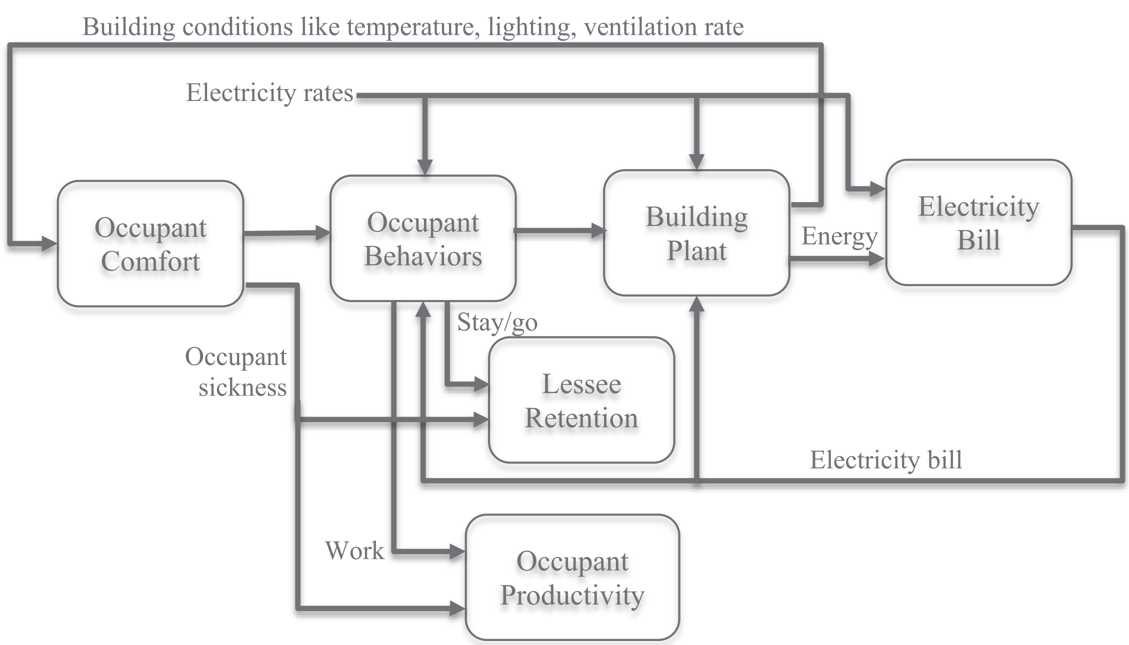


Figure 10.9. Simplified Interconnections between Common Operational Model Sets in the Buildings Domain

According to an RMI report, deep retrofits can reduce costs associated with maintenance, water, insurance, and occupant churn rate (Bendewald et al. 2014). Non-energy operating cost savings create value directly for the property owner by increasing net operating income, which is capitalized to create property value. To the extent a TS becomes part of deep retrofits, these impacts can be derived in part from the TS. Smart building technology can help owners and operators determine where equipment replacements will generate the greatest return on investment. In two 2012 studies, Economists Intelligence Unit and Delioitte indicated that energy savings associated with smart buildings and equipment replacements have become increasingly essential for a building to remain financially competitive in the marketplace (Probst 2013). A short discussion will address the modeling of some of these "softer" types of building impacts later in this section.

10.2.1 Occupant Behavior

While the roles of occupant behavior will be discussed later in relation to buildings' thermal, lighting, and ventilation systems, some general discussion might be useful. In most demand-response programs, including TE systems, the role of an occupant in realizing desired energy outcomes is critical. The occupants are often active decision makers in such programs, and they directly or indirectly interact with the grid. Hence, their behaviors and decisions directly influence system performance.

Persons affect buildings to some degree simply by the patterns that they exhibit as they interact with buildings. People tend to wake up, go to work, eat meals, and return home at consistent, if not predictable, times. These patterns naturally affect building performance, and the buildings settings must accommodate such patterns.

As was shown in Figure 10.9, occupant behaviors may be influenced by the occupants' comfort levels. A simple thermostat's settings may be nudged up or down during the day, for example, by different occupants who have their own preferred indoor temperatures. Lack of ventilation might cause occupants to become lethargic and less productive than their employer might wish.

People's perceptions of comfort may further affect a building's performance in a TE system. Some may accept greater variability in building settings than others because they are more adaptable or perhaps do not notice small deviations in a building's normal operations. Once a demand-response event has started, an uncomfortable person might altogether terminate the building's participation in the event. Some individuals may be more likely than others to accept a given incentive in exchange for temporary discomfort.

The approaches to modeling human behavior for these needs are based on regression and Markov models. Regression models simply learn and apply the probability of an action given a set of environmental conditions as inputs without necessarily making any presumption about the underlying processes. Markov models are also statistical in nature, but they presume the existence of underlying sequences of states. Constructing these models requires long-term, high-resolution building data. While occupants' actions (e.g., turning on or off lights) are observable, the motivations behind these actions are often unknown or unobservable.

10.2.2 Building Space Thermal Management

As was suggested by Figure 10.9, the modeling of impacts having to do with the management of thermal space conditioning in a building probably requires at least four interconnected operational models—an occupant thermal comfort model, an occupant behavioral model concerning occupants' responses to their levels of thermal comfort, the building's thermal performance model, and a model for the accounting of energy billing as it is affected by thermal management.

10.2.2.1 Occupant Thermal Comfort Model

The purpose of a thermal comfort model is to predict and quantify occupants' levels of satisfaction with their building's thermal conditions. An occupant who becomes uncomfortable might change the building's thermal set points or have the building manager do so for him. If the building manager consistently fails to satisfy occupants' desired thermal conditions, this unsuitability of the building environment could harm the manager's retention of building lessees.

Human judgment of comfort is a cognitive process influenced by a variety of physical, physiological, and psychological factors. Therefore, assessing comfort is a challenging task involving many different inputs with a distribution range for each.

From the building engineers' or operators' perspectives, comfort is paramount. Sacrificing comfort is antithetical to current building operational practice and standards (see (ASHRAE 2013)). For some building types, changes in comfort are inconceivable, especially when occupant comfort may affect occupant health and safety (e.g., hospitals and laboratories). For small commercial and residential buildings, there may be more latitude in how these buildings are operated, allowing traditional comfort boundaries to be expanded.

There are different guidelines used to rate thermal comfort levels, as reflected in the standards ASHRAE 55 (2004b), EN 15251 (2007), and ISO 7730 (2005). The main objective of these standards is to specify acceptable thermal conditions for 80% or more of occupants in a given built environment. Operational models presented here are based on methods used in these two standards. Fanger's method (Fanger 1970) is an often-cited application of these methods.

Because it is difficult to place an exact number on the value of comfort, it must be expressed in terms of other quantities. Two common comfort measures derived from these standards are predicted mean vote (PMV) and the predicted percentage dissatisfied (PPD). PMV is an estimate of the average desired thermal conditions. PPD predicts the percentage of occupants that will be dissatisfied with the building's thermal conditions. PMV is a function of different parameters, which are clothing levels, indoor and outdoor air temperatures, mean radiant temperature, air movement, relative humidity, and activity levels. PPD is a function of PMV and, as shown in Figure 10.10, as PMV moves farther from 0 (neutral), dissatisfaction, as measured by PPD, increases. For example, suppose that a thermostat set point is raised by 1 degree F in response to an external grid signal. The change in set point results in a rise in building temperature, changing the PMV from 0.5 to 1.0 (PMV is measured in the range between −3.0 and 3.0), indicating that there will be an increase in the percentage of people dissatisfied (too hot in this case).

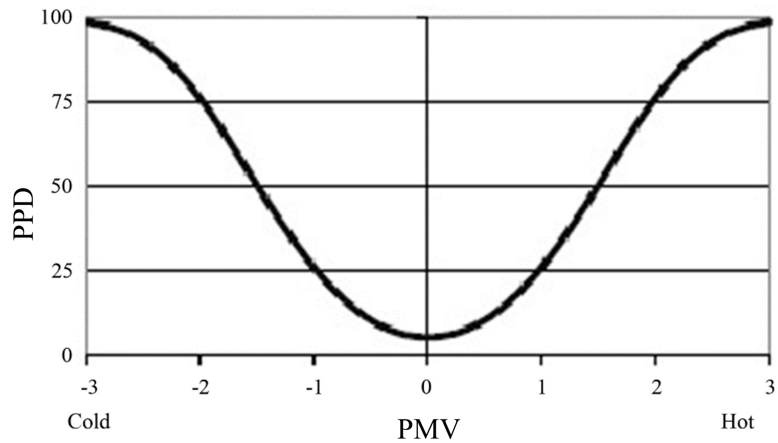


Figure 10.10. PMV-PPD Relationship

McCartney and Nicol (2002) developed an adaptive comfort model based on adaptive comfort theory for the European Standard as an alternative to fixed temperature set-point controls within buildings. The adaptive method assumes that the building is not conditioned but occupants are free to change their environment or clothing level within a range. This range is at least between 0.5-1.0 clothing level to achieve thermal comfort. The adaptive comfort zone would change based on the prevailing mean outdoor temperature. An adaptive method was also developed under ASHRAE Standard 55 (2004b). In these methods, an adaptive comfort standard serves as an alternative to the PMV-based method. It is a regression-based method using mean outdoor dry-bulb temperature, which makes it especially appropriate for naturally ventilated buildings. The PMV method is influenced by environmental and personal factors and uses a heat balance model of the human body to predict thermal sensation. The adaptive model, on the other hand, considers factors beyond fundamental physics. Although models based on heat-transfer balance are able to account for some behavioral adaptations (e.g., clothing), they do not consider, for example, the psychological dimension of adaptation.

A thermal comfort tool was developed by the Center for the Built Environment at the University of California, Berkeley (Tyler et al. 2013). This tool uses either the PMV or the adaptive method to calculate acceptable thermal comfort levels based on the European Standard EN 15251 (2007) or ASHRAE-55 (2004b).

The list of potential inputs to building thermal comfort models is extensive. The following useful inputs were identified by Fanger (1970): occupant clothing properties, like amount and insulative properties, and the surface temperature of the clothing; convective heat transfer coefficients; occupants' metabolic rate and level of activity; vapor pressure of air; air temperature; mean radiant temperature, based on a weighted temperatures of surrounding surfaces; air velocity; external work; and relative humidity. Details of these parameters and their estimations can be found in Chapter 8 of *2005 ASHRAE Handbook – Fundamentals* (ASHRAE 2005).

10.2.2.2 Occupant Behaviors Concerning Their Thermal Comfort

Occupant behaviors affect buildings' thermal management. Our experience and success in formulating operational models of these behaviors is limited. Establishment of thermostatic set points is perhaps the most direct impact. Many set points are scheduled. Others are changed upon events—

including occupant discomfort. A parametric model that determines the timings and distributions of temperature set points, based on human interventions, would be useful. Occupant work schedules and the activities that they conduct during those work hours indirectly affect building thermal management. Therefore, parametric models are also needed to predict the likelihoods that buildings will be occupied for various occupant purposes over time.

An ideal model would predict occupants' behaviors accurately in light of incentives and demand responses. Humans ultimately offer initial responses to such programs and may choose to alter or discontinue such responses if they become inconvenienced or uncomfortable. These behaviors are often presumed and remain static in valuation studies, but this report argues that such behaviors should be functionally defined and dynamic if long-term valuations are to be conducted.

The inputs to occupant thermal behavior models include metrics of occupant thermal comfort, building schedules, and various incentives like electric rates, electric bills, and dynamic incentives. The model formulation must be trained using long-term regression studies of observable occupant behaviors. If hidden Markov models are to be used, discrete state spaces must be formulated while considering occupants' psychological, physical, and social characteristics.

10.2.2.3 Building Thermal Performance Model

The purpose of the building thermal performance model is to functionally predict a building's indoor temperature (and perhaps other variables that affect the human perception of temperature) and to predict the energy impacts of the building's space-conditioning processes. The model is the equivalent of a plant model in a control system. In this section, simplified and detailed thermal models exemplify operational building models. A scenario may allow further simplification of building thermal models if no TS or asset is expected to change buildings' thermal performances during the evolution of the scenario.

A building model represents the natural response of buildings as the building and its occupants become affected by TS incentives. For example, a well-insulated building might be able to ride through a prolonged curtailment better than a poorly insulated one, but it might be unable to provide flexibility toward incentives that change rapidly.

Simplified building energy models are quasi-steady-state models derived to estimate energy consumption of end users in a given building. These models are designed to calculate energy flows of a building at the macro level with a simplified description of a building. A well-accepted normative method is defined in the CEN-ISO standards under the Energy Performance of Buildings Directive as the standardized methodology for energy performance calculation (ISO 2008; CEN/TC 2006). In this method, calculations of heat gains and losses are aggregated by transmittance heat transfer, ventilation heat transfer, solar heat gains, and internal heat gains (see Figure 10.11). Simplified building energy models approximate energy performances of the building systems (e.g., HVAC, lighting, domestic hot water, fan, and pump energy) with a small number of macro-level inputs based on a simplified description of a building and its systems.

A simplified building energy calculation is based on the balance of heat gains and losses in steady-state conditions. The calculation takes into account dynamic effects by introducing an internal temperature adjustment for heating and cooling intermittency and a utilization factor for the gain-loss mismatch. For each thermal zone, the total heat transfer, Q_{total}, is calculated as the sum of heat transfer through transmission (Q_{trans}) and ventilation (Q_{vent}) for each time step t:

$$Q_{total} = Q_{trans} + Q_{vent} \tag{10.2}$$

$$Q_{trans} = \sum_i (U_i A_i)(T_{in,setpt} - T_{out})t \tag{10.3}$$

$$Q_{vent} = \upsilon_{air}\, \rho_{air}\, c_{air}\, (T_{in,setpt} - T_{out})t \tag{10.4}$$

where for each building envelop element i,

U_i	=	the heat conduction coefficient
A_i	=	the area of surface element i
$T_{in,setpt}$ and T_{out}	=	the internal set point and the external air temperature
υ_{air}	=	the air exchange volume rate in each time step
ρ_{air}, c_{air}	=	the density and specific heat capacity of air.

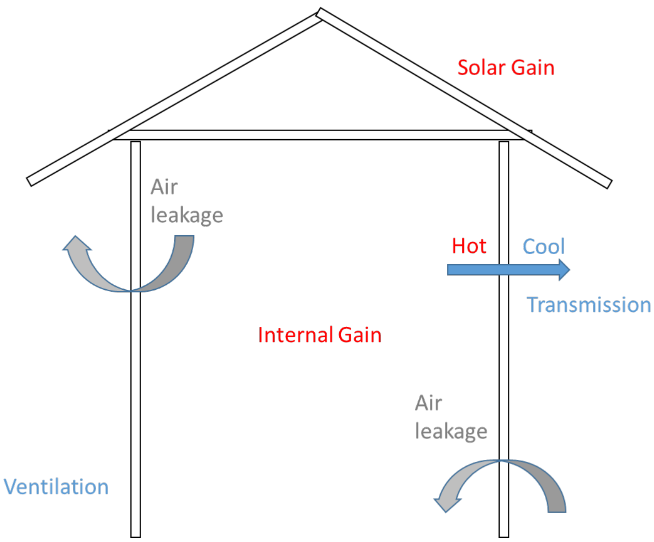


Figure 10.11. Simplified Schematic of Heat Transfer and Heat Gains in a Building

The total heat gain, Q_{gain}, of a building for a given time step can be calculated by summing the internal heat gains from occupants, appliances, and lighting ($Q_{internal}$) and solar radiation heat gains (Q_{solar}):

$$Q_{gain} = Q_{internal} + Q_{solar}, \tag{10.5}$$

where

$$Q_{internal} = A_{total}\, (\varphi_{occupant}\, q_{occupant} + \varphi_{appliance}\, q_{appliance} + \varphi_{lighting}\, q_{lighting})t \tag{10.6}$$

and

$$Q_{solar} = \sum_i (f_{sh,i}\, I_i\, A_{sol,i} - F_{r,i}\, q_{r,i})t. \tag{10.7}$$

These are the definitions of the variables used in Equations 10.5–10.7:

A_{total}	conditioned floor area
$\varphi_{occupant}$, $\varphi_{appliance}$, $\varphi_{lighting}$	fractions of heat gains from occupants, appliances, and lighting
$q_{occupant}$, $q_{appliance}$, $q_{lighting}$	heat production intensities of occupants, appliances, and lighting

$f_{sh,i}$ shading reduction factor

I_i solar irradiance, the mean solar radiation received over one time step, per square meter of collecting area of surface

$A_{sol,i}$ effective collecting area of surface given its orientation, tilt angle, heat conduction, and convection coefficients (for opaque) and solar heat gain coefficient (for glazing)

$F_{r,i}$ form factor between the building element and the sky

$q_{r,i}$ long-wave radiation flow rate from the element to the sky

t time interval

In high-fidelity building energy modeling engines such as EnergyPlus (DOE BTO 2015), the inputs are similar to those needed for simplified models. However, more inputs are required to define the buildings and their subsystems. Use of detailed models for grid studies should be carefully considered to avoid unnecessarily elevating the cost of modeling, computation, and post-processes associated with such models. Only detailed models can address multi-zone buildings, various types of heating and cooling equipment, details of air distribution systems, and airflow between zones.

Building thermal models typically require many of these inputs: location, heating and cooling equipment types and efficiencies, weather conditions (e.g., solar radiance, outdoor temperature, and wind speed), building qualities (e.g., building area; non-glazed and glazed wall areas; roof and wall materials and their thermal conductance; solar heat gain coefficient; glazing type, material, and solar transmittance; and air flow rates), and control set points and schedules.

10.2.2.4 Impact of Building Heating and Cooling on Electricity Bills

The average and specific electricity bill impacts can be calculated for electricity customers and customer categories from the modeled operations of space conditioning equipment and electricity rates and fees. For some scenarios, electricity rates and TE system incentives may be the same.

This report emphasizes electrical power, but similar treatments of natural gas heating and other alternative resources may be needed for valuation if buildings use, or can switch to and from, alternative fuels.

10.2.3 Building Air Quality

Indoor air quality should address relative humidity, carbon dioxide levels, particles, and other contaminants in building spaces. As for Sections 10.2.2, “Building Space Thermal Management” and 10.2.5, “Building Lighting Management.” discussion of building air quality will be divided into four interrelated operational models—occupant comfort model, occupant behavior model, the building model, and the electricity cost model. Review Figure 10.9. This suite of models supports TE system valuations, but building air quality also interacts with models of absenteeism and occupant health (Section 10.2.3.4), and therefore work productivity and insurance rates (Section 10.2.9).

10.2.3.1 Occupant Air Quality Satisfaction Model

As for the previous discussions of occupant satisfaction, the purpose of this model should be to quantify occupants’ satisfaction with their buildings’ air quality. The exact metrics of satisfaction levels are not well defined, but we propose they might be modeled after PMV, which was discussed in Section

10.2.2.1 concerning thermal comfort levels. If occupants become dissatisfied with their building's air quality, they take direct actions or initiate changes in automated ventilation schedules, as will be discussed in the next section.

Fanger (1988) published an equation to estimate the number of dissatisfied occupants as a function of the perceived air pollution using the decipol unit. Equation 10.8 shows the correlation between the PPD of building occupants and the decipol level (*C*). This equation indicates that the number of dissatisfied people is a function of air quality and airflow.

$$PPD = 395e^{(-3.25 \cdot C - 0.25)} \tag{10.8}$$

Occupants' satisfaction with building air quality is important for TSs because building ventilation fans may be targeted by these systems for control in large commercial buildings. Occupants' tolerance of reduced ventilation ultimately affects whether fan operation may be reduced or curtailed, and for how long.

Inputs to an occupant air quality satisfaction model would include the observable evidence of compromised air quality, including mugginess (i.e., high relative humidity) and odors. Other outcomes of poor ventilation may be imperceptible, so it is unlikely they would affect occupant satisfaction.

10.2.3.2 Occupant Behaviors concerning their Satisfaction with Building Air Quality

The purpose of an occupant behavior model should be to predict the building set points and building conditions that would be established by occupants and their building managers in response to their satisfaction with their building's air quality. In many buildings, automated ventilation will be scheduled, and the schedules might become overridden should occupants become uncomfortable. When occupants' access to building controls is limited or unavailable, the occupants may take matters into their own hands and open windows (if possible), or run portable devices like room fans, humidifiers, dehumidifiers, and air filters.

10.2.3.3 Building Air Quality Performance Model

The building model should quantify the operation of building air handlers and the indicators of building air quality. Therefore, the building model should predict relative humidity, odors, allergens, dust particles, CO_2 levels, and other pollutants. The quantified impacts, in turn, affect both occupant satisfaction levels and occupant health outcomes that may be caused by the building environment.

To the degree that TSs alter the performances and schedules of building ventilation and other air quality systems, the predicted building air qualities are important to the long-term viability of the TSs.

Model inputs include set points (e.g., air ventilation exchange rates, humidity control set points), building qualities (e.g., occupancy, building volume), building air treatment system capacities and capabilities (e.g., air handler type and capacity, system electrical power and efficiency), and outdoor conditions (e.g., outdoor humidity levels, allergen counts, dust). The maintenance condition of the building ventilation system might also be important (e.g., filter cleanliness, duct leakage, duct obstructions).

The costs of providing ventilation and other air quality services may be estimated from the modeled operation of the equipment, its power and efficiency, and electricity rates.

10.2.3.4 Impacts of Building Air Quality on Occupant Health and Safety

The costs of poor indoor environmental quality can be significantly greater than direct building energy costs (Seppänen 1999). Poor occupant health, for example, can be especially costly. The purpose of an operational health model should be to quantify the occurrences of health issues among building occupants.

On average, people spend up to 90% of their time indoors. Studies have evaluated the relationship between indoor air quality and occupant health in office buildings in three different areas (Clements-Croome 2006; Fisk 2000): sick building syndrome, symptoms of which include fatigue, headache, dizziness, difficulty breathing, and irritations of the skin, eyes, and nose; asthma and allergies; and communicable and respiratory diseases.

In about 500 indoor air quality investigations performed in the past recent years, the Occupational Safety and Health Administration found that indoor air quality problems are related to low and insufficient ventilation rates in more than 50% of cases (OSHA 2016). This cause is followed by others such as contaminations from inside and outside the building, microbial contamination, and contamination from building fabric. While it is difficult to quantify occupant health in terms of indoor air quality causes like these, it may be possible to formulate functional relationships by regression analysis between each health concern and the corresponding air quality measures. Much research is needed. Model inputs include levels of air pollutants like CO_2, concentration of allergens, and levels of moisture, molds, and dust mites.

Occupant health further affects work absenteeism and work productivity, and it may affect business health coverage and insurance costs over time.

10.2.4 Energy Usage by Appliances and Other Building Loads

The listing of operational models in this report is admittedly incomplete. The authors have attempted to provide guidance for modeling large building electrical loads that might become affected by TSs. However, unique industrial and commercial processes cannot be addressed well without detailed knowledge of those processes. In addition, models for the following list of building loads will not be addressed in detail by this report. Existing literature concerning the controllability of these devices and the examples provided in this report should provide guidance for analysts as they conduct valuations using these electric loads:

clothes washing and drying
conveyance (escalators, elevators)
cooking
entertainment
hot water heating and use
plug loads
pools, spas, etc.
refrigeration

Transportation warrants special mention due to the enthusiastic advocacy of vehicle electrification and control in support of grid services.

10.2.5 Building Lighting Management

At the beginning of this chapter, lighting management was argued to be one of three groupings of building operational models that can be represented within Figure 10.9. In the case of building lighting management, building occupants' actions are driven by their levels of comfort with the buildings' lighting (Section 10.2.5.1). The occupants take actions (Section 10.2.5.2) that affect the performance of the building's lighting systems (Section 10.2.5.3). There is a consequent electricity cost impact that can be easily predicted from the buildings' performances.

10.2.5.1 Occupant Visual Comfort Model

The purpose of a visual comfort model is to quantify occupants' satisfaction with their building's lighting. Visual comfort is associated with lighting levels, but it may include other factors such as aesthetics (e.g., being able to view outdoors) and lighting qualities (e.g., glare, uniformity of illuminance, and color). Lighting quantity and quality are not entirely independent measures. Glare increases if illuminance is increased beyond recommended levels. Visual comfort probability is a viable measure to quantify the percentage of people who are comfortable with the glare from a fixture.

This section will focus primarily on lighting level because aesthetics and lighting quality are relatively immutable after building designs have been completed and are therefore not very controllable by TSs.

In general, the determination and measurement of visual comfort in terms of lighting quantity is not as complicated as determining thermal comfort because occupants' sensations of comfortable lighting levels do not vary as much as thermal sensations.

To quantify visual comfort during the operation phase of a building, illuminance should be measured in terms of lux (lumen/m^2) or foot-candles (lumen/ft^2) and be compared against illumination standards provided for different spaces. A more accurate expression of visual comfort should consider percentage of surface reflectance as well.

Task types, ages of occupants, and the importance of task accuracy have implications for the adequacy of lighting. Older buildings were designed to accommodate paper-based reading tasks at light levels of 750–1000 lux, which is a measure for illuminance. Today, most office tasks are computer based, and do not require more than 300–500 lux. Recommendations and guidelines for lighting levels and illuminance for different types of spaces can be found in a handbook published by the Illuminating Engineering Society (IES 2011), which presents example lighting levels specified by IES for different types of activities. Section 9 of *ASHRAE/IES Standard 90.1* (ASHRAE 2013) also specifies lighting power densities expressed in watts per square foot (W/ft^2) for different spaces.

Table 10.3. Example Lighting Levels Specified by the IES for Different Types of Activities (IES 2011)

Activity	Recommended Illuminance
Public spaces	3 foot-candles (~30 lux)
Work spaces with simple visual tasks	10 foot-candles (~100 lux)
Visual tasks with high contrast and large size	30 foot-candles (~300 lux)
Visual tasks with high contrast and small size or low contrast and large size	50 foot-candles (~500 lux)
Visual tasks with low contrast and small size	100 foot-candles (~1000 lux)

10.2.5.2 Occupant Behaviors Concerning Their Visual Comfort

This section discusses the modeling of probabilities that installed lighting will be on or off. People play a deciding role in this outcome, whether by directly turning lights on or off, or by affecting or overriding automated lighting schedules.

People's occupancy schedules largely determine whether lights in a space will be on or off. Their habits and attitudes (about the importance of conservation, for example) determine whether the lights get turned off when they leave the space.

Some lighting decisions are increasingly taken out of building occupants' hands through automation. Lights are turned on and off in anticipation of spaces becoming occupied, and controllers increasingly sense occupants' presence, as well, to turn lights on and off based on whether the spaces are occupied. These timers and controllers are sometimes inaccurate and wasteful, and the likelihoods of these errors should also be subject to modeling. Building managers must be responsive to occupant concerns and requests concerning the performance of automated lighting.

Lighting impacts are indirectly related to work productivity and the likelihood that building leases will be renewed. They are also inextricable from safety, which is potentially more valuable than comfort and eventually must be quantified as an impact in its own right.

At least where lighting is remotely dimmable, lighting systems may be made to respond to TS incentives.

The main inputs to an occupant lighting behavior model would be occupant's quantified comfort with the building's lighting, and building occupancy schedules. Modeling people's interactions with building lighting systems will require long-term regression analysis of rich building data.

10.2.5.3 Building Lighting Performance Model

The building lighting model predicts which lights will be on and the actual resulting lighting levels, based on the building's physical layout; layout, type, and size of lighting features; building design; and other workspace qualities (e.g., wall color and surface textures) that determine whether the lighting will be effective for its purpose. The types of lighting and their efficiencies also inform the electrical energy needed to operate the lighting, from which the impact of lighting on electricity bills may be straightforwardly predicted.

A building lighting performance model should be responsive to space occupancy schedules, the areas of floors and surfaces to be lit, daylighting utilization factor, dimmable control and other automation strategies, and numbers of indoor and outdoor luminaires and their electrical efficiencies. In reality, the numbers of luminaires will usually be inferred from luminaire type, the surfaces to be lit, and illuminance at those surfaces.

10.2.6 Tenant Retention Model

The purpose of a tenant retention model should be to quantify the rates of tenant (and perhaps employee) turnover. Human costs (wages and compensation) in commercial buildings eclipse energy costs (a ratio often quoted as 100:1), suggesting that any change in operation for energy-economic reasons that negatively affects occupant satisfaction might be a losing proposition.

Employees in buildings retrofitted with improved energy efficiency and general green upgrades tend to be more satisfied with their work environments than employees not in such buildings. The following were cited in a 2014 RMI report called "How to Calculate and Present Deep Retrofit Value" concerning recruiting and retaining building tenants and employees (Bendewald et al. 2014).

- In a survey of 1,065 tenants in 156 buildings managed by the real estate services firm CBRE, 34% of office tenants agreed that green office space is important to recruiting, while 14% disagreed.
- Nearly 95% of surveyed building managers reported higher tenant satisfaction immediately after green upgrades.
- 79% of surveyed employees were willing to forgo income to work for a firm with a credible sustainability strategy, while 80% said they felt greater motivation and loyalty toward their company due to its sustainability initiatives.

To the extent an actively engaged TS may be part of a company's sustainability initiative, churn rate reduction and increased employee satisfaction can be a benefit and impact of a TS.

In summary, the causes of tenant loss that are relevant to TSs include tenant and employee comfort, green building performance, and perhaps other measures. For example, in tenant-occupied commercial buildings, the number and frequency of comfort complaints (hot/cold calls) are important factors in determining tenant retention.

10.2.7 Workplace Productivity Models

Workplace productivity will be discussed with respect to the productivities of building occupants (Section 10.2.7.1) and manufacturing processes (Section 10.2.7.2).

10.2.7.1 Occupant Productivity Models

The purpose of an occupant productivity model is to quantify building occupants' work output. Between 80 and 90% of the costs of a commercial building are associated with occupants' salaries, while only about 3% are related to the buildings' operations and maintenance (Kats et al. 2003; Wilson 2004). Although a productivity loss of about 0.5–2% sounds small, its financial cost is about the same as that of operating an HVAC system for a year (Woods 1989). Therefore, reduced occupant performance and productivity have greater financial implications than the costs associated with energy management in a building (Brager 2013).

Quantifying impacts of improved productivity and performance can be considered a derivative of occupant comfort and well-being, but there are studies that have evaluated the direct relationship between indoor air quality and occupant productivity and performance through experiments (Lagencranz et al. 2000; Wyon 2005; Wargocki et al. 1999; Wargocki, Wyon, and Fanger 2000; Kosonen and Tan 2004). In 1989, the U.S. Environmental Protection Agency (EPA) submitted a report to Congress indicating the impact of improved indoor air quality on higher productivity and fewer lost work days. The EPA has estimated that the financial cost of poor indoor air quality may exceed tens of billions of dollars each year for the United States in terms of lost productivity and increased medical care (EPA 1997).

Measuring productivity is not a straightforward task, and modeling it in terms of indoor air quality or other building conditions involves subjectivity. It is difficult and sometimes impossible to collect the data needed for measuring productivity, especially in the case of office professionals and experts, whose work is knowledge-intensive and is not easily quantifiable. Direct measurement of productivity in office environments requires monitoring of office professionals' abilities to focus and think, abilities to contribute in a team, and abilities to produce quality work outputs (Miller et al. 2009). While these work elements are difficult to measure, there are simpler tasks like typing that can be used to measure productivity more objectively.

Kosonen and Tan (2004) used results from experiments by Wargocki, Wyon, and Fanger (2000) to create a productivity loss model to estimate the impact of air quality on the productivity loss of office occupants. Figure 10.12 shows the relationships derived between occupants' levels of dissatisfaction with air quality (Figure 10.12a) or actual perceived pollution (Figure 10.12b) and percentage reduction in worker productivity. These relationships are themselves a simple operational model.

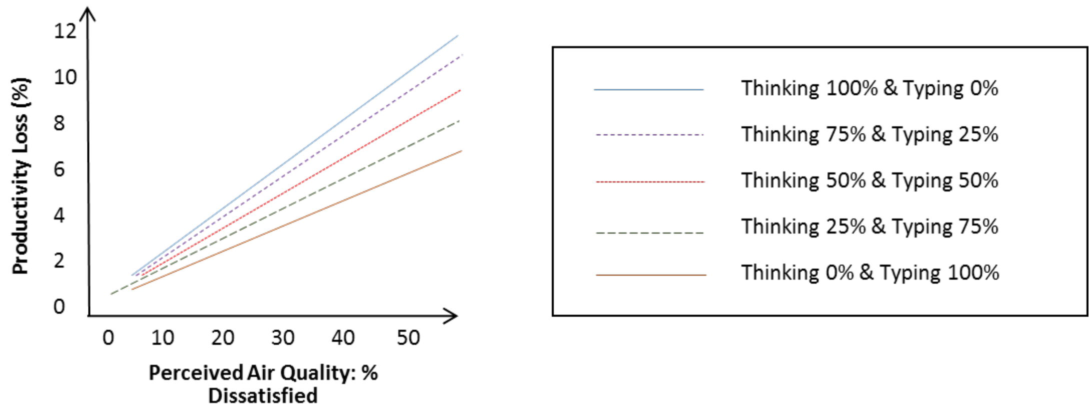
Similarly useful relationships are shown in Figure 10.13 and Figure 10.14. The first figure, based on the work of Fanger (1988), expresses a relationship between perceived air quality measured by decipol unit[7] and productivity loss, and the second expresses a relationship directly between normalized airflow rate and percentage of productivity lost.

Based on the studies cited in this section, typical inputs to an occupant productivity model should be chosen from occupant density (e.g., occupants/m^2), normalized rate of natural and forced fresh air introduction (e.g., L/s per m^2), normalized material and ventilation system emissions (e.g., olf /m^2), and the effectiveness of contamination removal in the building space.

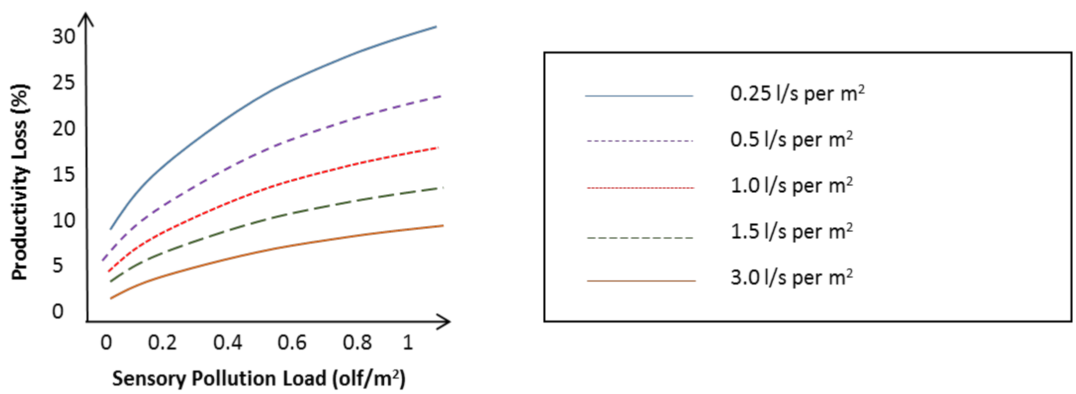
10.2.7.2 Manufacturing Productivity

The purpose of a manufacturing productivity model should be to predict manufacturing process output as it is parametrically affected by various inputs like incentives and resource availability. This operational model is important to the discussion of TSs because manufacturing processes may be made responsive to TS incentives. For example, an energy-intensive process may be shifted in time to take advantage of preferable energy rates. An even greater level of integration is conceivable wherein a TS objective includes the optimization of manufacturing at a facility. These types of transactions can help satisfy a facility's operational objectives and corporate financial objectives as well as energy and sustainability goals and objectives. This is similar to the concept of an "Industrial Internet" or "Internet of Things" (Rogers et al. 2013).

[7] The decipol unit is attributed to Fanger. It is a measure of perceived air quality that is based on CO_2 concentration and fresh air introduction.



(a)



(b)

Figure 10.12. (a) Linear Relationship between Percentage Dissatisfied with Perceived Air Quality and Percentage of Productivity Lost during Different Work Activities and (b) Correlation between Sensory Pollution Load and Percentage of Productivity Lost (Kosonen and Tan 2004)

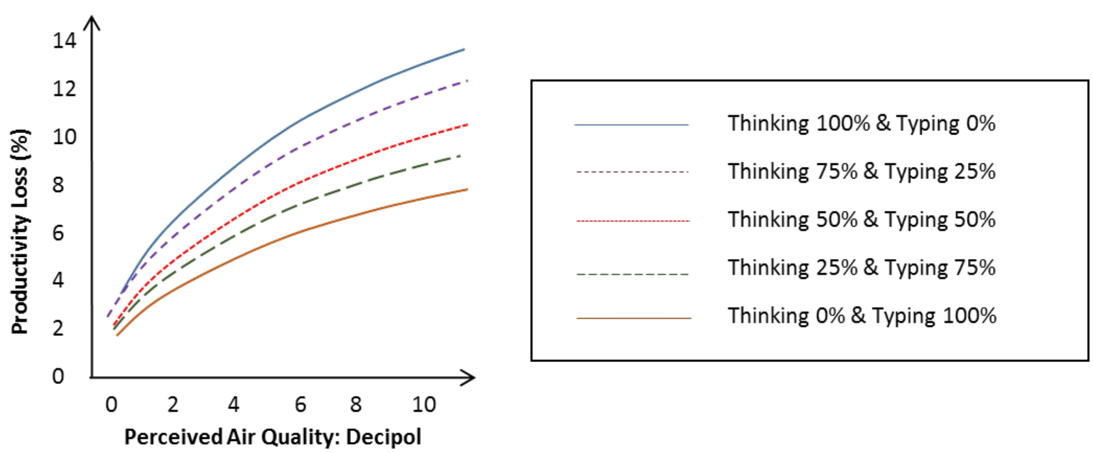


Figure 10.13. Non-linear Relationship between Percent of Productivity Loss for Different Combinations of Tasks and Perceived Air Quality using Decipol Unit (Kosonen and Tan 2004)

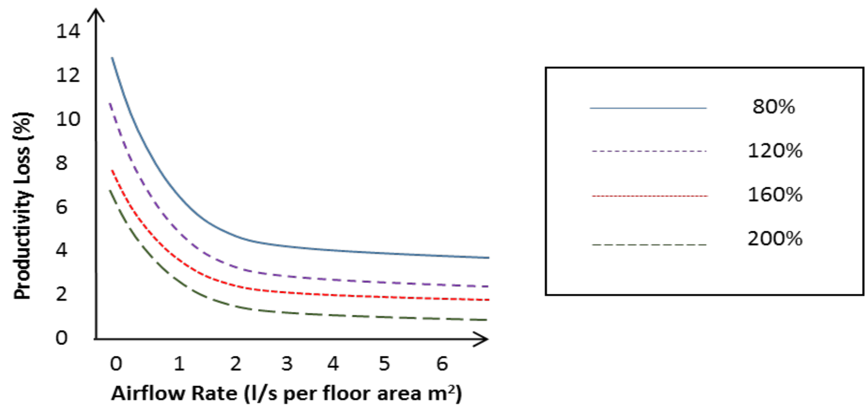


Figure 10.14. Relationship between Airflow Rate and Percentage of Productivity Lost (Kosonen and Tan 2004)

10.2.8 Building Maintenance Model

The objective of a building maintenance model should be to predict equipment failure rates or life spans as functions of maintenance practices. Good maintenance practices and schedules are treated as a type of investment. There are initial costs for conducting maintenance, but if the maintenance is sustained, then much of the invested maintenance cost will be later recovered as savings. Equipment may be less likely to fail, which avoids replacement costs, the costs of responding to equipment failures, and the costs of outages as employees and equipment sit idle.

Buildings and building systems are becoming remarkably smart. Self-diagnostic, comparative, and anticipatory analytical capabilities of smart devices can reduce the amount of time a system spends outside of optimal operating parameters. Advanced building management systems can identify and prioritize problems that come up such that technicians dispatched from a centralized location are required to travel to buildings only as needed and can combine trips when multiple settings are out of alignment simultaneously. Historical data coupled with operational models can be used to promote more efficient operations (Rogers et al. 2013). The models may be unique for different equipment types and different maintenance and diagnostic practices.

This model is important to TSs where TSs interface with building maintenance or where TSs may affect equipment reliability and lifetimes that are also impacted by maintenance practices.

Inputs to a maintenance model might include maintenance and diagnostic practices, frequency of maintenance, date that maintenance was performed, and equipment age. Each type of equipment may be argued to have its own model for the prediction of equipment failures or other maintenance-related outcomes. The performance and lifetimes of equipment are functions of interval between maintenance (oil changes or filter cleaning, for example) and usage and misusage patterns.

10.2.9 Insurance Expense Model

The purpose of an insurance expense model would be to predict insurance expenses and changes in insurance expenses. These expenses might address usage of group insurance plans that are intended to spread the impacts of unexpected, infrequent events. For example, an unhealthy building environment might eventually lead to increased costs of employee health coverage. According to a 2009 Wall Street Journal article, insurance companies are offering discounts to businesses that build green because the structures typically have fewer energy disruptions—unlike those that depend solely on the grid—and are less likely to be destroyed, thanks to features such as energy-efficient lighting, which reduces fire risks, and durable windows (Mincer 2009).

To the degree that TSs foster healthy, safe, and green work environments, TSs may further affect insurance expenses. Buildings with TSs that support increased energy efficiency and renewable energy generation might also benefit from reduced insurance premiums.

10.2.10 Green Image Impacts Model

Increasingly, companies are concerned with having an image or brand that is green and sustainable. For example, Facebook set a goal of powering its data centers with 25% clean and renewable energy by 2015 (DOE 2013). Google also announced that its newest data center will be powered by 100% renewable energy through an arrangement with the Tennessee Valley Authority, and it has an ultimate goal of powering all its operations with 100% renewable energy (Energy Matters 2015). Furthermore, in a recent Oregon Public Utility Commission docket (No. UM 1690), the Oregon PUC conducted a study to consider the impact of letting utilities offer voluntary renewable energy tariffs (Noland 2014). Voluntary renewable energy tariffs are used for customers who want their specific power to be supplied by a renewable product of some similarly green resource. Companies who attended these proceedings and voiced their support for such tariffs included Walmart, Facebook, Staples, CH2MHill, the cities of Hillsboro and Portland, and Oregon's National Guard. In many cases, companies are willing to pay more for green energy to support their brand and to support customer retention.

TSs designed to minimize GHG emissions can provide benefits to companies looking to maximize renewable generation and minimize carbon footprint as part of a green or sustainability image. Impacts and benefits associated with green image are very real to some companies but are difficult or impossible to quantify.

10.2.11 Subsidies and Tax Incentives

Many states offer incentives, tax credits, grants, or loan guarantees for projects that support renewable energy or emissions goals or projects that are part of least-cost, least-risk resource portfolios for utilities. These types of shared-cost projects represent transactions that are often beneficial for the buildings, customers, and the program administrator.

10.2.12 Building Growth Modeling

Building characteristics are not static and evolve over time as building systems deteriorate, occupants change, buildings' usages change, new technologies emerge, and buildings become retrofitted to meet new codes and standards.

Currently, the building sector accounts for 39% of total energy consumption in the United States and in European countries (EPA 2008). The energy consumption of buildings is projected to increase by 1.7%

yearly until 2025 (Ryan and Nicholls 2004). However, the total floor area of buildings is expected to grow by roughly 1–2% (1.6 billion square feet of new constructed floor area) per year. Existing buildings must undergo significant changes if they are to achieve 50% energy reduction by 2030, a stated goal the DOE Building Technologies Office Multi-Year Program Plan (DOE 2016b, p. 14). In addition to energy conservation goals, buildings will increasingly become equipped with smart features to enable them to interact with a modernized grid. Factors that will greatly impact energy consumption practices of buildings and lead to the evolution of buildings over time can be categorized as

- building codes and standards
- retrofits
- intelligent technologies.

It is important to consider health and safety of the system and its equipment when applying TS mechanisms because these transactions may affect the degradation rate of systems like the HVAC system. By a rule of thumb, practitioners say it is safe to cycle HVAC equipment every 3–4 minutes (Zhang and Lu 2013). However, an increase in the wear and tear of the HVAC may result as the frequency of the equipment cycling increases. The average number of switching cycles in a time period is a function of the total number of switching cycles for all HVAC units divided by the number of HVAC units (Zhang and Lu 2013). This number should be kept less than the maximum allowed number of switching cycles.

HVAC degradation rate calculations are typically based on degradation of seasonal energy efficiency ratio (SEER) as specified by Building America Performance Analysis Procedures for Existing Homes (Hendron 2006). The current SEER of an HVAC system is based on its original installed SEER value, its current age, and a maintenance factor.

Annual fuel utilization efficiency (AFUE) for a furnace is another measure that can be used to estimate degradation rate of a heating system. AFUE is also a function of the base AFUE value for the system, the furnace's age, and a maintenance factor. Typical base values for AFUE are included in Hendron (2006), and they can be obtained for other systems from the ASHRAE HVAC Systems and Equipment Handbook (ASHRAE 2004a), the 1987 EPRI Technical Assessment Guide (EPRI 1987), or the Technical Support Documents for appliance standards (DOE 2015). Estimates of degradation rates in Hendron (2006) are partly based on the E-Source Space Heating Technology Atlas (E-Source 1993).

10.3 Societal Impacts

Valuation studies often define *society* as a stakeholder. The actor *society* incurs all the costs and benefits (and detriments) that accrue to society as a whole rather than to any specific stakeholder or stakeholders. That practice is adopted here. In some cases, the responsibilities and costs fall to society by default because no other stakeholder accepts responsibility or is required to be responsible. This section will focus on air pollutant emissions and their impacts on outdoor air quality and public health. Many other impacts and costs to society could and eventually should be addressed but will not be addressed further by this report. Some of the many possible examples might include the following:

- economic health and jobs
- fairness of access to resources
- land use
- national competitiveness
- national energy security
- recreation
- resource extraction
- thermal pollution
- water use and pollution
- wildlife for sustenance and recreation

10.3.1 Emissions of Air Pollutants

Calculation of emissions of air pollutants follows quite directly from knowing total energy generation and the mix of dispatched generation resources (Section 10.1.2). Generators' fuel conversion efficiencies lead to the quantities of fuels that are burned. The production of various gases then follows from the fuel quantities, although adjustments may be needed if mitigations exist and are effective toward reducing any of the emissions. The EPA tool eGRID contains much historical data concerning these emissions for various U.S. locations (EPA 2014).

According to the EPA, the electricity sector was the largest source of GHG emissions produced in the United States in 2013, accounting for 31% of CO_2 equivalent. Furthermore, GHG emissions from this sector increased 11% between 1990 and 2013 (EPA 2016a). Electricity demand increased over that period, and fossil fuels remained the dominant source for electric power generation. The peak-to-average electricity demand ratio is also rising in the United States, as shown for New England in (EIA 2014). This is a troublesome trend, given that peak generation resources are often among those having the greatest rates of GHG emissions.

Fossil-fuel–based electricity generation is a major source of GHG emissions (e.g., CO_2 and SO_2) and air pollutants (e.g., particulate matter and lead). GHG emissions contribute to global climate change, and air pollutants are serious risks to public health. These emissions and air pollutants increase premature mortality and exacerbate health conditions such as asthma, respiratory disease, and heart disease. Reduction of air pollutants is linked directly to positive changes in public health (EPA 2015a).

The monetary value of changes in carbon emissions can be calculated in different ways. In some cases, carbon value is estimated based on EPA's social cost of carbon (EPA 2015b). In other instances, carbon value is calculated based on actual or projected carbon pricing, as through a cap-and-trade program or carbon tax of some kind. The latter is largely dependent on the location where emissions are occurring and whether or not a carbon market or carbon prices are in place or projected to be instituted in the future. California's cap-and-trade program is an example of an active carbon market. Typical California carbon prices are presently in the range \$12–\$13 per Tonne CO_2 equivalent as viewable on a California Carbon Dashboard (Climate Policy Initiative 2016).

The Regional Greenhouse Gas Initiative (RGGI) in the Northeastern United States and Eastern Canada is cap-and-trade system for carbon emissions from power plants in member states (RGGI 2016). In an RGGI auction that took place on December 2, 2015, a clearing price of \$7.50 per ton of CO_2 equivalent was reported (Potomac Economics 2015).

In the Minnesota Value of Solar study, the cost of carbon is estimated using the EPA's social cost of carbon (CO_2) (Norris et al. 2014). Costs per metric ton were estimated for a given year and published in 2007 dollars, converted to current dollars, converted to dollars per short ton, and then converted to cost per unit fuel consumption using the assumed values. The EPA social-cost-of-carbon externality cost for 2020 (3.0% discount rate, average) was \$43 per metric ton of CO_2 emissions in 2007 dollars. This was converted to 2013 dollars using the consumer-price-index adjustment factor and a general escalation rate, which for the Minnesota Value of Solar study resulted in social cost of \$50.77 per ton of CO_2 in 2020 dollars (Norris et al. 2014).

The value of emissions of sulfur oxides (SO_x), nitrogen oxides (NO_x) and PM-10 (particles less than 10 microns in diameter) are less readily quantified. EPA's cross-state air pollution rules provide specific requirements for the reduction of SO_x, NO_x and particulates for certain states (EPA 2016b). For states with specific requirements, the cost of mitigation can be used to quantify the value of reducing such emissions.

10.3.2 Outdoor Air Quality

Results found for generator emissions and air pollutants can be used in another operational model to quantify impacts on outdoor air quality. The GHG emission impacts of Section 10.3.1 are the inputs to this operational model. The modeled impacts should be the resultant concentrations (e.g., parts per million) of the emitted gases and particles. The concentrations may be affected by location, dissipation over time, weather conditions (e.g., wind speed and direction), and proximity to emissions' sources.

10.3.3 Public Health

Impacts to public health for society at large may be represented by premature mortality and exacerbation of health conditions such as asthma, respiratory disease, and heart disease. The EPA's Benefits Mapping and Analysis Program (BenMAP) is an example of a tool that can be used to estimate health effects associated with different aspects of air quality (EPA 2016c).

11.0 Example Building-to-Grid Valuation

The example in this chapter is based loosely on the AEP gridSMART Residential Transactive System that was part of an ARRA-funded DOE smart grid demonstration project. PNNL analyzed the performance of this TE system for the project, which was described by Widergren et al. (2014b). The simulations conducted for that report were extended for this report; a number of significant details differ, however, which are described below.

We note that the following example is intended to be illustrative in nature, and that no definitive conclusions regarding the general applicability or accuracy of the results should be drawn. The example is intended principally to demonstrate the type and complexity of the evaluation that must be performed in order to account for the many impacts a TS may have. This example does not capture all possible impacts, nor does it address the larger distribution and transmission system interactions and long-term implications of a TS in meaningful detail. These limitations are noted in the discussion below. Indeed, there is a need for expanded simulation studies that capture a more comprehensive set of interactions and impacts, pointing the way toward future valuation efforts in this area.

11.1 TS Description

The TS presented in this example utilizes a double-auction market applied to a representative distribution feeder. The distribution system, buildings, and the electric loads therein are modeled in detail and simulated using GridLAB-D (Chassin et al. 2008; PNNL 2012). The market is cleared at 5-minute intervals, using historical LMP data, which is transmitted to price-responsive thermostats located among the residential and commercial buildings on the feeder. These thermostats respond by adjusting either their heating or cooling set-point temperature (depending on mode), according to the LMP. In theory, high LMPs incentivize the buildings to engage DERs, thus reducing need for more expensive peaking generation, alleviating congestion, and lowering system losses. Transmission and generation are treated simply in the example using reduced-order models, which provide insights into the larger system impacts resulting from the TS.

11.1.1 Case Description

The distribution feeder and building characteristics used in this example are based on a residential feeder typical of the Midwest United States. The feeder is physically located in Indianapolis, Indiana. Historical weather obtained from the Indianapolis airport drives the simulation. We assume that only the price-responsive thermostats participate in the double-auction market, and that there are no additional DERs on the feeder. A full year of simulation is performed using historical LMPs for each of three cases characterized by 3%, 10%, and 30% penetration levels (by number of buildings) of price-responsive thermostats. A fourth case without the double-auction market provides a baseline for comparison.

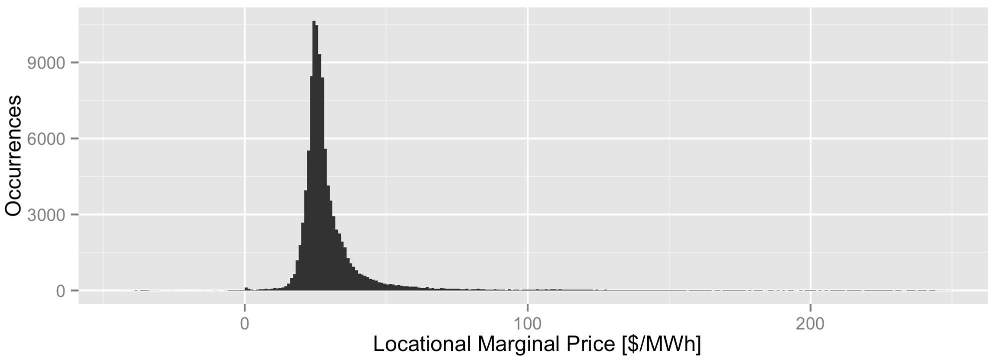
11.1.2 LMPs

The Pennsylvania–New Jersey–Maryland Interconnection LLC (PJM) LMPs were found unavailable at 5-minute intervals for this report, so the authors elected to translate the devices and auction to a Midcontinent Independent Transmission System Operator, Inc. (MISO) location where historical 5-minute data was found available online. Specifically, the example used the historical 2013 LMP obtained from the MISO "IPL.IPL" node, which is physically located in Indianapolis, Indiana (MISO 2015). This price data includes total LMPs as well as the marginal congestion costs and marginal loss costs at each 5-minute market clearing interval.

Statistics and distributions for the LMP price components are summarized in Table 11.1 and Figure 11.1(a)) has a long tail of expensive prices. The marginal loss and congestion cost components, however, are found to be fairly symmetrically distributed around zero cost.

Table 11.1. Statistics of LMPs and their Cost Components ($/MWh)

Component	Mean	Median	Std. Dev.	Min.	Max.
Total LMP	32.94	26.53	37.85	−42.02	1,889.27
Congestion Cost	1.31	0.00	20.05	−208.53	744.22
Loss Cost	0.41	0.48	0.74	−32.67	24.82



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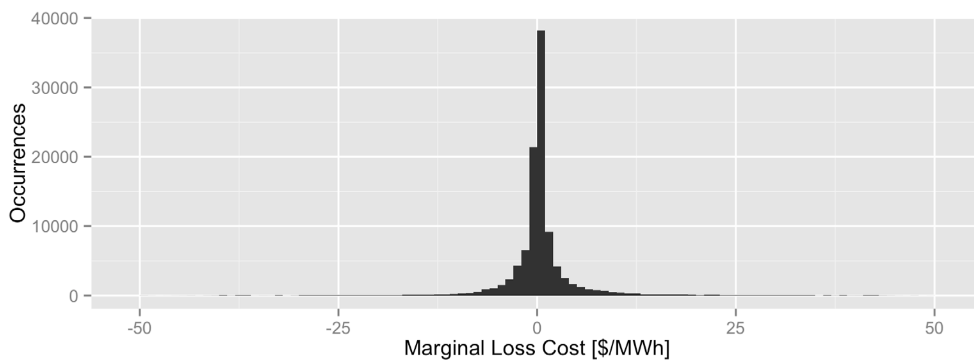

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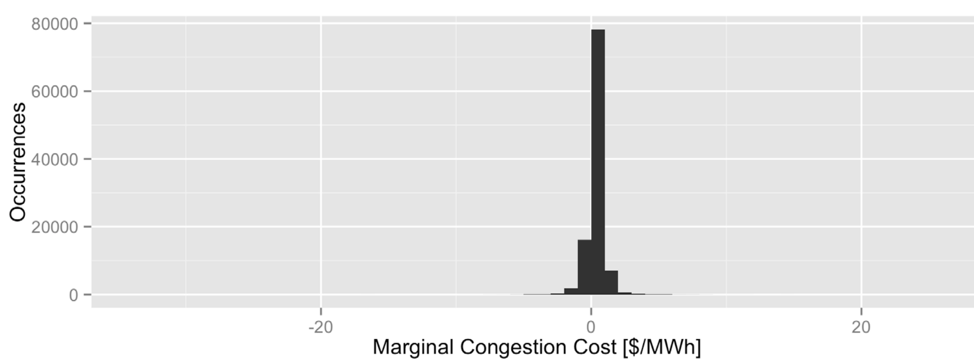


(c)

Figure 11.1. Distributions of (a) Total LMP and (b) Marginal Loss Cost and (c) Marginal Congestion Cost Components of the Example LMP Data

Because the example TE system double-auction market is foundationally based on an LMP, its incentives are traceable to several objectives of the MISO system, including the economic dispatch of resources, an impact of system energy losses, and an impact of system congestion. However, our ability to explore and scale these impacts is severely limited. At some hypothetical scaling of responsive transactive devices, the impact would be great enough to change the LMPs. Also, the growth of the system from one year to the next does not provide for a simple scaling of the LMP zonal prices. These and other limitations will be discussed further as operation models and the growth model are discussed.

11.2 Operational Models

The following section describes the operational models adopted for the TS example.

11.2.1 Generation Model

The bulk generation system is simulated by a simple dispatch "stack" model described by the EPA (2015a). This method allows for more detailed analysis of the impacts that load shifting has on primary fuel usage and emissions, but neglects higher-order effects resulting from ramp-rate limits, intermittency of renewable resources, and others. This method dispatches generation according to an estimated production cost by generator type, with lowest production cost generation dispatched first, followed by the next highest, etc., until the dispatched resource power matches the bulk system load. In this case, the total system load is being represented by historical load measured in the MISO region in 2013. Dispatch is calculated for every hour of the year.

Annual historical generation percentages for each generator type are calculated from 2013 data in the Energy Information Administration (EIA) *Electric Power Annual* (EIA 2016a) using values from the Electric Utilities column in the East North Central region. Where generation percentages were not available for specific generator technologies (e.g., internal combustion natural gas generators), an equal distribution was assumed for all generator technologies that use the same fuel type. These percentages determine the mix of generation technologies that are dispatched to meet demand.

Resource dispatch order is assumed to proceed from least to greatest estimated production cost, as calculated from the generator heat rates and costs of fuel shown in Table 11.2 and Table 11.3. The generator types in Table 11.3 have been ordered to show the likely succession of dispatches based on the estimated production costs.

Wind and hydropower are notable exceptions and are assumed to be always dispatched as they are available, effectively moving them to the bottom (first to be dispatched) of the resource stack. This assumption prevents these renewable resources from being the marginal resource at any given hour, and neglects the intermittent behavior of these resources. However, this is a reasonable assumption given the low penetration levels measured in this region for these renewable resources.

Also among the very first to be dispatched in the model are landfill gas and waste and biomass, which are assumed to have zero production cost for purpose of this example. In practice, biomass production could include costs for fuel ethanol, bio-diesel, and wood waste processed into fuel pellets; however, this level of detail is beyond our scope for this example.

Table 11.2. Heat Content and Cost of Fuels Used to Generate Electricity

Fuel	Heat Content (MMBTU/Unit)	Cost ($/Unit)	Unit
Biomass	16.7[c]	-	ton
Uranium	37,100[b]	853[f]	lb
Coal	19.2[a]	32.6[d]	ton
Natural Gas	1.02[a]	4.89[e]	mcf
Petroleum	5.89[a]	85.5[e]	bbl

(a) (EIA 2016c, Table A1)
(b) (ENS 2015)
(c) Average of wood heat contents in (Boundy et al. 2011)
(d) (EIA 2016c, Table A5)
(e) (EIA 2016c, Table 9.10)
(f) (WNA 2016)

Table 11.3. Generator Heat Rates and Estimated Production Cost by Fuel and Type (EIA 2016a)

Generator Type	Heat Rate (MMBTU/MWh)	Production Cost ($/MWh)
Hydropower	-	-
Wind	-	-
Landfill Gas and Waste	12.93	-
Biomass	12.93	-
Nuclear	10.45	0.24
Coal	10.09	17.10
Natural Gas (CC)[a]	7.67	36.77
Natural Gas (ICE)[b]	9.57	45.88
Natural Gas (ST)[c]	10.35	49.62
Natural Gas (CT)[d]	11.37	54.51
Petroleum (ST)	10.33	149.99
Petroleum (ICE)	10.40	151.00
Petroleum (CT)	13.55	196.74

(a) CC = combined cycle
(b) ICE = internal combustion engine
(c) ST = steam turbine
(d) CT = combustion turbine

Historical MISO system load was used to develop a load duration curve, which is the envelope shown in Figure 11.2. This load duration curve was then used to estimate the total capacity of each generator type and the dispatched capacity as a function of total system demand. Starting with the resources having the lowest production costs (bottom), the capacity was increased until the area it enclosed (not including the previous generators) summed to that generator type's annual production. These capacities are illustrated by the horizontal banding in the figure. To summarize, the areas in Figure 11.2 represent total energy production and the heights represent dispatchable resource capacities. Modeled in this way, the generators that are required to satisfy a given total system load can be found by summing generator capacities, from the bottom up, until they equal the given total system load.

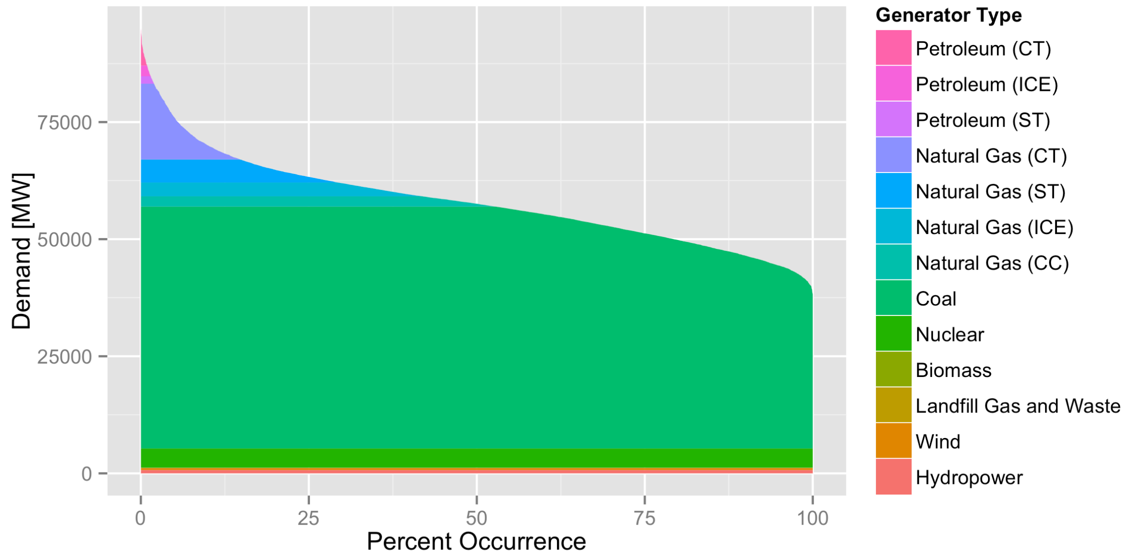


Figure 11.2. 2013 MISO Load Duration Curve Stacked according to Increasing Production Cost

Table 11.4 summarizes the percentage fraction of total annual generation and the resulting dispatchable generation capacity for each generator type along with its presumed dispatch order.

Table 11.4. East North Central Region's Fractional Annual Productions and Dispatchable Capacities by Generator Type

Generator Type	Annual Generation (%)	Total Capacity (%)	Dispatch Order
Hydropower	1.23	0.75	1
Wind	0.68	0.41	2
Landfill Gas and Waste	0.09	0.05	3
Biomass	0.09	0.05	4
Nuclear	7.03	4.29	5
Coal	83.44	54.12	6
Natural Gas (CC)	1.82	2.32	7
Natural Gas (ICE)	1.82	3.10	8
Natural Gas (ST)	1.82	5.14	9
Natural Gas (CT)	1.82	16.95	10
Petroleum (ST)	0.05	1.67	11
Petroleum (ICE)	0.05	2.41	12
Petroleum (CT)	0.05	8.72	13

11.2.2 Emissions Model

Emissions of GHGs and particulate matter from a given generator type are modeled as a product of load served by the generator type, the generator type's heat rate, and its emission rates for each type of gas and particulate. The emission rates for four important environmental contaminants were adopted from previous work (Fuller et al. 2012) and are shown in Table 11.5. The aggregate emissions from the entire generation fleet can be found by using the dispatch stack to first determine the amount of load served by each generator type, and then simply summing the emissions from each.

Table 11.5. GHG and Particulate Emission Rates for Fuels Used to Generate Electricity

Fuel	CO_2 (lb/MMBTU)	SO_x (lb/MMBTU)	NO_x (lb/MMBTU)	PM-10[(a)] (lb/MMBTU)
Biomass	195.00	0.000	0.0800	0.023200
Uranium	0.00	0.000	0.0000	0.017157
Coal	205.57	0.100	0.0600	0.000000
Natural Gas	117.08	0.001	0.0075	0.000000
Petroleum	225.13	0.100	0.0400	0.000000

(a) PM-10 is particulate matter 10 micrometers or less in diameter

11.2.3 Transmission Model

The transmission model is a very simple representation of transmission losses. This model estimates losses based on the square of the estimated current passing through the conductor. Although neither the current nor the resistance of the region's individual transmission lines are unknown in this example, we may use a simple relationship to estimate total transmission system losses, $P(t)_{trans,losses}$, at time t as a function of the square of the total system power, $P(t)_{system}$.[1]

Total transmission system losses are commonly estimated to be about 2-3% of total annual energy delivered (see, for example, the cumulative Southern California Edison generation rate case loss factors in the "Subtransmission" column of (Wong 2011, Table 7)). Thus, for a time series of historical load, we can calculate a coefficient, K, according to the following equation:

$$P(t)_{trans,losses} = K(P(t)_{system})^2 \tag{11.1}$$

This coefficient K can then be used to estimate transmission system losses for a given total system load at each hour of a TS simulation. While this simple model captures the gross effects of system load on resistive losses, it neglects to address the effects of transmission constraints that may manifest in a more detailed model or physical system. Because of the simplicity of this model, we are limited to making general qualitative statements about the impact of TS on average transmission losses.

11.2.4 Distribution System Model

The distribution system is modeled in significant detail, from the distribution transformer to individual end uses in buildings, using the open-source distribution-simulation software, GridLAB-D (Chassin et al. 2008; PNNL 2012). We have selected prototypical feeder model R4_12.47-1 from the Modern Grid Initiative Distribution Taxonomy Final Report (Schneider et al. 2008), which is typical of the region covered by the MISO service area. The feeder is described as a "representation of a heavily populated urban area with the primary feeder extending into a lightly populated rural area."

The voltage regulator and secondary transformer models are noteworthy because of their potential to be affected by the TS. In our TS example, the transactive signal induces a change in feeder load, which

[1] Transmission power factor can affect transmission losses, but the example's effect on transmission power factor is expected to be insignificant in respect to this simplified model. In this example, the relative transport by distribution and transmission systems is assumed to be unaffected.

may affect feeder voltage and transformer loading. In the former case, variations in voltage may result in a change in regulator tap position as the device compensates. In the latter, transformer loading may suddenly change upon a coordinated increase in demand. In both cases, a change in system behavior can affect equipment life spans.

The impact on the regulator can be quantified by the total number of tap changes, which can be used to estimate a change in the expected service life of the equipment.

The impact on secondary transformers is estimated using a thermal aging model in GridLAB-D according to IEEE Standard C57.91-1995 (IEEE 1996). This model estimates the loss in transformer life span using a relationship between transformer load, ambient temperature, and physical characteristics including the number of coil windings and coolant type. From the model's estimate of remaining transformer life, a replacement interval can be calculated, and changes in this replacement interval represent an operational and cost impact attributable to the TS.

11.2.5 Residential and Commercial Load Model

The selected feeder model contains 523 residential and 118 commercial buildings with characteristics typical of the region covered by the MISO service area. The distribution of building characteristics, heating and cooling types, and nominal heating and cooling set points are drawn from a distribution developed from the EIA Residential Energy Consumption Survey (EIA 2013). Of the 523 residences in the model, 103 have a heat pump, 59 have electric resistance heating, and the remaining are heated with natural gas. All but 11 have an air conditioner or heat pump for cooling. Of the commercial buildings, 24 represent stand-alone big box retail buildings and 94 represent attached strip mall structures. All commercial buildings are assumed to have an air conditioner and natural gas heating.

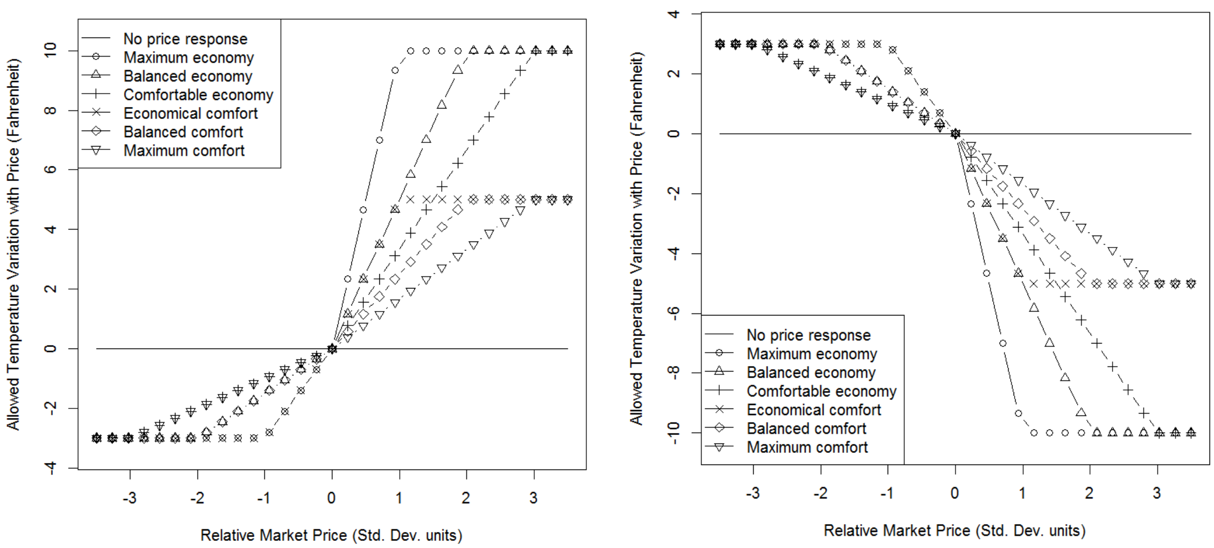
End-use devices, including lights, appliances, and electronics, are modeled as ZIP (constant impedance, current, and power) loads and are not responsive to price. Electric water heaters are modeled in 210 of the residential buildings and are similarly unresponsive to price.

Thermal loads and interior building temperatures are calculated using an equivalent thermal parameter model. These loads are served by an air conditioner in cooling mode, or by a heat pump, electric resistance heaters, or a natural gas furnace in heating mode. Both the air conditioner and heat pump are modeled as single stage with a coefficient of performance that varies with indoor and outdoor temperature. The heat pump model includes an auxiliary electric resistance coil that is enabled at low outside air temperatures. All heating and cooling models are controlled by a dual set-point thermostat having a 1°F dead band, and exhibit typical cycling behavior when operating. Full details of these models are described on the GridLAB-D wiki (BMI 2011).

11.2.6 Responsive Thermostat Model

Figure 11.3(a) shows the price-responsive impact on thermostatic cooling set points for the AEP gridSMART Thermostat. Relative price (horizontal axis) was defined by the average and standard deviation of a trailing 24-hour window of dynamic prices. Residential customers choose from among the preference settings that are shown in the figure's legend. The settings reflect the customers' willingness to exchange minor discomfort for energy savings. Seven comfort settings are listed, including the option offering no price response, but there were six additional settings that disallowed precooling like that shown bottom left of the origin in Figure 11.3(a). These characteristic response curves and the numbers of customers selecting each comfort setting define the price flexibility of the population. In contrast to the AEP gridSMART thermostats, those simulated in this example were not configured to precool or preheat.

Similar heating-mode responses exist for the price-responsive thermostats. The response functions are mirror images of those in the cooling mode if the functions are simply reflected across a line at relative price 0, as is shown in Figure 11.3(b).



(a) Cooling Mode (b) Heating Mode

Figure 11.3. AEP gridSMART (a) Cooling-Mode and (b) Heating-Mode Thermostat Design from which Its Price-Responsive Behavior may be Modeled

The distribution of the customers' comfort setting selections is modeled after those observed in the AEP gridSMART field study.

The price-responsive behavior of these thermostats is modeled in the GridLAB-D simulation environment. Each thermostat is coupled to a building whose temperature set points are modified according to the market clearing price. Residential and commercial buildings having air conditioning are eligible to host the price-responsive thermostats. Random selection of participants resulted in a small number of residential participants having electric heat (heat pump or electric resistance heaters) in each of the three penetration levels.

11.3 Growth Model

In this example, we are not modeling growth in the number of customers participating in the TS over time, nor are we modeling specific resource alternatives explicitly. Instead, we are adopting a simplified approach by modeling several participation levels in the proposed system. This simplified approach recognizes that participation rates and impacts will not be static, but it does not simulate the impacts that increased participation in the TS would actually have in terms of resource dispatch or negating the need for new resources.

Investments in new resources are discretized. A more fully developed and granular growth model that is consistent with the methodology described in this paper would simulate the impact of incremental increases in TS participation and how they would ultimately impact a discretized resource investment. Marginal costs and savings would be calculated based on resource sufficiency or deficiency in the system at large. If a new resource is deferred or avoided altogether, the savings that can be attributed to the TS are much greater than if the existing resource stack is dispatched in a different way.

In our simplified example, we are not using a sufficiency or deficiency approach that addresses the discretized nature of new resource acquisitions, but rather are calculating the marginal value of increased TS penetration using a dollar per kW based solely on our assumption regarding effect on LMP. This simplifies things, but we recognize that by doing so, we are not capturing the full potential value of increased participation in a TS. It is recommended that future studies include more specific resource modeling to show the actual avoided resources that may result from different penetration levels of TSs, as described below:

From a purely theoretical standpoint, the planning model should be configured or described based on the following key parameters:

- assumptions about load growth in the system being evaluated
- assumptions about changes to resource costs such as coal, natural gas, etc.
- assumptions about changes to environmental regulations that will impact the system being evaluated. These might include limitations based on regional haze rules or carbon regulation.
- assumptions about renewable-portfolio-standard requirements
- assumptions about specific generating plant retirements due to end of life or other reasons
- assumptions on the costs of deploying additional TSs and how the cost of TSs compares to those of other resources and the market.

Based on all of the above, and the projected or targeted level of TS participation, a model would be used to project changes to the dispatch order and resource stack of the utility system being considered.

Finally, based on the assumptions and calculations above, a model would be used to calculate how all of the above affect the LMP and therefore the deployment and performance of the TS over the planning horizon.

From here, parallel simulations over the planning horizon could be run with and without the TS. The difference in operating and capital costs over the planning horizon with and without the TS, including the differences in resource dispatch and the makeup of the resource stack generally (i.e., whether new generation resources are required), reflect an important part of the value of the TS.

To summarize, in this example we did not follow all the methodological steps recommended in this report. For simplicity, in this simulation we did not vary LMP based on changes to resource dispatch or the overall resource stack. Instead, the LMPs used were the historical 2013 LMPs from MISO (MISO 2015) that include total LMPs as well as the marginal congestion costs and marginal loss costs at each 5-minute market clearing interval. As such, the method used does not capture potential benefits of avoiding new resources or mitigating higher LMPs due to capacity constraints or high market prices.

11.4 Building and Occupant Impacts

This section summarizes a few of the building and occupant impacts of a TS on HVAC equipment, temperature, comfort, and customer costs.

11.4.1 HVAC Equipment Cycling

GridLAB-D software counts the total number of HVAC compressor cycles for each building over the simulation period. These totals are aggregated by building type and the percentage change relative to the baseline in Table 11.6 for each of the three penetration levels.

On average, the TS decreases the number of HVAC compressor cycles. The changes range from about a 12% decrease to a 2% *increase* in these cycles. Because the responses of the thermostats can affect distribution voltage, and HVAC compressor cycle time has an additional dependence on voltage, nonparticipants can also experience changes in their HVAC cycling performance. Additional work is required to understand the relationship between the incentive signal, cycling, and physical characteristics, and to what extent this result is generalizable to additional cases.

Table 11.6. Percentage Change in Residential and Commercial Participants' Annual Numbers of HVAC Compressor Cycles as a Percentage of Baseline for each Penetration Case

	Compressor Cycles (%)	
Case	Residential	Commercial
3% Penetration	−4.43	−5.78
10% Penetration	−4.57	−4.23
30% Penetration	−4.48	−4.29

The authors did not find modeled functional relationships between numbers of HVAC compressor cycles and the lifetime of HVAC equipment. If the equipment's lifetime were linearly related to the number of compressor cycles—a reasonable assumption—then the expected remaining lifetime of affected HVAC compressor systems might be extended by about 4.5%. The value of deferring the replacement of existing systems could then be monetized using typical HVAC system costs, the distributions of ages of the existing systems, the baseline expected lifetimes of the equipment, and the value of money over time. The calculated value would accrue to the utility customer, who is likely responsible to maintain or replace the HVAC systems.

11.4.2 Indoor Temperature

The simulated internal air temperature in each building is calculated by GridLAB-D software at each 5-minute simulation time step. Deviations from the baseline temperature provide a simple metric of the impact that the TS has on occupant comfort.

On average, the TS increases buildings' average interior temperature by a small amount, as shown in Table 11.7. Commercial participants' heating set point does not change because none of the simulated commercial systems have electric heat to which the price-responsive thermostats could have been applied.

Table 11.7. Average Changes in Residential and Commercial Participants' Air, Cooling Set Point, and Heating Set Point Temperatures from Baseline for each Penetration Case

	Residential			Commercial	
Penetration Case	Indoor Temp. (°F)	Cooling Set Point (°F)	Heating Set Point (°F)	Indoor Temp. (°F)	Cooling Set Point (°F)
3%	0.04	0.22	−0.05	0.13	0.26
10%	0.05	0.22	−0.06	0.11	0.22
30%	0.05	0.21	−0.05	0.11	0.22

11.4.3 Under-Heated, Under-Cooled Hours

Averaged air temperature masks the variability in participants' temperature deviations and does not provide a complete picture of the impact on occupant comfort. As was discussed previously, PMV is the preferred method for estimating comfort in commercial settings, but it is difficult in practice because of the large numbers of inputs and assumptions that must be made. Furthermore, GridLAB-D software (PNNL 2012) is not currently capable of calculating the required PMV inputs. Use of PMV is not widely practiced or accepted in the residential context.

A better measure of comfort in this domain could be based on occupant preference instead. We propose to estimate the impact on comfort by calculating the number of degree-hours the building is above the desired cooling set point (under-cooled) and below the desired heating set point (under-heated). This gives a measure of deviation from the occupants' desired interior temperature (inclusive of the thermostat dead band).

The calculation for under-cooled hours is relatively straightforward. At each simulation time step, multiply the interval duration (in hours) by the amount by which the interior temperature is above the cooling set point and sum over the year. Under-heated hours are calculated in an analogous way. Although our model includes only a small number of commercial buildings, we extend this method to those buildings as well for the sake of simplicity and ease of comparison.

Table 11.8 summarizes the annual impact the TS has on under-heated and under-cooled hours. As expected, the increase in thermostat cooling temperature with price results in a nontrivial number of degree-hours in which the internal temperature is above the desired cooling set point, equaling approximately 5% of the cooling season hours. Under-heated hours show much less impact, because peak prices tend to occur when heating load is relatively low compared with the other hours of the day.

There are no under-heated commercial hours because none of the modeled commercial systems have electric heat.

Table 11.8. Annual Degree-Hours that the Average Residential or Commercial Participants' Building is Under-Cooled and Under-Heated for each Penetration Case

	Residential		Commercial
Case	Under-Cooled (deg. F-h)	Under-Heated (deg. F-h)	Under-Cooled (deg. F-h)
3% Penetration	200	44	338
10% Penetration	216	50	286
30% Penetration	216	44	281

A building occupant's thermal comfort certainly has additional impacts, including commercial building occupants' loss of productivity. There is an interesting, but difficult to quantify, behavioral aspect to this too, in that occupants change the way they interact with the TS devices if their comfort needs are unmet. Unfortunately, one bad experience may cause customers to altogether quit participating in the TS. We do not yet feel comfortable further quantifying or monetizing all these potential impacts.

11.4.4 Customer Bills

To estimate the impact of a TS on customer bills, we compute the change in the energy component resulting from the time-varying price. Changes in bills are calculated using 5-minute energy usage and price for each participant's meter, then averaged over both residential and commercial segments. The purpose of this calculation is to show how the LMP changes the energy component of the average bill. This is specifically not a rate design exercise; rather it is a simple way to assess whether the TS results in energy cost savings to the consumer. In practice, a new rate design may be necessary to redistribute the costs and benefits between the customer and utility.

Nonparticipant bills change very slightly as a result of voltage variations and the subsequent energy consumption induced by the TS, not unlike those effects observed in conservation voltage reduction studies. However, the changes observed in these cases are relatively small, and close to zero on an annual basis.

The average monthly change in residential and commercial buildings' energy charges are shown in Table 11.9 for those buildings that hosted price-responsive thermostats. The small differences between the averages for the three penetration cases are due to small variations in the performance of the randomly selected populations of buildings in each case.

Table 11.9. Change in Average Participants' Average Monthly Electricity Bill (Energy Component Only) for Each Penetration Case

Case	Residential ($)	Commercial ($)
3% Penetration	−2.22	−2.25
10% Penetration	−2.52	−2.06
30% Penetration	−2.30	−2.04

11.5 Grid Impacts

This section addresses impacts of a TS from the perspective of the electricity grid.

11.5.1 Generation Dispatch

The generation stack model is used to estimate the generation mix dispatched each hour of the year. A few days of dispatch from the 2013 MISO system load are shown below. Figure 11.4 represents the baseline dispatch against which the TS dispatch will be compared for a peak load week from July 15 – July 21, 2013. Dispatch order and generation capacities are represented in the colored bands.

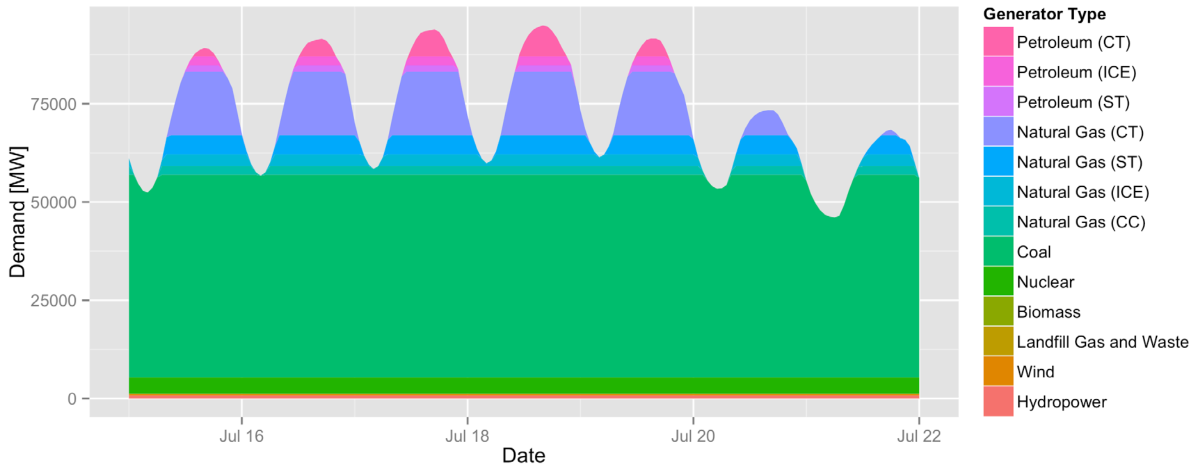


Figure 11.4. Generator Dispatch for the 30% Penetration Case, MISO Region, 2013 Peak Load Week

To find the dispatch in the transactive case, the baseline feeder-demand time series is subtracted from the 2013 MISO load, the transactive feeder-demand time series is added, and then the dispatch model is rerun. The resulting differences between the baseline dispatch and the transactive dispatch are shown for the same few days in Figure 11.5 below.

Most of the changes are observed to happen in midday while system load is peaking and resource prices are greatest. It will be evident in Section 11.5.4 concerning fuel consumption that production from most of the peak (most costly) fuel and generator types was reduced in the TS scenario. Therefore, some shift in energy consumption is evident. An unexpected *increase* was observed in annual production from petroleum-fired steam turbine generators. A hypothesis is that energy production from such generators was increased because they are the least expensive of the petroleum-fueled resources, so the TS moved load during periods of expensive petroleum power production to this plateau.

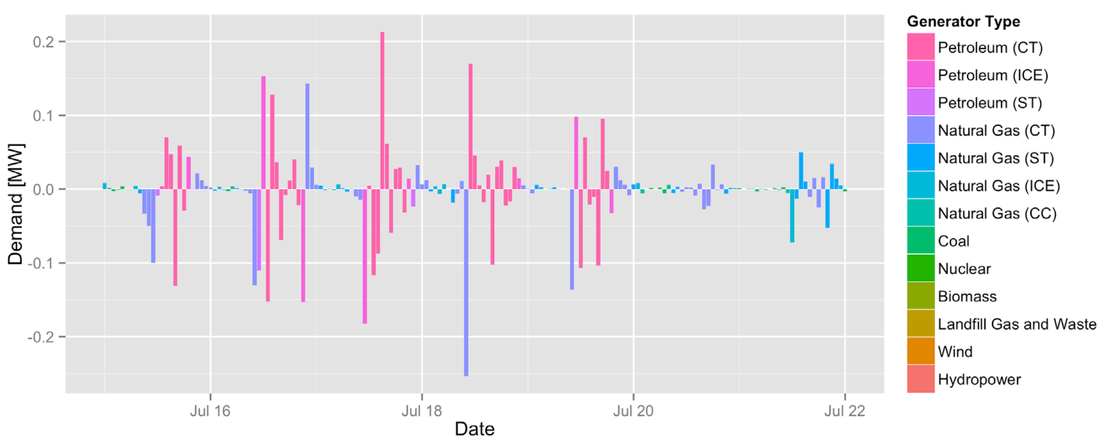


Figure 11.5. Difference in Generator Dispatch between 30% Penetration and Baseline Cases, MISO Region, 2013 Peak Week

In both the TS and baseline scenarios, the load represented by the feeder is a very small fraction of system load, and therefore does not greatly affect which generator is marginal (except perhaps on the fringes). A theorized benefit of TSs is the ability to change which generator is the marginal generator and/or reduce system peak by an amount that allows construction of new generation to be deferred. The current model, which considers only a single feeder, is incapable of demonstrating this benefit, making the estimation of capacity value problematic. In future investigations, this could be resolved by scaling the feeder in proportion to the residential load of the region, and by assuming a greater TS penetration level. The caveat, should this be attempted, is that at high TS penetration, the TS would affect LMP, which would necessitate modeling this feedback loop.

11.5.2 Total Feeder Electric Load

Total feeder electricity use calculated by the model is the sum product of feeder demand and simulation interval, measured at the distribution feeder transformer. This estimate does not include transmission losses. Generally, we see energy use decrease as a result of the TS, although the decrease is small compared to total energy consumption. In fact, if the thermostat is allowed to precool and preheat, an *increase* in energy consumption may result instead. In either case, the result can be explained by the inefficient charging and discharging of the buildings' thermal masses. When building temperature is maintained at steady state, the HVAC system need only match the gains and losses from the environment and internal loads, and mass temperature does not change. However, when building temperature is allowed to swing several degrees, mass temperature does change, losing some of its thermal "charge" to the outdoors. This is a loss that the HVAC system must then make up at a later time when outdoor conditions may not be favorable for efficient HVAC operation. This HVAC behavior can result in an overall increase in cooling energy.

As shown in Table 11.10, the TS decreases total electricity use in the feeder by about 50 kWh per participant having the price-responsive thermostat. The total annual feeder energy reduction is about 1 MWh for the 3% penetration case, 3 MWh for the 10% penetration case, and 9 MWh for the 30% penetration case.

Table 11.10. Change in Feeder Electricity Consumed Compared to Baseline, per Participant, by Penetration Level

Case	Change in Energy (kWh)
3% Penetration	−49.9
10% Penetration	−53.8
30% Penetration	−50.5

Additional reductions in system energy consumption were observed when transmission losses were included in the calculation. Table 11.11 summarizes the annual per-participant change in energy consumption that may be attributed, on average, to each residential or commercial price-responsive thermostat, including transmission losses. The savings are similar to those that were observed in Table 11.10, but the reductions are augmented by the further reductions in transmission losses.

Table 11.11 also shows the calculated percentage difference between the energy changes calculated in Table 11.10 and Table 11.11. While the simple transmission model described in Section 11.2.3 assumed that 3% of total annual system energy is lost in transmission, TS thermostat behavior resulted in about 6.5% additional energy reduction (considerably more than the 3%) because the TS reductions coincided with peak transmission loads.

Table 11.11. Change in System Electricity Consumed compared to Baseline, per Participant and for each Penetration Level, after Transmission Losses are Considered

Case	Energy Consumed (kWh)	Impact from Transmission Losses (%)
3% Penetration	−53.1	−6.4
10% Penetration	−57.3	−6.5
30% Penetration	−53.8	−6.5

11.5.3 Peak Demand

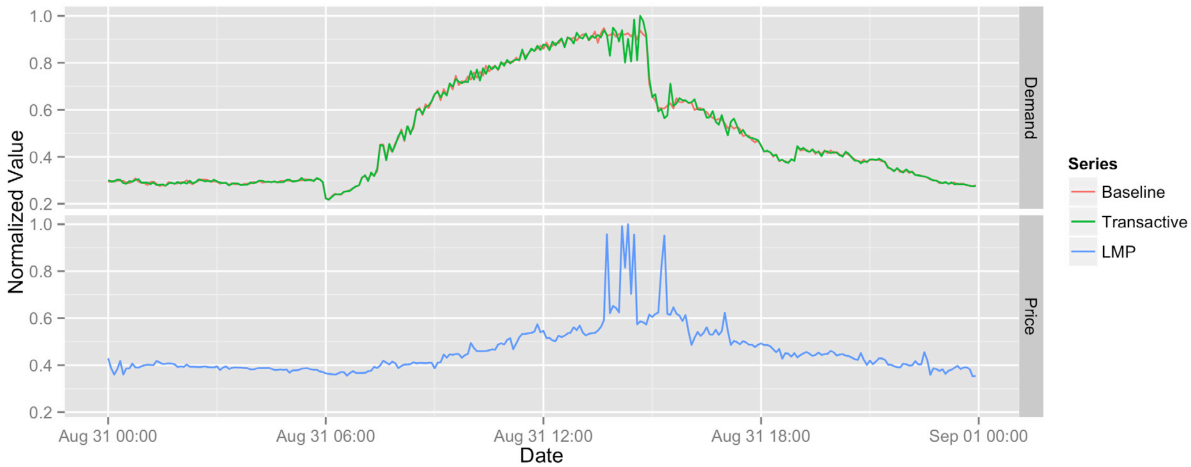
Annual peak feeder demand is calculated on both a 5-minute and an hourly basis. Annual system-wide peak demand is calculated on an hourly basis. Historical system data is unavailable for the shorter intervals. Although system-wide peak demand is generally decreased by the TS, the TS can fail to decrease, and can even increase, the feeder's peak demand. This is because the TS incentive (system-wide production cost, in this case) is primarily aligned with system-wide, not feeder, demand.

This lack of alignment is illustrated in the plots of normalized feeder demand and LMP in Figure 11.6. The historical incentive signal used in this example represents an area serviced by a large number of distribution feeders with demand profiles that are likely to be different from that simulated by the example's distribution circuit model. The feeder is shown to be active at times of high LMP by the divergence of baseline and TS scenario demand. However, while the highest LMPs correlate moderately well with feeder load on August 31 (panel "a" in Figure 11.6) and September 10 (panel "b"), the correlation is rather poor on July 18 (panel "c").

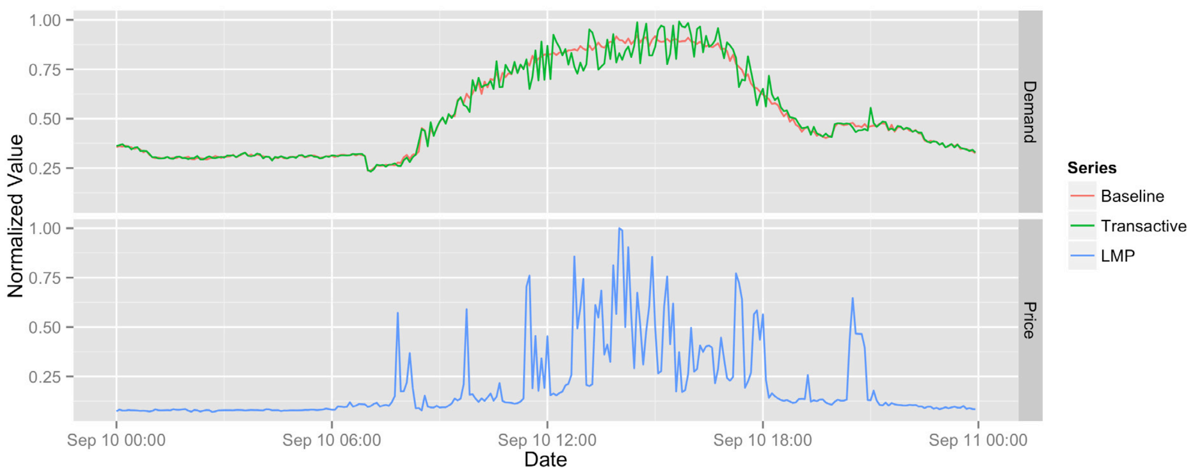
In practice, a TS may allow more granular incentives at the feeder level in order to mitigate local feeder constraints and accomplish other local objectives.

The changes in annual feeder peak and system peak upon introduction of the TS at various penetration levels are shown in Table 11.12, and this same data is shown again in Table 11.13 on a per-participant (residential or commercial price-responsive thermostat) basis. The system-wide peak demand is consistently reduced by about 600 W per participating thermostat. The feeder peak is reduced for two of the three penetration levels if the highest hour demand is considered, but the 5-minute peak is increased for all the penetration levels.

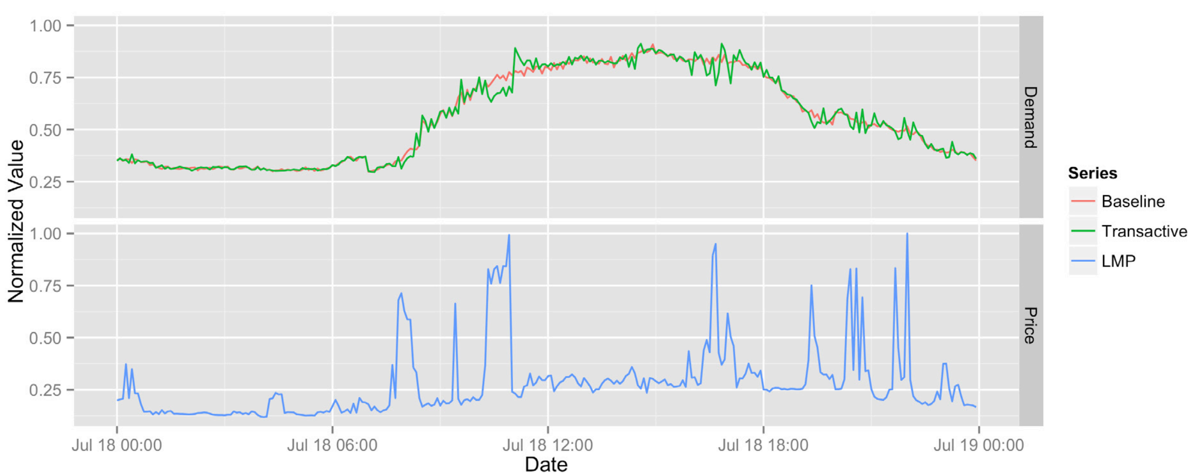
The inconsistent changes in the feeder peak data are understandable if the timing of the feeder peaks is reviewed. Table 11.14 lists the dates and times of the annual feeder and system peaks. The TS never changed the timing of the system peak hour, but the TS changed the timing of the peak intervals. The 5-minute feeder peak interval in the baseline scenario was different from those of the three penetration scenarios. On a 1-hour basis, the 30% penetration case reflected enough response to change the timing of the peak hour.



(a)



(b)



(c)

Figure 11.6. Simulated Normalized Feeder Demand and Actual LMP for Baseline and 30% Penetration Cases (a) August 31, (b) September 10, and (c) July 18, 2013

Table 11.12. Changes in Annual Feeder and System Peak Demands at Different TE System Penetration Levels

	Change in Total Peak Demand (kW)		
	Feeder Level		System Level
Case	5-Minute	1-Hour	1-Hour
3% Penetration	12.8	−13.6	−15.8
10% Penetration	39.7	−14.9	−39.8
30% Penetration	256.2	6.8	−102.6

Table 11.13. Changes in Annual Feeder and System Peak Loads per Participant at Different TE System Penetration Levels

	Change in Per-Participant Peak Demand (kW)		
	Feeder Level		System Level
Case	5-Minute	1-Hour	1-Hour
3% Penetration	0.68	−0.72	−0.83
10% Penetration	0.65	−0.24	−0.65
30% Penetration	1.40	0.04	−0.56

Table 11.14. Date and Time of Feeder and System-Wide Peak Demand Intervals

	Feeder Level		System Level
Case	5-Minute	1-Hour	1-Hour
Baseline	Aug 31, 14:40	Aug 31, 14:00	Jul 18, 16:00
3% Penetration	Aug 31, 15:40	Aug 31, 14:00	Jul 18, 16:00
10% Penetration	Aug 31, 15:40	Aug 31, 14:00	Jul 18, 16:00
30% Penetration	Aug 31, 15:40	Sep 10, 15:00	Jul 18, 16:00

11.5.4 Fuel Consumption and Purchases

Fuel consumption and purchases are calculated directly from the dispatch model described in Section 11.2.1. The model calculates the total load and energy served by each generator type. The difference between the cases is calculated for each fuel and generator type. This difference is multiplied by the heat rate of each generator and the heat content of each fuel to find the number of units of fuel that are consumed. Fuel costs are simply the product of the number of fuel units and the cost per fuel unit.

Fuel consumption was reduced for nearly all the generator types, as shown in Table 11.15. However, all three penetration levels see an increase in fuel use by petroleum-fired steam turbines, and the 10% case shows an increase in petroleum-fired combustion turbine fuel use as well. Changes in fuel consumption are not equally borne by each generator type. This illustrates that the impact of the TS on generation asset owners can be disproportionate. The extent to which this manifests is dependent on production costs, which factor heavily in determining the LMP that is responded to by the price-responsive thermostats. This argues for additional studies that incorporate an LMP price feedback mechanism, an important shortcoming of this example.

Table 11.15. Change in Annual Fuel Costs by Generator Type

	3% Penetration		10% Penetration		30% Penetration		Fuel	Dispatch
Generator Type	Units	Cost ($)	Units	Cost ($)	Units	Cost ($)	Units	Order
Coal	−0.08	−2.53	−0.32	−10.28	−0.82	−26.84	ton	6
Natural Gas (CC)	−0.72	−3.51	−2.63	−12.88	−7.65	−37.42	mcf	7
Natural Gas (ICE)	−0.79	−3.86	−2.85	−13.93	−7.79	−38.09	mcf	8
Natural Gas (ST)	−1.74	−8.49	−7.08	−34.64	−21.36	−104.46	mcf	9
Natural Gas (CT)	−5.55	−27.14	−15.73	−76.93	−43.06	−210.56	mcf	10
Petroleum (ST)	0.13	11.19	0.25	21.71	0.55	47.21	bbl	11
Petroleum (ICE)	−0.14	−12.34	−0.50	−43.18	−1.23	−104.98	bbl	12
Petroleum (CT)	0.00	−0.37	0.06	5.09	−0.10	−8.36	bbl	13
Totals		−$47.05		−$165.04		−$483.50		

On average, annual fuel purchases are reduced by approximately $2.60 per residential and commercial participant (price-responsive thermostat owner), as is summarized in Table 11.16 for the three penetration levels.

Table 11.16. Annual Change in Fuel Cost per Participant for each Penetration Case

Case	Fuel Cost ($)
3% Penetration	−2.48
10% Penetration	−2.71
30% Penetration	−2.64

11.5.5 Wholesale Electricity Sales, Congestion, and Loss Costs

The total LMP contains three components that represent energy production costs, costs associated with transmission congestion, and costs associated with losses in the transmission system. Together, these components represent the wholesale settlement price paid to the load-serving entities. Wholesale electricity sales are calculated by multiplying the total LMP by feeder demand at each 5-minute clearing interval. Similarly, energy, congestion, and loss components of the LMP are multiplied by feeder demand to estimate the contributions of the components to the wholesale price.[2] The changes attributable to the TS are shown in aggregate for the entire feeder in Table 11.17 and on a per-participant basis in Table 11.18.

The TS results in a net decrease in wholesale sales, representing a net loss in energy sales by the load-serving entities. Similarly, reductions in all energy, congestion, and loss cost components are observed. The reduction in loss costs is associated primarily with the overall reduction in energy use. The reduction in congestion costs is more directly associated with the high congestion costs that dominate the LMP at certain times of day. Again, without a price feedback model in place, these findings must be interpreted with some caution. However, the consistent reduction in all component costs is encouraging and warrants additional study.

[2] MISO publishes the total LMP and the marginal congestion and loss cost components. The difference between the total LMP and these two components has been assigned as the energy production cost component for this analysis.

Table 11.17. Change in Total Annual Electricity Sales and its Energy, Congestion, and Loss Cost Components for each Penetration Case

	Total LMP	LMP Cost Components		
Case	Electricity Sales ($)	Energy Cost ($)	Congestion Cost ($)	Loss Cost ($)
3% Penetration	−327.60	−262.60	−63.63	−1.37
10% Penetration	−1,188.90	−926.10	−258.31	−4.49
30% Penetration	−3,203.6	−2,525.08	−666.10	−12.42

Table 11.18. Change in total Annual Electricity Sales and its Energy, Congestion, and Loss Cost Components per Participant for each Penetration Case

	Total LMP	LMP Cost Components		
Case	Electricity Sales ($)	Energy Cost ($)	Congestion Cost ($)	Loss Cost ($)
3% Penetration	−17.24	−13.82	−3.35	−0.07
10% Penetration	−19.49	−15.19	−4.23	−0.07
30% Penetration	−17.51	−13.80	−3.64	−0.07

11.5.6 Transmission Losses

The loss coefficient, *K*, calculated from Equation 11.1 is used to estimate the impact of the TS on transmission losses; see Table 11.19. Losses are estimated at each hour of the year from system load, and the difference in annual sum between baseline and transactive cases is calculated. Baseline transmission losses are estimated to be 14,369 GWh annually. A marginal reduction in transmission losses is associated with the decreased demand and energy use observed previously, accounting for roughly 6.5% of the 55 kWh per participant system energy reduction. More detailed modeling of the transmission system is required to better estimate this impact.

Table 11.19. Change in Annual Transmission Losses per Participant for each Penetration Case

Case	Change in Annual Losses (kWh)
3% Penetration	−3.25
10% Penetration	−3.46
30% Penetration	−3.27

11.5.7 Distribution Equipment Impacts

GridLAB-D's transformer aging model is used to estimate the change in transformer life span associated with degradation, including the impact of electrical loading. The model reports the percentage of life span remaining at the end of the simulation for each transformer, assuming a 20-year useful life. These values are converted to hours for ease of interpretation. Table 11.20 reports the mean, minimum and maximum differences found between the transactive and baseline cases at each penetration level. Negative values indicate that the TS reduces transformer life span by the reported number of hours compared to the baseline. Some transformers experience decreased life spans, while others experience increased life spans, but average life span is not affected by the TS.

Table 11.20. Average and Extrema Changes in Transformer Life Spans Relative to Baseline for each Penetration Case

Case	Mean (h)	Minimum (h)	Maximum (h)
3% Penetration	0	−175	333
10% Penetration	0	−140	53
30% Penetration	0	−140	105

Table 11.21 summarizes the differences in regulator tap changes between transactive and baseline cases. Differences are mostly zero. The differences are insignificant compared to the 5023 total annual tap changes across all three phases in the baseline case. Since the TS in this example does not incentivize voltage variations, these results are purely a side effect of load variation that has been introduced by the TS.

Table 11.21. Change in Number of Regulator Tap Changes from Baseline Case for each Phase and for each Penetration Case

	Phases		
Case	1	2	3
3% Penetration	−2	0	0
10% Penetration	0	0	0
30% Penetration	−2	0	0

11.6 Societal Impacts

The only societal impacts to be tracked for this example will be GHG and particulate emissions.

11.6.1 Emissions

Emissions are calculated from the dispatch and emissions models that were described in Section 11.2.2. Changes in emissions naturally follow the trends observed in fuel consumption changes. Total emissions were found to scale nearly linearly with the numbers of homes having price-responsive thermostats. The total changes in annual emissions between the 30% penetration and baseline cases are exemplified by Table 11.22. Changes in particulate emissions (PM-10) were insignificant. The total annual reduction in CO_2 emissions for the 154 responsive residences and 30 responsive commercial buildings was about 13.9 thousand lbs.

Table 11.22. Change in Annual Emissions from Baseline by Generator Type, 30% Penetration

Generator Type	CO_2 (lb)	SO_x (lb)	NO_x (lb)	PM-10 (lb)
Coal	−3,255	−1.58	−0.95	0
Natural Gas (CC)	−918	−0.01	−0.06	0
Natural Gas (ICE)	−935	−0.01	−0.06	0
Natural Gas (ST)	−2,564	−0.02	−0.16	0
Natural Gas (CT)	−5,167	−0.04	−0.33	0
Petroleum (ST)	732	0.33	0.13	0
Petroleum (ICE)	−1,628	−0.72	−0.29	0
Petroleum (CT)	−130	−0.06	−0.02	0
Total	−13,865	−2.11	−1.74	0

Changes in net emissions on a per-thermostat basis are summarized in Table 11.23 for each of the three simulated penetration levels. As expected, the reduction in emissions on a per-thermostat basis were similar regardless of the number of responsive thermostats on the feeder. Small differences between these normalized values are likely attributable to minor variations in the modeled buildings and their occupancy settings, as they were randomly selected for each of the three penetration levels.

Table 11.23. Change in Annual Emissions from Baseline per Price-Responsive Thermostat for each Penetration Case

Case	CO_2 (lb)	SO_x (lb)	NO_x (lb)	PM-10 (lb)
3% Penetration	−72.9	−0.01	−0.01	0
10% Penetration	−80.3	−0.01	−0.01	0
30% Penetration	−75.8	−0.01	−0.01	0

Other health and environmental impacts may follow from these changes in emissions, but these extended impacts are presently difficult to quantify and monetize. We move forward with a presumption that the value of these impacts is captured to some degree by cap-and-trade auctions. The value of the CO_2 reduction from each household would then be on the order of \$0.26–\$1.48 per year. The lower bound is based on \$7.50 / metric ton CO_2 equivalent from an RGGI auction (Potomac Economics 2015), and the higher number is based on \$43 / metric ton CO_2 equivalent (2007 dollars) from the EPA Social Cost of Carbon externality cost that was used by Norris et al. (2014). No attempt to monetize impacts from the other gases was made.

12.0 Conclusions

This report portrays TSs as mechanisms that facilitate the creation and exchange of value as a means to balance the multiple objectives in system operations. A TS platform has relatively simple installation and recurring costs associated with it to support the exchange of values between system participants (aka actors). The TS platform has little intrinsic value; it is an enabler for coordinated decision making, and is better judged on its ability to ulock value. The proposed method of conducting valuation requires that measurable impacts be defined to quantify the resulting outcomes for each actor from the TS operation. The summation of the measurable impacts for each actor should determine the comparative benefit of a valuation scenario for that actor—whether the actor's outcome is net positive over time.

Today, few TS methods have been formulated and field tested for electric power-related systems. Research is active, so TS mechanisms continue to evolve. The valuation methodology needs to be flexible and extensible to compare different TSs under different scenarios. The qualities of TSs ultimately determine the time scales, actors, and system locations where the TS may be applied, and the operational objectives that may be addressed. *The valuation of a TS is not meaningful unless the TS and its capabilities and qualities have been clearly stated and compared against an alternative, clearly stated approach*. The methodology in this report offers a concise list of questions that may be used to reveal important qualities of existing and future TSs.

Many valuation approaches and associated tools may be adopted from conventional valuation studies and adapted to TS valuations. However, this report asserts that the inclusion of TSs probably cannot be adequately addressed by simply adding another module to existing valuation methodologies. TSs entail rich interactions between actors, in which responsive elements respond to multiple operational objectives. An example PNNL envelope study is appended to this report, wherein the total value of flexible, demand-responsive devices is projected to be \$22B/year nationwide. However, the responsive elements probably cannot simultaneously satisfy all the requests for such responses, nor are all of the operational objectives aligned such that they might simultaneously be mitigated by the system responses. The actual value is always less than would be defined by the limits of responses or by the total magnitudes of the operational objectives that we wish to mitigate. In addition, the accrual of benefits to the various actors in the system are not explored. *Therefore, this report stresses that the connections between the incentivization of operational objectives and responses must be tightly coupled during the valuation of a TS scenario*.

The report's emphasis on the necessity of coupling operational objectives and available responses implies two modeling challenges. First, the available responses must be characterized as a function of the the way that the given TS quantifies and invites responses to its operational objectives—often a dynamic price signal. This was shown to be relatively easy where responses to the TS have been automated. An automation agent either calculates the device's demand curve or can be used to infer the device's demand curve. This first challenge is compounded when the automation is poorly defined, or where the system response relies on human behaviors and interventions. Second, the the method with which the given TS quantifies and invites responses to its operational objectives must be modeled. Because multiple operational objectives are being incentivized by most TS mechanisms, the valuation process ultimately must correlate the net responses and net objectives. An analyst would expect strong correlations between impacts on operational objectives that are directly incentivized, but a study may also observe indirect benefits or unintended consequences from impacts that contribute to other operational objectives.

The valuation methodology proposed by this report drew from many prior valuation studies and IRP processes in particular. Some general guidelines were suggested to foster collaboration among valuation practitioners and to foster improved transparency of the valuation methods and of any assumptions that are being made. One of these recommendations was a structural separation between the modeling of a system's growth and operations. The term *operational model* was used to define any type of model that is used to quantify an important impact within a near-term time period that the system's operation with a set of assets remains relatively static—often a year. While many practitioners will presume that the operational models are time-series simulations, many other types of models—statistical, risk, behavioral—may be needed for valuations. *This methodology proposes to capture each such operational model as a UML activity block, which then clearly reveals the inputs that are needed to drive the model and quantify or qualify the needed impact.* The many UML activity blocks that represent the operational models are richly interconnected because the input to one may be the output product of another, and so on. The methodology accommodates the possibility that multiple alternative paths through the richly interconnected models may be possible. The term *growth model* describes how the modeled system matures from one time interval (typically a year) to the next. This growth includes both the drivers to which the system must respond (e.g., load growth, asset aging) and the plethora of resources (e.g., bulk generation and storage, delivery infrastructure, DER, policy changes, etc.) available to the system for that interval.

In addition to the UML activity diagrams that were advocated in the previous paragraph for representation of operational models, this report further advocates UML use-case diagrams for the standardized representation of business value exchange. The diagrams are based on pioneering work by e^3 value. *Such diagrams state specific pairings of business value being exchanged between actors, which can precisely state values that are facilitated by TSs. The report argues that consistent use of even these two UML diagrams would be a big step toward making valuations interoperable*. These diagrams would help those who consume such valuation studies to more rapidly understand the study's methods and assumptions and potentially contrast multiple valuation studies on similar topics.

Chapter 10.0 described, at a conceptual level, many impacts and their operational models that will likely be relevant to valuation of TS. Candidate operational models must reveal accurate changes to the corresponding impacts enabled by the TS's operational characteristics. The models were categorized by energy, building domain, and societal impacts. Among the energy-related impacts, we found we could draw heavily on well-established methods. Given the recent attention given to TS in the buildings domain, the authors challenged themselves to anticipate some of the proposals for emerging non-energy, non-grid scenarios.

The report then applied its methodology and guidance to conduct a valuation for a hypothetical installation of TS-responsive thermostats on a feeder managed by a double-auction market. This is a building-to-grid scenario. Because the valuation was explored on only a single feeder, the results were meaningful only for small penetrations of the price-responsive thermostats, and the results were best understood on a per-thermostat basis. Modest benefits were observed on the per-thermostat basis. Our ability to explore high penetrations of the thermostats and to model evolution of the system over time were severely limited by lack of scenario definition and by the corresponding lack of appropriate system models. The report's recommended approach to the growth model could not be easily applied. The scenario used an LMP as the basis of the feeder's incentive price. However, authors lacked usable production cost models that would have closed the loop between the thermostats' energy responses the responses' effects on the LMP as the penetration of the thermostats grows. Similar limitations in the scenario's definition prevented the authors from strongly stating capacity impacts.

We recommend the following research and development activities to support future TS valuations:

- Practice expressing business value, as facilitated by e^3 value and UML. This report made a case for the importance of expressing the exchange of business value with UML use cases that are based on e^3 value. Such visual models have the potential to represent value exchange in TSs and thereby define TS scenarios with clarity. However, the report offered mostly motivation and only a few examples of such visual modeling of business value transactions. We encourage the TS community to accept this challenge.
- Practice expressing operational models as UML activities. UML activity diagrams were shown to standardize the expression of measurable impacts as outputs and also the inputs that are needed to drive the model. The valuation community is encouraged to accept this challenge and represent operational models in this way. If this suggestion is accepted, this then paves the way to greater transparency and eventual sharing of interoperable analysis approaches.
- Continue to improve the specification and design of TS methods. Partly due to the immaturity of the field of TSs, existing TS mechanisms and platforms are unevenly documented, which makes them hard to understand and compare. The documentation does not yet support consistently meaningful valuations.
- Continue developing operational models. This report made a case for the parametric design of operational models. Operational models must be rich and dynamically responsive. If impacts are to be responsive to the sometimes subtle differences between alternative TS mechanisms as well as between baseline and treatment scenarios, then the inputs to the operational models cannot be static. Especially for TS valuations, the operational models must reflect the effects of the TS's incentives. The following operational models should be improved to better support TS valuations:
  - Building and building-device load models should be improved to reflect occupants' interactions with the building and its devices. Scaling issues also exist, given the diversity of commercial building sizes and qualities. The challenge is even greater for the modeling of industrial sites.
  - Both simplified and detailed methods to model granular resource dispatch and the resulting impacts are needed. While very important to a valuation study, recreating the dispatch model used by a given region is extremely difficult. Locations using LMP offer some transparency to the dispatch process, but historical trends do not necessarily inform future performance.
  - Generation, transmission, and distribution adequacy models should be unified, if possible, for improved consistency in the treatment of valuation. Today, the generation, transmission, and distribution level impacts are addressed separately, even though the arguments for each are similar, based on likelihoods that customer load will be affected. The ideal model will allow for different levels of rigor.
  - Develop models of human elastic energy behavior, including
    - effects of time of transaction notification, advance notice, method of notification, update frequency
    - effects of inattention

    - effects of event duration fatigue of occupant to comfort extremes (such as overriding automation or changing preferences)
    - prediction of how human behavior affects both conservation and time-shift impacts
    - differentiation by region, age, socioeconomic status, etc.

- Develop, model, and standardize responsive assets. Especially for TS mechanisms that automate the responses of assets, there is a lack of truly responsive devices that have been successfully commercialized. The discussion of TS behaviors remains hypothetical in their absence. Simulating the behaviors of responsive assets needs to be more informed by experiential test and field data.

- Prototypical data sets need to become available regionally or nationally. The data sets that are needed to configure and drive operational modeling are unevenly available. Researchers, in particular, would benefit from broadly accepted data sets that can be used to configure regional and nationwide studies. For example, broad access to standardized, prototypical transmission circuits, three-phase distribution circuits, and resource availability data would be useful for regional and nationwide studies.

- Conduct TS valuations in the grid and buildings spaces. This report recognizes a research thrust to implement TSs in buildings. New use cases in the buildings domain have introduced to us operational objectives other than grid- and energy-centric ones. Much work is needed to further define such non-energy scenarios so that the principles of this report can be applied to them. This report also found that the operational models in this area are sparsely available and do not yet support thorough valuations.

- Conduct comparative valuations of alternative TS mechanisms and platforms. As TSs evolve, planners will look to the valuation community to inform their selections of TS mechanisms and platforms. The comparison of the performance of systems using different TS mechanisms and platforms has not been done. Significant work is needed to accomplish this given the uneven documentation of the mechanisms and the reliance of the mechanisms on operational models of human behaviors and interventions that require more research. Under these circumstances, this report listed questions that may be used to understand, contrast, and ultimately model the various TS mechanisms.

- Launch online communities. The practice and consistency of valuations would benefit from the formation of online communities. A community for analysts could consist of a repository for operational models, associated tools, and access to representative standard data sets. A community may be useful, too, for state regulators and others who review and make decisions based on valuations. For this latter audience, an unbiased discussion of methods' strengths, weaknesses, and assumptions would be informative and foster improved trust toward the valuation community and its methods.

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Appendix A

An Estimate of the Potential Value of Supplying Grid Services Using Flexible Loads in Residential and Commercial Buildings

Appendix A

An Estimate of the Potential Value of Supplying Grid Services Using Flexible Loads in Residential and Commercial Buildings

Summary of Results

RG Pratt and N Fernandez, Pacific Northwest National Laboratory

9-10-2014

A.1 Introduction

In January 2014, at the request of the Building Technologies Office of the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy, Pacific Northwest National Laboratory (PNNL) developed an estimate of $22B/year for the potential value of continuously engaging, real-time-flexible loads in both residential and commercial buildings to provide grid services if deployed at the national scale. This document summarizes the basis for this estimate. We use the term *value* here to indicate the total cost of providing these services today. That is, it represents the utility infrastructure and operational cost savings available to buildings offering to provide these services. Hence, this represents the *gross* potential benefit that could accrue to building owners/operators. We did <u>not</u> include the cost of deploying the smart buildings/control capabilities required, and hence the *net* potential benefit to the building owner. These costs are uncertain, but are likely to significantly decline as the technology to provide such services is increasingly built into building equipment, appliances, and systems as a routine matter in the future.

The estimate was based on the following four value streams:

1. **Capacity displacement** – the reduced need for capital expenditure for electricity generation, transmission, and distribution capacity needed to meet peak loads, provided by shifting building loads to non-peak times.
2. **Wholesale-market/production cost reduction** – the reduced energy purchase costs (where wholesale markets exist) or reduced energy production costs (where they do not), resulting from shifting as much as 10% of buildings electricity usage to times when costs are lower.
3. **Supplying regulation** – the typical cost of supplying regulation services used to resolve short-term imbalances between supply and demand, as indicated by market prices where such markets exist.
4. **Providing spinning (contingency) reserve capacity** – the typical cost of supplying spinning-reserve capacity used to maintain grid reliability in the event of the unexpected loss of a grid asset (e.g., a large coal or nuclear power plant).

The basis for the computation of each of these value streams is discussed in more detail in the following section.

A.2 Methodology

A.2.1 Capacity Displacement

The estimate of the potential value of displacing capacity is based on the assumption that flexible building loads can displace peak load. The value of this displaced generation, transmission, and distribution capacity is based on marginal construction costs for them of $973/kW, $150/kW, and $250/kW, respectively. While average distribution system costs are closer to $450/kW, many of these costs, such as feeder lines and meters, are not avoidable. The $250/kW cost for distribution capacity represents the cost of transformers, voltage regulators, capacitor banks, and other costs directly affecting the distribution system's capacity to serve peak loads.

These costs are then annualized using assumptions of a 10.5% regulated return on equity to the utility, a 5% rate of straight-line depreciation of capital assets over 20 years, a 25% average utility marginal tax rate, and $7.04 per kW per year in fixed operations and maintenance costs. These assumptions result in an annualized cost of $202/kW of overall capacity.

A peak load reduction in residential buildings of 15% was assumed to be achievable, based on various studies conducted by PNNL and others. This figure represents the potential across residential buildings, with a representative range of responses on the part of the occupants comprising about 0.7 kW per home, on average, rather than the maximum technical potential, which is considerably larger. By scaling the fraction of commercial loads engaged in providing flexibility (71% representing heating, ventilation, and air conditioning (HVAC) and lighting) to the fraction of residential loads engaged (75% representing HVAC, water heating, and large appliances), the corresponding commercial building peak load reduction was estimated to be 14%. Residential and commercial buildings represent about 37% and 36%, respectively, of a U.S. peak load of about 783,000 MW.

The resulting potential value estimate for capacity displacement is about $16B per year. This is by far the largest potential of the four value streams.

A.2.2 Wholesale-Market/Production Cost Reduction

The estimate of the potential value of displacing wholesale energy costs is based on the assumption that flexible building loads can be engaged continuously to reduce consumption when such costs are high by shifting load to periods when such costs are low. In traditional, vertically integrated utilities, generation dispatch is based on the least-cost set of generators able to meet load without violating transmission constraints. In the absence of such constraints, this reduces to the production cost of the marginal power plant, and wholesale prices are directly related to the magnitude of the load being served, and hence vary in relatively predictable fashion.

A large fraction of U.S. customers are served by utilities that operate in areas where electricity production is managed by an independent system operator (ISO) using a wholesale market that indirectly represents production costs and transmission constraints. However, prices vary more widely in such markets, as they also reflect a degree of *scarcity rent* during high load periods and can drop below production cost when loads are low and hence supply is plentiful.

Because wholesale market prices are readily available from various ISO markets around the United States, we use these to produce the potential value estimate. Specifically, we utilize the annual time series of 15-minute wholesale prices from the PJM Interconnection (PJM) ISO (Mid-Atlantic to Midwestern region) and New York Independent System Operator (NYISO) as representative of the national costs. The avoided cost potential for residential buildings was studied in detail by PNNL in an unpublished analysis of the savings opportunity for responsive equipment and appliances in homes when controlled in a price-responsive fashion. The result was a savings of 1.2% of wholesale costs in an all-electric home. The individual savings for each type of major types of appliances and equipment are then weighted by penetration of each type at the national level, using the U.S. Energy Information Administration's (EIA's) penetration data to produce a national estimate of the value stream of $2.7B per year.

A similar study for response from commercial buildings is not available. Therefore, the estimate is based on a simple extrapolation of the residential results. End-use intensities (consumption per square foot of floor area) were based on the prototype small/medium and large commercial buildings used for the analysis of building energy standards. Flexibility is assumed to be obtained from HVAC, water heating, lighting, and plug loads in the same relative proportion to the load as in the residential buildings. The value stream potential estimate of $1B per year is based on EIA's estimate of 72B square feet of commercial building floor space. This implies an assumption of similar load-shifting potential, in absolute terms, from end uses in other building types. The estimate for the value stream from commercial buildings could be refined considerably to eliminate the uncertainty from some of these crude assumptions.

A.2.3 Supplying Regulation

Regulation is used to resolve short-term imbalances between supply and demand. If these are not in balance at the interconnection scale, then system frequency begins to deviate rapidly from 60 Hz as the imbalance extracts or injects energy from/to the momentum of the rotating mass of synchronous generators. These frequency deviations occur continually, reflecting quasi-random fluctuations in load at roughly a 1-minute time scale. At the primary level, *frequency regulation* is supplied automatically and autonomously by speed governors of generators. When larger imbalances exceed this primary capability, generators are commanded to increase or decrease output by 4-second-interval automated generator control signals from the balancing authority. Although most regulation is supplied by generators as described here, flexible loads are increasingly eligible to supply regulation services where markets for such services exist, if aggregated so their collective response follows the control signal with fidelity.

Regulation is also used more locally by the balancing authority to manage their import/export balance to match the planned schedule of such transactions. These deviations tend to occur on a somewhat longer time scale, typically 15 to 30 min. Compensation for these imbalances is implemented by superimposing this need upon the automated generator control signal from the balancing authority. Some balancing areas are moving to issue separate signals for *fast regulation* and *slow regulation* (PJM is an example). This is particularly valuable to responsive buildings, since it is much less obtrusive to defer loads on the minute time scale when the deferred load can be made up in the subsequent minute.

The estimate of the potential value stream for supply regulation services using flexible building loads is essentially limited by the total need for regulation. Today, this is less than 1% of the load, although the introduction of renewables is expected to increase the need for regulation (perhaps doubling it). If deployed at scale, flexible load technology in buildings, in principle, could easily supply virtually all of the regulation required to operate the grid. So, we estimate the potential value of regulation services based on annual average wholesale market prices for regulation from various ISOs: PJM, California Independent System Operator (CAISO), Electric Reliability Council of Texas (ERCOT), Midcontinent Independent System Operator (MISO–Midwest), and NYISO for the 2009 through 2011 time period, equal to $12.88 per MWh. We assume that 0.7% of average load is required for regulation, on average (the amount currently required by CAISO). Scaled to the annual national electrical energy consumption of 3.7×10^9 MWh per year, the upper bound on the potential value estimate is $0.3B per year. As noted earlier, this can be expected to increase as renewable resources continue to penetrate the electricity supply system.

A.2.4 Providing Spinning (Contingency) Reserve Capacity

Spinning reserve (also known as contingency reserve) is capacity set aside to manage the sudden, unexpected loss of a major asset such as a large generating station or a transmission corridor. Grid operators are required to maintain spinning-reserve capacity at least equal to that required to manage the loss of any single asset. In the worst case, this is often a large coal or nuclear power plant. Traditionally supplied by generators, assets supplying spinning reserve must begin to respond immediately upon receipt of a signal from the transmission system operator and ramp up to reach their full capacity within 10 minutes. Typically, spinning-reserve assets are replaced by non-spinning (replacement) reserves within 10 minutes, to restore the spinning-reserve cushion, but curtailments can last up to 30 or 60 minutes, depending upon the rules set forth by the grid operator.

The term “spinning” comes from the notion that a power plant must be up and running in order to respond quickly enough, either by not operating at its full output capability, or by simply being “hot” and ready to throttle up. Fast acting generation, storage, and response from flexible loads can also supply spinning-reserve capacity. Storage and loads can respond nearly instantly—a distinct advantage, but one that is unrewarded by current market structures.

Similar to the value estimate for supplying regulation, the potential value for flexible building loads supplying spinning reserve is based on annual average wholesale market prices for spinning-reserve capacity from various ISOs: PJM, CAISO, ERCOT, MISO, and NYISO for the 2009 through 2011 time period, equal to $6.61 per MWh. Also like the estimate for regulation, there is a limited market for spinning-reserve capacity. We assume the equivalent of 5% of annual average load is required as spinning-reserve capacity, although this is also expected to increase as renewables penetrate. The resulting upper bound estimate of the potential value of providing all spinning-reserve requirements value is about $1.2B per year.

A.3 Value Estimates

PNNL estimated a potential annual gross savings opportunity of $22.1 billion from these four value streams in a preliminary analysis. The itemized results are tabulated here. These value estimates do not include the effect of increased market competition in lowering the value of these services over time. They also do not include the retention of any value to incentivize utilities to adopt such a new approach vis-à-vis business as usual.

Table A.1. Opportunity for Grid-Ready Appliances ($B/year)

Value Stream	Residential	Commercial	Res. & Com.
Peak Capacity	8.8	8.0	16.8
Wholesale/Production	2.7	1.0	3.7
Regulation			0.3
10-min. Spinning Reserve			1.2
Total			22.1

Appendix B

Inventory of Valuations that Influenced this Report

Appendix B

Inventory of Valuations that Influenced this Report

Acadia Center. 2015. Value of Distributed Generation – Solar PV Methodology. New York. Available at: http://acadiacenter.org/wp-content/uploads/2015/04/AcadiaCenter_ValueofDistributedGeneration_StudyMethodology_FINAL_2015_0414.pdf.

This study assesses the value of six small marginal solar photovoltaic (PV) systems to understand the value to the electric power grid, ratepayers, and society. The authors calculate the solar output and estimate avoided costs and benefits for 11 components that make up grid and societal value.

Beach RT and PG McGuire. 2013. The Benefits and Costs of Solar Distributed Generation for Arizona Public Service. Crossborder, Berkeley, California. Available at: http://www.seia.org/sites/default/files/resources/AZ-Distributed-Generation.pdf.

This report presents a methodology for performing cost-benefit analysis of rooftop PV systems based on the value they provide in terms of avoided generation, capacity, and environmental costs.

Bendewald M and D Miller. 2014. Next-generation Energy Management. Rocky Mountain Institute, Basalt, Colorado. Available at: http://www.rmi.org/Knowledge-Center/Library/2014-31_CoreNet_Final.

This report, although designed to help commercial real estate investors understand the business case for radical energy efficiency, talks about the multiple value streams available from deep energy retrofits.

Birr D and TE Singer. 2011. NAESCO Analysis of Non-energy Benefits of Efficiency Benefits of ESCOs and ESCO Customers. NAESCO Summary Report – NEB Analysis Results, National Association of Energy Service Companies (NAESCO), Washington, D.C. Available at: http://www.naesco.org/data/industryreports/NAESCO%20NEB%20Report%2012-11-08.pdf.

New York State Energy Research and Development Authority (NYSERDA), in conjunction with the National Association of Energy Service Companies (NAESCO), develops a methodology to quantify the most valuable non-energy benefits resulting from energy efficiency building retrofits. The study team offers a literature review and survey to identify the state of empirical knowledge about the quantification of non-energy benefits and to better understand the role of non-energy benefits in the pursuit of energy efficiency implementation within the U.S. buildings.

Burman K, D Olis, V Gevorgian, A Warren, R Butt, P Lilienthal, and J Glassmire. 2011. Integrating Renewable Energy into the Transmission and Distribution System of the U.S. Virgin Islands. NREL/TP-7A20-51294, National Renewable Energy Laboratory, Golden, Colorado. Available at: http://www.nrel.gov/docs/fy11osti/51294.pdf.

This report focuses on the economic and technical feasibility of integrating renewable energy technologies into the U.S. Virgin Islands transmission and distribution systems. This study examines the economics of deploying utility-scale renewable energy technologies, such as PV and wind turbines, on the islands of St. Thomas and St. Croix. The study also analyzed the potential sites for installing roof- and ground-mounted PV systems and wind turbines and investigated the impact of renewable generation on the electrical sub-transmission and distribution infrastructure. This study also analyzed the feasibility of a 100–200 MW power interconnection of the Puerto Rico, U.S. Virgin Islands, and British Virgin Islands utility grids via a submarine cable system.

Cohen MA, PA Kauzmann, and DS Callaway. 2015. Economic Effects of Distributed PV Generation on California's Distribution System. Energy Institute at HAAS, University of California, Berkeley. Available at: http://ei.haas.berkeley.edu/research/papers/WP260.pdf.

This report presents results from studies conducted using Pacific Gas & Electric's feeder models to evaluate the impact of rooftop PV systems on the distribution system operations. The report also provides details on the impacts of net-energy metering policy on utility revenues as well as nonparticipant customers' rate impacts due to increasing penetration of rooftop PV systems.

Contreras JL, L Frantzis, S Blazewicz, D Pinault, and H Sawyer. 2008. Photovoltaics Value Analysis. NREL/SR-581-42303, National Renewable Energy Laboratory, Golden, Colorado. Available at: http://www.nrel.gov/docs/fy08osti/42303.pdf.

This study examines the value of photovoltaic systems to participating customers, utilities, ratepayers, and society. This is a meta-analysis of existing published reports on the value of solar, and the report summarizes the methodologies and quantified values. The report also identifies the gaps (in 2008).

Crofton K, E Wanless, and D Wetzel. 2015. The Electricity System Value Chain. Rocky Mountain Institute, Basalt, Colorado. Available at: http://www.rmi.org/Knowledge-Center/Library/2015-04_eLab-ElectricitySystemValueChain-final.

This report presents a visual framework to explore, in an organized manner, the potential value streams provided by a given technology across the electricity system value chain.

CSIRO (Commonwealth Scientific and Industrial Research Organization). 2009. Intelligent Grid: A Value Proposition for Distributed Energy in Australia. CSIRO Report ET/IR 1152, CSIRO Energy Technology, 10 Murray Dwyer, Mayfield, West, 2304, Australia. Available at: https://www.parliament.nsw.gov.au/prod/parlment/committee.nsf/0/7482f370da08bf4eca257a38000982f6/$FILE/CSIRO%20attachment%202a%20-%20Intelligent%20grid%20summary.PDF.

This study examines the economic, environmental, and societal impacts of using distributed energy resources (DERs) as an alternative to centralized generation. The impacts considered included emissions, energy prices, and water usage. The time frame for the study extended out to 2050, and distributed generation resource included PV, wind turbines, and energy storage.

Denholm P, J Jorgenson, M Hummon, T Jenkin, D Palchak, B Kirby, O Ma, and M O'Malley. 2013a. The Impact of Wind and Solar on the Value of Energy Storage. NREL/TP-6A20-60568, National Renewable Energy Laboratory, Golden, Colorado. Available at: http://www.nrel.gov/docs/fy14osti/60568.pdf.

This report presents results from a multi-national-laboratory effort to assess the potential value of demand response and energy storage to electricity systems with different penetration levels of variable renewable resources, and to improve an understanding of associated markets and institutional requirements.

Denholm P, J Jorgenson, M Hummon, T Jenkin, D Palchak, B Kirby, O Ma, and M O'Malley. 2013b. The Value of Energy Storage for Grid Applications. NREL/TP-6A20-58465, National Renewable Energy Laboratory, Golden, Colorado. Available at: http://www.nrel.gov/docs/fy13osti/58465.pdf.

This study uses a commercial grid simulation tool to evaluate several operational benefits of electricity storage, including load-leveling, spinning contingency reserves, and regulation reserves.

Denholm P, R Margolis, B Palmintier, C Barrows, E Ibanez, L Bird, and J Zuboy. 2014. Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System. NREL/TP-6A20-62447, National Renewable Energy Laboratory, Golden, Colorado. Available at: http://www.nrel.gov/docs/fy14osti/62447.pdf.

This report discusses various methods for valuing distributed rooftop PV. It does not attempt to calculate costs and benefits, nor does it provide a comprehensive framework for doing so. It does, however, include the main cost-benefit categories and several methods for calculating each one. The report also proposes the structure and flow of a "holistic" study for evaluating the benefits of distributed PV.

Energy+Environmental Economics (E3). 2015. Summary of the California State Agencies' PATHWAYS Project: Long-term Greenhouse Gas Reduction Scenarios. E3 project summary webpage, E3, San Francisco, California. Available at: https://ethree.com/public_projects/energy_principals_study.php.

This report provides details on the feasibility and cost of a range of potential 2030 technological targets along the way to California's goal of reducing greenhouse gas emissions to 80% below 1990 levels by 2050. The report contains details on scenarios that explore the potential pace at which emission reductions can be achieved as well as the mix of technologies and practices deployed. The study is based on the PATHWAYS model, which encompasses the entire California economy with detailed representations of the buildings, industry, transportation, and electricity sectors.

Glick D, M Lehrman, and O Smith. 2014. Rate Design for the Distribution Edge: Electricity Pricing for a Distributed Resource Future. Rocky Mountain Institute, Basalt, Colorado. Available at: http://www.rmi.org/Knowledge-Center/Library/2014-25_eLab-RateDesignfortheDistributionEdge-Full-highres.

This report presents the principles on which future electricity rates may be designed to fully reflect the benefits and costs of electricity services exchanged between customers and the grid, allowing utilities and regulators to unleash new waves of innovation in DER investment that will help to reduce costs while maintaining or increasing resilience and reliability.

Graham P, T Brinsmead, S Dunstall, J Ward, L Reedman, T Elgindy, J Gilmore, N Cutler, G James, A Rai, and J Hayward. 2013. Modelling the Future Grid Forum Scenarios. Commonwealth Scientific and Industrial Research Organization (CSIRO) Dickson, Australia. Available at: https://publications.csiro.au/rpr/download?pid=csiro:EP1311347&dsid=DS3.

This report provides details on the modeling of the future states that were explored in the Australian Future Grid Forum. The report details a "whole-system" modeling approach for evaluating the future grid scenarios. The four states ranged from business-as-usual with responsive customers, to high distributed generation penetration, and high central-scale renewable penetration.

Graham PW, TS Brinsmead, and P Marendy. 2013. Efuture Sensitivity Analysis 2013. CSIRO, Australia. Available at: http://efuture.csiro.au/

"efuture.csiro.au" is an internet site where users can explore Australia's electricity future through to 2050. It provides access to about 1300 pre-modeled sensitivity cases. This report describes an online tool that makes available the scenarios that have been modeled using the methodology. The internet site only reports a handful of the impacts considered by the model.

Graham PW. 2013. Change and Choice: The Future Grid Forum's Analysis of Australia's Potential Electricity Pathways to 2050. Commonwealth Scientific and Industrial Research Organization (CSIRO) Energy Flagship, P.O. Box 330, Newcastle, NSW 2300 Australia. Available at: https://publications.csiro.au/rpr/download?pid=csiro:EP1312486&dsid=DS13.

This report describes the current and projected future states of the Australian electric power system, as designed by various stakeholders over the course of Australian Future Grid Forum. The results were used to model and analyze the impacts on the Australian power system, as well as impacts on various stakeholders.

Hansen L and V Lacy. 2013. A Review of Solar PV Benefit & Cost Studies. Rocky Mountain Institute, Basalt, Colorado. Available at: http://www.rmi.org/Knowledge-Center/Library/2013-13_eLabDERCostValue.

This document reviews 15 distributed PV cost-benefit studies by utilities, national labs, and other organizations to determine what is known and unknown about the categorization, methodological best practices, and gaps around the benefits and costs of distributed PV.

Jones N, B Norris, and L Meyer. 2013. The Value of Distributed Solar Electric Generation to San Antonio. Solar San Antonio, Clean Power Research, and City of San Antonio, Texas. Available at: http://www.osti.gov/scitech/servlets/purl/1079489/.

This report presents a methodology for designing retail tariffs to compensate rooftop PV output for customers in the Austin, TX area. The tariff is based on the value of rooftop PV generation to a utility in terms of displaced energy, capacity (transmission, generation, and distribution), and reserves, as well as avoided greenhouse gas emissions. The rate based on this methodology was presented to and subsequently approved by the Texas Public Utility Commission (PUC).

Lacy V and J Sherwood. 2013. EDGE Model Executive Summary. Rocky Mountain Institute, Basalt, Colorado. Available at: http://www.rmi.org/Knowledge-Center/Library/2013-02_EDGEModel.

This white paper describes a framework for simulating the impact of DERs on the generation and distribution system. In addition to the engineering analysis, the model includes a module for evaluating rates and regulation impacts, and outcomes for different stakeholders. However, no detail on how these impacts are calculated is provided.

Larson P, C Goldman, D Gilligan, and TE Singer. 2012. Incorporating the Non-Energy Benefits into Energy Savings Performance Contracts. Lawrence Berkeley National Laboratory (LBNL), Berkeley, California. 2012 ACEEE Summer Study on Energy Efficiency in Buildings, American Council for an Energy-Efficient Economy, Washington, D.C. Available at: http://emp.lbl.gov/sites/all/files/incorp-nonenergy-benefits-aceee.pdf.

This study addresses the issue of non-energy benefits, or soft benefits, associated with comprehensive building retrofits in the public and institutional sectors. The report estimates the value of those benefits compared to traditional energy benefits in a number of energy savings performance contract projects.

MacDonald J, S Kilicotte, J Boch, J Chen, and R Nawy. 2014. Commercial Building Loads Providing Ancillary Services in PJM. LBNL Report LBNL-6778E, in ACEEE Summer Study on Energy Efficiency in Buildings 2014, Pacific Grove, CA, August, 2014. Available at: https://esdr.lbl.gov/sites/all/files/lbnl_6778e.pdf.

This study demonstrates the ability of demand-response resources providing two ancillary services in the PJM Interconnection territory—synchronous reserve and regulation—using an OpenADR 2.0b signaling architecture. The loads under control include heating, ventilation, and air conditioning (HVAC) and lighting at a big box retail store and variable frequency fan loads.

Madaeni SH, R Sioshansi, and P Denholm. 2011. Capacity Value of Concentrating Solar Power Plants. NREL/TP-6A20-51253, National Renewable Energy Laboratory, Golden, Colorado. Available at: http://www.nrel.gov/docs/fy11osti/51253.pdf.

This study estimates the capacity value of a concentrating solar power plant at a variety of locations within the western United States. This is done by optimizing the operation of the concentrating solar power plant and by using the effective load carrying capability (ELCC) metric, which is a standard reliability-based capacity value estimation technique. The study also shows that a simpler capacity-factor-based approximation method can closely estimate the ELCC value.

Milligan M, E Ela, B-M Hodge, B Kirby, Debra Lew, C Clark, J DeCesaro, and K Lynn. 2011. Cost-causation and Integration Cost Analysis of Variable Generation. NREL/TP-5500-51860, National Renewable Energy Laboratory, Golden, Colorado. Available at: http://www.nrel.gov/docs/fy11osti/51860.pdf.

This paper discusses how integration costs should be calculated, and the common mistakes that are made. The paper claims that some integration costs are “difficult, if not impossible to calculate.” It also claims that renewable generation cannot increase the generation capacity, except when the existing generation is not fast enough (flexible enough) to respond to changes in load. This has some implications for DERs, which could be assumed to be treated in the same way; i.e., DERs do not increase the generation capacity. The paper also presents some discussion of the associated question of rate design.

Navigant. 2015a. Demand Response Enabling Technologies. Boulder, Colorado. Available at: http://www.navigantresearch.com/research/demand-response-enabling-technologies.

This Navigant report analyzes the global distributed resources market, with a focus on three main categories of demand-response-enabling technologies: metering, communications, and controls. The study provides an analysis of the market issues, including drivers and challenges associated with demand-response-enabling technologies. Global market forecasts for demand-response sites and spending, segmented by application (residential and commercial and industrial), type, and region, extend through 2024. The report also examines demand-response adoption trends by country and provides profiles of key residential and commercial and industrial demand-response providers. According to Navigant, global demand-response spending is expected to grow from $183.8 million in 2015 to more than $1.3 billion in 2024.

Navigant. 2015b. Grid Edge Intelligence for DER Integration. Boulder, Colorado. Available at: http://www.navigantresearch.com/research/grid-edge-intelligence-for-der-integration.

This Navigant report analyzes the global market for grid-edge intelligence and automation solutions, equipment, and services. The study provides an assessment of current market drivers and inhibitors, regional trends, technology, and business segments related to grid-edge technologies for DER integration, in addition to business recommendations for both vendors and utilities. Global market forecasts for revenue, segmented by solution, category, and region, extend through 2024. The report also profiles key industry players and examines several utilities that have implemented grid-edge intelligence and automation solutions to align with more ambitious smart grid initiatives and aggressive regulatory policies. According to Navigant, revenue for global grid-edge technologies for DERs is expected to grow from $8.5 billion in 2015 to $14.5 billion in 2024.

Navigant. 2014c. Smart Grid Networking and Communications. Boulder, Colorado. Available at: http://www.navigantresearch.com/research/smart-grid-networking-and-communications.

This Navigant report analyzes the global market for smart grid networking and communications technology. The study provides a detailed analysis of market drivers and challenges, technical considerations, and key infrastructure vendors and service providers associated with communications infrastructure and services for smart grid applications. Global market forecasts for shipments, average selling prices, and revenue, segmented by application, device type, technology, and region, extend through 2023. The report also examines spectrum availability and cyber security requirements, as well as regional factors affecting relative shares among the major communications technologies. According to Navigant, cumulative global revenue for smart grid communications networking and communications equipment is expected to amount to more than $29 billion between 2014 and 2023.

Navigant. 2014d. Virtual Power Plants. Boulder, Colorado. Available at: http://www.navigantresearch.com/research/virtual-power-plants.

This Navigant report analyzes the global virtual power plant (VPP) market, with a focus on three primary segments: demand response, supply-side, and mixed asset VPPs. The study provides an analysis of the market issues, including business cases, market drivers, and implementation challenges, associated with VPPs. Global market forecasts for power capacity and vendor revenue, broken out by segment, region, and scenario, extend through 2023. The report also examines the key technologies related to VPPs, as well as the competitive landscape. Navigant forecasts that total annual VPP vendor revenue will grow from $1.1 billion in 2014 to $5.3 billion in 2023 under a base scenario.

Norris B, PM Gruenhagen, RC Grace, P-YYuen, R Perez, and KR Rabago. 2015. Maine Distributed Solar Valuation Study Maine Public Utilities Commission. Clean Power Research, Napa, California. Available at: http://www.nrcm.org/wp-content/uploads/2015/03/MPUCValueofSolarReport.pdf.

This report presents the methodology and valuation results of distributed solar power for three utility territories within Maine, and develops a summary of implementation options for increasing solar deployment. The methodology assumes that benefits and costs of gross energy produced by a solar PV system are realized based on its delivery to the bulk grid prior to serving any local load.

Norris B, M Putnam, and TE Hoff. 2014. Minnesota Value of Solar: Methodology. Clean Power Research, Napa, California. Available at: https://www.cleanpower.com/wp-content/uploads/MN-VOS-Methodology-2014-01-30-FINAL.pdf.

This report presents a methodology for designing retail tariffs to compensate rooftop PV output for customers in Minnesota. The tariff is based on the value of rooftop PV generation to utility in terms of displaced energy, capacity (transmission, generation, and distribution), and reserves, as well as avoided greenhouse gas emissions.

Pater JE. 2006. A Framework for Evaluating the Total Value Proposition of Clean Energy Technologies. NREL/TP-620-38597, National Renewable Energy Laboratory, Golden, Colorado. Available at: http://www.nrel.gov/docs/fy06osti/38597.pdf.

This report presents a "total value proposition" for clean energy technologies. It incorporates a series of values under risk management, emissions reductions, policy incentives, resource use, corporate social responsibility, and societal economic benefits, and describes the opportunities for recapturing investments throughout the power system value chain. The report claims that this framework may be used to create comparable value propositions for clean energy technologies supporting investment decisions, project siting, and marketing strategies, as well as policy-making decisions. The framework presented in this report also focuses on some hard-to-quantify values.

RMI (Rocky Mountain Institute). 2014. How to Calculate and Present Deep Retrofit Value – A Guide for Owner-Occupants. Basalt, Colorado. Available at: http://www.rmi.org/PDF_deepretrofitvalue.

This report spells out the value of deep energy retrofits that extend beyond energy. It attempts to categorize and quantify the value of deep energy retrofits by detailing nine elements of deep retrofit value beyond energy savings.

Rogers EA, RN Elliott, S Kwatra, D Trombley, and V Nadadur. 2013. Intelligent Efficiency: Opportunities, Barriers and Solutions. American Council for an Energy-Efficient Economy, Washington D.C. Available at: http://aceee.org/files/pdf/summary/e13j-summary.pdf.

This report describes the multiple value streams to the grid and to individual buildings or systems of buildings of advanced and integrated energy efficiency made possible through information and communication technologies. The report describes traditional benefits of energy efficiency as well as soft benefits.

Stadler M, M Groissbock, G Cardosa, and C Marnay. 2014. Optimizing DER and Building Retrofits with the Strategic DER-CA Model. Applied Energy 132:556–567. Available at: https://esdr.lbl.gov/publications/optimizing-distributed-energy-resourc.

This paper shows enhancements made to a European Union model used to support DER investments to consider building retrofit measures along with DER investment options. Specifically, building shell improvement options have been added to DER-Customer Adoption Model as alternative or complementary options to investments in other DER such as PV, solar thermal, combined heat and power, or energy storage. The model is demonstrated at an Austrian campus building by comparing results with and without building shell improvement options.

Woolf T, M Whited, E Malone, T Vitolo, R Hornby. 2014. Benefit-Cost Analysis for Distributed Energy Resources. Advanced Energy Economy Institute (AEEI), Cambridge, Massachusetts. Available at: http://synapse-energy.com/sites/default/files/Final%20Report.pdf.

This report describes a framework for determining the costs and benefits of DERs. It presents a list of cost-benefit elements and the types from the perspective of participating and nonparticipating customers in utility programs, including environmental and societal costs and benefits. The report does not provide guidance on how to calculate each element, but does discuss methods for estimating those that are much more difficult to quantify.

Zinaman OR and NR Darghouth. 2015. A Valuation-based Framework for Considering Distributed Generation Photovoltaic Tariff Design. NREL/CP-6A50-63555, National Renewable Energy Laboratory, Golden, Colorado, presented at India Smart Grid Week, Bangalore, India, March 2–6, 2015. Available at:http://www.nrel.gov/docs/fy15osti/63555.pdf.

This report outlines a joint LBNL/NREL project consisting of a holistic, high-level approach to the complex undertaking of distributed generation PV tariff design, the crux of which is an iterative cost-benefit analysis process. A multi-step progression is proposed that aims to promote transparent, focused, and informed dialogue on cost-benefit analysis study methodologies and assumptions.

Appendix C

Recommended Metrics for Comparing Valuations

Appendix C

Recommended Metrics for Comparing Valuations

Table C1. Draft Questions that May Be Used to Compare and Contrast Different Valuations and Valuation Methods

OBJECTIVES AND KEY ASSUMPTIONS	
<u>Objective - Defining Valuation</u>	
1	What is/are the specific objective(s) of the valuation?
2	How will the results of the valuation be used?
3	Does the valuation compare a test scenario against a baseline?
4	Are critical operational requirements defined?
5	What levels of locational and temporal granularity are used in the effort?
<u>Key Assumptions</u>	
6	Are the bases of market assumptions made clear? What are the assumptions?
7	Are the bases of other assumptions stated?
OPERATIONAL MODELS	
<u>General</u>	
8	What levels of granularity in space and time are used in operational models?
<u>Generation and Transmission</u>	
9	Is a specific system being modeled, or a prototype or generalized system?
10	What parameters and impacts are considered in generation and transmission operational models?
<u>Distribution</u>	
11	What parameters and impacts are considered in distribution system operational models?
<u>Buildings/Assets</u>	
12	What parameters and impacts are considered in buildings/assets operational models?
<u>Transactive Energy System</u>	
13	Are transactive system capabilities included?
14	What transactive system design and performance details are included in operational models?
GROWTH MODELS	
<u>Forecasts</u>	
15	Are the bases of growth rates and forecasts used in growth models made clear?
<u>Resource Portfolio Planning</u>	
16	Does valuation consider future resource portfolio planning and dispatch?
17	What kinds of resources are considered in resource planning models?
18	Does the model consider cumulative impacts?
<u>Transmission Planning</u>	
19	Is transmission planning capability included?
20	Is transmission planning connected to generation and distribution planning?
<u>Distribution Planning</u>	
21	Is distribution system planning included?
22	Which distribution system parameters and impacts are considered in growth models?
23	Does analysis include feedback between growth and operational models?

REGULATION AND RISK

Regulation/Rate Impacts

24 Are regulation/rate impacts considered?

25 What assumptions are made relative to regulation/rate impacts?

26 Are alternative business models and system architectures considered?

Uncertainty and Risk

27 Is risk analysis performed?

28 Are risks associated with price volatility and environmental compliance considered?

IMPACTS TO STAKEHOLDERS

29 Which stakeholder perspectives are considered?

30 For which stakeholders are monetary costs and benefits assigned?

31 For which stakeholders are non-monetary impacts defined?

32 Are resilience impacts explicitly addressed?

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