Technical Workshop on Electricity Valuation

Synthesis Report

QUADRENNIAL ENERGY REVIEW (QER)

Second Installment

Technical Workshop on Electricity Valuation: Synthesis Report

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Executive Summary

Workshop Structure

This document summarizes a workshop held by the U.S. Department of Energy (DOE) Office of Energy Policy and Systems Analysis (EPSA) on May 2–3, 2016, in Washington, D.C., to understand stakeholder issues relevant to the valuation of electricity system technologies, products, and services. This workshop was designed, in part, to address a recommendation identified in the first installment of the Quadrennial Energy Review (QER 1.1):

"DOE should play a role in developing frameworks to value grid services and approaches to incorporate value into grid operations and planning." – QER 1.1 (2015)

It is also one of several workshops supporting the second installment of the QER, focused on electricity. The event itself included presenters and audience participants from state and federal regulatory agencies, electric utilities, technology developers and manufacturers, universities, national laboratories, industry associations for consumers, and system operators.

The executive summary and introduction synthesizes the discussion at the workshop with materials submitted as well as outside resources. Each of the chapters starts with a synthesis discussion that provides context, and then lists some of the main points made by participants during the workshop. The goal of this was to provide both a workshop summary, as well as to go beyond and provide important information and context to help inform the reader of the significance of the discussions.

While this report exhibits a discussion of current analytical issues in electricity valuation as they were expressed during the workshop, it does not represent all energy industry stakeholders, nor does it represent all workshop participants equally. Presentations and documents submitted by speakers are also included in this report. Issues were identified by the weight of discussion and relative frequency of their occurrence throughout the event. Participants were not asked to provide consensus views on these topics; therefore, this synthesis report reflects their various perspectives.

Disclaimer

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Key Findings

New technologies and decreasing costs for distributed energy resources (DER) is creating opportunities and driving changes in the electricity industry. These technologies span a broad range including energy efficient devices such as LED lights, distributed generation including solar photovoltaics, communication and control technologies that control end uses, electric vehicle chargers, advanced distribution switching and power quality controls, energy storage devices and others. Evaluating these technologies is stressing current practices in valuation and market mechanisms are insufficient to encourage efficient system operation and optimal investment in grid infrastructure in a manner that incorporates the complete range of potential technology deployment. The information presented provides an understanding of the challenges that exist at many levels of planning and implementation, from top-level impacts on "system properties" to the daily working-level cost recovery of transmission system upgrades. As lower costs, greater functionality, and better performance creates new opportunities, the industry needs to improve its valuation capability to identify cost-effective and beneficial DER in a consistent manner, reject those that are not beneficial, and communicate this framework to the marketplace.

Workshop Responses to Pacific Northwest National Laboratory/Brattle Group Valuation Proposal

The Brattle Group opened the technical sessions with a presentation of a broad and comprehensive valuation methodology (described in the Introduction below). Workshop participant comments specific to the proposed methodology fell into three broad categories, which are variously described in the Key Findings sections throughout this Executive Summary.

Support for the Concept

Participants agreed that there is a substantive need to develop a comprehensive framework for valuation of advanced energy technologies, such as the one presented in the Pacific Northwest National Laboratory (PNNL)/Brattle Group report, that provides a framework sufficient to guide consistent evaluations of capacity additions in most utility environments in the United States. This framework would not need to advocate a particular model. Instead, it could provide guidelines and best practices for developing models, consistency and quality requirements for calculations, and enough examples for users to ensure consistent application in a variety of circumstances and uses. However, there is not yet universal agreement on what an appropriate methodology would look like or what data would support it. Figure 1 describes the challenge to find internally consistent values for a given attribute within a complex system, in which “value” may vary by both location and time.

Figure 1. The Valuation Challenge

These new methods must accurately allocate system costs as well as benefits. Inaccurate valuation of components, systems, products, and services across the electricity sector will result in a sub-optimal portfolio relative to both risks and costs.

Emphasis on Understanding which Metrics Can Be Monetized

Several participants noted that if the values (both positive and negative) of attributes ascribed to new technologies cannot be translated into financial terms, then utilities cannot perform a standard Net Present Value (NPV) analysis, and state utility commissions cannot subject such values to a prudency review for their inclusion in a rate case. There was discussion of how it might not be possible to properly monetize some metrics. Breaking out which metrics can and cannot be monetized can be useful to help inform how stakeholders should incorporate the values and properties associated with the metrics into their decision making.

Vital Need for Operational Data

Participants reiterated the need for component- and system-specific data in all aspects of the electric utility industry as described in this report: system characterization (modeling) and operation, planning, pricing and market development, and risk. There was support for the idea that a non-biased entity might collect or develop such databases and make it widely available to industry stakeholders. A similar need for data on grid operations was identified.

Workshop Responses to Discussions by Topic

The individual findings identified below are discussed in more detail within the corresponding sections of the report.

System Characterization and Operation

Achieving a high level of deployment for advanced, diverse technologies in future electric power systems will require that stakeholders achieve a thorough understanding of both the value and potential impacts of proposed system configuration changes at every level—bulk power generation, transmission, and distribution. Currently, dozens of industry models characterize grid operations and planning depending upon the time frame (millisecond transients to multi-year capacity planning). Workshop presentations and participant comments frequently highlighted the modeling challenges posed by future technologies and market operations.

Key Findings

The following are key findings as identified by workshop participants:

1. *Large-scale addition of new—particularly distributed—technologies to the existing infrastructure will require significant system modeling* and higher resolution, location-specific data to inform optimal investments.
2. *Integrated modeling of power flows across the transmission and distribution system* can help inform the impacts of large penetrations of distributed generation.
3. *Developing models that visualize the impacts on networked (meshed) versus radial system designs* can help determine integration strategies and efficiently improvements for different distribution systems when deploying advanced energy technologies and distributed generation.
4. *Comprehensive data is needed on the location-specific impacts of advanced energy technology implementation on power grids, as well as data to forecast evolving market demands*. Otherwise, DER penetration without careful consideration of these impacts could lead to practices, programs, and policies with unintended and adverse consequences.
5. *Outage data quality, consistency, and accessibility needs to be improved.* There are a few existing efforts to improve outage data, but not an industry standard.
6. *Modeling methods are needed to support diversified trading platforms*. Supporting transactive methods for valuation requires new ways of organizing the electricity grid, and may require advances in modeling and data processing to handle the volume of trades required at the distribution level.

Planning

If advanced power technology is to be fully deployed, appropriate valuing of new technologies and services will require a technical understanding of grid operations and planning processes to estimate the impacts of technology deployment locally, where the technology directly impacts the electric circuits, as well as at the higher level of bulk power systems. Additionally, there is a need for development of enhanced valuation metrics, methods, and processes, as well as a consistent valuation framework.

Key Findings

The following are key findings as identified by workshop participants:

1. *A methodology should be developed that enables decision makers to weigh multiple values* and perform complex tradeoff analyses in a manner that is transparent and repeatable.
2. *Improvements to operational visibility of "behind-the-meter resource" on the distribution system can help with the integration of new technologies and*

generation. This visibility is important for fault detection and restoration procedures as well as for predicting demand changes and informing investments.

3. *Capturing the impact of DERs and advanced energy technologies on future reserve margins* would improve system performance and also produce avoided cost impacts on future generation requirements. For example, Southwest Power Pool (SPP) implemented a set of electricity transmission upgrades, and the impact is that future capacity addition costs are lowered by approximately $1 billion.[1]
4. *The historical record may be inadequate as a baseline for evaluating planned generation and transmission assets* due to the accelerated rates of change in both the bulk generation mix and infrastructure over the last decade. Careful data collection is needed to help create information on new types of contingency events resulting from change to technologies and system topology that need to be planned for.

Pricing and Market Structures

Pricing and market structures are how value is captured and allows for the recovery of investments. When things are not properly valued in a market, then inefficiencies and externalities can results in sub-optimal investments in the short and long term. .

Key Findings

The following are key findings as identified by workshop participants:

1. *Rules and standards originally developed for static systems should be revisited*, to reflect the need for adopting current advanced technologies to realize benefits associated with them as well as to improve agility – the ability of a utility to adapt to potential upcoming changes in technologies and polices going forward.
2. *Revision of some market rules could facilitate the integration of distributed generation, energy management, and other advanced energy technologies.* Although some utilities[a] are working with aggregators to treat customer resources as an extension of the pool of resources available for grid response, without a formal market for those resources, they are not able to participate in markets for energy services.
3. *Current models face challenges with real-time price formation.* Current linear programming-based models, that are applied in wholesale market operations and settlements, make assumptions based on properties of the transmission grid that do not hold on lower voltage networks; therefore these models may not be sufficiently accurate or reliable for use in providing real-time prices for distribution system operations. The most representative mathematical formulation for calculating needs for both real and reactive power (to inform ancillary service requirements and calculate prices) would be non-linear and possibly non-convex.

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[a] For example, Pacific Gas and Electric and Southern California Edison (SCE) both offer aggregator programs. For more information, see Pacific Gas and Electric Company, "Aggregator Programs," Pacific Gas and Electric Company, May 2010, http://www.pge.com/includes/docs/pdfs/mybusiness/energysavingsrebates/demandresponse/fs_aggregatorprograms.pdf

4. *Proposals for change to distribution level pricing each have different effects on stakeholders and need to be carefully considered*. For example, locational marginal price plus distribution value (LMP+D)[2] is directly incorporates wholesale LMP prices with an adder for distribution costs, and can be set without real-time data but is a more administrative approach to pricing at the distribution level. This is different than the distributed locational marginal pricing (DLMP)[3] method which requires granular real-time data (and consequently some form of smart meter for the consumer).

Risk and Uncertainty

Risk, the potential for loss, comprises several issues that must be addressed in planning power grids of the future. These risks stem, in part, from the uncertainties associated with large-scale implementation of advanced energy technologies. However, they also arise from an uncertain understanding of future demands and threats to grid operations that are changing over time. A properly defined and agreed upon valuation process should be able to address risks in a way that minimizes them sufficiently to be acceptable to current and future stakeholders.

Key Findings

The following are key findings as identified by workshop participants:

1. *Valuation risk is the risk that the valuation process used to plan for power systems of the future is itself flawed or unacceptable to stakeholders.* A properly defined and agreed upon valuation process should be able to address risks in a way that minimizes them sufficiently to be acceptable to current and future stakeholders.
2. *The industry needs a comprehensive, agnostic method for assessing new technologies*. A database could be populated with component or system-specific information, a characterization of failure modes, financial risk, mean-time-to-failure data, cost, emissions, efficiency, and other operational data that can be accessed by grid planners and operators nationwide.
3. *Information that enables utilities to assess new technologies as financial hedge instruments would help inform decision making*. In the current regulatory landscape, high penetrations of intermittent generation can be a hedge for fossil fuel price volatility, and likewise fossil fuel plants are a complementary hedge to variability from intermittent energy resources; furthermore regulators may need assistance in identifying hedge instruments as well as the domain in which these instruments would reduce adverse effects from threats.
4. *There needs to be better understanding of the option value of distributed or advanced technologies versus expansion to the existing distribution and sub-transmission systems within utility territory territories*. In addition, utilities' choices must be made in a manner that state regulators and their staff can assess for investment prudency.

Conclusions

As new power generation, communication/control, and demand response technologies continue to advance, the traditional methods of pricing, planning, and operating the electricity value chain will need to enable a comprehensive reassessment of the value of those technologies. A breakthrough in complex system valuation is needed to change how the electric power landscape is characterized and operated, how capacity planning is performed, how asset or services are priced, and how risks are assessed.

The five sections of this synthesis report provide a more comprehensive description of the issues facing the industry today, outstanding concerns, and solutions identified by the participants themselves.

I. Introduction

This section provides an overview of issues relevant to the U.S. electric utility industry today regarding valuation, and current (DOE-funded) valuation efforts—including the PNNL/Brattle Group methodology proposed in the opening session. Subsequent sections break material into four broader topics that represent the vast majority of content and commentary presented during the workshop: system characterization and operation, planning, pricing and market structure, as well as risk and uncertainty.

Within this workshop, valuation was defined as "a process for determining the worth of something within the electricity system, whether it is technologies and equipment, system configurations, operational strategies, or services." [b] The U.S. electricity supply chain (production, transmission, distribution, and consumption) provides a suite of wholesale and retail services that has gone through a series of regulatory changes since it first began.[c] As competitive markets and new technologies (e.g., demand response, energy storage, advanced transmission controls) have developed, researchers and political economists have attempted to assign values to such products, but are not always successful.[4] Energy storage has long been recognized for its ability to provide values not currently recognized by retail or wholesale markets, as detailed in a presentation by Rocky Mountain Institute during the workshop (see Figure 2).

Recognizing the need for a valuation methodology that can be applied to all emerging technologies, products, and services across all elements of the electricity supply chain, DOE funded the development of a comprehensive approach to electricity valuation, which was presented by PNNL and the Brattle Group at the Technical Workshop on Electricity Valuation in Washington, D.C., from May 2–3, 2016. More information about the workshop, as well as a detailed agenda, can be found in Appendix A.

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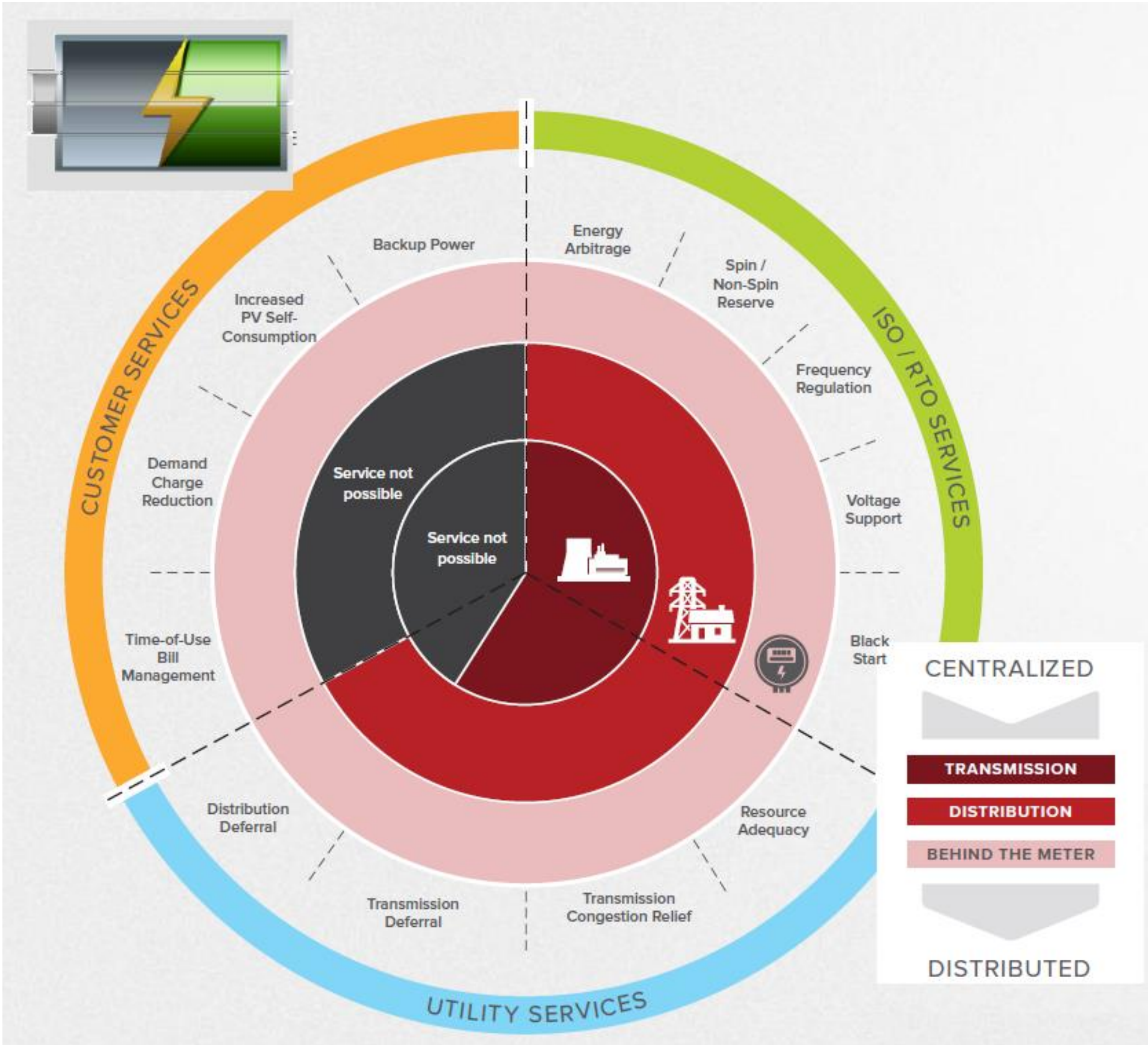
[b] For a complete description of the workshop purpose and design, see the agenda in Appendix A.

[c] For example, the ancillary services markets today include a host of elements necessary for stable grid operation. Prior to the advent of competitive markets by FERC in 1995, however, ancillary services were non-monetized values provided by the electric utility as a matter of daily operations. See E. Hirst and B. Kirby, *Electric-Power Ancillary Services* (Washington, DC: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, Office of Competitive Resource Strategies Program, 1996), ORNL/CON-426, http://www.consultkirby.com/files/con426_Ancillary_Services.pdf.

Figure 2. As Presented by Rocky Mountain Institute during the Technical Workshop on Electricity Valuation, Batteries, as a Sample Technology, Can Provide up to 13 Services to Three Stakeholder Groups.[5]



Current Valuation Efforts

PNNL and the Brattle Group provided a joint presentation on comprehensive valuation of electric power system enhancements at the workshop based on a draft report,[6] which was discussed extensively during the workshop. The PNNL/Brattle Group report stated that for utilities, investments in grid enhancements "are driven by system needs for compliance with safety, reliability, environmental, and other standards and by high-level goals of competitiveness, energy security, and environmental responsibilities."

PNNL noted that the broad spectrum of possible infrastructure modifications weighs against a one-size-fits-all methodology for valuing them. Within the overall framework and categories of investment types and system properties, the industry will need to define specific analyses for certain common assessments. However, PNNL and the Brattle Group's generalized approach proposes a set of elements or steps that constitute a comprehensive and transparent process for facilitating stakeholder review. These steps are detailed in the following table:

Table 1. PNNL/Brattle Group Proposed Steps for Facilitating Stakeholder Review

Step	Analysis Description
1 – Define Question and Scenarios	Casts the objective of the valuation analysis as one or more questions, such as "what would a new load or generation capability do for the system?"
2 – Define Scope and Approach	Identifies the baseline used in the analysis or the objective to be tested, the metrics to be assessed, and the methods to be utilized in performing the analysis
3 – Perform System Analysis	Determines results as a series of outcomes of various decisions and scenarios based on assumptions and uncertainties
4 – Review System Properties and Metrics	Compares the results or outcomes against a baseline or against the objective
5 – Make Resource Decisions	Compares outcomes to each other and identifies best relative value

The proposed approach advocates considering the six power system properties that could be impacted by any change in grid configuration or operation. These properties (and sub-properties) are defined in the PNNL report as follows:

Table 2. Power System Properties, as Defined in PNNL/Brattle Group Report

Property	Definition
Affordability	Providing electric services at costs that do not exceed customer capabilities and willingness to pay
Reliability	Maintaining power delivery to customers in the face of anticipated uncertainties and operating conditions (near term) and/or projected long-term obligations
Resiliency	Being able to withstand and recover quickly from extreme external events, such as natural disasters
Flexibility	Being able to respond to future uncertainties that may stress the system in the short term and require the system to adapt over the long term
Sustainability	Providing electric services to customers without negative impacts on natural resources, human health, or safety
Security	Being able to resist external disruptions to the energy supply infrastructure caused by intentional physical or cyber attacks

The six properties are system-level impacts, and other considerations, such as equity, would normally be deliberated at a more granular scale in a real decision-making process. The report provides a number of examples of system-level valuations of proposed or anticipated changes in utility grids. These examples provide a rich information base for users that can help to ensure properly conducted, useful valuations.

> **"The pace of change is rapidly increasing and the utilities, and the associated regulatory model, are not designed to keep up with that pace. … [The] model is not currently designed to foster competition or to incentivize the utilities to embrace competition."**
>
> California Public Utilities Commission, 2015
>
> (*Electric Utility Business and Regulatory Models.* See endnote 31.)

Industry Background and Current Issues

The history of the U.S. electric utility industry includes a century of technological and regulatory gradualism followed by 20 years of explosive change. Since the FERC Notice of Proposed Rulemaking of 1995 (which established open-access transmission systems), the introduction of wholesale markets, and the emergence of new technologies, both utilities and private energy service providers have worked to accurately value individual products or services within this formerly integrated system.

To a power utility, advanced energy technologies can provide benefits in the form of avoided cost of additional generation or transmission and distribution infrastructure. However, these technologies can also introduce vulnerabilities for power grid operators. With the introduction of more customer-owned generation assets on the distribution system, utilities must accommodate and make use of assets that they have limited visibility of and do not control. These challenges need to be addressed in some fashion in order for the full value of these technologies to be realized.

The need for valuation methods that incentivize enhancements to the electricity production and distribution infrastructure grows more urgent over time. For example, environmental sustainability is one of the six properties identified in the PNNL/Brattle Group report that requires a more comprehensive valuation and reflects a broader societal interest in environmental impact mitigation. Emissions reduction goals, in particular, are complicated by the potentially negative impact of losing much of the zero-carbon-emission nuclear generation capacity over the next two decades. Many nuclear plants are currently being shut down due to competitive market forces in the absence of an effective policy for valuing their contributions to sustainability.[7] Additionally, power system operations will require increased resiliency to wide-scale outage events and increased security from physical and cyber-attacks, while maintaining the flexibility to accommodate new technologies, conditions, and customer choices.

The need for such a valuation methodology was further highlighted in a recent study conducted by the Southwest Power Pool to fully value a portfolio of transmission system upgrades and expansions. Analysts, using a year of actual savings from the upgrades, predicted that production cost savings will be almost $700,000/day and benefits will exceed costs by a factor of 3.5 to 1 over the next 40 years.[8] However, while the study identified numerous benefits in addition to production cost savings, many of those benefits could not currently be monetized by the Net Present Value (NPV) calculations[d] often used by industry to identify promising investments.

Valuation and the Regulatory Landscape

Both state and federal agencies have oversight authority for establishing and adjudicating value in the electricity supply chain. FERC has jurisdictional authority for the bulk power markets and interstate transmission. Relevant FERC orders include Order 888, which addresses transmission line open access and the segregation of generation and transmission businesses. Order 889 created OASIS, or the Open Access Same-Time Information System, which provides system capacity information for all industry participants looking to wheel power. Order 1000 required state participation in regional transmission planning and established cost allocations. Order 2000 encouraged the establishment of regional transmission organizations, or RTOs, to promote competition in wholesale power markets and establish an open transmission system.

State public utility commissions (PUCs) have jurisdiction to review the prudent investment of ratepayer monies in electric utility infrastructure, particularly electricity sub-transmission and distribution systems. Since many of the DER technologies are integrated into the sub-transmission and distribution system and managed by distribution utilities, many of the investment decisions in DER are approved by state PUCs. This poses an additional challenge since fifty states each develop their own variation of evaluation framework. In particular, technology manufacturers express frustration of a fractured marketplace with varying rules state by state. While each state makes their own decision, there is some level of coordination, and emerging topics do carry across state boundaries. For example, California and New York have authorized similar experiments in developing electricity markets within the low-voltage electricity distribution system that may, if fully implemented, create a new level of market oversight by state authorities.

Changing Fundamentals in a Low- or No-Growth Industry

With technological advances in energy efficiency and energy management, as well as regulatory goals, the electricity business is experiencing a no- or low-growth era which will impact the ability of utilities to invest in new infrastructure. Utility investments have historically been predicated on a relatively stable load duration curve and predictable increases in customer population and demand growth. Since 2000 the growth in total kilowatt-hours (kWh) sold by utilities has been nearly flat—0.6% annual growth—and the total number of kWh sold is projected to grow at just 0.8% annually through 2040. Switching end uses to use electricity, particularly in electric vehicles, represents a new suite of opportunities for the electricity industry and valuation practices. As the transportation sector migrates from liquid fossil fuels to electricity, load growth will accelerate and the shape of the new load curve may change, ushering in a new era of business opportunities and challenges for valuation.

[d] The NPV of a proposed investment is the discounted financial value of total revenues minus total costs; if the NPV is negative, or less than the NPV of alternative investments, it will not be pursued.

Emerging Market Structures and Valuation

In California, the distribution resource planning process is defined as reducing the overall cost of supplying electricity. Assembly Bill 327 (PU Code 769)[9] requires utilities to evaluate the locational benefits and costs of DERs[e] in their distribution resource planning. The state is actively considering using DERs and grid modernization to achieve specific environmental and energy policy goals.

California's new system is driven by the expansion of demand-side resources and new information technology, as well as renewable and distributed power resources that are owned by customers, utilities, and third parties. One example of a new pricing option is an opt-in program offered to some of Southern California Edison's (SCE's) customers. For the program, the utility installs a device near the enrolled customer's meter or pumping equipment that controls the total load served. During times of critical demand, the California Independent System Operator notifies the utility in real time, and the utility then signals the device to turn off the electricity until the critical demand period has ended. SCE offers a variety of other programs to its business customers, all of which offer financial incentives to the customer.[10]

Other states have also moved toward demand response programs. In Illinois, for example, the Electric Rate Relief and Reform Act (SB 1592) (also known as the Illinois Power Agency Act) requires certain utilities to provide their customers with real-time pricing and air conditioning cycling. Both states are working toward standard net-metering processes for customers who use solar or otherwise generate electricity using renewable resources.

New York has also recently launched an initiative, "Reforming the Energy Vision" (REV), which is designed to integrate current and anticipated DERs and address the changes that will be required for utility planning. The initiatives in New York and California share three main aims: to reduce consumers' energy costs, to improve service reliability, and to achieve specific environmental goals. However, New York currently has limited DER adoption, low growth rates, and no existing state policy for DER development. The REV initiative seeks to create a regulatory framework that allows market opportunities for DERs while increasing benefits and resiliency to both the system and customers. The REV process involves two tracks:

- Track 1 examines and recommends changes necessary for the distribution system to integrate DERs, evaluates market designs, and defines new operational functions for utilities.

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[e] Distributed energy resources (DERs) are assumed to include distributed renewable generation resources, energy efficiency technologies, energy storage resources, electric vehicle resources, and demand response technologies. While multiple definitions of DERs are in current use, this definition is consistent with government resources, including a recent white paper by the California Public Utilities Commission: K. Ralff-Douglas and M. Zafar, *Electric Utility Business and Regulatory Models* (San Francisco, CA: California Public Utilities Commission, Policy Planning Division, 2015), http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Divisions/Policy_and_Planning/PPD_Work/PPDElectricUtilityBusinessModels.pdf.

- Track 2 examines and recommends changes in regulatory, tariff, and incentive structures and develops recommendations for planning, operations, market mechanisms, and technology to create a DER-enabling platform.

Valuation and Industry Challenges

The sections below represent concerns raised by workshop participants. These concerns will need to be considered as electricity valuation efforts proceed, but they do not represent insurmountable obstacles.

The Need for Standardized, Validated Methodologies

State PUCs are legislatively mandated to subject all utility investments to a prudency review to protect the ratepayers. However, the details of this review, including the data used and the approaches, are state-specific and subject to change by state utility commissioners. Typically, shareholder-owned utilities are required to provide specific analysesand replicable values that can be reviewed publicly and approved by PUC. As there are fifty states, industry best practices that can be shared and propogated across numerous jurisdictions could increase efficiency, decrease timeframes for decision-making, and better guide the marketplace for manufacture of new technologies that are broadly beneficial. Consistent and transparent electricity valuation methods will need to be combined with modeling and planning software in order to understand marginal impacts and cost-benefit calculations that may be presented to state and federal regulators for approval.

The Absence of Comprehensive Data

Participant comments touched on the need for better data for valuation overall, and in particular on distribution utility infrastructure including data to improve reliability assessment such as the maintenance needs and average time to failure of technologies, components, or products proposed for installation (i.e., solar photovoltaic systems, critical components in advanced controls or communications, and materials).[f] These data are needed to understand the real costs and impacts of new technologies on power quality for selected customers and locations, actual reliability as a delivered service versus industry claims, real operating and maintenance costs for selected equipment, and failure mode characterization. System planners and operators need such data to integrate these technologies into sub-transmission and distribution systems. Material suppliers, component manufacturers, and original equipment manufacturers may be reticent to divulge such information to competitors—including the grid with which they seek to interact.

Conversely, technology developers need system operating information for their own business development. And universities or national laboratories require enormous data sets to perform power flow modeling in a variety of time intervals. This business-sensitive issue may require a third-party to collect, house, and manage such data in order

[f] *Mean time to failure* and *mean time between failures* are frequently interchanged when discussing product reliability. In this instance, because failure modes and reparability are unknown, the paper utilizes mean time to failure. See S. Stanley, *MTBF, MTTR, MTTF & FIT Explanation of Terms,* (Foothill Ranch, CA: IMC Networks, 2011), WP-3011, http://imcnetworks.com/wp-content/uploads/2014/12/MTBF-MTTR-MTTF-FIT.pdf.

to protect the privacy and safety of consumers. Currently, there are efforts on energy data including outage data and energy usage data.

Privacy

New technologies and systems that will be installed both on the customer's side of the utility meter and across the electricity distribution and transmission systems raises privacy concerns. Enabling non-utility-owned assets to capture and represent their values to the larger electricity system will require that new data and information be collected and somehow made available to market participants without compromising the business- or customer-sensitive nature of that data. Aggregating the data in a manner that does not connect any one individual to their operating characteristics may provide a solution.

Valuation and Diverse Stakeholder Interests

Workshop comments delineated the broad diversity of opinions regarding "value" among electric utility stakeholders. *Shareholder-owned utilities* require a go/no-go financial analysis that can be presented to regulators (PUCs) and their own executive boards. *Municipal and co-operative utilities*, beholden to their own customers and to elected or appointed executive boards, can make investment decisions that reflect relative policy values as well as financial prudency, but they do not require the strict cost-accounting methods of shareholder utilities.

Federal and state regulators adhere to their legislative mandates for operational reliability, investment prudency, fair and equitable cost allocation across customer classes, and prohibitions against market manipulation. Additionally, regulators may incorporate public policy mandates into their industry oversight when legislated to do so. Examples of areas where mandates may apply include incentivizing energy efficiency and demand response, intelligent metering, retail competition, and fuel diversity or sustainability.

II. System Characterization and Operation

Context and Discussion Synthesis

Achieving a high level of deployment for advanced energy technologies in future electric power systems will require that stakeholders achieve a thorough understanding of both the value and potential impacts of proposed system configuration changes at every level—bulk power generation, transmission, and distribution. Workshop presentations and participant comments frequently highlighted the modeling challenges posed by future technologies and market operations.

As required by the North American Electric Reliability Corporation (NERC), reliability models are used to understand how losing one or more system components as a result of random failures impacts power service.[g] Risk models extend this analysis to consider extreme initiators that can impact multiple grid elements simultaneously.[h] Dynamic system simulations model power delivery at various locations in the system depending on the characteristics of demand and available generation. Such models are used to simulate power grid operations that could be impacted by uncertainties in demand, in generation output, and in carrying capacity of various transmission/distribution system elements:

- Near-term simulations model the dispatch of system resources to meet demands and contingencies, constrained by physical power flow processes and the engineered capabilities of the transmission/distribution system. These models help inform real-time pricing and demand charges.
- Long-term production cost models simulate the cost of producing, wheeling,[i] and distributing power with the planned generation mix and transmission/distribution system components. These models help inform investment decisions.[11]

Dynamic system simulations can be used to assess potential impacts of proposed changes in generation and in transmission/distribution infrastructure. As such, they are useful for understanding how increased levels of penetration by DERs and other types of advanced energy technologies can be effectively accommodated in power grid operations.

The capability of power system models, in particular long-term production cost models, to consider high levels of DER penetration is complicated by several factors that lead to significant uncertainties regarding basic model inputs:[j]

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[g] Per NERC TPL-001-1 standard. See http://www.nerc.com/files/TPL-001-1.pdf.
[h] Specifically, in NERC reliability standards, a Category C event results in loss of two or more components; N-1-1 requires that system survive with controlled loss of demand, the loss of a single system component plus an additional cascaded (consecutive) loss.
[i] "Wheeling" power is defined as "transportation of electric energy (megawatt-hours) from within an electrical grid to an electrical load outside the grid boundaries." See Edison Electric Institute, *Glossary of Electric Utility Terms*, Xcel Energy, 2005, https://www.xcelenergy.com/staticfiles/xe/Regulatory/EEIGlossaryIRPEEI2005Definitions.pdf.
[j] The "behind-the-meter" resources include onsite installed generation, storage, and demand management capability that is not directly monitored or controlled by the utility.

- The impact of DER elements on system operations may be location dependent and not necessarily aligned with current grid operation needs.[k]
- Utilities will not necessarily own DER assets that must be accommodated in modifications to transmission/distribution system configurations.[l] This can introduce uncertainties around maintenance, output, and fault detection.
- Despite the recent drop-off in venture capital investments in clean tech startups, commercialization of advanced energy technologies is anticipated to accelerate. Thus, predicting the performance and cost advantages of DERs further out in time may introduce additional uncertainties.[12]

Several participants discussed how system modeling might be used to support a granular, location-based, real-time pricing of real power, reactive power, and available reserves. For example, implementing DLMP[13] will require distribution system models that can be optimized for each location based on current data and predicted need, moving forward. Other participants mentioned that the computational challenges associated with calculating real-time reactive power needs may be limiting or prohibitive.[14]

An additional concern in modeling system responses is how a full range of possible benefits, including those outside of decreased marginal cost, would be modeled at the system level. Traditionally, the potential value of a proposed change in the configuration of a power system has been assessed based on its potential to result in a minimum marginal cost of delivered power service.[m] However, proposed system upgrades may impact other power system attributes, such as resiliency with respect to extreme natural events or flexibility to meet future changes in demand, the value of which is not easily monetized in marginal cost evaluations. This is particularly true for higher levels of DER penetration that may provide additional levels of flexibility and resiliency in power system operations. For example, a particular DER asset might increase reliability at specific locations and resiliency with respect to natural events and deliberate attacks. The need for inputs and acceptable multi-attribute models to support a robust decision-making process must be accurately and consistently accommodated in system models, to the extent possible.

A joint study by the Electric Power Research Institute (EPRI), Consolidated Edison (ConEd) Company of New York, and SCE,[15] which was presented during the workshop, showed that DER impacts cannot be easily generalized for distribution grid designs. Both positive and adverse impacts of DERs on the electrical system have been previously identified,[16] and preliminary field studies have verified that these impacts are highly localized, often circuit specific, and dependent on the amount and type of DERs; they are also a function of how the DERs are operated, by whom, and for what purposes. The EPRI study showed that significant work still needs to be done to fully characterize how

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[k] Contributions of DERs to grid capacity may not be well matched with demand at these locations. Also, the timing of DER outputs may not be matched with system power output needs. This may, in turn, introduce locational requirements for reactive power, voltage regulation, etc.

[l] In fact, under some scenarios being discussed for evolving the role of regulated utilities (for example in California, Texas, and New York), utilities would be restricted from owning DERs since their ownership is thought to constrain market forces from evolving toward the most efficient and environmentally sustainable power system configuration.

[m] Reliability is included in marginal cost calculations by estimating the modified likelihood and cost of forced outages and early equipment replacements as contributors to the cost of power service.

DER impacts the local grid and how specific DERs should be evaluated under specific conditions and systems. The EPRI work warned that grid effects of DER penetration without careful consideration of time- and location-specific impacts can lead to well-intended practices, programs, and policies with unintended and highly adverse consequences. A separate analysis of grid integration requirements in the West indicated that there are deficiencies in the bulk energy system's situational awareness, operational practices, and regional coordination throughout the West that are creating reliability threats for the region.[17] A recent a project co-funded by DOE[18] and Hawaiian Electric Company tested a combination of technologies to increase data collection, provide rapid analysis of evolving demand and resource availability, and facilitate rapid responses, as keys to meeting grid demands effectively under highly uncertain and varying conditions. Much of the functionality of the demonstrated system relies on rapidly updated and localized load forecasts matched with predicted availability of distributed storage. Although the project is small in scale relative to larger distribution grids in the mainland, the need-driven application, fundamental principles, and rapidly evolving technologies involved demonstrate the efficacy of a distributed management process for distribution system operators nationwide.

Although DERs can be factored in near-term dispatch models as assets to address reliability and capacity issues, it is in production cost models that advanced energy technologies and their economic impacts can be considered as potential resources to meet anticipated future load requirements and renewable portfolio standards over specific time horizons.

Technology can play a role in helping system operators identify and respond to problems far more quickly than is currently possible. Workshop participants also discussed the role of improved monitoring and control technology for improving grid performance and stability as the grid modernizes.

Relevant Presentations, Papers, and Panel Discussions

During the workshop, participants addressed issues related to the development of accurate and practical system models for grid modernization, and for predicting the impact of increasing DER penetration levels on power systems. These participant-identified issues are outlined in this section.

Modeling changes from DER additions – Workshop participants noted that additions of significant levels of DERs to an existing grid requires system modeling efforts to ensure that the grid itself can utilize the generated resource and that power quality and reliability are not affected in the process. Much of the discussion on modeling focused on near-term dispatch models in which DERs may provide the services needed to address immediate power quality, reliability, and capacity issues. Some discussion also focused on long-term models where the economic impacts of advanced energy technologies can be considered as potential resources to meet anticipated future load requirements and renewable portfolio standards over specific time horizons.

Combined modeling of transmission and distribution – One presenter noted that system-level models that integrate transmission and distribution systems may be necessary, supported by high-resolution data at a very granular time scale. The presenter further noted that the impacts of reverse power flows due to the quantity or timing of DER-produced power are not well modeled in current power flow models. Finally, the presenter noted three potentially important aspects of DER valuation that pose technical challenges from a modeling and analytics perspective:[19]

- Determining the impacts of high DER penetration on bulk power systems and wholesale markets
- Determining the localized effects of DER integration on the distribution feeders
- Extracting the most value for a given level of DER penetration.

Bulk system visibility –One presenter suggested that it would be beneficial to have increased interconnectedness and investment in awareness and control technologies at the bulk system level, particularly in the west.

Improving visibility on the distribution system – One presenter provided information on improving situational awareness, monitoring, and control in Hawaii, a state that has recently adopted a 100% renewable portfolio standard goal. The participant described the circumstance facing the utility: a combination of declining load, uncertain costs, more customer options and aggressive state policies, and, in particular, a sharply peaking demand curve as driving the need for a modified service relationship with consumers and prosumers.

Conflicting rules and standards – One participant noted that there is tension between the rules and standards required of a static grid system and the need for agility today, to enable the accommodation of new advanced energy technologies and new security (and resiliency) challenges. The implication is that models can identify a best system to meet evolving performance requirements, but one that cannot be implemented due to existing regulatory and legal constraints.

Power grid experience with advanced energy technologies – Several participants noted that power grid models currently suffer from a lack of data on location-specific impacts of advanced energy technology implementation on power grids, as well as data to forecast evolving market demands. Participants also noted that there may be other experience that, while not rigorously reviewed, could be used to informally consider how planning for higher penetration by advanced energy technologies is working.[n]

Standards for power quality and reliability – A participant noted that there are problems and challenges regarding data, modeling, and analysis for organizations seeking to comply with power quality and reliability:

- Data on power reliability and consequences for short-duration outages are extensive, but some are skeptical of this data due to the wide range of values observed in surveys. The participant suggested that
- Regional economic models be calibrated to actual interruption costs for known catastrophes and used to project the value of greater resilience versus cost.

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[n] Results are now available for an integrated smart grids demonstration project involving DOE and several utilities in the Northwest covering five states and involving approximately 60,000 customers. EPRI, “Pacific Northwest Smart Grid Demonstration” (presentation, Systems Driving the Integrated Grid, Charlotte, NC, October 28, 2014).

- There is a need for better data and information on the consequences (economic and other) of contingency and catastrophic events given new system configurations.
- There is also a need to better understand the relative economic value and incentives of moving from a centralized system to a more decentralized one.

Modeling of reliability – Several participants noted that while NERC reliability standards require planning to survive an N-1-1 contingency,[o] the industry and national laboratories lack comprehensive data on the likelihood of catastrophic events, which is necessary to generate adequate system-level reliability models and predictions. Participants noted that an economic value for the reliability of power service has not been established. One participant noted that high reliability of power service is currently only an issue for a small portion of large customers with backup power capabilities, but the demand for highly reliable power service (i.e., increasing reliability of power service to "more nines"[p]) may be growing, driving a need for improved power system reliability, even with extensive privately financed deployment of backup power systems. A strong need for a better understanding of the interaction between reliability requirements in the future and the predicted capability of a system to supply them, as well as the cost of providing various levels of reliability in service, was mentioned repeatedly. Another participant noted that results from a DOE-sponsored project with Pacific Gas and Electric to improve grid resiliency with high DER penetration should be reviewed for applicability.[q]

Need for modeling methods development to support a trading platform – One presenter noted that, while an adequate trading platform for matching power demand with available providers has been discussed in several reference documents, an adequate prototype has not been developed. Existing ISO software is not designed to handle the volume of potentially small trades that would be part of the operation of a transactive energy controlled system.[20] What is needed is a rapidly updating "trading" platform (one participant called this an "Airbnb" equivalent for power service) that allows demands throughout a power grid to be matched with available resources, including standard generation capacity, distributed generation resources, and non-transmission alternatives, in real time.

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[o] N-1-1 contingency refers to one of two worst-case scenarios that must be addressed to meet the requirements of NERC's TPL-001-1 standard. Specifically, in this standard, a Category C event results in the loss of two or more components; N-1-1 requires that the system survive with controlled loss of demand, the loss of a single system component plus an additional cascaded (consecutive) loss.

[p] This refers to the required level of reliability and the inverse of the unavailability or probability of loss. As such, a reliability of 0.9999 (4 nines) translates to a probability of lost service. Some activities such as server farms require greater reliability (i.e., 5 nines), and the mix of consumers may drift toward higher reliability needs over time (notwithstanding the impact of distributed backup power sources.)

[q] Pacific Gas and Electric's project was to install compressed air energy storage to support increased use of intermittent renewable resources.

III. Planning

Context and Discussion Synthesis

Power grids have traditionally been planned for and operated separately at two levels: bulk power (including transmission) and distribution systems. Bulk power systems, operating at the regional level, are defined by NERC to consist of facilities and control systems necessary for operating an interconnected electric transmission network. Bulk power systems do not include facilities used in the local distribution of electric energy.[r] Distribution systems deliver electric power service to the range of users served.

Penetration of advanced energy technologies, such as DERs and demand-side management, into power grid operation can directly impact the operation of all elements of the U.S. power system. In presentations and discussions at the workshop, system operations were included in planning for power grid enhancements and the further deployment of advanced energy technologies.

Planning processes for bulk power systems typically revolve around an integrated approach in which the power system operator plans to meet forecasted energy demand, including peak demands and contingencies, through a combination of supply-side (generation) and demand-side (conservation) resources over a specified future time period.[s, t] Twenty-seven states currently require a formal Integrated Resource Plan (IRP) that meets this requirement.[21] There is not a similar required planning process for distribution systems. However, a fully integrated planning process would include both levels of the power grid system.

An integrated planning process could address a wide range of operational issues, such as

- Load forecasts
- Analyses of reserves and reliability
- Anticipated costs, such as fuel and maintenance
- Options for increased supply (additional generation and transmission capabilities)
- Environmental costs and constraints
- Demand-side management

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[r] The term "bulk electric system" is sometimes used. As defined by the NERC regional entity, the bulk electric system includes the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kilovolts or higher. In more complex bulk power systems, the bulk electric system is the portion meeting the criteria.

[s] Integrated Resource Plan (IRP) rules governing utilities have been created in a number of ways. Bills that mandate integrated resource planning have been passed into law by state legislatures; rules have been codified under state administrative codes; and state utility commissions have adopted IRP regulations as part of their administrative rules, or have ordered IRP to be done as a result of docketed proceedings. Although some state IRP rules have remained unchanged since they were first implemented, other states have amended, repealed, and in some cases reinstated their IRP rules.

[t] FERC provides an additional planning requirement in the form of FERC 1000. Passed in 2011, FERC 1000 requires transmission planning to occur at the regional level that evaluates possible transmission alternatives and produces a regional transmission plan.

- Planning for non-utility-owned generation[u] and DERs to meet anticipated demands.

During the workshop a suite of basic planning and operational challenges were discussed. Several of the concerns centered on the need to provide for increased visibility and control over power grid operations in order to support greater integration of renewable energy resources. While these challenges cannot be met solely through development of better models, improved power system flow models could rapidly identify potential imbalances and shortfalls. For example, when linked to visualization and control capabilities, improved power system flow models would also allow operators to take timely and effective actions for avoidance of power anomalies and lost service incidents.

The process of planning for advanced energy technology deployment inevitably includes discussion of the criteria for valuing proposed grid enhancements, methods and data used to estimate their impact on grid operations. Presentations and panel discussions at the workshop embraced these issues, and this section presents the resulting inputs and comments that provide an integrated view of future planning processes and their development requirements.

Relevant Presentations, Papers, and Panel Discussions

The impact of greater levels of deployment for advanced energy technologies is anticipated to render greater diversity in the resources available to meet future demands. Presentations, papers, and panel discussions at the Technical Workshop on Electricity Valuation focused on the issue of how an integrated planning process can effectively consider such resources and their impacts as the level of penetration increases over time, as well as how load requirements on the system will change over time. During the workshop, participants identified the following issues as requiring further attention:

Need for consistent metrics, methods, and processes for planning efforts – There was general agreement in a number of referenced sources that current valuation methods and rate structures lack consistency, flexibility, scalability, and capabilities to assess and quantify the benefits of a diverse set of demand-side resources, distributed technologies, and bulk power grid assets; the problem is not simply finding a universally acceptable set of metrics, but is inextricably tied to the grid planning process itself.[22, 23, 24, 25] If advanced power technology is to be fully deployed, appropriate valuing of new technologies and services will require a technical understanding of grid operations and planning processes to estimate the impacts of technology insertions locally, where the technology directly impacts the electric circuits, as well as at the higher level of bulk power systems. Additionally, there is a substantive need for development of enhanced valuation metrics, methods, and processes, as well as a consistent valuation framework.

DERs and regional planning – Several participants noted that DERs should be factored into regional transmission planning models if conditions are such that DERs can be stable alternatives to generation and transmission and distribution investments; inversely, the

[u] Many generation assets in the United States are owned by power utilities (investor-owned like Consolidated Edison Company of New York and publically owned like the Bonneville Power Administration). However, an increasing number of assets are owned by independent power producers or non-utility generators that own facilities to generate power for sale to utilities.

potential negative impact on DER deployment should be factored into regional planning models where transmission and distribution investments could facilitate greater penetration by DERs to meet future load forecasts.

Bulk transmission planning in Southwest Power Pool – One participant noted that SPP, an RTO, embarked on a comprehensive transmission system upgrade program to produce a more robust and flexible transmission network that would accommodate future expanded use of alternative generation sources and an enhanced capability to wheel power effectively. In SPP's study of a major bulk power transmission system,[26] using a standard production cost algorithm and data taken from a year of actual operations after the upgrade, SPP found that the benefit versus cost ratio for the upgrades project was significant[v] and that the upgrades would support significantly greater penetration by wind power in the grid.[w] SPP's analysis considered but did not quantify environmental benefits, economic development benefits, and other metrics such as storm hardening and flexibility to accommodate future needs in its model.

Multi-criteria decision analysis – Participants noted that in some cases, multi-value analysis models have been used to support regional transmission planning. For example, as part of a FERC requested MISO developed a multi-value project portfolio framework for identifying those investments that provide the lowest-cost solution, subject to an increasing reliance on advanced energy technologies to meet grid demands.[27] Participants generally agreed that given multi-dimensional valuation results, decision makers may need to weigh the multiple values and perform complex tradeoff analyses to arrive at a set of metrics and measures.

Behind-the-meter resources – Participants raised challenges with behind-the-meter resources that are customer owned; utilities may not be able to rely on power produced by these resources to offset capacity requirements, even though they will be required to maintain the necessary transmission and distribution capabilities that ensure system health and product quality. Several workshop presentations, including the PNNL/Brattle Group presentation and a paper by the Analysis Group,[28] addressed this issue.

DER adoption driving planning at the distribution level – Several participants noted that utilities are being encouraged by state utility commissions, ISOs, and other governing entities to add DER capacity to enhance service capabilities and as a means of avoiding costs for additional generation capacity, while maintaining service quality and to meet the requirements mandated by the renewable portfolio standard. In particular, Hawaiian Electric Company presented on both the operational and planning challenges presented by high-penetration DERs (see Figure 3). They noted that the addition of DERs to an existing grid requires a significant amount of planning to ensure that the grid itself can

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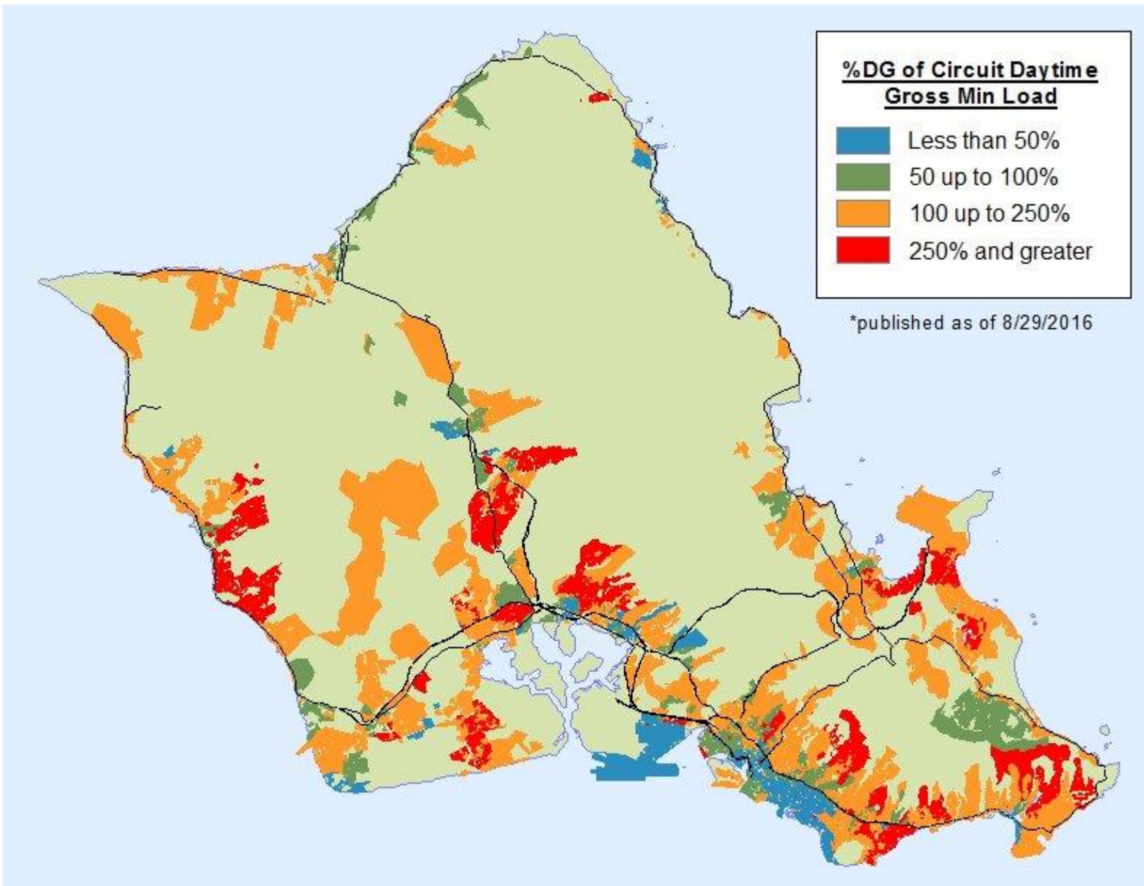
[v] The model projected that benefits expected from the upgrade would outweigh benefits by a factor of 3.5/1 over a 40-year benefit period, assuming that the network of generation sources would continue to expand in areas with high renewable energy potential. See endnote 28.

[w] SPP's report, *The Value of Transmission,* cites modification to facilitate increased generation through wind power as a "public policy benefit." However, the report does not include the economic benefits of these projects in the NPV analysis used to project the life-cycle value of the upgrades. The SPP report also states that "187 MW of new wind farms installed in 2014 would not have been interconnected to SPP absent the evaluated transmission projects." See endnote 28.

utilize the generated resource and that the grid and consumers tied to it are not harmed in the process.

Figure 3. As Presented by Hawaiian Electric Company during the Technical Workshop on Electricity Valuation, Locational Value Map of Oahu: Percent Distributed Generation of Circuit Daytime Gross Minimum Load[29]



Need for a universally accepted valuation framework – Several participants argued that a flexible and universally accepted methodology framework that goes beyond the simplistic benefit-cost analysis typically done to support decisions on DER installations may be required for adequately assessing the multi-attribute benefits of advanced energy technologies. Participants agreed that there is a substantive need to develop a comprehensive framework for valuation of advanced energy technologies, such as the one presented in the PNNL/Brattle Group report that provides a framework sufficient to guide consistent evaluations of capacity additions in most utility environments in the United States. This framework would not need to advocate a particular model. Instead, it could provide guidelines and best practices for developing models, consistency and quality requirements for calculations, and enough examples for users to ensure consistent application in a variety of circumstances and uses. One presenter discussed an upgraded approach to benefit-cost assessments, implemented in New York State that supports comprehensive consideration of parameters that impact DER value.[30] However, there is not yet universal agreement on what an appropriate methodology would look like or what data would support it.

Impact of DERs on future reserve margins – Planned reserve margins are impacted by the diversity of resources available to meet demands and loads that constitute the demands. SPP implemented a set of electricity transmission upgrades that "will improve system performance and result in lower loss of load probabilities as well as loss of load expectations."[31] The impact is that future capacity addition costs are lowered by approximately $1 billion. SPP's report, *The Value of Transmission*, concluded, as noted above, that increased wind resources could be interconnected with the transmission system in the future, which would also produce avoided cost impacts on future generation requirements.

Impact of grid enhancements on DER penetration – One participant noted that curtailments of renewable generation on the transmission grid will be a big issue in the near term. Curtailments of wind power that may occur if grid upgrades are not made to accommodate their interconnection. In particular, SPP noted that there will be increasing pressure in the future to recognize the value of limiting these curtailments.

Impact of NPV assumptions – A participant noted that SPP used an 8% discount rate in their study of transmission upgrades and that this was a higher rate than is usually employed in public good projects.[x] The 8% discount rate plus a 2.5% escalation rate are standard rates that SPP uses in NPV calculations. The net result, even with a higher discount rate, estimated a significant adjusted production cost savings for transmission system upgrades, for a benefit-cost ratio of 3.5 to 1. First-year actuals point to the fact that the benefit-cost ratio is, if anything, likely to be understated.

Wind resources and NPV methodology – One presentation by a participant from the transmission sector noted that the wind resources considered in the planning process (but not fully valued using the NPV methodology) could be considered highly reliable and distributed since they were geographically diverse and not concentrated into large, gigawatt-scale wind farms.

Definition of value attributes – One participant expressed concern that the six categories of system attributes described in the draft PNNL/Brattle Group framework report for comprehensive valuing of power grid enhancements—affordability, reliability, resiliency, flexibility, sustainability, and security—not be the only properties we would ever consider. Based on the evolving nature of stakeholder concerns as well as progress in development of advanced energy technologies, we may be hemming ourselves in.

Impact of DERs on avoided capacity – One participant noted that while bulk power systems are not generally planned around high DER and advanced energy technology penetration, distribution systems are; therefore, the current tendency is for utilities to modify distribution grids to accept greater penetration of DERs. However, another participant noted that, in some cases, ISOs are encouraging planning for high DER penetration scenarios and an evolutionary path to fully integrate the operator with merchant DERs, customers, and self-sustaining microgrids.[32]

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[x] The discount rate considers the relative value of an investment against a dictated (minimum) adequate return on investments. A higher discount rate then lowers the NPV of an investment, and, per the SPP study, it ignores the "public good" and other indirect future benefits of the project.

Lack of a baseline – Power utilities have seen accelerated rates of change in generation mix and infrastructure over the last decade. This presents a situation in which the historical record may be inadequate as a baseline for evaluating planned generation and transmission assets.

IV. Pricing and Market Structure

Context and Discussion Synthesis

When workshop participants raised issues regarding either pricing or market design, comments and concerns revolved around the ability to realize the fair and complete costs/benefits of new technologies within such systems.

Enabling utilities to invest in technologies that support national energy goals, such as optimizing the electricity value chain for advanced generation and control systems, requires a process for translating attribute values into recoverable costs. Historically, this occurs when legislative mandates are coupled to timelines, and PUCs develop an analytical framework for approving the costs of such investments.

Market participants trade electricity in day-ahead or real-time spot markets, in which prices for electricity are set hourly based on bids submitted by the sellers. Sellers must meet qualifications set by RTOs/ISOs based on rules specific to each market. Ideally, this allows for robust competition between new and existing supply, traditional and novel technologies, generation and demand-side resources, and centralized and distributed resources. Although wholesale markets do not consider or identify specific alternatives and optimal combinations of alternatives, competition should result in an efficient mix of resources and reduce the societal costs of providing power.

Supply factors that influence prices include capital costs, transmission capacity and limitations, and the different types of power generation. Likewise, changes in demand—in particular, changes that require switching to less efficient or more expensive power sources—can lead to fluctuations in market prices. Participants recognized that planning for, incorporating, and aggregating DERs could help reduce variability by allowing RTOs/ISOs to see the resources and actively dispatch them in real time. Indeed, the integration of demand response resources could reduce forecasting errors and associated electricity price spikes.

As advanced technology deployments increase, new integrated market designs may be necessary to ensure competitive marketplaces and balance policy objectives, system reliability, environmental concerns, consumer protection, and other factors. Planning frameworks, such as those adopted in New York and California, would are examples of emerging change in market designs. The California Public Utilities Commission's *Electric Utility Business and Regulatory Models* offers three business and regulatory models for future utilities that may serve as a template for other regulatory agencies.[33]

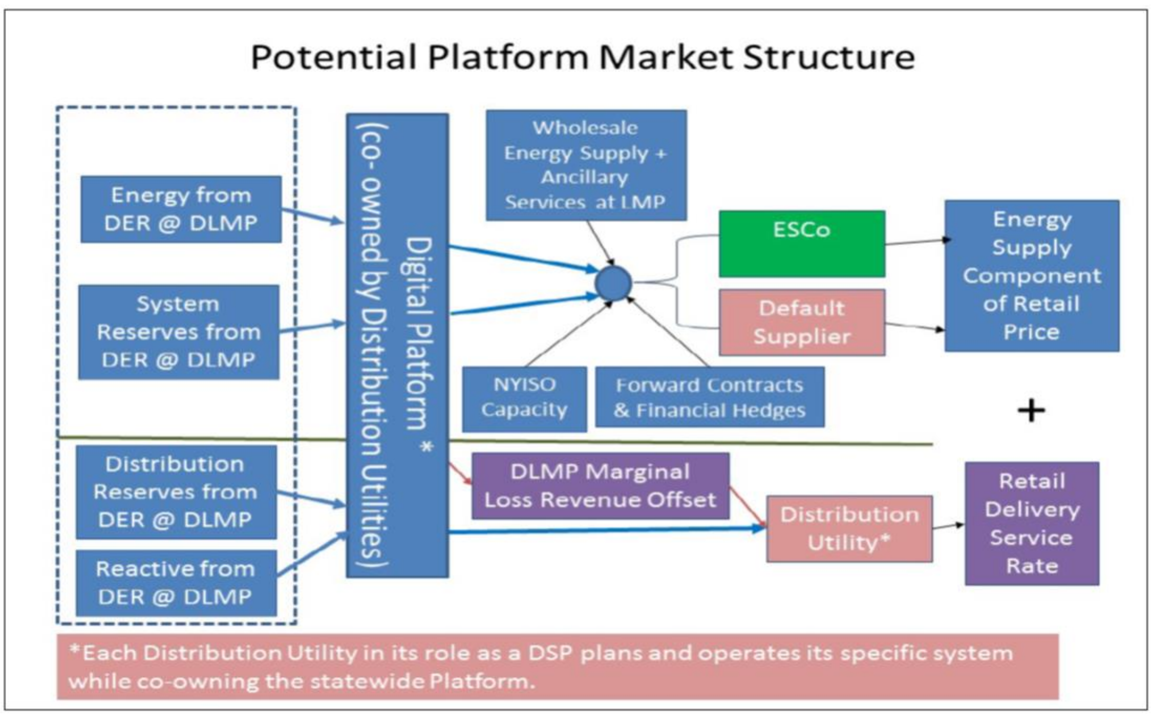
The New York State Department of Public Service has initiated proceedings to develop rate structure and utility business model alternatives that enable the full value of distributed resources—customer-owned renewables, energy storage or demand response, and electric vehicles—to be recognized.[34] As noted in a Department of Public Service white paper (2015), New York State Department of Public Service initiatives in response to the REV include:

- Development of a benefit-cost analysis framework and a methodology for calculating the full value of DERs to the distribution system

- Incorporation of Market Design and Platform Technology Working Group recommendations into State of New York Department of Public Service staff guidance for utility Distributed System Implementation Plans
- Improved rate designs for low-income customers
- Studies (currently underway) to (1) examine the benefits and costs of net energy metering and (2) develop approaches to appropriately value the multi-sided market aspect of the modern utility model
- REV demonstration projects.[35]

Participants emphasized, however, that there may not be a standardized methodology or data set that would be acceptable to all stakeholders or applicable to all types of utilities. Without drastic change in the rate structures to allow fair recovery of invested capital, utilities may be faced with the prospect of a future grid highly dependent on DERs that may not allow them to fully monetize the cost of operations. It was noted that this is not tenable for any enterprise, and workshop participants urged that rate structures be addressed in parallel with the development of any valuation methods. Figure 4 describes one potential market design that was presented at the workshop for distribution-level operation. It envisions a real-time operation in which system requirements and distributed assets respond to localized and NYISO information, with a near-instantaneous market clearing within the distribution system itself.

Figure 4. Potential Platform Market Structure, as Presented by Tabors during the Technical Workshop on Electricity Valuation[36]



NYISO – New York Independent System Operator; ESCo – Energy Service Company; DSP – Department of Public Service.

Relevant Presentations, Papers, and Panel Discussions

For electric utilities now, valuation decisions on assets can impact the consumers and businesses that are served. Several participants referenced sources[37, 38, 39] and discussed the complexity of valuing the role of advanced technologies in power systems, particularly the fact that some contributions cannot be readily monetized in standard marginal cost models.[40, 41, 42] Participant-identified issues and concerns are outlined in detail below.

Pricing at the distribution level for consumers– Several participants discussed using models to support accurate determination of a Distribution Locational Marginal Price (DLMP) for use in congestion management on power grids as penetration of new—particularly distributed—technologies increase.[43] A participant noted that a real-time DLMP pricing algorithm could also support a transactional market platform run by the distribution system operator, where providers, consumers, and prosumers of power can efficiently match power needs with available resources. The efficiency of such a market would reduce the need for managed interventions to remedy imbalances and eliminate shortfalls.[44] Other participants noted that implementation of such a pricing mechanisms would be computationally challenging to do, and not all utilities have the required equipment.

Pricing at the distribution level for consumers (LMP+D versus DLMP) – LMP+D can be set without real-time data and is a more administrative approach to pricing at the distribution level. This is different than the DLMP method as the consumer does not need to have a smart meter. One participant pointed out that while LMP+D is easier to implement, DLMP would be particularly useful for large commercial buildings where there is more value to grid operators and consumers.

Price-driven and non-price-driven properties – One participant suggested identifying the properties (as outlined in the PNNL/Brattle Group framework report) that can be price driven, separating those properties from those that cannot, and then working towards enabling those (monetizable) properties to actually present prices to the consumer.

FERC requirements to address DERs in wholesale markets – One participant suggested that FERC may become more involved in planning for grid enhancements in the future.[y] The intent is for power system operators to consider and integrate advanced energy technology resources as non-transmission alternatives into planning for future generation and transmission needs at all levels of the power grid. Another participant noted that planning for high-DER environments should include planning for potential loss of an

[y] FERC Rule 745 ensures that when (1) a demand response resource participating in an organized wholesale energy market administered by an RTO or ISO has the capability to balance supply and demand as an alternative to a generation resource and when (2) dispatch of that demand response resource is cost-effective as determined by the net benefits test described in this rule, that demand response resource must be compensated for the service it provides to the energy market at the market price for energy, referred to as the locational marginal price. This approach for compensating demand response resources helps to ensure the competitiveness of organized wholesale energy markets and remove barriers to the participation of demand response resources, thus ensuring just and reasonable wholesale rates. FERC 745 intended to encourage the inclusion of non-transmission alternatives in planning for power system upgrades.

important element, citing the Aliso Canyon experience as a cautionary tale.[z] Also, one participant noted that work is ongoing to improve tools for calculating the actual reliability being delivered to customers via the distribution system.

Difficulties of creating market rules – Participants noted that it is difficult to create market rules that encourage fair competition while allowing merchant developers to identify new system resource opportunities. Participants noted that without new frameworks, current rules will influence types of resources and response times. New planning frameworks would necessitate the inclusion of a complex range of engineering and economic valuation issues and should encourage the participation of relevant stakeholders. Although some utilities[aa] are working with aggregators to treat customer resources as an extension of the pool of resources available for grid response, without a formal market for those resources, they are not treated as ancillary services.

Inadequate metrics – Several participants identified the lack of consistent and universally accepted metrics for power system attributes such as resiliency, reliability, flexibility, and security. Traditionally, reliability has been treated by utilities as an objective for power system operation within which production costs could be minimized. However, there is less agreement on the scope and definition of attributes such as resiliency, flexibility, and security, and metrics for valuing changes in these attributes are in an early stage of development.

Non-monetized metrics – As stated above, there is not a consistent and accepted basis for monetizing measures of system attributes such as resilience and reduction in environmental impacts. Several participants noted that valuing services that do not have direct financial translations can lead to decision-making errors, particularly where the valuations are made on the basis of simplistic analyses and assumptions that would not be widely held. Other participants said that if a metric cannot be monetized, then it may not belong in valuations. It should be quantified and provided to decision makers for consideration when making investments.

Legal context – Several participants agreed with referenced sources that it may only be possible to ascribe value to some attributes, such as resiliency and reduced environmental impact, if they are legally mandated. In such circumstances these system attributes would be valued in terms of their capability to support compliant utility operations.

Challenges with real-time price formation – One participant argued that current linear programming–based power flow models, because they cannot be used to calculate reactive power needs, may not be sufficient for use in pricing distribution system ancillary services and that using the full power flow equations would be non-linear and possibly non-convex.

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[z] Aliso Canyon Pipeline and Storage Project for the Los Angeles Basin recently made headlines by leaking and having to be shut down. The shortfall in natural gas availability for peaking units in the basin has resulted in an n-1 impact (NERC TPD-001-01), that is, a lower probability of meeting all anticipated load requirements given loss of a single power grid element (see below). The intent of the comment is that some power grid architectures are more sensitive to losses of a single grid element than others, and such possibilities may be mitigated with greater implementation of advanced energy technologies.

[aa] For example, Pacific Gas and Electric and SCE both offer aggregator programs. For more information, see Pacific Gas and Electric Company, "Aggregator Programs," Pacific Gas and Electric Company, May 2010, http://www.pge.com/includes/docs/pdfs/mybusiness/energysavingsrebates/demandresponse/fs_aggregatorprograms.pdf

V. Risk and Uncertainty

Context and Discussion Synthesis

Risk comprises several issues that must be addressed in planning power grids of the future. These risks stem, in part, from the uncertainties associated with large-scale implementation of advanced energy technologies. However, they also arise from an uncertain understanding of future demands and threats to grid operations that are changing over time. A properly defined and agreed upon valuation process should be able to address risks in a way that minimizes them sufficiently to be acceptable to current and future stakeholders. Valuation risk then is the (very real) risk, identified in this Technical Workshop on Electricity Valuation, that the valuation process used to plan for power systems of the future is itself flawed or unacceptable to stakeholders.

While the workshop was convened to discuss the valuation process and the inherent risk associated with an inadequate process, much of the dialogue focused on the risks that have to be addressed in the process and not the process itself. Also, risk to utilities, who have been the traditional planners of power grid upgrades and modifications, has a very specific meaning that is restricted to the financial losses that can accrue from poor or inadequate planning.

What follows is a discussion of risks as currently understood in the electric power industry and the necessary developments identified in participant discussions. This information can provide a set of objectives for further development and an adequate basis for ensuring that valuation risk (the vector of attribute risks) is minimized in the process.

Using the valuation metrics discussed in the workshop, and presented by PNNL and the Brattle Group, the risks can be categorized as follows:

- *Affordability* – The potential for a negative impact on consumer demand or the capacity to consume power of users who do not have the option of becoming prosumers interacting with the grid
- *Reliability* – The potential for negative impacts on the reliability of power service at given locations of the grid or an inability to meet increasing reliability requirements for users
- *Resiliency* – The potential for grid operations and grid service for many users to be negatively impacted by external events, such as seismicity or extreme weather events, whose frequency and severity may be changing over time
- *Security* – The vulnerability of grid infrastructure and service to extensive or prolonged outages due to physical or cyber attacks
- *Flexibility* – The potential for current and planned grid configurations to be unable to meet future requirements for power service, either due to changes in demography or changes in the way power distribution systems are organized and managed
- *Sustainability* – The potential for future grid configurations to fail to meet objectives for reduced environmental impacts, particularly reductions in carbon emissions.

Risk associated with the cost of delivered power (affordability) and compliance with federal and state regulations (sustainability) could be assessed using standard evaluations of the financial implications as inputs to management decisions that limit and reduce the projected impacts.

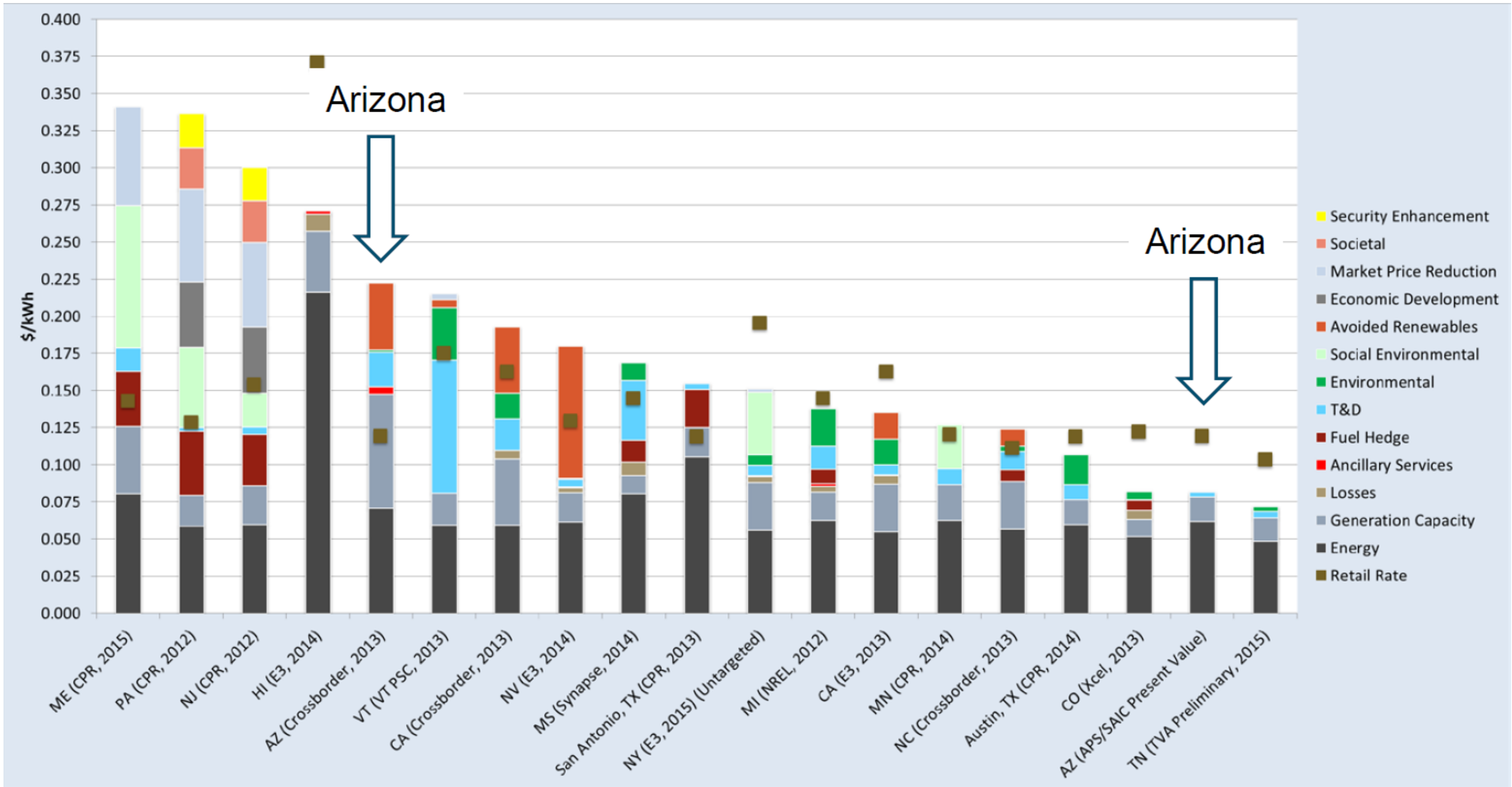
Risk associated with loss of power and damage to equipment and infrastructure can result from internal system failures (reliability) or from external events such as natural disasters (resiliency). The reliability and resiliency risks could be appraised using probabilistic evaluations of the frequency and consequence of initiating events. Likewise, the value of risk mitigation measures could be judged by the impact made on risk producing conditions versus their cost to implement.

Risk of physical and cyber-attacks (security) is managed by assessing potential initiating events and their severity, and subsequently "hardening" the power system to mitigate their impacts.

Risk-Adjusted Valuation

Due to variation in valuation methodologies and perspectives among stakeholders of the appropriate method and desired regulatory decisions that favor particular industries, state-regulated electric utilities may be petitioned with a wide variation in value assessments of specific assets or utility programs, such as solar photovoltaics installed on the customer's side of the service meter. An excellent example of this can be found in Figure 5, presented during the workshop. Workshop participants emphasized the importance of developing a methodology that can be standardized and efficiently regulated so that results of the analysis are meaningful and appropriate for decision-making.

Figure 5. Levelized Value of Solar and Retail Rate Level for 19 Studies, 2012–2015 ($/kWh), as Presented by Energy + Environmental Economics (E3) during the Workshop[45]



The same technology, when risk-adjusted by stakeholder, can present highly divergent values. The results for Arizona show this broad range.

The three aspects of risk as they are currently understood and managed for (which became the foundation for most participant comments) are financial risk, operational risk, and adequacy risk.

Financial Risk

Hedging—reducing the risk of an adverse price adjustment in an asset through the purchase of a financial instrument—is quite different for municipal or co-operative utilities than for publicly traded, shareholder or "investor"-owned corporations. Investor-owned utilities hedge on behalf of their shareholders to maximize operational profit, while public utilities hedge on behalf of their ratepayers to maintain rate stability. Financial risk, therefore, is quite different between utility ownership classes.

Operational Risk

Both state PUCs and FERC have jurisdictional authority for reliability and resiliency. State commissions also have jurisdiction for delivered power quality. In each of these instances, operational risk is a liability risk for non-performance by the utility.

Workshop participants noted the long history and technical understanding of delivered power quality and considered it to be the operational risk with the greatest amount of current information. However, customer requirements for reliability have changed as the role of electricity in daily life and power quality requirements have changed.

The same holds true for service reliability. Participants noted the enormous amount of historical data already collected on customer interruption impacts, frequency, business costs, etc. Participants noted, however, that new technologies may enable their customers to purchase hedge instruments for their own load, once the operational data is made available to price such financial products. The battle between established monopoly utilities and non-utility-owned assets is well known. In this instance, it may be possible for utilities to price such an option, and their retail customers can decide if they want to buy the insurance. Attendees also mentioned the potential for event-driven correlations that must be factored into hedge instruments, such as a policy-driven mandate that causes a huge number of new products to be installed in the same year—and therefore fail around the same time years later.

Adequacy Risk

Adequacy risk involves the utility's ability to supply the quantity of electricity required by ratepayers at all times. In this workshop, participants noted the added risk to this metric that non-utility-owned assets represent. If a customer-owned generator fails, who will be liable for ensuring adequacy? A portfolio approach to such generators may reduce both the real level of operational and adequacy risk, and the subsequent cost calculations for hedging.

Workshop Participant–Identified Issues

The following is a synthesis of relevant issues identified by participants during the breakout session of the workshop.

There was some discussion regarding the most effective order of operations in this exercise, considering whether or not it is possible to develop a standardized valuation methodology when the utility business model (and its regulation) may not comport with the goals described above.

Participants discussed whether the utility business model itself needs to be modified first, before non-monetized values can be accurately reflected in the planning and operation of the electric power landscape. This conflict between the business, its regulation, and new technologies can be discerned from the issues outlined below.

Asset visibility – Beyond customer-side hedge instruments, workshop attendees agreed that asset visibility to system operators is paramount. Regardless of ownership or the ability to dispatch such assets, grid operators must know the performance status of any assets interacting with grid operation. Therefore, the functional needs of the system must be incorporated into any valuation analysis.

Comprehensive operational risk – In multiple sessions, several participants noted that the industry needs a comprehensive, agnostic method for assessing new—particularly distributed—technologies, and that resiliency or operational risk profiles should be developed. This should include component or system-specific information, a characterization of failure modes, mean-time-to-failure data, and system impacts.

Data needed to quantify and manage risk – New technologies and electricity products may indeed have an option value for operational risk. Workshop participants identified two major data sets that they will need to accurately value such technologies: (1) system impacts by the individual and collective asset, and (2) life-cycle failure modes and durability. Participants agreed that large-scale data sets are currently absent for system resiliency.

DERs as a hedge instrument – Utility electricity production still involves, primarily, fossil-fuel central plants, and therefore, hedging fuel price volatility is paramount. Ratepayers cover the cost of fuel price fluctuations today, when utility commissions allow fuel surcharges. The landscape is changing, however. As one participant pointed out, hedging reduces price volatility but increases the unit cost from the minimum non-hedged price, and utility commissions are seeing this increasingly as a negative value. Additionally, commissions in both Washington and Florida are questioning $6 billion in fuel hedge losses by their respective utilities.[46]

Renewables as a hedge against fuel price and supply volatility – In such a regulatory landscape, renewables can be a hedge for fossil fuel price volatility, and commissions may find such an argument attractive for cost approval. However, participants noted that commissioners need assistance in identifying acceptable hedges—duration (e.g., hourly, daily, monthly), optionality, and others. No such instruments currently exist; utilities utilize ISO-managed spot markets for competitive electricity purchases. Several participants noted the need for a tool or method to evaluate the efficacy of such hedges. This is not only vital for utility operation—state commissioners will need such assistance to assess hedges for prudency.

APPENDICES

Appendix A: Technical Workshop on Electricity Valuation Background and Agenda

DOE's EPSA held a technical workshop on key aspects of electricity valuation in order to gather perspectives on the nature and scale of challenges and opportunities related to electricity valuation. This workshop was held on **May 2–3, 2016,** at **the Metropolitan Washington Council of Governments at 777 North Capitol St. NE, Washington, D.C. 20002**. The purpose of the workshop was to explore and inform valuation research and methodologies. A summary of the workshop, including its themes and policy implications, will constitute part of the Quadrennial Energy Review (QER) second installment—*An Integrated Study of the Electricity System*.

Introduction

President Obama issued a Presidential Memorandum establishing a QER in January 2014. The White House's Domestic Policy Council and Office of Science and Technology Policy jointly chair an interagency QER Task Force, while the U.S. Secretary of Energy provides support to the QER Task Force through an Executive Secretariat in EPSA. EPSA's support involves coordinating activities related to the preparation of the QER report, policy analysis and modeling, and stakeholder engagement.

The first installment of the QER examined the nation's infrastructure for transmission, storage, and distribution, including liquid and natural gas pipelines; the grid; and shared transport such as railways, waterways, and ports. On April 21, 2015, the QER Task Force released the QER first installment—*Energy Transmission, Storage, and Distribution Infrastructure* (QER 1.1). Given the critical, enabling role of electricity, as articulated in QER 1.1, the Obama Administration has determined that the second installment (QER 1.2) will develop a set of findings and policy recommendations to guide the modernization of the electric grid and ensure its continued reliability, safety, security, affordability, and environmental performance through 2040.

QER 1.2 will continue to have a systems approach. It will analyze the fundamental elements of the electricity supply chain, including generation, transmission, distribution, and end use. Interactions and interdependencies within the supply chain and broader societal trends, like growing digitization and population movement, which affect the system as a whole, will also be analyzed. QER 1.2 will include an integrative, crosscutting examination of alternate approaches and their impacts on electricity's reliability, affordability, and resilience, as well as their effects on the environment, national security, and the workforce. In addition, QER 1.2 will look at removing regulatory barriers, addressing externalities, and providing incentives to incorporate values that are not fully recognized in market prices or rates.

Valuation

Traditional electricity supply-chain technologies provide different services and features that have been taken for granted in the development of markets or regulated prices. New technologies such as intelligent grid equipment and DERs can offer benefits or impose costs that market prices do not currently reflect. DERs include the suite of technologies that supply energy services at the distribution level (including solar energy, wind power, energy storage, demand response, and fossil-fuel generation).

For example, depending on fuel supply-chain risk and ramping characteristics, different generators will impact reliability differently. An impact, whether negative or positive, influences the value that a generator can provide to the electricity system. Environmental externalities like criteria pollutants, greenhouse gases, and water use may or may not be reflected in prices, but they still impact society and the economic system. Some of these impacts occur within the electricity supply system itself, such as production costs, while others occur in society, such as effects on the environment or electric reliability.

Failure to fully consider all benefits and costs to the consumer increases the likelihood of deploying a suboptimal portfolio of energy services. However, it may be difficult to determine a broader set of costs and benefits when deploying electric supply-chain technologies due to a lack of data or appropriate benefit-cost models. As investments in new assets are made, and as policies and grid operations evolve, they should reflect the true costs and benefits of multiple attributes valued by consumers. Such a challenge can be especially acute when introducing new technologies, like grid-scale battery storage or DERs, given that many of the costs and benefits of the services that these technologies provide may be rapidly changing or not fully understood. Desirable attributes will range widely but generally include reliability, resilience, and environmental performance.

Definition of valuation – Valuation is a process for estimating what something is worth. The items that are valued through the process may have positive attributes (i.e., assets or benefits) or negative attributes (i.e., costs or liabilities), and the worth (i.e., value) is the net sum of the negative and positive. Sometimes, the term is used to refer to the result of the process—for example, a price, an appraisal, or estimate is often termed a “valuation.” In this workshop, the term will be used only to refer to a process for determining the worth of something within the electricity system, whether it is technologies and equipment, system configurations, operational strategies, or services. The scope used for analyzing the cost and benefits of technologies can change depending on the focus of the analysis (i.e., distribution system, transmission system, or overall system with societal impacts).

Function of valuation – The essential function of valuation processes is to inform reasoned decisions. Reliable valuation processes can optimize the benefits and costs of electric-system investments and operations as well as manage risks that may not otherwise be formally recognized. Credibility and transparency are essential to the functional effectiveness of valuation processes. If sound, credible valuation information is not available to a decision maker when needed, the likely results will be increased uncertainty, procrastination, and risk. A well-developed valuation process is likely to have several key components:

1. Broadly accepted concepts and working definitions of the particular cost or benefit that is to be valued
2. Broadly accepted metrics that are consistent with the definitions
3. High-quality data to operationalize the metrics.

Agenda

DAY 1 –Valuing Electricity System Components and Attributes

3rd Floor Board Room

9:30 a.m. – 9:45 a.m. **Welcome**

Speaker: Melanie Kenderdine, Director of Office of Energy Policy and Systems Analysis, U.S. Department of Energy

The goal of this workshop is to identify key themes and concepts for power-system valuation. We propose addressing four major topics: Valuing Electricity System Components and Attributes, Valuing Technologies for Contributions to Power Quality and Reliability, Managing Electricity Risks, and Valuation within the Distribution System.

9:45 a.m. – 10:45 a.m. **Valuation of Electric Power System Services and Technologies – The Brattle Group**

This presentation will present a comprehensive valuation framework for grid investments that will allow DOE, regulators, and policy makers to value existing and new services and technologies along the entire electricity-delivery chain. Valuing current and new technologies appropriately is imperative for ensuring efficient delivery of evolving, desired attributes.

10:45 a.m. – 11:00 a.m. **Break**

11:00 a.m. – 11:45 a.m. **Valuation of Components and Attributes**

The electricity system is going through a simultaneous period of unprecedented change and mounting performance expectations. Traditional engineering cost methodologies used to determine the cost-effectiveness of investments are inadequate for identifying the full costs and benefits of a change, either within the system or for the nation at large, as well as the associated risks and uncertainties surrounding those investment options. For example, many new products and services are being introduced, especially at the distribution and customer level. Simultaneously, the bulk-power generation fleet is evolving quickly—renewable and natural gas generation is increasing while significant quantities of nuclear and coal baseload capacity are retiring. In the face of these changes, reliability must still be maintained, and physical and cyber security and resilience must be intensified. Ultimately, to actualize these attributes, it will be necessary to develop market standards or requirements.

Questions for discussion include the following:

- How do stakeholders monetize or otherwise account for the value streams provided by electricity-system elements? How are valuation frameworks useful for this?

- How are valuation frameworks useful for different stakeholder groups (regulators, industry, and researchers)?
- How can valuation frameworks help with decisions regarding policies, market designs, prices, or rates, for ensuring sufficient deployment of high-value technologies and systems as the system evolves?
- What are the limitations of valuation frameworks? How are those limitations likely to change over time?

Valuation of Components and Attributes
Moderator: Ashley Brown, Executive Director, Harvard Electricity Policy Group
Panelist: Travis Kavulla, President and Vice Chairman of the National Association of Regulatory Utility Commissioners
Panelist: Jeff Nelson, Director, Federal Energy Regulatory Commission Rates and Market Integration, Southern California Edison
Panelist: Jay Caspary, Director, Research and Development, Southwest Power Pool

11:45 a.m. – 12:00 p.m. **Brief Remarks on Valuation within the Grid-Modernization Lab Effort**

12:00 p.m. – 1:00 p.m. **Lunch Presentation: Treatment of Valuation in Electric Power Research Institute's (EPRI's) Integrated Grid**

Speaker: Rob Manning, Vice President, Transmission, EPRI

1:00 p.m. – 1:15 p.m. **Break**

1:15 p.m. – 2:00 p.m. **Valuation Breakout Session I**

We'd like to discuss the following questions:

- What does the valuation framework presented earlier illustrate well? What needs further development?
- What are the most useful next steps in valuation-framework development?

A. Feedback on Valuation Framework: Finding Common Approaches to Valuation across the Supply Chain [DEP Conference Room]

Facilitator: Rich Scheer, Scheer Ventures, BCS, Incorporated

B. Feedback on Valuation Framework: Using Valuation to Affect Policy Development, Prices, and Rates [Board Room]

Facilitator: Jeanette Brinch, BCS, Incorporated

2:00 p.m. – 2:15 p.m. **Break**

2:15 p.m. – 2:45 p.m. **Synthesis and Regrouping from Valuation Breakout Session I**

Facilitators will present conclusions from the breakout sessions to the entire workshop.

2:15 p.m. – 3:00 p.m. **Break**

3:00 p.m. – 4:00 p.m. **Valuation Breakout Session II**

A. Power Quality and Reliability Discussion [DEP Conference Room]

While new technologies and energy sources bring potential challenges for power quality control, information and communication technology advances offer innovative methods of providing needed ancillary services. Questions for discussion include the following:

- What are the most significant data, modeling, and analytic problems and challenges for improving the valuation of power quality and reliability for assessing new investments in grid modernization?
- What are your ideas for the development of new data, tools, and techniques for overcoming the problems and challenges and improving valuation of power quality and reliability?

Value of Power Quality and Reliability Discussion Technical Expert: Michael Sullivan, Senior Vice President, Utility Services, Nexant Facilitator: Rich Scheer, Scheer Ventures, BCS, Incorporated

B. Managing Electricity Risks [Board Room]

The energy industry must hedge against many risks, including price volatility, price increases, reduced electric reliability, and black swan events. Since the cost of risks is ultimately borne by ratepayers, it is essential to ensure that risks are appropriately valued and hedged, especially as energy markets continue to transform. Risk and valuation are highly interactive; if the costs and benefits of alternative policies can be estimated on the basis of good information, risk becomes much more manageable. Nevertheless, we live in great uncertainty, and the quality of available information is often less than we would prefer. This session aims to explore which utilities currently manage risk on behalf of ratepayers, review current risk-hedging strategies and their efficacy, and identify opportunities for policy to support new risk-management measures. Questions for discussion include the following:

- What types of risk do utilities hedge against and why? What instruments are used?
- How far forward does the utility hedge go and up to what amount?
- Have risk-management programs changed with the evolving energy sector? How?
- How are hedging programs evaluated?

Managing Electricity Risks

Technical Experts: Tim Metts, Senior Manager, Deloitte & Touche LLP; Steve Engler, Director, Deloitte & Touche LLP

Facilitator: Jeanette Brinch, BCS, Incorporated

4:00 p.m. – 4:15 p.m. **Break**

4:15 p.m. – 5:00 p.m. **Synthesis and Regrouping from Valuation Breakout Session II**

DAY 2 – Valuation within the Distribution System

1st Floor Training Center

9:30 a.m. – 9:45 a.m. **Welcome – Valuing Technologies on the Distribution System**

Speaker: Carol Battershell, Deputy Director for Energy Systems and Integration, Office of Energy Policy and Systems Analysis, U.S. Department of Energy.

The proliferation of energy resources and advanced grid-sensing technologies at the distribution level requires a reexamination of the traditional methods of valuing and comparing energy resources. DERs include the suite of technologies that provide energy services at the distribution level (i.e., solar energy, wind power, energy storage, demand response, fossil-fuel generation, and advanced grid-sensing and control technologies). Valuation methods that allow efficient utilization of infrastructure at the distribution level can increase options for system operators to meet reliability objectives and reduce the need for additional spending.

9:45 a.m. – 10:30 a.m. **Current and Future Distribution System Outlook**

- What specific factors drive value at the distribution level (for example, reliability, location, inertia, or other qualities)?
- What are current concerns for the impact of new and existing technologies, and are there external factors or conditions that greatly affect the value?
- What could DERs do from an engineering perspective? For example, what are the potential solutions to grid and generation challenges, streams of benefits and costs associated with deployment of the technologies like distributed storage or system control technologies (advanced metering, smart inverters, etc.)?

Current and Future Distribution System Outlook

Moderator: Carl Imhoff, Manager, Electric Infrastructure Market Sector, Pacific Northwest National Laboratory

Panelist: Steve Fine, Vice President, ICF International

Panelist: Anya Castillo, Senior Research and Development Systems Engineer, Sandia National Laboratories

Panelist: Dora Nakafuji, Director of Renewable Energy Planning, Hawaiian Electric Company

10:30 a.m. – 10:45 a.m. Break

10:45 a.m. – 11:30 a.m. Regulatory and Economic Valuation at the Distribution Level

- As the grid becomes more interactive and intelligent, how can the flexibility and consumer control offered by DERs be monetized?
- How could the regulatory process be streamlined to promote innovation and improve the future deployment, planning, and utilization of DERs?

Regulatory and Economic Valuation at the Distribution Level

Moderator: Paul Centolella, Independent Consultant

Panelist: Snuller Price, Senior Partner, Energy + Environmental Economics (E3)

Panelist: Dan Cross-Call, Manager, Rocky Mountain Institute

Panelist: Richard Tabors, President, Tabors Caramanis Rudkevich, and Co-Director, Utility of the Future Project, Massachusetts Institute of Technology

11:30 a.m. – 1:00 p.m. Discussion – Summary – Workshop Conclusion

Appendix B: Workshop Participants

Name	Organization
Alice Chao	DOE
Andrew Campbell	University of California, Berkeley
Andrew Stocking	DOE
Anya Castillo	Sandia National Laboratories
April Salas	DOE
Ashley Brown	Harvard University
Barbara Tyran	EPRI
Bob Schmitt	DOE
Brian Krambeer	Tri-County Electric CoOp
Carmen Difiglio	DOE
Carol Battershell	DOE
Caterina Fox	DOE
Chris Irwin	DOE
Christina Cody	DOE
Courtney Grosvenor	DOE
Cyndy Wilson	DOE
Cyril Draffin	Massachusetts Institute of Technology
Dan Cross-Call	Rocky Mountain Institute
David Meyer	DOE
Dora Nakafuji	Hawaiian Electric Company
Elise Caplan	American Public Power Association
Emily Lewis	DOE
Erica Qiao	BCS, Incorporated
Fred Hoover	National Association of State Energy Officials
Hugh Chen	DOE
Ira Shavel	The Brattle Group
Jan Brinch	BCS, Incorporated
Jay Caspary	SPP
Jeanette Pablo	DOE
Jeff Nelson	SCE
Jignasa Gadani	FERC
Jim Cater	American Public Power Association
John Agan	DOE
John Caldwell	Edison Electric Institute
John Larsen	Rhodium Group
Joisa Saraiva	Getulio Vargas Foundation
Judi Greenwald	DOE
Kerry Worthington	National Association of Regulatory Utility Commissioners
Lara Pierpoint	DOE
Mary Ann Ralls	National Rural Electric Cooperative Association
Melanie Kenderdine	DOE
Michael Kintner-Meyer	PNNL

Michael Sullivan	Nexant, Inc.
Mike Carr	Boundary Stone Partners
Mike Hagerty	The Brattle Group
Monica Ghattas	SCE
Nicholas Powers	The Brattle Group
Pamela Silberstein	National Rural Electric Cooperative Association
Paul Hibbard	Analysis Group
Raisa Ledesma	DOE
Richard Scheer	Scheer Ventures
Rob Hochstetler	National Rural Electric Cooperative Association
Rob Manning	EPRI
Rob Naranjo	BCS, Incorporated
Robert Borlick	Borlick Association
Rohan Ma	SolarCity
Ryan Hanley	SolarCity
Samantha Hines	BCS, Incorporated
Sandra Jenkins	DOE
Snuller Price	Energy + Environmental Economics (E3)
Stan Hadley	Oak Ridge National Laboratory
Steve Engler	Deloitte & Touche LLP
Steve Fine	ICF International
Tim Metts	Deloitte & Touche LLP
Travis Kavulla	National Association of Regulatory Utility Commissioners
William Hederman	DOE

Appendix C: List of Abbreviations and Acronyms

ConEd	Consolidated Edison
DER	Distributed energy resource
DLMP	Distributed locational marginal pricing
DOE	U.S. Department of Energy
EPRI	Electric Power Research Institute
EPSA	Office of Energy Policy and Systems Analysis (DOE)
FERC	Federal Energy Regulatory Commission
ICE	Interruption Cost Estimate
IRP	Integrated Resource Plan
ISO	Independent system operator
kWh	Kilowatt-hour
LMP+D	Locational marginal price plus distribution value
MISO	Midwest Independent System Operator
NERC	North American Electric Reliability Corporation
NPV	Net Present Value
PNNL	Pacific Northwest National Laboratory
QER	Quadrennial Energy Review
REV	Reforming the Energy Vision
RTO	Regional transmission organization
SCE	Southern California Edison
SPP	Southwest Power Pool

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