Summary of Discussion

U.S. Department of Energy Workshop

on

Estimating the Benefits and Costs of Distributed Energy Technologies

Hall of the States
444 North Capitol Street, NW
Washington, DC

September 30–October 1, 2014

Table of Contents

U.S. Department of Energy

Workshop on Estimating the Benefits and Costs of Distributed Energy Technologies

Day 1

1. Welcome and Opening Remarks

Mr. Rich Scheer (the facilitator for the workshop) opened the meeting. He thanked attendees for coming and explained meeting logistics. Noting that the word "workshop" should be underlined, he said the meeting would be a technical discussion about distributed energy technologies, looking primarily for input and suggestions from attendees. He then requested all attendees to introduce themselves.

1.1 Kevin Knobloch, Chief of Staff to the Secretary, U.S. Department of Energy (DOE)

Mr. Knobloch welcomed everyone to the workshop and noted the intellect and diversity of expertise in the room, stating that the diversity of attendees was by design. He said that the challenges are worthy of the attention of such a talented group. The states represented are pioneering the development of relevant policies, and utilities are challenged by the need to develop appropriate business models. He noted that the group also included experts from academia, think tanks, and federal and state government.

Mr. Knobloch also brought good wishes from DOE Secretary Ernest Moniz, who looks forward to reading the results of the discussion and is very supportive of work in this area. Distributed energy (DE) can be a controversial topic, he said, but wider use of DE technologies is both desirable and inevitable. Because of the enormous challenge of climate, our expanding menu of technological options, and other factors, we need to find ways to deploy renewable energy (RE) to our collective advantage. We need to ensure the value of RE is understood and factored into business models.

The purpose of this workshop, he said, was to support development of tools and models so that planning can be more fruitful regarding deployment of these technologies. The regulatory responsibilities rest with the states, and processes and tools will evolve through the efforts of analysts and users such as those in the room. Mr. Knobloch made clear that DOE was seeking ideas and candid discussion from the group, not driving toward consensus.

Mr. Knobloch also noted that most of the dialogue about DE to date has focused on the costs and benefits of solar power, but other DE technologies are at or near commercial viability. Some of the technologies will be interactive, which will make the analytic challenges even more complex, and we need to learn from our solar experiences to be better prepared for the more complex questions that lie ahead.

He thanked the group again for their time and expressed his gratitude for their attendance.

1.2 Williams Parks, Senior Advisor, DOE Office of Electricity Delivery and Energy Reliability

Mr. Parks also thanked everyone, especially the organizations that have aided DOE in planning and staging the workshop. The workshop is a start of what could easily be a multiyear discussion. The purpose of the workshop is a reconnaissance of the key challenges regarding valuation, as well as how to address them, by whom, how results should be used, and what DOE's role should be. Mr. Parks reflected on the many positive intersections that have influenced the evolution of the grid, and the contributions that have come from many organizations and people over the years. He then gave an overview of how the workshop's discussions would be organized.

1.3 Steve Chalk, Deputy Assistant Secretary for Renewables, DOE Office of Energy Efficiency and Renewable Energy

Mr. Chalk also thanked everyone for coming to the meeting. He noted that we all are in the midst of a transformation of the electric sector, and that we need to make a difference in clean energy with regard to climate. Distributed generation has tripled in the last three or four years, so a huge change is coming.

He, too, emphasized that DOE is not looking for unanimity or driving toward consensus during the workshop, and added that DOE would like the participants' feedback at the end of the workshop as to whether DOE should have more of these meetings on other topics. He also hoped that everyone would be able to take lessons learned back to their organizations.

Mr. Chalk said that the presenters at the workshop are senior people from the national laboratories, other research organizations, and representatives of state government. The national labs have the important role of advising DOE about big national challenges, and there is nothing bigger than the climate challenge.

2. Framing the Issues

2.1 Presentations (3)

2.1.1 The Honorable Michael Champley, Commissioner, Hawaii Public Utilities Commission

Commissioner Champley discussed lessons learned from the experiences of Hawaii's utilities. The state has had high growth of residential and other solar photovoltaic (PV) over the last five years and is poised for a major thrust in the development of utility-scale PV. As a result, the state faces a number of significant economic, policy, and grid-related technical challenges.

Electrically speaking, Hawaii is a collection of island electric grids. There is no interconnection between islands; each island has effectively become a laboratory for renewable resource integration. The Federal

Energy Regulatory Commission (FERC) and NERC have no jurisdiction, so the Hawaii Public Utilities Commission can establish its own rules, within state statutes.

Annual renewable energy output in 2013 ranged from 12% on Oahu (the main population center) to 48% on the main island (Hawaii) and renewable energy growth continues. The state leads the nation in penetration of rooftop PV and, as a result, is at the forefront of the integration challenges associated with high distributed PV penetration levels. By 2017, two islands will have over 75% of day-time system load supplied by distributed and utility-scale solar. Solar has seen exponential growth, but the growth has been slowing down in 2014. Hawaii is approaching 50,000 solar customers; over 10% of total residential customers have solar PV. Installed customer solar PV capacity represents roughly 23% of annual system peak load. Average residential customer electricity usage has dropped by about 30% over last ten years due to customer energy efficiency, conservation and distributed generation (but the grid investment did not shrink 30% and in fact, increased during this time).

On Kauai Island, solar generation is approaching 50 megawatts (MW), while oil will soon be down to around 10 MW. However, solar resources energy output contributed only 18% of the daily energy used due to limited hours of full solar energy output. Regarding solar penetration at the distribution level, approximately 50% of all distribution circuits for the Hawaiian Electric Companies have greater than 75% solar PV penetration.

Commissioner Champley reviewed lessons learned, regarding both technical topics and policy matters. Exponential growth in renewables was market-driven, but if the consequences are not anticipated and appropriately addressed proactively, such growth will lead to unintended results. Developing renewables makes sense in Hawaii due to its current dependency on oil for electric generation, but with state tax and rate incentives and no penetration level check points, the growth outpaced the utility's ability to manage interconnection queue and grid integration issues. As a result, the residential PV industry in Hawaii faces a boom-bust cycle. Commissioner Champley noted that there are now emerging substantial integration challenges uniquely associated with incremental additions of utility-scale and distributed solar PV, and that the integration costs of solar may exceed those of other forms of renewables, due to less solar energy output to spread integration fixed costs and due to PV's inherent low capacity factor. Other technical issues include:

- Many issues have arisen that were not initially evident at lower penetration levels.
- The size of a customer's PV grid "footprint" matters when excess solar energy is exported.
- Bulk power system reliability challenges, not distribution circuit issues, have become binding constraints on the island grids.
- PV inverters are a crucial part of the distributed solar PV integration equation.
- Inability to curtail customer solar PV output leads to curtailment of utility-scale renewable projects, to the economic detriment of customers without solar PV.
- Legacy customer and technology issues are an emerging concern.

The current business development model for customer solar PV in Hawaii is not sustainable due to economic, policy and grid-related technical challenges associated with high solar penetration levels. New options for future customer solar development are emerging in Hawaii. A customer self-supply model, or "retail choice" model must be defined that is a non-energy export option and does not affect the grid adversely. Another option is customer grid-supply, or wholesale supply model, that is driven by the utility's RPS competitive procurement requirements. Under either model, utility service offerings and pricing options will be a critical component moving forward. The policy focus in Hawaii is not on how to manage potential cost shifting but how to integrate a substantial amount of RE into grid operations in a cost-effective manner.

It is encouraging that the solar industry is seeing these needs in much the same way. Utilities have to look at distributed energy resources (DERs) and distributed generation (DG) as potential solutions for grid modernization rather than as integration problems that must be accommodated. The solar industry must migrate to a new business model that reflects the value DER provides to the grid, and vice versa.

Customers must recognize that the recent rapid pace of customer solar PV interconnections is not sustainable when grid infrastructure mitigations need to be developed and deployed. Public policy challenges include pursuing a balanced, least-cost portfolio of renewable energy resources for benefit of all customers versus a single renewable technology strategy for a sub-set of customers, while recognizing and allocating grid integration costs and DER benefits.

2.1.2 Karen Forsten, Electric Power and Research Institute (EPRI)

Ms. Forsten noted the recently-produced draft EPRI concept paper: *The Integrated Grid, Phase II: A Benefit–Cost Framework*. The framework includes possible action plans. EPRI is in the process of circulating the draft for peer review and plans to go public soon with a final published document. The EPRI paper is only the start of a methodology to engage in focused discussions. EPRI is trying to leverage not only EPRI's own work but also that of many stakeholders. EPRI's role is to conduct applied research and that builds on others' work. The concept paper discusses where EPRI is in its action plan, with a focus on Phase II.

The Integrated Grid is about enabling consumers and allowing local energy optimization to become part of global energy optimization, rather than being one or the other. This does not mean we do not need a grid, as only through the grid do we recognize the potential of both central generation and distributed energy resources. Adherence to interconnection technical guidelines is essential, as is working with IEEE and others to facilitate interconnection.

EPRI indicated that the industry does not yet have the tools needed to conduct a full-blown optimization study, and that is one of the research gaps identified. Existing resources allow comparison of a few types of futures with the base. The action plan, which requires ongoing collaboration and technology transfer, is divided into three areas:

- A framework for evaluation of grid modernization investments based on a transparent and repeatable methodology

- Interconnection technical guidelines
- Integrated grid planning and operations

In the past, each component could be addressed separately, but now a more holistic view is needed. Ideally, all of distribution and bulk assessment could be done together using one set of tools. As of today, however, there is no systematic approach; it has to be iterations back and forth.

Ms. Forsten showed a distribution flowchart made up of four components: hosting analysis, energy analysis, capacity analysis, and reliability analysis. She noted the importance of location, stating that there is no one-size-fits-all. Location and even individual feeders have unique characteristics that make it difficult to generalize.

Ms. Forsten noted that we are just starting to understand where the research gaps are for the integrated grid. Research areas to close these gaps include architecture for the integrated grid, integrating the customer, integrated planning and operations, and advanced asset management.

EPRI is already starting on next steps and applying the framework in pilot applications. EPRI recognizes that it is only one entity and would like to enter into conversations with others about collaborative studies.

2.1.3 Steven Fine, ICF International

Like the national labs, ICF prides itself on credible and impartial analysis. Mr. Fine presented slides from a recent workshop on benefits and costs of DG. He was heartened by that discussion, which showed that maturation is occurring in the solar industry.

He discussed the solar PV market, noting that most systems (96%) will be residential: ICF forecasts over 1.8 million distributed PV systems by 2018, showing exponential growth from about 6 gigawatts (GW) to 25 GW.

The challenge is the relative coincidence of solar with the broader system. Solar is typically not coincident with the system load right now, and the implications are compounded by DG.

Debates about the value of solar and net metering will intensify. Net energy metering (NEM) is in flux; discussions are going on in a number of states already. When discussing the value of solar, there is also the question of the value of the grid. Some have a vision of many microgrids, abrogating the need for a grid. Others, however, see the grid as enabling DG. In turn, DG is seen as enabling a wider range of futures.

There are several major issues associated with widespread DET adoption, such as rate reform and system resource planning. The value of solar is one component.

The net value of solar can be compartmentalized into six areas: energy and capacity, grid support services, financial, security, environmental, and social. Different stakeholders vary as to which (of the six) should be included in analyses. The numbers from studies are often inconsistent, and methodologies are very different. ICF looked at five studies done over the past two years and saw a wide range of findings (in terms of cost per megawatt-hour). Some studies considered the costs of integration (although they used different methodologies), but most studies did not account for that at all.

Ideally, such studies should be consistent, transparent, fair, and easy to replicate. Analysis to value solar is just one of many actions needed to address DER growth, and valuation should account for the fact that distributed PV can be more than a reduction in load; it can also export to the grid. The absence of a replicable analytic approach impedes long-term deployment.

2.2 Discussion

Note to reader: DOE affirmed to the participants that it would take notes on the discussion, and that a summary of the dialogue would be made public – but that to help foster a candid exchange, the views expressed would not be attributed to specific individuals. In the pages below, key points made by the participants are denoted by arrowhead symbols.

- It is easy to draw the conclusion that there are methodological differences, but the core issue is assumptions and what you choose to include.

- From a policy and national standpoint, development of a proposed clean power plan must be pushed down to the states, because regional differences are very important. Even within a state, there are differences among municipalities and between municipal utilities (munis) and investor-owned utilities (IOUs).

- Utilities want rate restructuring done now while penetration is low. There are different rules in different territories, different customer bases, and different needs. EPRI has laid out a nice framework because the one thing that is the same is the economics. Reaching agreement on methods for valuing costs and benefits would be helpful.

- Regarding similarities and differences between utility-scale and residential PV, residential is more diverse. Regarding pricing, utility-scale represents a book end if you want solar on your grid. Regarding policy, the most important thing is providing customer choice. As solar prices come down, the customer choice angle will become more pronounced. We have to figure out key regulatory and pricing issues:
  - What are the obligations to serve?
  - What is the regulatory compact?
  - What is the corresponding customer obligation?
  - Are we creating future stranded costs?

- We must align where the market is going so that we get 20-year solutions rather than 3-year solutions.

- States are currently making a series of choices as to how to address rooftop solar, and they could be making choices we will come to regret. We could end up on a higher cost curve and face the question of who pays the costs. What are the things we should tell our colleagues *not* to do?

- We need to make sure we are tracking which stakeholders accrue benefits and which pay costs.

- If you try to look at one resource or policy in a vacuum, you miss opportunities.

- We need to understand how this discussion fits in a broader framework, e.g., greenhouse gas regulations.

- Valuing DG costs arises in several contexts, including net metering debates. Net metering at low levels has provided rough justice, in terms of compensation for the value solar provides to the utility and the customer. Value, however, is very location-specific and tool-specific. Doing it well will require a lot of resources, and it is not a level playing field in terms of resources on the solar industry side and the utility side, so we need to find ways to share data and analytical tools and draw conclusions.

- As the grid gets more saturated, it becomes more critical to utilize capacity to integrate renewables thoughtfully. If capacity to accommodate variable renewables is limited, I have to determine whether I want another megawatt of solar or wind. All technologies have a value, but we need the right service offers and right pricing. If the pricing is right, the market will work.

3. Avoided Energy

3.1 Presentation by Ryan Wiser, Lawrence Berkeley National Laboratory

Mr. Wiser focused his presentation on estimating the costs and benefits of energy from distributed energy technologies. He noted that he would not be covering energy losses or capacity, as those topics would be covered by others during the workshop. He would define energy value, discuss methods used to estimate that value, and identify fundamental issues.

For the purposes of his talk, Mr. Wiser defined energy value as how much power-system variable costs are reduced (or increased) because of DETs. The basic premise of understanding energy value is straightforward, but there are complexities. Some DETs shift electricity use (DR) or increase it (storage, EVs); when we talk about avoided energy, we talk about avoided fuel cost, but there is also some discussion of curtailment (forced reduction in DET generation).

Regarding methods for valuation, there are three main questions / steps:

- Step 1: When is DET generating (or charging)? Determining when DET is generating (or charging) is straightforward for solar and wind (e.g., use historical meteorological data) but more complicated when considering a broader set of technologies where generation (or charging) depends on customer choices , e.g., demand response, electric vehicles, customer-sited storage, and combined heat and power.

- Step 2: What generation is displaced (or used) during those times (i.e., what is the marginal unit), and at what heat rate? A paper by the National Renewable Energy Laboratory (NREL) identified six methodological options that can be used in this process, ranging from assuming a particular generator such as a CCGT is always on the margin to a long-term capacity expansion model that captures the dispatch of generation units and changes in the generation mix over time. The choice of method depends on tradeoffs among simplicity, transparency, and accuracy.
  - Step 2A: Can all DET generation be used, or is there a need for some curtailment? Curtailment mostly occurs with low load and high levels of DET generation. Only some methods can endogenously estimate curtailment needs. It is a minor issue now but may become significant at high penetration.

- Step 3: What are the variable costs of the displaced generators? Variable operations and maintenance costs are small, but future fuel costs are uncertain and this uncertainty is a source of inconsistency in energy value estimates.

Fundamental issues include:

- Creating DET output profiles, particularly for sources such as storage, EVs, and DR is difficult due to limited data. Different assumptions for dispatch/availability can be credible and reasonable yet lead to different values (e.g., assume storage is dispatched to minimize the customer's bill vs. dispatched to maximize value to the grid). Dispatch can also vary depending on penetrations of other DETs.

- Change in marginal units (and curtailment) with time, DET penetration, or footprint of analysis.

- Fuel cost projections and uncertainty.

Mr. Wiser also noted some overlap between energy value and other value categories:

- Separating energy value from capacity value and integration costs. To some extent, it does not matter how the elements are categorized as long as they are accounted for, but some elements and data from an energy perspective overlap other costs and benefits. The key issue is to consider all costs and benefits without double-counting them. For example, we must be cognizant that a portion of capacity value is sometimes embedded in historical wholesale electricity prices.

- Accounting for compliance cost savings. Values associated with reduced pollutants can be considered part of energy value or social costs and benefits – or might be considered separately altogether.

- Wholesale electricity price reduction (“merit-order”) effects. The addition of DET can reduce wholesale power prices, but it is unclear whether this is permanent and whether it benefits society as a whole or only represents a transfer from generators to customers.

3.2 Discussion

3.2.1 Costs

- We are trying to plan from both the supply side and the demand side, with uncertainties regarding both from a regulatory standpoint.

- Is the displaced generation sold for profit? Is it sold for a loss? What happens to a nuclear/coal generator when it is displaced by DET? Is there value there that should be considered?

- We may be incurring additional T&D costs because of constraints on the system when generation plants are shut down.

- It is important to clarify the context and purpose of determining costs. An investment / planning context is very different from pricing in a real-time market.

- A critical part of DG cost analysis is how resource variability changes the mix of resources the utility must balance against, whether at distribution or bulk power level. The cost curve changes compared to the mix of resources in the past, and it needs to be forecast accurately. The energy forecast also needs to incorporate changes based on weather conditions, e.g., cloud cover.

- If we have granularity for one type of technology, we should we do it for all types rather than having disparate treatment. We want to ensure fairness.

- The analysis will come to different results depending on the characteristics of the source of the displaced generation. Also, we need to capture solar valuation starting at low penetration rates and then escalate.

- From the perspective of energy value of DETs – figuring out the generation source and the cost of the generation source – only Step 1 (figuring out the generation profile) is unique. There might be a difference in distributed storage (central is optimized for central station costs), but other profiles are the same.

- If we are putting in more solar, we are avoiding CCGTs, and we are avoiding a peaker plant for that generation. Assuming that to be true, a higher or lower capacity value is not a make-or-break issue.

- Capacity value is independent of the type of plant. Capacity is a residual; it has no physical reality.

- Solar is the easiest DER to value; it is not dispatchable. You can make simplified assumptions and get the same number. Other DERs are much harder because you have to make choices.

- We have to take into account the difference between a regulated and restructured market and how that influences trajectory and transparency, as well as the valuation's purpose. There is tension between legacy assets and future forecast; you do not want to get locked into a future rate.

- Rates are typically based on accounting costs, not value. When utilities talk about value, we mean value to the customer. Pricing has to change to maximize DG.

3.2.2 Benefits

- We cannot do valuation and avoided costs in different streams. There is a disconnect in pricing, but the real disconnect is at the retail level. Bilateral markets have the same price considerations. The regulatory albatross of treating PV based on a rolling price puts utilities and ratepayers at cross purposes.

- Retail offerings to customers and cost calculations are non-time-differentiated. Displacing a renewable may result in savings but will have no benefit for the customer. We cannot think of values as static.

- One of the reasons we are moving to solar or wind is to reduce pollutants. There has to be a specific means of monetizing externalities. It should be explicit for every technology, e.g., cost of carbon as a way of monetizing.

- Emissions are included in our avoided energy rates; we need to be mindful about double-counting. We also need to ask where we start the point of comparison, other than to the grid. If a technology is using less water, is it the best among DER technologies?

- The answer is simple: design retail tariffs to reflect marginal costs. However, that does not happen in the real world. The problem is retail regulators.

- Unless we want to completely reconstruct the grid, avoided energy becomes avoided renewables at some point. Energy that cannot be curtailed has priority over other renewables. This not about the curtailment issue, but about the foregone opportunity.

3.2.3 Tools

- You are talking about a marginal unit being brought into the system. What is getting displaced? Our sophisticated tools need to be that neutral arbiter.

- You create a market proxy based on renewables or whatever you are displacing next.

- Modelers run the models, but if they are not transparent, people cannot audit the results. Knowing what is and is not in the model is necessary to allow us to debate assumptions.

- There are a number of models that can do this sort of analysis at different levels of complexity and different time frames. But the farther out you get in time, the greater the uncertainty.

- Also, there is a conflict between accuracy and transparency. Some of the most accurate models use private or market-sensitive data.

- Try to assemble a portfolio that mirrors the load you are trying to serve. If customer solar could be modeled as a portfolio of certain characteristics as an aggregate, that would provide target and pricing for customers.

- On the energy point, the value of energy should not be differentiated – energy is agnostic whether on the customer side or central station.

- Ultimate costs of solar reflect assumptions based on values in every state based on that state's stakeholders and what the populace has determined is important. It would be good to be able to parse out some of those value areas and have those as separate parts of the model, e.g., based on stakeholders' views.

- State laws regarding NEM discourage or prohibit metering of DG production. Regulators prefer actual data from their state rather than estimated or national data.

- States will want to track DG production, which is important information for EPA goals.

- We do not want to discourage DG but want to make sure it is transparent and costs are right. We need apples-to-apples comparisons.

4. Avoided Generation Capacity

4.1 Presentation by Robert Margolis, National Renewable Energy Laboratory

Mr. Margolis' presentation focused on estimating the costs and benefits of avoided generation capacity. Estimating capacity value involves two steps: determine capacity credit, i.e., the fraction of a DET's capacity that adds to system reliability; and translate capacity credit into a monetary value, i.e., capacity value. There are four methods to calculate capacity credit:

- Capacity factor approximation using net load
- Capacity factor approximation using loss of load probability (LOLP)
- Effective load-carrying capacity (ELCC) approximation (Garver's Method)
- Full effective load-carrying capacity (ELCC) calculation

The basic method for approximating the capacity factor is to examine generator output/ capacity factor during periods of high net load or periods of highest risk. Look at when the peak occurs and compare that to rate capacity. The choice of peak period can significantly influence results. Peak periods vary across utilities, seasonally and regionally.

Some methods may not fully measure contributions to resource adequacy. Some methods provide inaccurate results, and other methods do not provide results as comprehensive as with an ELCC approach.

The reliability-based (effective load-carrying capacity, or ELCC) approach to approximation methods addresses the issue of sufficient planning reserves. Mr. Margolis explained the method:

1. Develop a benchmark system (excluding the DET in question) that meets the target reliability level.
2. Add DET and rerun the model, noting any improvement in annual reliability.
3. Incrementally increase load until annual reliability is reduced to match the benchmark system case.

The capacity of the added load is the ELCC of the DET. The amount load is increased is the DET's effective load-carrying capacity. The ELCC method requires a very large quantity of data. In translating capacity credit, the bounds for DETs are likely to be somewhere between a CC and a CT. The capacity values depend on the level of penetration. Most studies indicate that above 10% energy penetration of distributed PV, the capacity credit and capacity value of additional distributed PV is very low.

As penetration of DETs increases, we may see interactions between technologies. Reducing peak may be made easier depending on what is added to the system. There are synergies and interactions between the technologies on the system.

Mr. Margolis concluded his presentation by noting additional issues, including: the need for multiple years of data and analysis; and whether there is a need for a flexibility assessment in addition to ELCC.

4.2 Discussion

4.2.1 Costs

- In the context of large-scale transmission planning, this may be the last gasp of such planning, thus changing the paradigm in terms of what utilities do.

- The way to look at capacity is through the reliability lens. Once you get high penetration, reliability starts to decline. The system in Hawaii has becomes less robust against big transient events, so the utility now has to spend millions to enable the grid to respond to transient events as it did before. There may be some societal tradeoffs, i.e., is climate change more important than near-perfect reliability? Adding flexible generation also adds capacity cost. When penetration levels get significant, huge ramp events can occur for which the system was never designed.

- We are positing a static or passive model of the technology. We must think in terms of how the ability to forecast is changing.

- Regarding capacity for larger facilities, we need a framework for taking location into account; we cannot control where DET resources may be located.

- The context/framework is applicable for non-dispatchable resources, but we need to look at the capacity value of storage and demand response.

- In policy terms, we need to remember that avoided capacity is very location-specific, not general.

- Capacity and energy impacts may blur. Building/rewarding solar for meeting summer peaks can lead to over-generation in winter/shoulder months (unintended consequences).

- My utility pumps water uphill at night with nuclear and lets it down during the day. We used to sell from this source at peak during the summer. If that is changing, what is the lost opportunity cost, and should that go into pricing?

- In Texas, traditional and energy-only market price approaches gave very similar numbers.

4.2.2 Benefits

- The incentive provided through typical retail mechanisms today is for DET owners to generate as many kilowatt-hours as possible, regardless of how. Theoretically and technologically, there may or may not be capacity value. How do we incentivize more efficient behavior?

- My utility will not defer new generation unless the DET can meet all requirements – some skepticism about DETs' ELCC.

- The concept of resiliency – what used to be envisioned as security – is now driving microgrids, i.e., continuity of service to critical assets.

- Should we link LOLP and ELCC to SAIDI and SAIFI? Intelligent islanding may have much higher impact on CAIDI and CAIFI.

- Enabling high penetration of DETs will increase the cost of the distribution infrastructure. We will need to redesign the system but will still want to ensure least costs.

- Industry has focused on LOLP, but 90% of outages occur at the distribution level.

4.2.3 Tools

- We need to be consistent in methodology, e.g., so that the production cost model and the capacity expansion model are inherently linked. As the system's need for more ramping grows, that will induce a bias toward aero-derivative turbines as compared to other kinds.

- We need to include an assumption of a flat or 1% growth scenario.

- Any tools that get developed should make algorithms, functions, and assumptions entirely visible – no black boxes. Open source is best.

- Modelers could take into account adding larger versus smaller amounts and issues with variability and intermittency.

- It is important to identify the level of penetration and, separately, the location of that penetration. Geographic diversity may contribute to higher reliability even with higher penetration.

- There could be a way to formalize our approach: Do long-term planning using a system based on ELCC and a cost model that could account for flexibility, and then piece them together.

- With different price signals and time-of-use rate structures, we will see great changes in load profiles. How do we capture such changes in patterns with new technologies in modeling?

- Most utilities look at net load when doing resource planning. Sometimes distributed energy is a resource and sometimes a decrement from load.

- If a utility's load is not growing but they need to add to the rate base with new technologies, that creates inherent pressure on rates. They have to go before the commission and explain the need.

5. Avoided Transmission and Distribution

5.1 Presentation by Steven Fine, ICF International

Mr. Fine's presentation focused on estimating the costs and benefits of avoided transmission and distribution (T&D), as well as avoided energy. He noted that after discussions with others, he decided both avoided T&D and avoided energy losses should be covered.

Avoided/deferred T&D capacity is dependent on peak coincidence and lumpy investments in a growing system or on peak and energy reduction. Regarding avoided energy losses, we need to account for relative power displaced from the grid (as opposed to energy generated and inserted onto the grid). Storage and managed load could be game-changers in terms of how avoided T&D is calculated.

PV generation is relatively predictable but it is not necessarily coincidental with peak usage. For avoided transmission investment, we need to determine the relative coincidence of distributed PV production with peaks on the transmission system. Deferred transmission is more difficult to ascertain than deferred distribution. Distribution system impacts are more discrete, which is both good and bad. Extremely granular data are required – an overwhelming level. With "dumb" inverters, there is a risk of voltage violations and losses of 10% to 30%. We can avoid overloaded feeders. Avoided capacity also has a potential impact on extension of service life for system equipment.

DET can reduce or defer infrastructure investment, relieve congestion, offset peak demand, and offset wear and tear on the system. However, these benefits often require some infrastructure investment and load-flow modeling is essential.

Even at low penetration rates, DER can cause reliability issues. Mr. Fine showed a chart with possible effects at 10% penetration levels.

Regarding the avoided energy loss component, offset energy will always have positive value, and there are already methodologies for calculating avoided losses, although there is debate as to specifics. These methods are appropriate when energy consumption from the grid is offset as a result of on-site generation but not appropriate when on-site energy consumption is low and on-site energy generation is high, resulting in net exports to the grid. In calculating value, T&D losses are affected by time and location. Average losses are 6% (EIA), but marginal losses can be as high as 20%. The four methodologies for calculating the avoided energy component are T&D average loss rate, T&D marginal combined loss rate, locational marginal loss rate, and loss rate determined by power flow modeling.

Mr. Fine concluded his presentation by asking the group to consider what cost elements and benefit streams should be included in DER valuation calculations, what analysis tools are needed, and what the associated challenges are.

5.2 Discussion

5.2.1 Costs

- Regarding DG penetration's relationship to avoided costs of transmission, what is the penetration level at which you go from none or marginal to something you have to account for?

- That level is locational-specific and even feeder-specific. Prototypical analyses that can be applied to the system could be helpful.

- Historically, we have pursued DER more for a variety of policy reasons and not specifically as a tool to avoid distribution upgrades. There are costs to making this work: e.g., for telecommunications and integration. Perhaps we could develop a protocol to elicit alternatives from customers' third-party providers.

- Regarding avoided transmission costs, the deferral of a transmission line is worth a good deal.

- T&D investments are often made to relieve congestion, and a reduction in LMP is often a fuel saving, not a transmission cost saving; so we have to be careful not to double-count.

- We are studying doing conservation voltage reduction, but if not done carefully, some customers' costs may increase. In some locations, adding new utility generation will require new transmission.

- These new technologies mean more hard costs and opportunity costs. Normally this would entail a study, then another study, then a pilot… Both utilities and commissions are going to have to become more accustomed to taking on risk.

- T&D planners can calculate the benefit for a perfect technology, then do the technical comparison, and then determine whether the (imperfect) technology is worthwhile.
- Some utilities are skeptical about T&D benefits; it is hard to do all of this analysis and learning at one time.

- Regarding integration costs, there is a learning curve. If you do more, you improve, and integration gets cheaper. The marginal cost of technology is changing.

- Regarding regulatory proceedings such as New York's REV, utilities could be required to show that they included DG in their analysis before proposing a capital expense upgrade.

5.2.2 Benefits

- Assuming deferred generation implies a likely deferred T&D upgrade.

- Utilities are keeping track of what circuits need upgrades, and they are the circuits that serve customers – those are the ones that should be studied.

- Timing and location are key. Plan for the worst case, and recognize that a combination of technologies may provide the most value.

- Another source of benefit is better communications. If the distributed technology talks to the system, then you'll know more about reliability and load forecasting.

5.2.3 Tools

- We are building an hourly database that captures everything, and it will be location-specific, including how solar increases the cost and complexity of planning. With new modeling tools, we need to check load levels, reconfiguration schemes, and so on.

- It can go both ways. DOE did a study on 30% penetration of wind that showed $143 billion of additional transmission would be needed to meet the additional wind.

- Our existing utility grid is built for one-way power flow. We are moving into a paradigm with many technologies, and forces are leading us to a more distributed future. Transmission and other capacity expansion costs are not necessarily attributable to the next technology that comes online but rather to the need to change the grid to accommodate these technologies.

- In Spain, network reference models used by regulators to evaluate decisions are publicly available.

- Models for the distribution system typically have no economic component, as opposed to a cost model that would give you optimum dispatch.

- Regarding cost at the distributor level, sometimes customers' interconnections fail or they do not charge. That cost does not get captured on the distributors' side.

- We should avoid having early adopters getting a "free ride" while later customers take on the burden. Also, not all circuits have the same socioeconomic characteristics.

6. Social Costs and Benefits

6.1 Presentation by the Honorable Anne Hoskins, Commissioner, Maryland Public Service Commission

Commissioner Hoskins' presentation focused on quantifying DER social costs and benefits. She began by providing a list of recent relevant reports and proceedings. She also provided a table of social costs and benefits, such as environmental challenges and economic development, and cross-walked those with the organization(s) that are addressing those challenges.

Commissioner Hoskins noted that the subject is both a political issue and an economic issue. PUCs have always been concerned with societal impacts, but have not always quantified those impacts. Explicitly accounting for social and environmental factors is an expansion of the traditional "economic regulator" role. Ms. Hoskins emphasized the need to ensure that regulators have the capacity to do this correctly.

Commissioner Hoskins noted important developments in some states, particularly New York and Minnesota, that are advancing the regulatory processes for utilizing and valuing distributed energy. The New York REV initiative is considering new mechanisms, such as distribution system platforms, to facilitate increased integration of distributed resources, along with a new cost benefit testing protocol that explicitly accounts for non-energy benefits. She noted that New York's initiative appears to be quite resource intensive, and that lesser-resourced commissions may have difficulty replicating all aspects of it. The Minnesota "value of solar" approach provides a framework that other states could build from, while tailoring cost and benefit components to their specific situations. Commissioner Hoskins stated that it would be most efficient for a state commission to develop its valuation regulations through a generic proceeding, and that Commissions should consider proactively initiating such proceedings, rather that reacting to utility specific proposals (such as requests for stand-by charges).

States may also face legal challenges as they seek to value social costs and benefits in their regulatory rulings. For example, if a restructured state chooses to adopt a Value of Solar tariff which compensates DE providers directly for selling generation in the wholesale market, they could run afoul of wholesale pricing regulation, and specifically, recent federal court rulings which have affirmed FERC's jurisdiction over wholesale prices. States in restructured markets will need to consider the impact of their policies on their retail and wholesale energy markets, and the interplay with RTO and FERC rules.

Commissioner Hoskins' final slide showed several types of social costs and benefits that could be considered when valuing distributed energy:

- Economic development
  - Jobs
  - Taxes
- Public health
- Environmental
  - Carbon Reductions
  - Air Quality
  - Water
  - Solid Waste
- Energy Security

– Reliability and Resiliency

- Electric System Impacts
- Public policy goals

Moving from an NEM approach to a solar-rate approach requires moving beyond identifying pecuniary costs and pecuniary benefits—it will require policy judgments about which types of social costs should and could be included in the calculus.

6.2 Discussion

- This category has significant potential for double-counting. Compliance costs in modeling address social impacts. We need to determine whether there is value remaining after accounting for what someone is willing to pay.

- In Minnesota, the calculated social cost of carbon and the value of solar was 18 cents/kWh. The price for wind was 4 cents. Wind and solar power share environmental factors. Would these attributes be used for only DG or for all generation?

- The Minnesota methodology is transparent – a great improvement. But for other generation, we do not have a cost of carbon yet. The other way of looking at it is that other ways of generation are now being overvalued.

- If we employ a social cost, we need to do it for all types of generation. There are economic benefits to most types of generation, e.g., jobs created and lost. We need to include all of them.

- There is a difference between valuation and ultimate payment. The value of water is far higher than the cost of tap water. Being concerned about climate change is different from what should be included in a tariff.

- PUCs should be economic regulators, not social regulators. I might ride my bike to work as a way of addressing social costs, but I do not expect you to buy me a bike.

- Less affluent members are bearing a bigger portion of the cost.

- The appropriate thing is to set up methodologies to determine benefit. We are starting to monetize things that should be done by rough justice in the beginning. You want to make sure you do not create a non-value proposition or provide over- or under-compensation.

- Minnesota did not set a rate, they set a methodology. Also, when you talk about value of solar, is the rate marginal, short-term, long-term…?

- To the extent we continue setting retail rates on the current basis, regulators have to answer two questions: 1) is there any societal/environmental matter that should be included if DG replaces another renewable, and 2) what would be the rationale for requiring retail customers to pay more for societal/environmental impacts than they would pay for a similar resource for a utility-scale project?

- There should be recognition that there is an overall societal value, a benefit to everybody, from our requiring utilities to offer these programs.

- It would be valuable for DOE to create a platform for decisions from a resource-planning perspective. Analysts could take states' values and put them into the platform.

- We cannot go through all the factors here in the list [from Commissioner Hoskins' presentation]. For example, creating solar is not clean; manufacturing creates toxic substances and heavy metals, and when panels are removed from a roof, they have to be recycled. Also, factors such as workers who will not get hired to build a thermal plant – those factors are highly speculative.

- Regarding double-counting, DSIRE (the DOE database) shows over 350 state laws that give tax incentives for solar. If we calculate a value for solar, how do we take into account these other public policies?

- If there is a duplication in policies, that may reflect that current policies are not achieving or reflecting community desires. The issue is putting a number on this social cost. The goal is to address an externality not included in the cost – not just to address that specific economic issue but to develop an incentive to increase diversity, increase resilience, grow jobs, etc. We are not striving for a perfect market signal.

- There is an argument to be made for internalizing external costs from an economic standpoint. But there is a problem when you do that in one sector and not in another. If you raise the cost of electricity, you have an impact on the use of electric cars. We also need to be mindful of profound measurement issues.

- Values will reflect types of incentives developed to drive market transactions. That is very different from including externalities in the rate. Also, picking and choosing which externalities to include is dangerous.

- Long-term tariff design might be different from the need for short-term incentives.

- We're dealing with climate change. If we do not put a price on carbon, we'll always come up with second-best solutions. To ignore externalities is to ignore the nature of the problem.

- How options are priced is an increasing trend in a longer-term timeframe. Consumers want increasing control over choices in the marketplace and will soon have a plethora of options.

- Germany paid 56 cents per kilowatt-hour to incentivize rooftop installation, and they face a price tag of a trillion dollars. Calculate and understand it, but do not necessarily use it to incent.

- RECs are simple transactions. There is not an REC market for distributed generation, but there is experience in terms of utilities and RECs.

- There has to be a way for the model to be updated. The model should be able to take into consideration changing circumstances, e.g., if the world changes to electric cars.

- This should be part of a resource optimization and comparison tool. Valuing externalities helps me determine a "no regrets" strategy.

7. Day 1 Wrap-up

Rich Scheer wrapped up the day, identifying the big takeaways. At the outset, there was general agreement that transparent tools are needed, and they must be developed now. EPRI's tool is a good place to start. Location-specific modeling is key. There is a good deal of work involved, as well as many risks; but there are proceedings and tools to do this. One challenge is that a transparent modeling framework will not be available for a while.

There are complicated and sometimes controversial economic issues regarding social costs and benefits as value streams, including whether and how to monetize them.

Day 2

8. Ancillary Services

8.1 Presentation by Robert (Bobby) Jeffers, Sandia National Laboratory

Mr. Jeffers' presentation focused on the costs and benefits of providing ancillary services using DETs. He noted that a system dynamics approach thinks of the grid differently – as a dynamic control system with humans in the loop.

Growth in intermittent, non-controllable DETs can be limited by the need for ancillary services. The number of PV permits issued in Hawaii rose significantly until 2013, when the number began to level off because of tighter technical restrictions related to DETs. Potentially, DETs can provide many benefits to the bulk grid. Mr. Jeffers showed a graph comparing system load from 2010 through 2014. The graph showed decreasing daytime system loads, so there has been an impact.

Some distributed energy reserves can actually provide contingency reserves – decreased system inertia results in wider frequency swings. More contingency reserves can free up conventional generators to do what they do best, which is to generate electricity at peak efficiency. The cost model is run using production cost methods with worst-case contingencies using both power flow and transient models. The transient modeling has shown us that faster responses to frequency swings have a net efficiency impact, which should ultimately be counted as a cost savings. .

There are costs for wear on assets used in ways for which they were not designed. DETs can provide frequency regulation, but some generation just adds to the need. There is an asymptotic relationship between added distribution and the need for frequency regulation. Again, a faster response needs less frequency regulation.

Regarding voltage regulation, DER does not provide much benefit to the bulk grid because VARs do not travel well. Because of this phenomenon, low penetrations of DETs have less of an impact on bulk grid voltages, but if big generators are pushed offline, the cost of providing VARs will become an issue.

In terms of integrated resource plans/costs, we need to consider how methods and models are working together. We need to close feedback loops and see how rate structures will change behaviors, which will change load and DE. There is a need for better modeling of load. The distribution-to-transmission continuum is not being bridged right now. The interaction between T&D must be researched.

Regarding dispatching for performance, Sandia National Laboratory (in collaboration with Pacific Northwest National Laboratory) is looking at forecast error. If the amount of energy caught up in slow versus fast events can be determined, then researchers can look at the generator's ability to provide slow or fast responses. Then dispatch can be done on a performance basis – across a continuous domain.

Mr. Jeffers concluded his presentation with three key questions:

- What is the net impact of increasing DET on the grid's overall cost of providing ancillary services?
- What are the most promising technologies that will offer the most net benefit with respect to providing ancillary services?
- How do we minimize the total cost of providing all grid services?

Important needs include: understanding better the response speeds needed on the system; aggregation as a DET resource management tool; improved communications and cybersecurity. He concluded by stating that we should not plan for technologies available today but for those we will see tomorrow.

8.2 Discussion

8.2.1 Costs

- Many ancillary services are net energy zero, and many technologies are not production technologies – such as those on the demand response and storage side. Storage, for example, would need to be optimized to provide both time shifting and frequency regulation service. There are limits on the ability to provide both, so we need to think about optimization.

- At the state level, we need to think about resources on the system and try to package them so you can provide clean load on the bulk system. Otherwise, it is like not having yield signs on the freeway. Set up "rules of the road" based on characteristics of resources available and loads being served. Local distribution can look like net load or a resource, so we have to know how to regard it.

- For reactive power, it is part of the generators' cost to connect with the system. Eventually maybe this can be monitored / metered, and they can receive credit for it.

- If you are load-following with DER, providing VARs instead of kilowatt-hours, you are not maximizing production – you have to hold back to provide in both directions. Are there issues with customers signing lease agreements (e.g., with Solar City) that may be predicated on maximizing production?

- You have to unbundle DETs. Some are or can be part of the solution, and some are part of the problem. This could result in potential pricing for a specific technology, at least in some applications. Regarding allocating associated cost streams, the solution is aggregation. This is beyond the comprehension of many customers and even installers. Through aggregation, we can end up with a virtual distributed power plant. Also, backing down production can be a problem because there may be commitments on output, so that backing down would contractual financial issues. Also, if I own my system, I have to forego the use of some zero cost energy to provide ancillary services.

- What customers provide and the cost should be influenced by when and where customers are interconnected into the system: how much, when, in what order, what was the system doing at that time, what kind of improvements had to be made? Modeling has to be done at the granular level because needs can be very different.

- How to handle resources at scale is increasingly important. Most ancillary services are delivered under bilateral contracts. How do we ensure measurement and verification of ancillary services delivered so as to enable the move to scale and greater flexibility?

- (In response to a question about the number of smart inverters): The number of smart inverters required depends on the services the inverters would provide. For voltage regulation, you do not want or need to enable all inverters to provide that service. For frequency regulation, more is better.

- Germany has 600% to 700% peak and is meeting its outage standard of 2.5 minutes/year for two reasons: 1) Germany re-built the whole grid after the war and got everything underground, and

2) there are standards for inverters. The set point is randomized on the inverters so they do not trip off or on at the same time. Not even the utility knows or decides what the set points will be; there is a randomized time lag.

8.2.2 Benefits

- Some CHP manufacturers design their equipment to have the potential to provide ancillary services. Perhaps down the road they can get rewarded for some of those capabilities.

- Does the communications capability exist to manage demand response dispatch in real time? We may sit on a dispatch overnight, before deciding whether to call on a demand response program. Perhaps we should push automated decision-making downstream to the feeder level.

- We would be hard-pressed to assess the benefits of storage without understanding grid needs. Thinking of storage as an ancillary service provider is different from the classical view of storage, i.e., as enabling arbitrage. How do we value those benefits?

- Some takeaways from the QER stakeholder meeting in Portland: We want storage to be prevalent and easy, but there are several big issues: cost competitiveness, environmental concerns, permitting and siting, monitoring and control, how it is integrated into a system…. Much work is needed. DOE can help with pilots and analysis.

- Takeaways from Germany include less focus on storage. TSOs have more penetration than they need already, and they are not expecting to need storage till they get to much higher penetrations. Do not put all your eggs in this basket.

8.2.3 Tools

- Where does safety fit in: outages, who is responsible, worker safety issues, community issues, where something is caused, how far it flows across the system, how costs and benefits are being captured? Do cyber security issues increase with more points of entry into the system?

- The safety issue is a good point, but it is not necessary to have revenue streams to solve all problems; many can be solved technically. The cost difference between smart and dumb inverters is negligible. Many of these things are being solved as we speak.

- We need to figure out safety and measurement and communications. It is not cost-effective to bring a SCADA node into a customer’s house. We could look at other protocols and third parties getting into the home and leverage those resources.

- Nest, Honeywell, and OPower work not by having meters everywhere but using samples and statistics and algorithms. Having millions of randomized distribution points softens control needs, but there is an infrastructure cost. How do you control all those points?

- We need education for state regulators. It is important for those involved in regulations to understand the tradeoffs and what they should anticipate.

- In a high-penetration PV scenario, we need to consider the cost of having to re-do under-frequency load shed schemes. You may need one scheme for daytime and another for evening.

- Underlying costs can be very high. It is possible that we will put a lot of work into developing policies, etc., and the customers will decide to switch to natural gas.

9. Grid Services

9.1 Presentation by Carl Imhoff, Pacific Northwest National Laboratory

Mr. Imhoff's presentation was titled "Inputs and Methods Affecting Estimates of Control/Grid Services Provided by Grid Operators to DET Users." The talk focused not on methodology but on changes in the marketplace, framing emerging issues that make it challenging to address the value of these services. The previous sessions focused on the value DETs could provide to the utility; this session focuses on the value the grid provides the DET owner – an alternative way of looking at the valuation challenge. There is an emerging trend of people asking for tools as if they want to pull away from the grid. Some entities want a clean, fully separated microgrid.

Mr. Imhoff provided a list of services to be considered. Regarding those most commonly considered, utilities have an approach to address capacity, but load composition is changing, so loads will be more complex to manage. Load is increasingly an active variable in the management of the grid. Recent changes are not so much in methodology but in improvement of tools. The California Independent System Operator (ISO) has embedded statistical concepts into forecasting tools, which has saved them tens of millions of dollars because of the more precise forecast. This is a microcosm of a transition about forecasting risk. The trend in dealing with increased variable generation is to add more statistical or probabilistic ability into planning tools. There is a debate as to how much improvement in forecasting is cost-efficient. There are opportunities to improve forecasting further, but it is not clear how much improvement is beneficial.

Grid operators have addressed ramping through the same mundane approach for decades, but with penetration of RE, the cost of dealing with ramping increases. Mr. Imhoff asked what role DETs can play in helping with ramping and how much can be provided to offset supply side ramping. DR at scale can become part of the ramping solution, and growing consideration of transactive energy concepts is being considered to test approaches for coordination of the full range of intelligent demand and variable / distributed generation at scale.

With increased penetration of variable generation, frequency regulation becomes more of a challenge at the bulk system level. Primary and secondary costs are straightforward. States are having individual issues. Most reliability activities are trans-state, and two interconnections have seen increased degradation at the bulk system level. Some of that is from losing inertia. Frequency regulation at the bulk system level is not a resolved issue and will get more complex.

Regarding transient stability, there have been significant advances in tools to help monitor and detect dynamic issues. Damping issues can now be analyzed in real time; there is real-time knowledge of system dynamics. There will soon be 1,200 PMUs around the United States, which provides great transparency but with associated costs. There is increasing interest at the utility level. The other challenge is data access and capturing the value of new data sets. Voltage regulation is mostly covered through broader use of smart inverters.

Mr. Imhoff concluded with some key points to consider:

- Bulk system services are typically embedded in the cost of delivered electricity. Existing and prospective DET owners are becoming more sophisticated their understanding of the value of grid services.
- Many bulk system valuation studies cross state boundaries, adding complexities; new efforts are promising.
- DET futures make load more complex and an active player in grid operations. Better tools for understanding load composition may be needed.
- Energy and distribution management system tools are being improved to better reflect uncertainty; they increase the operator's ability to mitigate historic cost risks.
- Data access is a barrier in current EIM efforts.
- Future reliability management for very fast events (frequency response, transients) is increasingly dependent on new monitoring concepts.

9.2 Discussion

9.2.1 Costs and Benefits

- ➢ When people ask about going off-grid, what are their reasons? DOE might be interested in finding out the costs and benefits of a macro-grid compared to a collection of microgrids. If customers are asking about off-grid options because of economics, that indicates one set of solutions. If the concern is resilience, there might be another set of cost-efficient solutions. Customers moving in this direction will presumably be heavy users or people who need resilience – hospitals, military. Large portions of the cost of maintaining the grid would fall onto the remaining grid-connected customers.

- ➢ As DET penetration increases, the system's ability to dampen itself goes away. The cost needs to be evaluated – or maybe there is a technical fix.

- ➢ When you begin putting systems on the grid that have or cause certain characteristics, at first there is usually not enough of that characteristic to necessitate control. You want to give the benefits to the DET owner, but at a later stage, there is no longer a way to charge the creator of the cost.

- It is also good to think about the cyber security issue. Today we allow devices to connect to the grid, but the device owner is not afforded or guaranteed any level of security by the grid operator.

- That goes both ways – connecting outsiders increases the utility's cybersecurity risks as well.

- As we think about rising penetration, we may think about thresholds. You could keep an eye on the metrics so that you would know when you are approaching a certain ceiling and will have to change the admission requirements. Is this a fruitful way to think about this evolutionary process?

- There is no magic number; it is very feeder-specific.

- We have to do more in feeder modeling and understanding. The 15% rule is no longer valid.

9.2.2 Tools

- The grid itself can provide a market signal. Price-reactive appliances themselves could respond *en masse* to price signals. We should explore this through modeling to avoid unintended consequences.

- Regarding thresholds, there are lessons to be gained from the wind industry, which has developed a mature framework for interacting with the system. Distribution and transmission have to be more integrated – think about a common framework to get more out of near-term investments for maximum flexibility for options further out. There is value in setting aspirations across sets of benefit streams.

- One benefit the local grid provides to customers is network resiliency. Has EPRI examined support services the grid provides to DETs?

- That goes back to capacity. The startup current required by motors is typically eight times greater than what is needed for steady-state operation, and customers will probably not have that startup capability from a DET device unless it is deliberately oversized. We are continuing to look at that issue in an integrated grid, looking at investment strategies that support DET under startup conditions, full load conditions – and the tradeoffs.

- The question about the value of grid services to the customer will not go away. It will resurface at the local level whenever DET generation and storage technologies hit the right price points.

10. Discussion of Next Steps

Rich Scheer: In this last discussion, we want to digest the key points that have been made and have a brainstorming session on two topics: 1) what are the needs in terms of data, models, and tools, and 2) what are the respective roles of different kinds of organizations for getting those needs met?

- We need to work on convergence. When several technologies become standard in a customer's home, what is the utility providing, what is the customer providing, and how do we deal with rate design?

- From the small utility perspective, what are the penetration levels at which we need to worry about X and Y and Z?

- From an overall policy perspective, I am very concerned about work that only looks at DG. We are not including costs and values inherent in other resources. If one goal is to provide regulators with tools to value various resources, and you are presenting methodologies for only some of those, you are only providing half the loaf needed for objective, cost-effective valuation. I encourage DOE to consider a broader scope.

- Competition both within and between technologies is good for our customers. I share Mary Ann's concern about drawing a line and looking only at distributed technologies.

- I also urge DOE to note in the final product (from this workshop) that certain policy elements, such as cross-subsidization, can be presumed acceptable if they serve the greater good.

- In integrated resource planning, you also need to consider customer needs and pricing services. There is also a contractual issue: once you give an arrangement to an initial, small group of customers, the same arrangement will be expected by later entrants, or there will be accusations of discrimination. You need to set policies that anticipate the need for evolution.

- Will storage happen at home, or be part of a substation, or both? What is the value proposition from the customer perspective and from the utility perspective?

- Make sure the forecasting model is flexible and can change regularly.

- We need visibility into the system – sensors and communication. Modeling must be done in time series, not static. Central and distributed controls have to be set up – starting at bulk power down to lower-level systems / advanced DET equipment. Also, we need to consider the AC/DC grid – new grid constructs that incorporate DC.

- Regarding methods, we have talked about models that produce technical results, and now we are adding the complexity of taking a technical model and transforming it into an economic model. In terms of transparency, maybe you could add locational profiles in your menus, and make it easier to translate some of this for non-modeling non-technical people.

- Research must be done into operational issues. After capacity, resource adequacy is the next big value stream.

- Regulators and policymakers need menus (rather than recipes) about how to get things done. Regarding cyber security, we cannot underestimate what one person can do to the overall system with one small DET system. How do we work on the gaps as we move away from a centralized system?

- DOE's role is to help develop options – not to make decisions – and develop costs and benefits. Tell the complete truth.

- There is a need for better communication between vendors, utilities, regulators, even customers. Perhaps we need a technical arbiter to boil everything down into each individual entity's bottom line. We need to keep an eye out for a vicious cycle between PV penetration and rates; there are ways to dampen that feedback loop.

- The proliferation of cost–benefit solar studies comes down to a battle of methodologies. What is needed from DOE is dissemination of best practices in this area, technical assistance to state regulators, and best approaches for determining associated value streams. One alternative is to unbundle all the value streams that are not separately considered in market rates and take a more market-based approach.

- DOE could provide an estimate of costs for people to go off-grid. It is a suboptimal solution for everyone to go off the grid. What can we offer people to keep them on the grid?

- Getting into actual dollar amounts for microgrids, etc., ten years out – that is a slippery slope and should not be the purpose of this exercise.

- There is value in educating all stakeholders, including about what things cost. Before we get to who should pay and who benefits, it is important to understand what something actually costs. Then stakeholders can address fair allocation.

- DOE could make laboratory staff available to come out to states or other forums.

- Utilities are asking to upgrade infrastructure that usually has social costs. How does a commissioner know that what utilities are requesting is going to move us toward integration of these distributed technologies, rather than technologies that have a central station point of view? As utilities make decisions, DOE could help them think through how to invest money to enable the grid to reduce the costs of integrating these technologies. Regarding interconnection, commissions are looking at interconnection rules. In the past, DOE has helped to provide third-party technical assistance. A continuation of that technical assistance for all these technologies would be helpful.

- DOE could help with areas of deficiency in terms of understanding. Also useful would be an understandable explanation of the system and components needed to get to where you want to be tomorrow. If an authoritative voice says, "These are some of the operational changes needed to make the system function better," that provides a basis for policymakers. Right now everyone else is bringing a pet interest to the table.

- Since you have funds and access to labs, focus on the technical issues. Help with the translation issue for complex matters; provide things that governing bodies can use and that we can explain to our customers. On DET penetration, for example, we know there may be some non-linearities. For policymakers, technical issues may distinguish between going off-grid and remaining integrated. Also, we cannot just think on the supply side; we also have to think on the customer side. We have to think about disparities between customers, those paying $100/month and those paying large amounts. Such disparities can result in rent-seeking behavior.

- For those utilities too small to do the research themselves, what communications are needed to enable delivery of all the things we want? We would like to be able to go to a regulator and say, someone we trust says we will need this, and that is why we bought it (e.g., more bandwidth). DOE could help with needs of that kind.

- As we transition from economic dispatch to environmental dispatch, what are the effects on everything we have talked about? Coordination with and buy-in by FERC will be critical. Compensation for DETs has to be translated into the retail level. The retail level is where it will fail or succeed.

- We have seen through many industries that customers want choice (e.g., the Internet of Things). How do you value that choice and pay for that choice? DOE can help with understanding those issues.

- Many innovators bringing DETs to market bemoan the fact that they cannot get access to multiple value streams because of the regulatory environment.

- Well-designed DETs provide streams of benefits that are more than negative energy. If well built, they provide value to the utility trying to integrate them. When comparing distributed technologies and a solar farm, I recognize that integration costs for distributed are higher because of economies of scale, but we should treat them as if they were on a level playing field.

- It is difficult to convince regulators to move away from the cents-per-kilowatt-hour approach because we have not convinced customers. Customers do not like real-time pricing; there is tremendous resistance. The customer base does not want to buy and sell ancillary services, so it will be a hard sell.

- We are in a position at the retail level to compensate for DG. We have three arbitrary methods that are not satisfactory to anyone. It is incumbent upon our regulators to determine the value to the grid.

- It is not DOE's job to increase the penetration of certain technologies but to provide information about options. That should be a Department-wide view.

- DOE should convene another workshop to talk about tools and models (and invite the appropriate people).

- Are societal impacts so location-specific that they should not be rolled up and addressed at the state or national level (e.g., tax policy)?

- Take the industrial customer's view into account: competitiveness matters.

- Help large customers to understand the complexities of DET integration and make their decisions after considering multiple value streams.

11. Closing Remarks

David Meyer, Senior Advisor, DOE Office of Electricity Delivery and Energy Reliability

Mr. Meyer thanked everyone for attending and thanked the labs for their efforts and input. He noted that there was not yet a clear answer to where DOE will go on the basis of the discussion. Significant DOE resources are spent by the labs, and they deliver high-quality results; the group's feedback will affect DOE's decisions about the labs' project designs and overall agendas. Regarding tool development and other kinds of activities, DOE has several parallel strategic efforts under way, including the Quadrennial Energy Review and the Quadrennial Technology Review, as well as a coordinated, multi-office effort to support grid modernization. Dealing with the valuation challenge will have to be meshed with these broader efforts.

Kevin Lynn, Director, Grid Integration, DOE Office of Energy Efficiency and Renewable Energy

This workshop was partly motivated by the range of studies that have been done. We wanted to determine a direction that would lead to a better set of tools. We have to have a policy discussion and a technical discussion as well. We got a good deal of input and have a lot to think about. This was an even-handed discussion, which is important. DOE wants to speak with one voice with respect to the grid, and to coordinate our diverse grid-related activities better. We want to move forward in a holistic way. We see this as the start of a process, rather than a stand-alone event.

Participant List

DOE Workshop on Estimating the Benefits and Costs of Distributed Energy Technologies September 30–October 1, 2014

Name	Affiliation
Tony Anderson	Cherryland Electric Cooperative
Lori Bird	Nat. Renewable Energy Laboratory
Katie Bolcar	Solar Electric Industries Association
Bob Borlick	Borlick Assoc.
Phoebe Brown	Energetics Incorporated
Scott Burnham	SAIC
Caitlin Callaghan	USDOE
Jim Cater	American Public Power Association
Steve Chalk	USDOE
Michael Champley	Hawaii Public Utilities Commission
Kerry Cheung	USDOE
Charlton Clark	USDOE
Chuck Clinton	National Association of State Energy Officials
Ed Comer	Edison Electric Institute
Paul Denholm	National Renewable Energy Laboratory
Greg Dierkers	National Governors Association
Phil Dion	UNS Energy
Emily Felt	Duke Energy
Steve Fine	ICF International
Karen Forsten	Electric Power Research Institute
Brent Gale	Pacificorp
Sue Gander	National Governors Association
Charles Gray	Nat. Assoc. of Regulatory Utility Commissioners
Stanton Hadley	Oak Ridge National Laboratory
Julia Hamm	Solar Electric Power Association
Maria Hanley	National Energy technology Laboratory
Tom Hoff	Clean Power
Alex Hofman	American Public Power Association
Anne Hoskins	Maryland Public Service Commission
Lon Huber	AZ Residential Utility Consumers Office
Carl Imhoff	Pacific Northwest National Laboratory
Robert (Bobby) Jeffers	Sandia National Laboratory
Sandra Jenkins	USDOE
Mike Judge	Massachusetts Energy Office
Jason Keyes	IREC
Julia Kittel	Energetics Incorporated
Mike Kleinberg	DNVKEMA
Kevin Knobloch	USDOE
Steve Lindenberg	USDOE

Kevin Lynn	USDOE
Robert Margolis	Nat. Renewable Energy Laboratory
David Meyer	USDOE
Doug Middleton	USDOE
Andrew Mills	Lawrence Berkeley National Laboratory
David Mohre	National Rural Electric Cooperative Assoc.
Alan Mosher	American Public Power Association
Ellen Nowak	Wisconsin Public Service Commission
David Ortiz	USDOE
William Parks	USDOE
Carl Pechman	USDOE
Lara Pierpoint	USDOE
Lee Ragsdale	North Carolina Elec. Membership Cooperative
Mary Ann Ralls	National Rural Electric Cooperative Assoc.
Matt Rosenbaum	USDOE
Rich Scheer (facilitator)	Scheer Ventures, LLC
Lori Singleton	Salt River Project
Steve Steffel	PEPCO Holdings
John Sterling	Solar Electric Power Association
Kenya Stump	Kentucky Energy Office
Elaine Ulrich	USDOE
Ellen Vancko	Maryland Public Service Commission
Aliza Wasserman	National Governors Association
Peggy Welsh	Energetics Incorporated
Ryan Wiser	Lawrence Berkeley National Laboratory
Jay Worley	JEA
Fred Zalcman	SunEdison