Memorandum
From: Seth Handy
To: Jonathan Schragg
Date: June 2017
Regarding: Rhode Island Division of Public Utilities and Carriers & Office of Energy Resources Power Sector Transformation Q&A on Distribution System Planning

I respond on behalf of Handy Law. We are not representing NERI with regard to these proceedings as of this time. We also, admittedly, do not have the expertise of others on these matters so have mostly relied on other sources (that we've accumulated over years of work on reform efforts) to gather what seemed to be pertinent and possibly helpful input. The exercise of hunting and gathering took considerable time so please forgive us if some content isn't directly responsive or perfectly organized.

Questions for stakeholders on Distribution System Planning

Questions for stakeholders on DSP elements

1) How important are each of the DSP elements described here to the future electric utility? Are there additional elements not described here that should be included as a strategic focus of the electric utility? What does success look like for each element?

Response*:* All the noted elements are essential. Success would be:

Forecasting: Being able to forecast load adequately to be able to plan for it comprehensively so as to reduce cost and maximize benefits (ie, provide value) to the system, to customers, and society.

Power flow analysis: As an element of the above, understanding where and when system capacity needs to be enhanced to serve anticipated load and providing for such enhancement as effectively as possible.

The planning and investment policies that govern our power grid were developed in an earlier era, when large fossil-fueled power plants were constructed to energize population centers. Longstanding policies skew decisions in favor of legacy power grid investments over newer, often less expensive and more advanced solutions. For example, the costs of paying for transmission projects are "socialized" in many regions of the country. This approach spreads the cost of transmission projects to ratepayers in all states in the power pool, while lower cost local options are rarely considered and are not eligible for this type of socialized cost recovery. These rules need to change so that viable, often lower-cost alternatives to large-scale trans- mission projects—such as energy efficiency, clean distributed generation, energy storage, and demand response—are not excluded when considering investments to maintain and improve power reliability. Such alternatives can replace or defer the need to construct more grid infrastructure, immediately delivering economic and environmental benefits. [Source – ENE, Energy Vision Framework]

Condition assessment: Understanding and transparency regarding any threats to system performance, security and sustainability so that enhancements can be planned effectively and implemented in such a way as to maximize value.

In New York, the NYDPS Staff Straw Proposal proposes that utilities should file near-term "distributed system implementation plans" (DSIPs), in which utilities will describe how they plan to transition to being a DSP provider, and how they will recognize DER contributions that might otherwise compete against traditional infrastructure investments. [Source – Crosby & Call, "NY & CA Are Building Grid of Future"]

California, AB 327 requires IOUs to file DRPs that include scenario-based planning as well as integration analyses. Scenario-based planning accounts for different DER adoption scenarios, as well as other factors that might impact the need for DERs, such as retirement of large power plants. The CA IOUs are required to define the criteria for determining what constitutes an optimal location for DER deployment, and then identify values for the deployment via online mapping tools. The IOUs are also required to conduct integration analyses to measure the threshold integration of DERs, based on assumptions related to DER impacts on electric system reliability and safety. [Source – Crosby & Call, "NY & CA Are Building Grid of Future"]

Discuss with electric distribution planning staff at National Grid ways to address a gap in stakeholder engagement. Start by confirming the set of interested stakeholders (e.g. OER, the EERMC, and the DG Board), then identify or create opportunities outside of PUC dockets for these stakeholders to engage with the utility on distribution investments pertaining to load growth. Concurrently, determine if and how distribution planning/SRP can be coordinated with net metering to offer enhanced incentives above what is currently available to promote the development of DG where it is most needed, if determined to be cost-effective. Work with National Grid distribution planning to determine how and to what extent forecasted DG from REG, net metering, and any other applicable renewable energy promotion processes can be incorporated into distribution planning. Also consider how this can be done for other forms of DER and for strategic electrification in the longer term. Ensure that any resulting information from above is coordinated with Grid's current "long-range capacity plan" and future distribution planning where appropriate. Gain an understanding of how the long-range capacity plan and ISR could be used to merge traditional "poles and wires" approaches with new technologies in a multi-year, strategic approach. Explore the role that robust measurement and verification processes have in distribution planning to enable planners to better understand the costs and benefits of capital investments and technology deployment, ultimately as a basis for informing future decision-making. Work with National Grid to better understand the overlap between "asset condition" and "load relief" projects as identified in distribution planning and proposed in the ISR. Understanding the dynamic between asset condition and load relief projects is necessary information for the future update of the Standards to potentially open up more projects to NWA eligibility. [Source – SIRI]

Solution identification: Ensuring that all stakeholders can participate in the identification of needs and design and implementation of solutions to ensure that process is not framed by any specific interest other than maximizing value to the system, the customer and society. Removing any conflict of interest that causes incumbent utilities to prefer building new infrastructure to conservation, efficiency, or local power from competitors or even utility customers. Proactive system planning is the key. Hawaii and New York are good examples of states that are implementing energy plans that incorporate the integration of local and regional resources. New York's Reforming the Energy Vision also proposes the independent operation of the distribution system.

The approach to distributed resources should be reevaluated to determine how demand management can be used not as a last resort but rather as a cost effective, primary tool to manage distribution system flows, shape system load, and enable customers to choose cleaner, more resilient power options. It is technically feasible to integrate energy-consuming equipment, as well as distributed generation and storage, fully into the management architecture of the electric grid. The purpose of this inquiry is to examine how the distributed grid architecture that is now technically feasible can be achieved on a wide scale. Such architecture offers the potential of increased efficiency and reduced volatility in system management at both bulk and distribution levels, as well as reduced total consumption and greater penetration of clean and efficient technologies, with ensuring benefits in overall system costs, reliability, and emissions. It also offers the potential for customers to optimize their individual priorities with respect to resilience, power quality, cost, and sustainability. It is not intended to replace central generation, but rather to complement it in the most efficient manner, and to provide new business opportunities to owners of generation and other energy service providers. Distribution utilities will play a pivotal role, representing both the interface among individual customers and the interface between customers and the bulk power system. The utility as Distributed System Platform Provider (DSPP) will actively coordinate customer activities so that the utility's service area as a whole places more efficient demands on the bulk system, while reducing the need for expensive investments in the distribution system as well. The function of the DSPP will be complemented by competitive energy service providers; both generators of electricity and retailers of commodity will expand their business models to participate in Distributed Energy Resources (DER) markets coordinated by the DSPP. [Source - NY REV]

The DSPP will identify, plan, design, construct, operate, and maintain the needed modifications to existing distribution facilities to allow wide deployment of distributed energy resources. The DSPP will therefore be responsible for transforming existing distribution systems into a platform not only for DER, but also for a range of products and services that will enable greater efficiencies in the generation, management, and consumption of electric energy. To achieve this, the DSPP will also have to control, manage and balance distribution-system-level DER in real time, and promote new products and services to meet customers' evolving needs. [Source - NY REV]

Planning must integrate local and regional level resources. In other words, ensuring that when planning for new power plants or power lines, utilities (or grid managers) consider how needs can be met with local solutions including rooftop solar, energy storage, electric vehicles, and even non-capital measures like controllable, smart appliances.

We cannot plan for the future until we figure out how to fully value DERs. Historically, the electricity system has not fully valued DERs in distribution system planning and investment, despite potential benefits of DERs to the grid. While some utilities have employed DERs to modify peak loads and reduce wholesale peak costs, DERs can provide other services that may not been fully accounted for in existing tariffs. In fairness, utility companies may not have fully leveraged DERs in part because the regulatory framework guiding utilities' business model did not explicitly orient the utility to recognize that value. Now that is changing. Due to cost reductions and accelerating adoption curves, DERs matter, and states and utilities are taking DERs more seriously in business model development and planning. [Source – Crosby & Call, "NY & CA Are Building Grid of Future"]

Integrated Distribution Planning encourages the incorporation of DERs into every aspect of grid planning. The framework expedites DER interconnections, integrates DERs into grid planning, sources DER portfolios to meet grid needs, and ensures data transparency for key planning and grid information. Ultimately, the approach reduces overall system costs, increases grid reliability and resiliency, and fosters customer engagement. If grid planning decisions are made before consideration of customers' decisions to adopt DERs, – which is frequently the case today – grid investments will underutilize the potential of DERs to provide grid services, ultimately resulting in lower overall system utilization and higher societal costs of the collective grid assets. In contrast, prudent planners who proactively plan for customer adoption of DERs may avoid making unnecessary and redundant grid investments, while also enabling the use of customer DERs to meet additional grid needs. [Source – Solar City, "A Pathway to the Distributed Grid"]

Solar City proposes the creation of a new utility incentive model, Infrastructure-as-a-Service, which would neutralize the utility incentive to deploy utility-owned infrastructure in lieu of more cost-effective third-party options. This model would enable utility shareholders to derive income from third-party grid services, mitigating the financial impact that may bias utility decision-making. Such a model would help ensure that utilities take full advantage of DER readily being adopted by customers. Infrastructure-as-a-Service is a regulatory mechanism that would modify the incentives faced by utilities when sourcing solutions to meet grid needs. This new mechanism would allow utilities to earn income, or a rate of return, from the successful provision of grid services from non-utility owned

DERs. Infrastructure-as-a-Service facilitates the least cost/best fit development of distribution grids by creating competitive pathways for DERs to defer or replace conventional grid investments, while maintaining equal or superior levels of safety, reliability, resiliency, power quality, and customer satisfaction. As the figure below shows, the three primary steps of a utility distribution planning process (forecast, identify needs and evaluate solutions) remain identical to the current process, followed by the infrastructure-as-a-Service mechanism's enhancements to sourcing in steps four (select and deploy) and five (operate and collect). Under the proposed approach, after evaluating all feasible technical solutions for a particular grid need, including alternative grid solutions derived from DER portfolios, Infrastructure-as-a-Service would empower distribution planners to select and deploy third-party assets that address the specified need if more cost-effective for ratepayers than conventional solutions. Importantly, Infrastructure-as-a-Service would create an opportunity for utilities to operate and collect streams of service income, or a rate of return, based on the successful deployment of competitively sourced third-party solutions. This service income provides fair compensation for effective administration of third-party contracts that enable alternative resources to deliver grid services, and helps mitigate the structural bias towards utility-owned infrastructure that currently exists under distribution "cost plus" regulation. Note that other mechanisms attempting to achieve a similar utility indifference to DER solutions have been proposed, such as the modified clawback mechanism being discussed in New York. While the clawback mechanism offers the potential to reduce the financial disincentive that utilities face in utilizing DERs, the potential utility upside may be small as compared to the lost opportunity and insufficient to neutralize the utility disincentive. This downside to the clawback mechanism may be overcome via the infrastructure-as-a-service mechanism.

Neutralizing the utility disincentive to utilizing DERs is critical but not sufficient to drive transformation in distribution planning. New incentives may be ignored in practice without corresponding changes to long-established and familiar utility processes that have sourced only self-supplied solutions to date. The adoption of a Distribution Loading Order50 would borrow an existing concept from bulk system procurement policy in California, which prioritizes procurement of preferred resources, including energy efficiency, demand response, and renewable energy, ahead of fossil fuel-based sources. In the distribution context, a Distribution Loading Order prioritizes the utilization of flexible DER portfolios over traditional utility infrastructure, when such portfolios are cost-effective and able to meet grid needs.

In concert with a mechanism like Infrastructure-as-a-Service, a Distribution Loading Order provides the procedural framework for evaluating distribution solutions in order to ensure grid planning is consistent with longer term policy objectives that support environmental, reliability, and customer choice goals. Importantly, a Distribution Loading Order would ensure that DER solutions are properly incorporated into grid planning. However, utilities would always maintain the authority to select and deploy a suitable portfolio of solutions, including conventional solutions when more appropriate, to ensure reliability. For these conventional investments, utilities would continue to earn an authorized rate of return.

A final incentive that hampers transition to a 21st century electricity system is that utilities have every incentive to operate existing and new capital assets for as long as possible. When the payments for construction are fully depreciated, the low operating costs of existing infrastructure makes utilities reluctant to shut down power plants or power lines when they can still earn revenue in operation, even when they are no longer in the public interest. [Farrell – “Beyond Utility 2.0 to Energy Democracy”]

One of the central governing rules of interstate transmission – FERC Order 1000 – was supposed to create a meaningful evaluation of non- transmission alternatives to new power lines. But the rule only requires that a utility consider alternatives proposed in the process, it does not obligate them to offer alternatives. In other words, to have a meaningful debate of alternatives requires a dedicated third party – a state agency, commercial or industrial customer, or nonprofit – to show up to contend with a utility’s transmission line proposal on its own dime. [Farrell – “Beyond Utility 2.0 to Energy Democracy”]

Participation by third parties is remarkably onerous. For an outside entity to offer a transmission alternative, they have to request access to data about grid operations that many utilities shield as “trade secrets,” be able to competently model the grid impact of a non- transmission alternative without access to the same proprietary software package or trained engineering staff used by the incumbent utility, and then cast the alternative in the technical and legal language expected at a regulatory proceeding. [Farrell – “Beyond Utility 2.0 to Energy Democracy”]

Alternatives to transmission projects face another hurdle: compensation. While FERC has established rules for sharing the cost of transmission lines along the route they extend, non- transmission projects have no such cost allocation process. [Farrell – "Beyond Utility 2.0 to Energy Democracy"]

Not only is it difficult for non-transmission options to share costs, but utilities frequently receive federal incentives for high voltage transmission lines that cross state boundaries. The overseer of these bonus payments – the Federal Energy Regulatory Commission – has doled them out to 4 of every 5 requesting utilities, resulting in an average return on equity of 13%.

Finally, the federal overseers of transmission projects don't consider any non-grid benefits that would weight a decision toward a transmission alternative for serving grid needs. For example, while Vermont state regulators consider a wide range of benefits in their cost-benefit calculation of energy efficiency improvements (shown in the following chart), only a small slice of the benefits (in blue) would be considered by federal transmission planners, even though energy efficiency can meet the same needs for reliability and grid capacity. [Farrell – "Beyond Utility 2.0 to Energy Democracy"]

Hosting capacity analysis: Ensuring that we are not limiting our perspective on potential system enhancing value just because the current capacity of the system is not able to support the implementation of enhancements that will ultimately maximize that value.

Rate plans should have pre-established means to determine whether a utility is spending adequate levels on necessary investments and maintenance of its system, so that later catch-up spending is not needed. There should also be upside protections on Capex spending to prevent unnecessary inflation of the rate base. Performance metrics need pre-established trigger points for re-evaluation, especially when the incentive includes both upward and downward reconciliations. Plans should have provisions to review and assess the long-term effect of the incentives and to modify them, as necessary. [Source NYREV]

2) Utility investment in grid modernization capabilities will provide increasing visibility into the system, allowing a more sophisticated and granular approach to DSP. What should the future state of planning look like as visibility improves? What should the transition look like between current DSP and the future state of DSP?

Reply: Ultimately, planning processes must ensure that DERs are effectively counted on by grid planners and leveraged by grid operators. The first step in grid planning is to identify the underlying grid needs. The use of alternative solutions such as DERs should be included in the portfolio of solutions that are considered to meet these grid needs. While utilities could ostensibly assess these alternative solutions within their existing process, opening up the planning process by sharing the underlying grid data would drive increased competition and innovation in both assessing and meeting grid needs. Any concerns from sharing such data – such as customer privacy, security, data quality, and qualified access – can be mitigated through data sharing practices already common in other industries. In fact, stakeholder engagement and access to planning data is already a central tenet in electric transmission planning across the country. The challenges of ushering a new industry norm of data transparency are far outweighed by the potential that broader data access can drive in increased stakeholder engagement and industry competition. Data transparency efforts should first focus on communicating the exhaustive list of grid needs that utilities already identify in their planning process. While utilities may claim that such needs are already communicated within general rate cases, the information contained in those filings are incomplete. A standard set of comprehensive data should be shared about each grid need and planned investment so that stakeholders can proactively propose and develop innovative solutions to those needs. This proactive data access broadens the set of innovative solutions made available to utilities and guards against an insular approach to deploying grid investments. While data on specific utility-identified grid needs is critical to assessing innovative solutions in place of traditional investments, underlying grid data should also be made available to foster broader engagement in grid design and operations. Access to underlying grid data allows third parties to improve grid design and operation by proactively identifying and developing solutions to meet grid needs, even before they are identified by utilities. Data that is made available on grid needs and planned investments is rarely provided in an accessible format. Often, information is provided in the form of photocopied images of spreadsheet tables within utility GRC filings, hardly a format the enables streamlined analysis. This data communication approach requires stakeholders to manually recreate entire data sets into electronic version in order to carry out any meaningful analysis, a time-intensive and needless exercise. Other potential stakeholders never attempt to engage due to the barrier of data access. The use of standard, machine-readable data formats is prevalent in many industries and within the utility industry itself; organizations like the Energy Information Agency (EIA) foster such broad access to electronic, standardized data sets. Distribution grid needs and planned investments should follow suit. [Source – Solar City, "A Pathway to the Distributed Grid"]

The DSPP will create markets, tariffs, and operational systems to enable behind the meter resource providers to monetize products and services that will provide value to the utility system and thus to all customers. Resources provided could include energy efficiency, predictive demand management, demand response, distributed generation, building management systems, microgrids, and more. This framework will provide customers and resource providers with an improved electricity pricing structure and vibrant market to create new value opportunities. The DSPP will enable the adoption of information technology and real-time information flow among market participants, and establish a platform to support demand-side markets and technology innovation. DSPP products and pricing structures will allow for large scale deployment of clean DER, including energy storage that complements renewables, into the electric system. The DSPP should serve simultaneously as the interface among retail customers in distribution-level markets, and the interface between retail customers as a whole and the ISO. At present, a utility generally bids its load into the market as a price taker. Taking advantage of more responsive distributed energy resources, it could bid load in a more predictive fashion that saves money for customers and creates greater system wide efficiencies. The DSPP could function as the aggregator of aggregators and interface with the ISO in this manner. In addition, just as we have seen in the bulk power markets, as technology evolves the DSPP can introduce new markets and products at the distribution level that will yield further benefits to consumers. This will require the DSPP to use localized, automated systems to balance production and load in real time while integrating a variety of DER, such as intermittent generation resources, and energy storage technologies. The DSPP would manage DER products and services in real time, using technologies that allow the flexible and instantaneous use of generation or demand response to meet customer and system needs. Such applications could potentially maximize the operational and economic efficiency of DER and distribution systems. Implementation of DSPP functionalities will need to be carefully staged, taking into account cost-effectiveness, customer participation, local system needs, and the scalability of near-term measures toward long-term implementation of a fully integrated grid. Resolution of pricing issues in a DSPP model could affect the long-term role of net metering for solar and other clean energy projects. Net metering acts as an incentive to promote desirable technologies, and also serves as compensation for the system contribution made by customer-sited generation that feeds into the grid. If DSPP markets are developed correctly and aligned with the Commissions policy objectives, in time they should serve as a replacement for net metering that serves both functions -- incentive and compensation – via market mechanisms that more properly value both environmental benefits and system contributions. [Source NY REV]

Rather than a specific program funded through a surcharge, efficiency will be one of the DER tools at the utility's disposal. The DSPP will integrate energy efficiency into its system planning, targeting efficiency where it will produce maximum system value, and thus optimizing the economic value of energy efficiency expenditures for all customers. Efficiency programs may also be implemented on a territory-wide basis by enhancing customers' ability to manage bills and other objectives of the Commission. The existing DMS infrastructure must be upgraded as a part of the anticipated transformation of the electric grid. The DSPP must procure and employ advanced distribution management systems that will be needed to enable distribution systems to serve as the platform for integrating DER technologies. Such advanced systems will be essential to allow wider deployment of DER, including renewable generation resources such as solar and wind. To the extent the DSPP manages a market, an independent operator is arguably preferable. [Source NY REV]

Developing a smart grid will require highly accurate monitoring of energy supply and demand, sophisticated analysis and modeling of supply and demand patterns under numerous conditions, real-time fault detection, and reliable nearly instantaneous control of varied and dispersed energy resources. To meet these goals, the DSPP must adopt communications networks capable of supporting a smart grid. Issues presented will relate to the reliability, reach, cost, latency and security of such systems. [Source NY REV]

The pace and scale of DER deployment in both NY and CA will rest, in part, on the breadth and depth of system and customer data and the availability of that data to customers (to manage their use), as well as to DER service providers (to develop new services and target those to locations most in need). For example, combined with a price signal, system data (such as metering at substation or other system nodes) exposes areas on the system where DERs can provide the most value, for example by alleviating congestion in load pockets. Customer usage data reveals the largest users of power, and therefore those most likely to be interested in DER solutions that can reduce their bills. [Source – Crosby & Call, "NY & CA

Are Building Grid of Future"]

California has the head start in metering data collection due to roll-out in advanced metering infrastructure (AMI), as well as pioneering data-sharing tools such as Green Button, Green Button Connect, as well as other data-sharing mechanisms to make DER valuation more transparent that are considered in the DRP process. [Source – Crosby & Call, "NY & CA Are Building Grid of Future"]

However, NY has the potential to leapfrog CA on data in novel ways. The NYDPS straw proposal envisions a two-way data exchange, where DER providers are required to provide DER size and load reduction data to the DSP (like a generator would to a bulk system operator), and utilities would share system and customer data to the DER providers. Also, while AMI is an important enabler of measurement, verification, and communication, alternative metering and communication solutions such as revenue-grade metering and communication chips embedded in smart devices may offer more advanced features than existing AMI functionalities, particularly where metering is a challenge in environments such as New York City. [Source – Crosby & Call, "NY & CA Are Building Grid of Future"]

Additionally, in NY, the REV proceeding seeks to create a distributed system platform that allows customers, third-party service providers, and energy service aggregators to interact, not unlike other platform markets such as computer operating systems and smartphones. For example, the Apple iOS and iPhone serve as the platform on which other services are available, linking data and algorithms to devices that perform countless tasks, such as car sharing. [Source – Crosby & Call, "NY & CA Are Building Grid of Future"]

In both states, the customer is central to the adoption and integration of DERs, as well as the future business model of the utility. While utilities have established trust with many of their customers and provide safe and reliable service, there is an opportunity to let other companies offer more innovative customer solutions integrated with our online, digital lives. JD Power recently found that while overall customer satisfaction with utilities has improved, utilities are not keeping pace with other tech companies such as Google, Facebook, and Amazon that are positioned to disrupt the residential electric utility business models. [Source – Crosby & Call, "NY & CA Are Building Grid of Future"]

To achieve the goals of least cost, least risk and maximum customer benefit, regulators must require utilities to synchronize their implementation of advanced grid technologies with the growing DER market. Utilities perform this planning function today, but not usually in the public arena and not closely coordinated with other actors providing services on an upgraded distribution grid. This planning exercise is now loaded with new responsibilities for the grid operator. Further, if the utility also has a stake as a competitor with DER services, it is essential that an independent authority such as the state regulator oversees the planning. Consider the telecom sector following the passage of federal legislation in 1996. Incumbent carriers were required to unbundle their grid (the public switched network) and provide access to new players with new products, often competing with the grid owners. Regulators ensured that new competitors got access to the network on the same terms as the incumbents. Regulation of all players moved significantly away from the traditional cost-of–service model. [Source – Ceres, "Practicing Risk Aware Utility Regulation"]

Questions for stakeholders on DSP transparency

1) Who are the users of system and customer data? What data do users need to guide investment decisions, support business models, or guide policy/program activities? What are the specific use cases for each dataset? What is the desired format of each dataset? What is the frequency with which datasets should be updated?

Response: What's really needed today is competitive markets on the distribution edge. It makes no sense to have utilities hostile to distributed energy and local energy management. We need entrepreneurs thinking about how to package energy services in new ways for customers, and we need utilities not just to stop impeding them or to get out of their way, but to actively empower them. [Roberts, "Utilities for Dummies Part 2" in Gristmill]

Small commercial and residential customers in New York and other states are beginning to benefit, to a limited extent, from metering retrofit services, wireless HVAC control and diagnostic sensors, single open protocol software platforms, controllable Wi-Fi thermostats, energy advisory support, mobile applications, desktop dashboard alerts, and financial business incentives. ESCOs and other vendors are generally just beginning to offer these products and services to mass-market customers. In addition, the cable television industry is beginning to offer energy commodity service as well as home energy management tools to residential customers. Products designed to change customers' behavior regarding their energy use have been developed by companies that are partnering with utilities and ESCOs to promote behavior change primarily for residential customers. [Source NY REV]

The emergence of new analytical software tools is helping to make portfolio-scale energy assessments easier and more cost effective, both for cities and for other large portfolio owners. RMI examined the use of these software tools to support the portfolio- assessment process and concluded that these new analytical software tools are helping to make portfolio-scale energy assessments easier, although the process does present challenges as well. Private-sector companies selling such tools include First Fuel, Retroficiency, and others. Communities considering portfolio analytics for public buildings may wish to interview a select few providers and conduct a pilot to assess cost effectiveness and potential before committing to a larger portfolio. [Source – RMI, Community Energy Resource Guide]

Local control and equitable access are the keys to unlocking an economic transformation that parallels the technological one, by allowing communities to maximize capture of their local energy dollar. It means an energy system that empowers electricity customers to manage their electricity use, produce power individually or collectively, and transact with their neighbors, local businesses, and their city. Consumers become, in Alvin Toffler's elegant description "prosumers." They can make the decision as to whether to consume, or produce, or store electricity at any given moment. Individuals and communities, formerly simply passive observers of utility-driven power generation, can become the agents of their own energy futures. . . The flattening of electricity demand and rise in distributed renewable energy are causing tension in the utility business. Utilities continue to make investments in the grid as though these changes are not already happening, largely because their financial incentives remain tied to a Utility 1.0 business mode. As former utility executive Karl Rabago says, "utilities simply do not think things they do not own or control can be resources." [Farrell – "Beyond Utility 2.0 to Energy Democracy"]

2) What are the key data access safety and security considerations? How should customer privacy be protected? How will the utility's requirement to protect the grid and maintain sensitive information be balanced with the need for more visibility?

Response: Third parties, including energy service companies, will play a crucial role in optimizing customer participation, and improved access to data may be needed for these market participants. The regulatory framework must balance that usefulness with appropriate protections related to individual privacy, critical infrastructure, trade secret and other confidentiality concerns. Marketers will need to identify incentives and technologies to increase customers' knowledge and ability to manage their energy bills. For example, energy product interfaces (e.g., web portals, mobile applications, etc.) should be easy to use, simple to understand, and educate customers through the use of these technologies. Also, many customers will stay with a default option over an option that requires an affirmative decision. Default options for usage data access should be carefully weighed both for their effectiveness in shaping consumer decisions and their fairness to all customers. In many other cases, customer behavior is simply a matter of resource allocation. [Source NYREV]

Questions for stakeholders on DSP process

1) What DSP information – such as information associated with the DSP elements identified earlier in this document – should be made available to users, including the market, regulators, and policymakers?

Response: Utilities should employ open and transparent planning processes that consider the risks, probabilities, benefits, impacts and applications of multiple energy resources under various scenarios. Planning processes should include a full commitment by utilities to implement cost-effective energy efficiency and renewable energy. Resource planning should involve greater stakeholder involvement on a wider regional level and consider the full spectrum of energy efficiency and distributed energy resources. Clear policy frameworks allow all parties to better understand the goals and regulatory objectives that will influence or constrain the planning process. Finally, utilities should update planning processes to reflect current and future values of CO2, energy efficiency, distributed energy resources, equipment and permitting. [Ceres – 21st Century Utility Business Model]

Market participants must design, and the Commission should carefully monitor, promotional frameworks that address the cultural and behavioral challenges presented by this fundamental and transformative change in how we generate, deliver, use, manage, and regulate electric energy. A vital part of a healthy market is information. Toward this end, customer outreach and education best practices will need to be identified. The interplay between traditional methods (i.e., bill inserts, direct mailings, print and digital media, etc.) and more contemporary methods (i.e., social media and community-based marketing approaches) will need to be examined. Customer diversity should be considered to accommodate different customer segments in demand-side programs. A vital part of a healthy market is information. Toward this end, customer outreach and education best practices will need to be identified. The interplay between traditional methods (i.e., bill inserts, direct mailings, print and digital media, etc.) and more contemporary methods (i.e., social media and community-based marketing approaches) will need to be examined. Customer diversity should be considered to accommodate different customer segments in demand-side programs. [Source NYREV]

2) How often should this information be made available and in what format? Should this information be compiled in a new DSP docket proceeding (or filing within an existing docket)? How should any new DSP filings be coordinated with ISR and SRP? How should they be coordinated with any other applicable filings?

3) Utility DSP must take into account both current and long term system impacts. Solutions require multiple years for design and implementation. How will the utility and stakeholders coordinate efforts to develop solutions, particularly those that are implemented by customers and not controlled by the utility, such that there is certainty of implementation before system operational issues arise? How will a "safety net" be implemented to ensure that the utility can implement solutions (traditional or NWA) if third party commitments fail, particularly when there are long lead times for implementation?

Response: Extending the length of the rate plan (to as long as eight years, see later discussion of RIIO) may provide benefits such as better planning, more certainty, and fewer rate cases. This may give utilities the time and opportunity to implement an innovative sea change. An extended rate plan will create very powerful efficiency incentives (for both capital and operating expenditures) since utilities may reap more of the benefits of efficiencies until rates are reset. The term may enable utility management to focus less on rate matters and more on performance and customer goals. Deterioration of plant has always been a risk under multi-year plans and can be mitigated by clear metrics and oversight. The impacts of some extraordinary unforecasted changed circumstances (e.g., taxes, interest and inflation rates) can be resolved via reopeners; the need for flexibility and the benefit of certainty are balanced both through uniform policies and in individually negotiated cases. Perhaps the most effective tool to mitigate unintended results from extended rate plans is the presence of an earnings sharing mechanism with associated monitoring of the results. [Source NY REV]