STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision	x x x x	**Case 14-M-0101**

Initial Comments of the Joint Utilities on Staff's August 22, 2014 Straw Proposal on Track One Issues

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EXECUTIVE SUMMARY

Central Hudson Gas and Electric Corporation, Consolidated Edison Company of New York, Inc. ("Con Edison"), New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation (collectively the "Joint Utilities") generally support the Staff Straw Proposal on Track One Issues ("Straw Proposal"). The Joint Utilities are prepared to assume the responsibilities of the Distributed System Platform ("DSP"), as contemplated in the Straw Proposal.

The Joint Utilities provide these comments to further the implementation of Reforming the Energy Vision ("REV") proceeding by providing recommendations that will help the Commission successfully achieve its objectives over a reasonable transition period. To do this, Track 1 and 2 efforts need to be synchronized in order to define a comprehensive REV framework. The Joint Utilities believe REV has the potential to deliver meaningful benefits to New York's electricity customers, however, the success of increased reliance on Distributed Energy Resources ("DERs") to meet REV goals is contingent on the sound design and implementation of grid operations, market design, and the establishment of a new regulatory framework. REV must also be implemented in a way that is designed to ensure the safety and security of all who utilize the electricity network.

Customer preference and demand for services are integral to REV's success. This depends on the availability of advanced energy management tools and new products and services offered by the utilities and third parties to provide value to customers (including reduced energy costs). Customer engagement has presented a challenge to program development in New York in the past, and the work involved in this area for REV should not be underestimated.

Many of the Joint Utilities' concerns with respect to the Straw Proposal relate to specific implementation challenges. These concerns include how best to transition and refocus energy efficiency and clean energy programs, implement a more open integrated distribution system planning process, and implement processes and systems to exchange data and other information. These concerns are summarized below:

(1) Implementation/Transition: The transition to REV must necessarily be iterative, taking place over a period of years, to permit thoughtful responses to evolving technologies, customer engagement, and the evaluation of REV itself.[1] The REV design process will require staging of interdependent stakeholder and regulatory processes, including ongoing Commission proceedings, as well as clarity regarding major elements in advance of design and construction of new processes, information systems, and infrastructure. The REV implementation will involve substantial investments by utilities, third-party service providers, and customers. However, utilities can only make large investments on behalf of customers and DER providers within a clear regulatory framework.

(2) **Data Exchange:** The purpose of the data exchange is to manage operational data and customer usage information. Each of these purposes presents its own challenges related to the development of standards, interoperability, communication infrastructure, and the privacy and security of customer and systems data. The Joint Utilities propose an efficient approach to achieve the Commission's information goals that reflects each category of information to be shared (customer usage data, DER data, network operational data, and network planning data) while addressing distribution system security and customer privacy concerns. This approach would leverage existing system capabilities and initiatives envisioned in the Straw Proposal and will provide parties with the information they need in a form that is useful.

(3) **Clean Energy Transition:** The Joint Utilities are committed to working toward continuing existing energy efficiency programs without interruption and support filing Energy Efficiency Transition Implementation Plans ("ETIPs") based on Staff's proposed schedule. Toward that end, the Joint Utilities propose to use the existing E^2 Working Group process to identify the content of the initial ETIP filings and to address transitional issues. Specific clean energy program design will be driven by the Commission's REV policy goals. While the current Energy Efficiency Portfolio Standard ("EEPS") and Renewable Portfolio Standard ("RPS") programs focus on MWh-based clean energy goals, the use of greater amounts of clean energy DERs in the future may lead to an increased emphasis on demand reduction (MWs) or carbon reduction goals rather than energy (MWhs). It is not possible to maintain the current energy savings goals while adding new demand and carbon reduction goals without increasing overall funding levels. Finally, the Joint Utilities will comment on

[1] The Straw Proposal expressed this challenge as follows: "[t]he comprehensive, complex, and transformative nature of REV will require years of iterative planning and increasingly granular design determination, which should begin as soon as the Commission makes a policy decision to proceed." Straw Proposal, p. 78.

the main tier RPS program separately consistent with the Commission's recent public notice in the NYS Register.

(4) **DER Ownership:** Utilities have an important role to play in triggering growth in retail markets due to their singular knowledge and understanding of their respective distribution systems as well as their existing relationships with electricity and gas customers. Utilities are uniquely positioned to help customers engage in REV technologies and to expand interest of all customers in DER whether through the utility or through a third party. The efforts of utilities to increase DER will facilitate the state's ability to meet its near-term objectives of enhancing resilience, promoting clean energy adoption, increasing system efficiency, and building robust competitive markets. As a result, we believe utilities must be allowed to participate in the development of localized energy resources, including the ability to own DERs behind-the-meter. Any potential market power concerns should be addressed through mitigation measures developed as part of continuing discussions.

(5) **Demand Response Tariffs/NYISO Coordination:** The Straw Proposal fails to draw the distinction between wholesale and distribution demand response programs and tariffs. The Joint Utilities believe that a stakeholder process is required so that the utilities, Staff, and the New York Independent System Operator ("NYISO") can address the complexity of the issues that must be resolved to assure a smooth transition.

(6) **Benefit Cost Analysis ("BCA") Framework:** The BCA is a critical element of REV and the Joint Utilities support the early establishment of a stakeholder consultation process to develop the BCA framework. The BCA framework will evolve over time with changes in technology and developments in other elements of the REV policy agenda. The bar for including externalities in this framework is high particularly because of customer bill impacts: while the Joint Utilities support economic evaluations that reflect relevant quantifiable externalities, such externalities should not be monetized in payments to DER providers. Any BCA framework must include consideration of bill impacts and overall affordability concerns.

(7) **Microgrids:** Microgrids may be appropriate, if properly planned, to address resiliency and reliability needed for continuity of service (i.e., the ability to island). Microgrids serving a single customer could be owned by a customer or a third party. However, when a microgrid serves more than one customer (in contrast to a campus-style microgrid serving only a single customer) and operates within the surrounding electric distribution infrastructure, utilities

are in the best position to own and properly operate such distribution infrastructure when it involves systems within the utility franchise area. In addition, the Joint Utilities object to the Straw Proposal's recommendation to remove the requirement that a microgrid be capable of islanding, which is a distinguishing element of a microgrid as defined by the U.S. Department of Energy ("DOE"). This fundamental change would infringe upon a utility's existing franchise rights.

As directed, our comments are organized by the section numbers in Staff's Straw Proposal. As can be seen throughout, the Joint Utilities have not offered specific comments in response to many of the subheadings.

JOINT UTILITIES RESPONSE TO STAFF'S STRAW PROPOSAL

I. CONTEXT AND OVERVIEW

B. Summary of Findings and Recommendations

1. Critical Path Objectives

The Joint Utilities appreciate the need to begin implementing immediate and near-term actions that will lay the foundation for the full transition envisioned in REV. The Joint Utilities address these actions as part of an overall proposal for implementation of REV in Section VII.

D. Support for a Track One Policy Decision by the Commission

1. Business as Usual

The Joint Utilities have concerns regarding the practical value of taking time away from REV design and implementation to develop a state-wide high-level "business as usual" ("BAU") case and prefer to focus the effort on development of the BCA framework.

2. Drivers of Change

The Straw Proposal recognizes the need to replace aging infrastructure. REV will address future system constraints through nontraditional approaches; the Joint Utilities will continue to face significant replacement and refurbishment investment requirements during and after the transition to REV.

3. Benefits of REV

The Joint Utilities agree that the potential benefits are significant enough to advance the REV process. The Joint Utilities are concerned however, that the "illustrative examples" on pages 9-10 of the Straw Proposal have not been thoroughly vetted, depend on critical assumptions, and might be misinterpreted. The Joint Utilities believe that the focus should be placed on the BCA framework and how to deliver value to customers.

II. ESTABLISHING REV: DSP MARKET VISION

A. Distribution System Functions Required Under REV

The Joint Utilities agree with the Straw Proposal's recommendations that utilities should be the DSP, and that the DSP should be responsible for facilitating the development of retail markets. The Joint Utilities believe that public safety, reliability, and customer benefit should be among the primary objectives of the DSP. A phased approach to developing the DSP and retail markets should be adopted to allow for the evolution of technology, processes, standards, and protocols as retail markets mature. Initially, utilities may focus on direct procurement of DER via projects such as Con Edison's Brooklyn-Queens Demand Management program. In time, such an approach could transition to price signals and, ultimately, to functional operating markets.

1. Regulated Monopoly Functions

The Joint Utilities agree the three distribution level functions that must be performed to provide reliable electricity service and animate retail markets to achieve the REV policy goals are: (1) market operations; (2) grid operations; and (3) integrated system planning. The Joint Utilities do, however, have a particular concern related to the Straw Proposal's recommendations that to achieve a more open planning process significant access to granular, operational planning data is required,[2] and a platform for sharing such data should be developed.[3] Overall, the Joint Utilities believe that many of the contemplated planning processes described in the Distributed System Implementation Plan ("DSIP") coupled with immediate actions will address concerns regarding information transparency and open planning.

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2 Straw Proposal, p. 75.

3 Straw Proposal, p. 24.

The Joint Utilities will be required to establish a structured and transparent planning process. Under this planning process, it will be the DSP's responsibility to identify when and where such DER participation provides the greatest benefit to the local distribution system. The utilities, as the DSPs, will work with DER providers to develop a sufficiently transparent platform that accommodates diverse technologies and products and services, and is standardized to the extent possible to minimize participation costs that are ultimately borne by customers.

The Joint Utilities distinguish between two system planning circumstances: (1) a near-term system need; and (2) a longer-term system need. The first circumstance relates to a near-term distribution system need, where DERs could serve as an alternative to a more traditional utility-identified investment. In the second case, the utility has not identified a specific future investment or project but has identified a more general longer-term future system need. In such case, the DSP would provide a relatively simple price signal that DER providers can rely on to assess their value to the distribution system. Each circumstance is discussed below.

The first circumstance is likely to involve some aggregation of DER technologies that may present a potentially lower cost alternative to a major system investment and/or utility-owned DER solution. The need will involve a distribution constraint for reliability and resiliency purposes. The potential DER solution providers will need sufficient advance notice of such opportunities and will be provided with adequate information to tailor proposed solutions that will maximize the value of their offerings in response to competitive solicitations. Potential solutions will need to conform to reliability and resiliency requirements consistent with utility performance expectations and such reliability and resiliency requirements would need to be clearly identified. This type of need will be provided in each utility's No Regrets Action Plan to identify capital projects likely to be deferred and later as part of each utility's filed DSIP.

As envisioned in the DSIP methodology stakeholder process, stakeholder consultations are appropriate to determine: (1) information needed by DER solution providers to prepare a bid; (2) information needed by the DSPs to evaluate the bids; and (3) the most efficient process for exchanging such information. In this context, information security for the distribution system and customer data privacy concerns will need to be addressed and resolved.

In the second circumstance, a potential need is based on long-term system forecasts that do not require immediate action. The DSP should provide a "price" signal that reflects the value of various DER attributes, products and services to the distribution system at various points along the system. This price signal will be dynamic and change over time as the network needs change (e.g., as deployment of DERs on the network grows, as network infrastructure capabilities are upgraded). The price signals that the DSP should provide to DERs will need to be updated periodically to reflect such changes.

The Joint Utilities are committed to developing a standardized approach for implementing information-sharing processes to address both of these circumstances as part of the DSIP stakeholder consultation.

B. DSP Market Structure

Certain of the concepts described in this section of the Straw Proposal have been addressed in this Section II, as well as, Section III and Section V below.

C. Overview of Market Participants' Roles and Interactions

The Straw Proposal envisions that the DSP will facilitate retail interactions with the wholesale market in addition to the operation of retail DER markets. Cost-effective DERs can offer value to both the distribution system and the wholesale markets. It is important to recognize that the value of DER's to the distribution system and the bulk power wholesale market are distinct values that are not always aligned. They may be complementary at times (when the dispatch of DERs benefits both the distribution system and the wholesale market at the same time) or the DERs may actually be constrained from being dispatched by criteria or conditions in one market even when it can provide value in the other market.

The Straw Proposal identifies two potential market model mechanisms to realize the full value of DER whether to the distribution system or to the bulk power system or both. The first is a supply aggregation model while the second is a load modifier model. The details of each are very complex and need to be considered thoroughly prior to selecting the most appropriate method. Any model would need to consider rules for interactions between the DSP and NYISO such that DSP maintains the ability to dispatch and manage the DER resources for the purposes of maintaining local reliability. Retail and wholesale market operations must be well coordinated with the NYISO to achieve effective and optimal interoperability. The Joint Utilities endorse the Straw Proposal's recommendation that this issue be addressed in a stakeholder consultation process. To the extent current wholesale market rules need to be revised to interface appropriately with the DSP, the Joint Utilities and the NYISO must work together to assure such coordination.

III. ENABLING NEW ROLES FOR KEY PARTICIPANTS

A. Identity of the DSP Provider

The Joint Utilities agree with the Straw Proposal recommendation that they serve as the DSP, and are prepared to assume this responsibility.

B. Customer Engagement

While opportunities to animate markets and engage customers exist, the challenges cannot be underestimated. Achieving REV benefits depends critically on the willingness of customers to engage in new product and service markets, and to make behavioral and financial commitments when particular offerings meet their needs.

As the Track 1 Straw Proposal has emphasized, the achievement of REV policy goals will be determined in large measure by the degree to which customers respond to the opportunities introduced in new markets and by actions of the DSP, utilities, and third-party vendors. Customer preferences and demand must be the driving motivation behind the design of markets to support new energy products and services accessible to customers. This requires understanding as much as possible about customer behavior and interest in new products and services. There are many ways to obtain this type of feedback from potential DER customers, including surveys of the type cited in the Straw Proposal. However, there is always uncertainty regarding whether a survey of customers in one market is a reliable representation of customer attitudes in another market, and indeed New York has significant demographic variation even within the state. Nevertheless, every experience provides insight. The Joint Utilities plan to explore additional methods of measuring customer engagement, including demonstration projects to gauge customer interest in DER and to identify concerns that must be addressed to engage customers in REV market products and services. Encouraging utility innovation, research, and practical experience over the next few years will advance information and identify best practices that can be shared.[4]

1. Data Access and Privacy

A thoughtful approach to these issues is necessary to provide customers with the confidence that they require to accept REV and for both customers and DER providers to participate in REV programs and markets. The Joint Utilities emphasize that customer privacy and data security are of paramount concern to their customers and must be safeguarded throughout the implementation of

[4] This concept was introduced on pages 28-29 of the Comments of the Joint Utilities on Track 1 Policy Issues, July 18, 2014.

REV policy goals. Third-party sellers seek access to customer specific information to contribute to the success of marketing and sales campaigns. The utilities support the Straw Proposal's objective to advance data access to enable markets while meeting reasonable privacy and security expectations.

i. Data Exchange

The Joint Utilities propose an efficient approach to achieve the Commission's information goals that reflects the different categories of information that need to be communicated (customer usage data, DER data, network operational data, and network planning data) while preserving distribution network security and customer privacy concerns. This approach leverages existing system capabilities and should provide parties with the information that they need in a form that is useful.

The Straw Proposal suggests that ownership and management of a Data Exchange could be opened to a competitive procurement process, which implies the need for a new, centralized system. While the Joint Utilities understand that certain information will be helpful to DER providers for a variety of reasons, including marketing and sales campaigns, the utilities do not believe that it is necessary or efficient to create a new and separate system for data sharing at this time. It would be more timely and cost-effective to leverage existing utility systems that already provide much of the functionality envisioned in the Straw Proposal.

The Joint Utilities believe that system solutions, privacy, and security concerns need to be considered for each of the four types of data under consideration for inclusion in a Data Exchange: customer data, DER data, operations data, and planning data. Customer data includes Personally Identifiable Information ("PII"),[5] defined as information that can be used to identify, contact or locate an individual. Because it is so closely associated with a customer's PII, individual customer usage profile data are generally considered protected information as well. Moreover, customers should have the opportunity to opt-in to sharing their information with providers. DER data pertains to the asset and commitment information of DERs that exist on different segments of the distribution system. Operations data pertains to a particular location on the distribution system, and includes load profiles, asset performance, and other information describing the dynamic state of the system. Planning data pertains to anticipated demand growth, existing asset conditions, distribution capital investment requirements, and other planning metrics. Each of these types of information has unique features that raise different considerations; which must be addressed in order to ensure

[5] The Commission is currently reviewing PII in Case 13-M-0178.

appropriate protection for critical infrastructure and customer confidence and engagement as REV evolves.

The privacy of customer data is a serious concern shared across many industries. Utilities have a responsibility to protect a large volume of PII that pertains not only to customer names and addresses, but also to consumption, financial data, credit information, and payment histories. The Commission needs to reaffirm or establish new data privacy policies and guidelines that utilities and customers can rely on to adequately protect sensitive customer information.[6] This is critical to utility efforts to comply with the law and rules governing the privacy of customer information. The current practice is that no PII (including name, address, usage, and payment history) be provided to a third party without receiving prior customer authorization.[7] The Joint Utilities understand that this issue will be one of the topics of a REV-related forum to be held in November at New York University School of Law and look forward to participating in that discussion to learn more about issues that are of concern to customers.

The Straw Proposal suggests a significant shift in policy from current data privacy trends.[8] This proposed shift is inconsistent with the approach in other states and with proposed federal guidelines,[9] all of which raises the importance of gathering the perspectives of different parties, particularly customers. If customers have concerns with data access and privacy rules, they will be hesitant to engage in the market.

The Joint Utilities disagree with the Straw Proposal's suggestion that "DER providers require standardized, time-stamped customer energy usage information where technically available to develop business cases, attract investment, and quickly bring DER products and services to market."[10] Competitive service providers across a wide spectrum of industries find ways to market to and attract customers without customer-specific information. As an alternative, the Joint Utilities

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6 *See* Case 07-M-0458, et al., *Proceeding on Motion of the Commission Regarding an Energy Efficiency Portfolio Standard*, Order on Rehearing Granting Petition for Rehearing, issued December 3, 2010, at p. 17, describing current policy on disclosure of customer energy usage data.

7 *Id.*

8 *See,* California Public Utilities Code, P.U. Code Sec. 8380(b)(1); *see also*, Colorado Regulations governing customers' data, 4 Colorado Code Regs. § 723-1-1104; *see also*, 79 F.R. 54965, describing the proposed federal guidelines.

9 The Department of Energy (DOE) issued a Notice seeking comments on September 11, 2014 on a proposed Draft "Data Privacy and the Smart Grid: A Voluntary Code of Conduct (VCC)." (79 F.R. 54695) DOE suggests the VCC should be adopted by electric utilities and any third parties handling smart grid-related data. The DOE's initial position would have utilities restrict access to customer data for anything beyond the provision of utility service. Other uses of data would require express customer consent. While this is a voluntary code, the Public Service Commission may find the proceeding relevant and useful in the context of consumer cyber security protections.

10 Straw Proposal, p. 24.

suggest that providing aggregated load information for various customer market segments would assist in the development of product offerings while maintaining protections on PII. DER providers could use this information to engage potential customers and secure individual customer authorization to access additional usage information. As discussed further below, this capability may be accommodated by making revisions to the existing Electronic Data Interchange ("EDI") infrastructure. DER providers could use this aggregated and segmented customer information system to refine proposals they make to aggregate customers and DER loads (including load reduction, energy efficiency, storage, and distributed generation), or to address a distribution system issue in a situation in which the DSP has requested bids from DER providers.

The Straw Proposal provides a list of customer information that should be made available to registered DER providers through the Data Exchange.[11] A considerable amount of this information is already available today and is communicated in a standardized format via EDI. This platform can be leveraged in a robust and cooperative process as the markets evolve. The Joint Utilities believe that until the DSIPs and DSP data sharing processes become more fully developed, it would be more cost effective to enhance the existing standardized platform and use EDI as the system to exchange those data. This would permit stakeholders to investigate new or enhanced interfaces and communications infrastructure that will align with the DSIP over the long term.

The Straw Proposal also suggests that additional customer data not available through EDI should be made accessible to DER providers. The utilities are open to providing certain of this information subject to appropriate authorization and protection considerations. As requirements for customer data evolve over time, so will the systems used to communicate those data.

The Joint Utilities agree that the DSP requires DER asset and commitment data and a process must be in place to complete effective measurement and verification of performance associated with DER services. This asset information is generally compiled both when facilities are being connected to the distribution system and when customers sign up to specific programs. The Joint Utilities believe that separate DSP operational systems will need to be developed to manage data[12] to perform tasks in the marketplace, rather than using an independent data exchange. In the same manner, the DSP will need to compile adequate interval data to create predicted baselines for load projections to verify load reduction performance of a DER provider. Since these data are

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[11] See the Straw Proposal, pp 24-25.

[12] Con Edison is already developing a Demand Response Management System.

already required for real-time grid operations, the DSP will already have the data to perform measurement and verification of the DER provided resource. By maintaining this critical information within the DSP operational systems, the data will be subject to privacy and security measures consistent with existing utility systems.

The Straw Proposal recommends that planning and operational data be provided as part of the proposed information exchange to address information asymmetry and to support open planning. The Straw Proposal seeks party comment on the "types of system data will be most useful for developing DER services and making investments of highest value."[13] The Straw Proposal further provides that prior to submitting their DSIPs, utilities should develop more structured, open, and transparent planning processes. These processes are expected to include, among other things, the necessary data elements to assist third-party market participants in determining when and where DER development is most valuable. However, the Joint Utilities believe that advanced means of data access should be established as part of the DSP functional requirements only after technology-platform defined interfaces and standards, as well as the DSIP planning process and the DSP market mechanisms, have been established. Experience gained from the commencement of near-term actions, demonstration projects, standards, interfaces, and DSIP development should be captured and used to inform the development of data sharing processes. Finally, the Joint Utilities do not agree that utility supervisory control and real-time data should be provided to third-party providers out of concern for cyber security, critical infrastructure, public safety, and reliability. Such raw data has limited use to parties that are not cognizant of distribution connectivity, real time equipment status at the time of a reading, asset ratings and design parameters in addition to load flow capabilities. The Joint Utilities suggest that adequate system information should be provided with a competitive procurement of alternative solutions for utility infrastructure projects. The required system information should be discussed during the stakeholder process for the DSIP.

ii. Access by Customers to Their Own Data and to Comparative Product Offerings

The Straw Proposal recommends that customers should have access to their usage data in a secure and standard format. In addition, customers should be able to authorize provision of their energy usage data to non-utility entities such as DER providers. The Joint Utilities believe that the Federal Green Button standard and a customer information portal will make it easier for customers to access their data while increasing their awareness of DER offerings and other energy-related,

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13 Straw Proposal, p. 76.

value-added services. The Joint Utilities endorse the Federal Green Button standard and are prepared to make investments in the development of websites, mobile apps, and other channels to communicate with customers using the Green Button Application Programming Interface ("API").

The Joint Utilities support the Straw Proposal recommendation that the utilities should jointly design and develop web-based tools to enable customers to shop for and purchase DERs and other energy-related, value-added services. Studies conducted by Accenture and Deloitte indicate that utilities have established trust and strong brand recognition with their mass market customers.[14] This relationship may offer the most effective channel for providing trusted information to customers on value-added services using the utilities' websites.

The Joint Utilities recognize that standardization and consistency among electric distribution utilities are important and are committed to working alongside stakeholders to accomplish this over the long term to the extent reasonable and practicable, and in a manner that recognizes distinguishing characteristics among utilities and their service territories.

2. Customer Acceptance

Customers will benefit from the introduction of new and innovative products and services to the extent that those customers are aware of and perceive value from the services marketed by DER providers. Customers must also decide that the benefits are sufficient to warrant their participation in the program. This implies that the animation of markets for third-party services must take place in a manner that prevents unnecessary barriers to market entry, but also establishes proper customer protections are in place. A constructive Commission oversight framework is required to ensure that protective measures are implemented, including cyber security protections.

New York has regulatory mechanisms that were put in place to accommodate retail access and that can be modified to address the oversight of DER providers. The lessons learned from New York's experience with the oversight of retail competition can also be used to develop a regulatory model that strikes an appropriate balance between customer protections and encouraging third parties to enter the market and offer innovative products and services. The goal of optimizing economic participation by customers can be realized in the context of a regulatory framework that is flexible to account for experience gained as programs mature.

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[14] The New Energy Consumer Architecting for the Future, Accenture, 2014. Informed and In Charge: Knowledgeable Electricity Customers Seek Greater Choice and More Control of Energy value Chain. Deloitte Center for Energy Solutions, 2014.

The Straw Proposal suggests enhancements to the consolidated utility bill currently utilized by utilities and ESCOs. Specifically, Staff proposes that utilities make available approximately 1,000 characters on their bills for ESCO bill messages concerning DERs or other related value-added products. In addition, the Straw Proposal suggests ESCOs could conceptually develop customer-specific messages based on the energy usage of their customer, and use EDI to transmit that information to utilities for printing on a consolidated bill. Staff specifically requested implementation information from the utilities, including cost recovery.

The Joint Utilities have four principle concerns with this approach: (1) it is not clear that providing an incumbent ESCO the ability to use 1,000 characters on a paper bill would be effective in animating the market; (2) messages on the consolidated utility bill must be limited to the ESCO that is actively serving the customer; (3) utilities must have oversight of messages to determine whether each specific message is for energy-related value-added services; and (4) the Commission and stakeholders need to consider the prospect of increased federal regulation of utility communications. With respect to this last concern, any proposed expansion of utility communications as a vehicle to market to customers should occur only after a thorough review of potentially applicable federal statutes and guidelines (e.g., CAN-SPAM,[15] Stored Communications Act,[16]) to evaluate potential adverse impacts on existing utility communications and compliance costs. For example, mixing commercial messages (e.g., DER advertisements or marketing promotions) with the content of customer bills, could trigger CAN-SPAM regulation, and thus, could impair a utility's ability to communicate with customers via electronic billing or other email messaging, particularly when a customer reacts to the message by objecting to receiving further electronic communications from the utility (e.g., by "unsubscribing").

In addition to costs for system changes, providing ESCOs with up to 1,000 characters on consolidated bills would entail extra expense for paper and postage when messages extend to additional pages. Estimates for the integration effort and cost by the Joint Utilities are provided in Table 1 below. These estimates are conceptual in nature, and may need significant revisions depending on final specification and requirements. In response to Staff's request on page 29 of the Straw Proposal, the following is a schedule of the Joint Utilities' conceptual estimates of time and cost to accommodate customer specific ESCO bill messages of up to 1,000 characters.

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15 15 U.S.C. 7701-7713, Controlling the Assault of Non-Solicited Pornography and Marketing Act of 2003 ("CAN-SPAM").

16 18 U.S.C. § 2701, et seq., Unlawful Access to Stored Communications.

Table 1:[17]

Company	Time to Complete	Conceptual Estimates
Central Hudson	4-6 Months	$55,000
Con Edison	7 Months	$300,000
National Grid - Niagara Mohawk	3-4 Months	$120,000
NYSEG/RG&E	2-3 months	$45,000
O&R	7 Months	$300,000

3. Affordability

The Straw Proposal's discussion regarding affordability centers on low- and moderate-income customers as well as high usage customers. In keeping with the discussion of the Straw Proposal, the Joint Utilities are aligned with the Commission and Staff with regard to the importance of engaging all customers with value-added services. To that end, the utilities will continue to facilitate and promote existing programs directed to low-income customers. The question of how best enable low- and moderate-income customers to benefit from REV is worthy of consideration as the REV and Clean Energy Fund design and implementation becomes further refined.

With respect to high-usage customers, the Joint Utilities agree that engagement of large customers offers potential to add to New York's DER base. It is important that high-usage customers have the opportunity to benefit from REV, including as DER providers. REV should facilitate this outcome, informed by reliable intelligence regarding current customer needs. All customers, but particularly the largest customers, are motivated to spend less on energy.

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17 Time to complete is an estimate and is defined as the amount of time for completion after a Commission Order is issued. Orange and Rockland Utilities, Inc. requires more than six months to implement the bill message changes due to the time required to develop and implement a new EDI transaction to be used to transmit the ESCO's customer-specific bill message, to make code changes to the company's billing system to accept and process the message, to make changes to the company's bill print software, and to test all of the required changes. The Joint Utilities had to make numerous simplifying assumptions to derive the estimates. The assumptions include, but are not limited to: (a) the account-level DER bill message will be available only to the customer's incumbent ESCO (i.e., other prospective ESCOs will not be able to provide bill messages); and (b) the necessary EDI transactions and segments will have been decided and agreed upon by the utilities. For Central Hudson this will require a new EDI transaction and the estimate does not include testing with EDI vendors and/or marketers.

C. DER Providers and ESCOs

The Joint Utilities agree with the Straw Proposal that all DER providers, be they utilities, ESCOs, or third parties, must be subject to Commission oversight, including requirements for registration as a DER provider, and compliance with any business rules under which a DER provider must operate. In order to apply a standard set of rules to functionally similar entities, the utilities suggest that the Uniform Business Practices that currently apply to ESCOs be amended as necessary and applied to DER providers. In addition, the Commission should ensure that cyber security rules are consistent with emerging industry-wide codes, and appropriate for the degree of data exchange that is required by REV.

D. Wholesale Market Interactions

2. Coordination between DSPs and the NYISO

As previously discussed in Section II, the Joint Utilities support well-coordinated wholesale and retail operations to improve system safety and efficiencies, maintain reliability, and enhance the visibility and flexibility of a modernized distribution system. Staff identified two potential approaches to a market operations model; a supply aggregation model and a load modifier model. The details of each are very complex and need to be considered more thoroughly prior to selecting the most appropriate method. Among other things, any model would need to consider the interaction rules between DSP and NYISO such that DSP maintains the ability to dispatch and manage the DER resources for the purposes of maintaining local reliability. As is discussed in Section II, the Joint Utilities endorse the Straw Proposal's recommendation that this issue be addressed in a stakeholder consultation process.

As Staff has recognized in the Straw Proposal, either option would require complex changes to the current wholesale market rules that would require collaboration among the NYISO, the distribution utilities, and market participants to establish well-articulated market principles in advance of full implementation.

3. Coordination Impacts Resulting From FERC Order 745 Being Vacated

Staff states that uncertainty related to court challenges to FERC Order 745 requires a process under which "stakeholders work with distribution utilities, Staff, and the NYISO to immediately develop programs that allow demand response providers, interfacing with the distribution utilities, to respond to bulk power system needs currently addressed by the NYISO's Special Case Resource ("SCR") and Emergency Demand Response Programs ("EDRP")."[18]

The Joint Utilities support a process to develop a transition plan in the event that DR is no longer able to participate in wholesale markets. While discussions were recently initiated by Staff with individual stakeholder groups, the Joint Utilities recommend that any process with stakeholders discussing this subject matter should engage all interested parties including the NYISO, Staff, Joint Utilities, and as appropriate, FERC. This process should focus on identifying and analyzing potential alternative approaches that avoid adding unnecessary costs, have minimal impact on wholesale markets, provide for an alternative mechanism to recover related costs as they occur, and have clearly defined rules. The process should involve a detailed review of existing NYISO and New York State Reliability Council rules and procedures, and will likely lead to changes that go beyond the elimination of the NYISO SCR and EDRP programs. A successful approach must be coordinated among all affected parties to avoid adding confusion in the marketplace and to ensure these valuable resources continue to be available when needed during operating reserve shortages.

IV. GAUGING FEASIBILITY

A. <u>Platform Technology</u>

Platform technology decisions will drive major capital investments necessary to provide the many new functionalities contemplated by REV, most of which are identified in the Straw Proposal. These investments will occur over many years as REV is implemented. The Joint Utilities support a stakeholder process that meets market and system operational needs and ensures that the decision-making approach retains sufficient flexibility to respond to the evolution of REV.

1. DSP Functional Requirements

The Straw Proposal documents a set of DSP functional requirements organized in three categories (Grid, Customer/DER/Microgrids, and Market) closely aligned with the capabilities identified and described by the Platform Technologies Working Group. The introduction of many of these features will not only improve the system's flexibility, they will also make it both more secure and resilient than the current distribution system. The DSP functions will also facilitate the participation of an array of DER technologies as determined by demand for these products by consumers.

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[18] Straw Proposal, p. 63.

As discussed in the Joint Utilities' July 18, 2014 Track 1 comments, the Joint Utilities believe the following foundational investments will be necessary to support key functionality for the DSP and the goals and objectives of the REV. Foundational investments fall into five major categories:

- Communications;
- Grid automation;
- Grid edge monitoring;
- DER control/management; and
- Market operations/administration.

The Joint Utilities highlight that the Straw Proposal portrays equipment monitoring as foundational to the DSP, without highlighting the importance of control. The Technology Platform Working Group was very specific in discussing the control of assets as critical to the evolution of the DSP functionality. The Straw Proposal lists several aspects of equipment control including real-time load transfer, power flow control, automated islanding and reconnection of microgrids, direct load control, DER power control and DER power factor control. The Joint Utilities support the Working Group position. Control of utility assets and DERs will be critical to both Grid Operations and Market Operations.

As the Straw Proposal states, each of the Joint Utilities is already "making ongoing improvements to distribution systems to enable functions consistent with the level of visibility, control and communications network that would be adequate to support the 'end-state' DSP."[19] Substantial additional capital investments will need to be made to enhance communications, grid automation, grid-edge monitoring, DER management and control, and market operations and administration. These investments will be required to support distribution network solutions that are provided by the utility or alternative DER providers. The Joint Utilities expect to work with Staff to determine what needs to be accomplished to provide a sufficient level of standardization both to achieve interoperability and reduce transaction costs for third-party providers.

3. Technology Evaluation

The Joint Utilities agree that the integration of the vast array of new data streams (e.g., data from customer information systems, meter data management systems, outage management systems,

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19 Straw Proposal, p. 84.

billing systems) will be of considerable value when that integration is achieved. However, the Joint Utilities emphasize that this is an exceptionally challenging technical problem that will take time to complete. While the Joint Utilities will begin initial integration efforts in the near-term, full integration will be achieved over the course of a multi-year timeframe.

ii. Customer Facing Technologies

The Joint Utilities welcome the opportunity to facilitate a market that will make value-added services available to customers. However, while these services hold great promise, there is a corresponding risk related to cyber security that must be managed in order to maintain reliability, and ensure data and infrastructure assets are protected from security breaches. As noted above, a constructive Commission oversight framework is required to ensure that protective measures are implemented.

iii. Technology Platform Policy Mapping

The Joint Utilities agree with Staff that technology modernization efforts and investments must be aligned with the high-level policy goals of REV. A methodology should be developed to ensure that investments are directed by policy goals. The BCA framework discussed in Section IV.B will help ensure that policy goals and modernization efforts are "harmonized" as envisioned in the Straw Proposal.

The Joint Utilities will be making substantial, long-term investments (and in some cases already are) and technology will continue to evolve in response to REV and similar industry developments. It is important to evaluate the evolving technology environment so that specific technology mapping tools reflect the changing technology market prior to committing large sums to specific investments. Nevertheless, the Technology Platform Technology Mapping exercise is valuable and will help inform the consideration of new technologies and investments, and identify crucial interdependencies to reflect in technology commitment decisions.

iv. Technology Standardization

It is recommended that the New York State Smart Grid Consortium, in conjunction with the distribution utilities, initiate and lead a stakeholder process to develop the DSP technical architecture, including standards and protocols, necessary to achieve the Commission's REV goals. The objective of this effort is to provide advice to the Commission, Staff, the distribution utilities, technology vendors, and other key stakeholders in the technical areas most critical to successful DSP implementation.

B. Benefit Cost Analysis Framework

The Joint Utilities believe specific BCA tests should be defined by the BCA stakeholder process. Development of the BCA framework is clearly on the critical path for REV design. In general, the Joint Utilities do not support including monetized externalities in payments to DER providers for the reason that all customers should receive some of the environmental value and economic savings provided by DERs and such value streams should not be exclusively awarded to DER providers.

As discussed in Section I.D, the Joint Utilities have concerns regarding the practical value of taking time away from REV design and implementation to develop/refine a high-level BAU case. Rather, the Joint Utilities believe that stakeholder resources are better directed to defining the BCA framework that will estimate customer costs on a project-specific basis. The BCA framework will be used to identify economic DER programs that could collectively produce state-wide savings for New Yorkers. The Joint Utilities are committed to moving the REV initiative forward expeditiously and the resolution of BCA issues is a critical path element.

Many subsequent REV policy and implementation decisions depend on the development of the BCA framework. Staff has recognized the importance of a sound BCA approach because it will be applied at many levels within REV. The Straw Proposal establishes: (1) proposed principles to guide development of the BCA; (2) guidance on parameters in the BCA; and (3) a process for developing the BCA framework. The Joint Utilities support the establishment of a stakeholder consultation process to develop the BCA framework.

The REV implementation will evolve over time with changes in technology and developments in other elements of the State's energy policy agenda. As a consequence, the BCA framework should be revisited periodically to ensure that the BCA methodology continues to align with REV objectives. Likewise, the BCA framework must be designed with flexibility so that it can evolve over time and be used in the context of each utility's unique circumstances. An overly prescriptive approach may hamper the ability of the utilities to innovate. Given these considerations, the Joint Utilities believe it would be premature to define specific BCA tests in advance of the stakeholder consultation process.

Recognizing that additional work will be undertaken soon, the Joint Utilities offer the following general observations regarding the BCA framework. The ultimate objective of the framework should be to help New York achieve its energy policy objectives in the most efficient and cost-effective manner. A foundational premise of the BCA is that it must create a level playing field for the evaluation of DER products, bulk energy resources, and transmission and distribution ("T&D") options. To accomplish this, the BCA framework should primarily focus on the costs and benefits that are directly linked to aggregate customer bills, including: (1) the net impacts on T&D operations and costs; and (2) the net impacts on wholesale energy and capacity costs, and (3) consideration of certain directly relevant and quantifiable externalities. While the Joint Utilities support economic evaluations that reflect relevant quantifiable externalities, such externalities should not be monetized in payments to DER providers.

Further, the Joint Utilities are not fully in agreement with every element of the very detailed list of benefits, costs and input assumptions in Straw Proposal Tables 3-6. Rather than focusing on every element of these tables in these initial comments, the Joint Utilities believe that the most efficient approach will be to carefully consider this information as part of the stakeholder consultation process.

V. Building the DSP Market

A. Clean Energy

The Joint Utilities are committed to working towards uninterrupted continuation of New York's energy efficiency programs. Toward that end, the Joint Utilities propose to use the existing E^2 Working Group to identify the content of the initial ETIP filings.

The modernization of energy systems within New York requires the development of a variety of products and services in existing and new markets. The EEPS and RPS programs have been the primary tools for delivering clean energy to New Yorkers for almost a decade. The Straw Proposal references the Clean Energy Fund Order, notes the importance of continuing clean energy programs after their current funding expires at the end of 2015, and introduces a number of new concepts including: (1) the overall transition of New York's clean energy programs away from a heavy reliance on one-time incentives to a REV-based model; (2) modifications to the process currently employed to obtain supply-side renewable resources; and (3) changes to the way New York's energy efficiency programs are delivered to the public.

1. Transition

The Joint Utilities believe that the acquisition of clean energy resources should occur through processes designed to meet long-term targets in the most efficient and cost-effective manner. These processes should be established to best determine how to achieve this result. The availability of increasing amounts of clean energy options to New Yorkers is an important element of the State's energy policy. Clean energy DERs should be integrated into distribution system planning and operations. However, until numerous issues related to performance metrics, cost recognition and recovery and incentive provisions are better defined as part of Track 2, the integration of clean energy DERs with system planning cannot be precisely defined.

The specific Clean Energy program design will be driven by the Commission's REV policy goals. Targets should be statewide and applied to both energy efficiency and renewable resources. Ultimately, the challenges for New York's clean energy programs are how best to use a limited amount of clean energy funds to obtain the most value for the public and whether the focus should be on demand (MW), energy (MWh), and/or emissions reduction (lb CO_2e). It is also important to recognize that it is not possible to maintain the current energy goals, add new demand and emissions reduction goals, and achieve the desired outcomes within a revised and uncertain regulatory framework without increasing funding levels.

Funding for new projects and programs in both the RPS and the utility-administered EEPS is scheduled to expire at the end of 2015. Renewable resources and energy efficiency measures are essential components of New York's energy mix and the Joint Utilities support the Commission's intent to avoid any interruption in these programs as REV is being implemented. Staff envisions that responsibility for most clean energy programs administered by NYSERDA will be transferred to the utilities over a transition period and that the plans governing the transition and the funding of these initiatives will be in place prior to December 31, 2015. The timeline to accomplish this objective is uncertain because it requires: (1) distinct, staged approaches to manage the transition of the efficiency and renewable resources programs; (2) approval of transition proposals and future programs; (3) establishment of new clean energy goals with potential Track 2 performance incentives; and (4) identification in Track 2 of clean energy funding sources and performance metrics.

The Joint Utilities propose that the Commission make unencumbered clean energy funds (along with any incremental clean energy cost recoveries) available to support the utilities adoption of incremental clean energy programs.

2. Supply-Side Renewable Resources

As noted on page 53 of the Straw Proposal, the issue of RPS Main Tier renewables has not heretofore appeared in this proceeding. The Joint Utilities intend to address the series of questions posited by Staff regarding the future solicitation of supply-side renewable resources through comments in response to the notice issued under the State Administrative Procedures Act ("SAPA") appearing in the September 10, 2014 NYS Register in the REV proceeding.[20]

There are many factors to consider in the proposed procurement shift from NYSERDA to the utilities that will require more extensive discussion and analysis. In particular, it is not clear whether bundled utility PPAs could or could not be used to meet the statewide RPS Main Tier program requirement. Additionally, there are concerns that long-term PPAs could create higher costs for customers and contribute to higher costs of capital. It is also possible that long term contracts could limit flexibility with respect to the development of renewable technologies. These are a few examples of many factors that lead the Joint Utilities to recommend that Staff establish a separate process. This process should provide for careful consideration of the issues and possible development of alternative approaches for procurement of renewable resources to meet the State's goals. The process employed should also take into consideration any potential lessons learned from the NYSERDA Main Tier procurement experience as it may provide insight into a post-2015 approach.

3. Energy Efficiency with Load Management Controls

The Straw Proposal recommends that utilities develop and file ETIPs by March 31, 2015 to become effective on January 1, 2016. The Joint Utilities support filing ETIPs by this date, and further recommend that the existing E^2 Working Group be used to develop guidelines for the content of initial ETIP filings. The Joint Utilities envision the ETIPs, while high-level, will include a more holistic customer approach than has been the case to date. The ETIPs will largely be a transition or recalibration of existing plans with future program proposals including enhancements related to demand management and demand response activities. Because it will not be possible to make significant changes to the programs at the outset, the ETIPs are likely to define 2016 programs as similar to programs being implemented today in the EEPS program portfolio. Higher-level identification of REV concepts may be worked into the plans over time, some in the near-term, and some in the longer-term. The initial ETIP will have less definition for program activities beyond 2016 in order to provide the flexibility to align program design with REV implementation specifics.

ETIPs will also specify the tools that will be employed to assess and monitor the effectiveness of the efficiency program. These tools would include: (1) a form of BCA; (2) program

[20] NYS Register Volume XXXVI, Issue 36 (September 10, 2014), I.D. No. PSC-36-14-00010-P- *Procurement of Main Tier Renewable Resources Will Become the Responsibility of the State's Electric Utilities* (Case 14-M-0101).

cycle and evaluation planning; and (3) a Technical Resource Manual ("TRM"). The Joint Utilities support the use of these tools and will work within the E^2 Working Group to develop frameworks that are consistent throughout the State while also accommodating individual utility-specific inputs that recognize regional differences in costs, climate, and other factors that will vary by utility. The Joint Utilities support the periodic reevaluation of the rules as more experience is gained with DER applications. Program rules must evolve as markets, technologies, and customer preferences change.

The Joint Utilities support the Straw Proposal's suggestion to develop a statewide data management system to monitor and track the progress of clean energy programs. However, embarking on such an undertaking will necessitate considerable effort and resources by both the utilities and NYSERDA. While the timeline presented in the Straw Proposal for benchmarking of existing practices may be appropriate, full development of a Request for Proposals ("RFP") to provide statewide data-management services would need to include the scope of proposals developed for program years 2017 and 2018. Therefore, the timeline should be pushed back to ensure that post-REV program designs are incorporated into the data tracking needs RFP. Until these issues are resolved, the utilities will continue to rely on the existing EEPS reporting scorecard.

Staff also suggests that future efficiency programs should have a broader scope and scale. The Joint Utilities agree. Overall, these changes, coupled with increases in and changes to efficiency targets, will impact the size and cost of the energy efficiency program and the target markets. Further analysis is required after the ETIP filing to fully identify the implications of these changes.

B. <u>Demonstration Projects</u>

Demonstration projects are essential to provide the information necessary to finalize the design of REV and to guide the development of DSIPs, where capital investment decisions will be made. An appropriate set of flexible guidelines with funding provisions is needed to achieve the desired level of knowledge and innovation.

The Joint Utilities endorse the Straw Proposal's discussion of demonstration projects because they provide valuable information to DSPs, DER providers, and ESCOs about a variety of factors. Demonstration projects involve the deployment of technologies, products, and customer engagement strategies in real world settings at a scale that provides reliable information to evaluate their potential effectiveness in larger scale applications. Innovation will be promoted through demonstration projects that provide the opportunity to learn more about customer behavior, technological capabilities and the integration of DER in the electrical network.

The Straw Proposal lists nine criteria that "should guide utility investments in DSP system technologies." [21] While it is useful to have a set of transparent guidelines for demonstration projects, the Straw Proposal's criteria, if applied uniformly and collectively to all projects, could be overly restrictive and discourage innovation. A more flexible approach will create the environment needed to encourage demonstration projects that produce the desired information and subsequent innovation.

The Joint Utilities will work with stakeholders to develop the process for demonstration projects. Utilities should have the flexibility to propose their own demonstration projects, jointly propose demonstration projects with third parties, or seek proposals for demonstration projects from third parties at any time as opportunities develop. The Commission should adopt a streamlined review process for demonstration projects that allows these projects to keep pace with changes in technology and consumer expectations/requirements. Expedited Commission consideration of these projects, as well as their source and timing of funding, should be integral to the revised process. In a regulated context, a well-conceived and executed demonstration project should receive cost-recovery irrespective of the results of the project.

C. Interconnection Procedures

The Joint Utilities are committed to continuing ongoing work with distributed generation ("DG") providers to streamline the interconnection process, while maintaining requirements designed to maintain public safety and reliability.

The Straw Proposal: (1) states the current interconnection practices are likely to be a barrier to increased DER penetration; (2) recommends standardized interconnection requirements for most new DG and other DERs; (3) supports greater transparency in utility reporting regarding responses to interconnection requests; (4) recognizes future technologies may not need to be subject to interconnection rules; and (5) envisions a periodic interconnection reform process. The Joint Utilities acknowledge that the interconnection process takes more time than many applicants would like, but adherence to such procedures, including a determination of whether additional supporting infrastructure is needed, is fundamental to maintaining safety and reliability. Size alone of a proposed DG installation is not necessarily the driver for the rigor of the interconnection study or the system upgrades needed. For example, a proposed 300 kW DG installation behind-the-meter

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21 Straw Proposal, p. 56.

for a 2 MW customer load may require no system upgrades, whereas clustering of many 10 kW DG installations served by the same distribution feeder may result in a need for service, transformer, or feeder upgrade due to thermal concerns, unacceptable voltage rises, or reverse power flow. One of the more common challenges in performing interconnection studies is having the necessary information from the applicant to analyze the impacts of the proposed DG installation.

With that said, the Joint Utilities are: (1) ready to work with the DER community to improve the interconnection process for both applicants and the utilities; and (2) supportive of periodic reviews of the Standardized Interconnection Requirements ("SIR") to identify opportunities for cost reductions and process improvements through standardization where appropriate without compromising safety and reliability. The Joint Utilities would additionally be willing to consider the expansion of the SIR to DG installations greater than 2 MW in capacity, inclusive of combined heat and power ("CHP") technologies,[22] provided timelines for accomplishing interconnection milestones are commensurate with the complexity of the generator and its location on the distribution system. In contrast, the inherently complex nature of microgrids warrants an interconnection process that is distinct and separate from a SIR. In all cases, the publication of certain types of information upon denial of an interconnection application (as proposed in the Straw Proposal) raises public disclosure issues relative to confidential customer data and utility system data.

Plug-and-play technologies should not be allowed to bypass the interconnection process as the potential risks to such customers and the distribution system are not dissimilar to that which exists for other DERs. Appropriate review is needed to ensure plug-and-play technologies comply with safety codes and standards, and are compatible with premises wiring. Utilities also need to know where on the distribution system such technologies reside. The Joint Utilities recommend against allowing technologies to bypass the interconnection process as they may jeopardize safety and reliability, unless and until necessary protections are in place.

The Joint Utilities caution that screening is not a substitute for analysis and screening does not eliminate the need for an impact evaluation of the proposed DG interconnection to identify safety and reliability issues. However, screening as a tool for proposed smaller DG projects (e.g., less than 100 kW capacity) may be appropriate.

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[22] However, the Joint Utilities do not support the inclusion of CHP as an eligible net metering technology.

D. Microgrids

Microgrids can meet certain REV objectives and provide benefits for a single customer (e.g., educational institution) or a group of customers if properly planned as part of an existing electric distribution system. The Joint Utilities believe microgrids can be particularly appropriate to address resiliency and reliability needs to ensure continuity of service (i.e., ability to island). For customers seeking enhanced reliability benefits at a higher cost, microgrids may also be appropriate for localized areas or groups of customers with: (1) greater susceptibility to reliability issues or (2) critical infrastructure needs.

As noted in the Straw Proposal, there are various ownership models for the electric generation and distribution infrastructure components that comprise a microgrid. The Joint Utilities agree that DG facilities within a microgrid could be owned by a customer, a third party, or the utility. Further, utility-owned DG could be fixed or mobile, and when coupled with existing utility distribution infrastructure, could provide redundancy for critical customers or create "islands of reliability." However, when a microgrid serves more than one customer (in contrast to a campus-style microgrid serving only a single customer) and operates within the surrounding electric distribution infrastructure, utilities are in the best position to own and properly operate such distribution infrastructure when it involves systems within the utility franchise area. Each utility employs a skilled workforce and has robust work procedures and processes in place which are critical to the safe and reliable operation of a microgrid and the surrounding distribution infrastructure. Further, utilities have emergency response plans, practices, and procedures, including drills with local authorities, to effectively operate local distribution systems that are pertinent to microgrids. Utilities additionally have the obligation to supply customers as providers of last resort, which necessarily has evolved, and must continue to evolve, as the regulatory framework is changed. The Joint Utilities do not believe that the Straw Proposal has given full consideration to these fundamental requirements when it suggests that microgrid developers could own their own distribution infrastructure and billing systems.

The Straw Proposal also recommends a significant change to the industry standard definition of a microgrid as established by the DOE. The DOE defines a microgrid as a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that act as a single controllable entity with respect to the grid with the ability to operate in both a grid-connected and island mode. However, the Straw Proposal suggests that the ability of a microgrid to island from the grid and operate off-grid is not a fundamental requirement. The Joint

Utilities oppose this departure from the industry definition of a microgrid. The ability to island and re-connect to the grid is a fundamental requirement of a microgrid and the proposed definitional change disregards the fact that the ability to island is a distinguishing and principal benefit of a microgrid—enabling the ability to meet customer load with little or no interruption in service. The Joint Utilities agree that integrating DERs into distribution system operations, with or without islanding capability, has the potential to provide system benefits within the REV framework and should be valued appropriately across the distribution system. However, the proposed definitional change would allow microgrid developers to aggregate certain loads and DERs that are always connected to the distribution system and in so doing effectively authorize such microgrids to encroach on a utility's franchise rights and operate as a utility selectively, without the broader responsibilities of a regulated utility, such as serving as the provider of last resort. Altering the microgrid definition should not be the means to affect such a substantial regulatory change.

The Joint Utilities believe that where a utility-owned microgrid provides a lower cost alternative to a traditional utility solution or where extraordinary public benefits are provided such as continuity of public services during times of natural disaster, such microgrid costs should be recovered through rates. Microgrids that are proposed to be owned, operated, and maintained by the utility should be supported by an effective BCA process.

Finally, while the Straw Proposal indicates that the Commission will address needed regulatory reforms to enable the development of microgrids, the Straw Proposal does not address the process itself or the corresponding timeline. The Straw Proposal further suggests that consideration should be given to a new tariff structure that allows groups of customers to sign up to receive microgrid delivery service from the incumbent utility so as to be able to implement Commission regulatory policies through such a tariff and thereby eliminate the need for qualifying applicants to obtain direct Commission approval. The Joint Utilities caution that before such a tariff can be developed, the application of standby tariffs, demand charges and net metering relative to microgrids needs to be determined. Given that these issues have been deferred to Track 2 of the REV proceeding, it is unclear how a policy on microgrids, let alone a tariff, can be forthcoming until an order from the Commission is issued on Track 2 addressing microgrid standby tariffs, demand charges, and net metering.

E. Demand Response Tariffs

The Straw Proposal states that utilities should "be directed to revise reliability-oriented DR programs, as needed, to use DR as an economic system resource and provide a platform on which DSPs can ultimately utilize (DR) as a component of their supply portfolio along with purchases from the bulk power system."[23] Staff also notes that currently Con Edison is the only New York State utility with retail demand response programs. The Joint Utilities fully support moving forward with the process to address new and expanded DR programs (including the filing of appropriate DR tariffs) consistent with timetables and approaches to be discussed with Staff and other stakeholders.

Staff's proposal recommends the development of new and expanded DR programs that could be treated as DERs. Individual utility programs address specific reliability and or economic needs, which are different on the distribution and bulk power systems and do not necessarily coincide. Considerations including the timing, frequency, location, and duration of specific needs must be evaluated when designing program requirements and levels of compensation. To the extent the Commission expects utility DR programs to go beyond distribution system reliability needs and simultaneously or additionally address bulk power system needs (either reliability or economic), a more comprehensive evaluation of the various needs and inter-relationships between programs will be required. The Joint Utilities support interim measures to address the Commission's concerns, which may include demonstration projects that would use DR to address specific distribution system needs.

A DR program designed to relieve a reliability constraint on a night-peaking residential distribution circuit may rely on a different set of technologies and customers than a program designed to relieve transmission or resource capacity constraints at the bulk system level, which generally occur during summertime afternoon peaks. Depending on system conditions, the distribution-level reductions may be needed over longer time periods which may lead to a strategy that develops more permanent load shape modifications as opposed to the dispatchable strategies more appropriate to a bulk power system need. The two programs offset different costs and therefore create different value streams.

Resolution of the interdependencies between these two distinct programs will have significant implications for the overall value of a specific DR program, and will inform the

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23 Straw Proposal, p. 64.

appropriate funding mechanisms for these investments. As these programs will represent a new initiative for utilities, incremental funding will be needed for both program development and operation. Cost recognition and recovery, as well as performance metrics, must be addressed by the Commission in Track 2 of this proceeding.

F. <u>Planning REV Implementation</u>

REV implementation matters are addressed in Section VII.

VI. MITIGATING MARKET POWER

A. <u>Utility Engagement in Distributed Energy Resources and Vertical Market Power Concerns</u>

Utility Ownership of DER

The Joint Utilities support a pragmatic approach to utility DER participation. Utilities have an integral role to play in deployment of DERs. Because of the Joint Utilities' existing relationship with customers, they will be able to add significant value in catalyzing the DER market in their service territories. Thus, a balanced ownership structure will best deliver on the Commission's critical path objectives of increasing DER penetration and catalyzing the DER market in New York as quickly and successfully as possible. The Straw Proposal notes that other jurisdictions have permitted ownership of DERs and ultimately concludes that market power concerns can be addressed through regulatory requirements and limitations subject to appropriate oversight.

Customers should be able to choose their DER provider and should be provided the option to meet all their energy needs through their utility should they choose to do so. Enabling convenience for customers and expanding customer access to DER solutions should be central to all REV initiatives.

The Joint Utilities recommend expanding utility DER participation to the customer side of the meter. Utilities seek to partner with third-party providers to provide these services to customers, which will provide a pathway to a competitive marketplace. This approach will provide double benefits to customers—those that accrue from the price-limiting effects of robust markets and the convenience of managing their energy profile in one place. A utility DER program provides the opportunity to deliver broader customer engagement across all market sectors, including customers with limiting circumstances (space, property ownership, financial), or for customers that simply want their utility to manage these resources for them. The Joint Utilities also believe that it would be beneficial to propose DER programs ahead of and outside of the formal DSIP filing through separate filings with the Commission to support the growth of new technologies and meet system needs. This would allow utilities to more expeditiously implement aspects of REV.

The Joint Utilities agree with the Straw Proposal that mitigation measures governing regulated utility DER activities can be developed to adequately address any potential for market power and thereby support the utility ownership of DG and other forms of DER. These measures could include: (1) regulated cost of service recovery mechanisms for utility owned DER, as the Straw Proposal suggests, which would eliminate any incentive for a utility to favor or dispatch its own DERs over DER owned by a third-party (incentive mechanisms can be developed in Track 2 to make the utility indifferent as to whether third-party or utility-owned assets are dispatched to meet system needs); and (2) leveraging existing organization structures to isolate the DER market function from the DER ownership functions. The Joint Utilities also agree with the Straw Proposal that market power concerns also apply to third party owners of DERs[24] and will need to be monitored and managed by the Commission. Regulated utility ownership of DERs by its nature provides regulators with an added degree of control.

Additionally, regarding utility affiliate ownership of DERs, a code of conduct governing interactions with the utility DSP combined with existing cost allocation and affiliate transaction rules should effectively address concerns related to self-dealing. The Joint Utilities are also open to considering establishment of a DER ombudsman.

While competitive energy affiliates should have the ability to participate with other third parties for behind-the-meter products and services, the Joint Utilities acknowledge the importance of public confidence in the transparency and efficiency of the DSP functions and confidence that all DERs will be treated on a level playing field. The Joint Utilities support the Straw proposal suggestion that an independent evaluator be used when utility competitive affiliates are participating. More specific rules should be developed around the independent evaluation process. For example, the utility should still add value by providing technical review and input to the independent evaluator, and therefore a process should be adopted by which the proposals are masked with the utility providing technical evaluation information on all proposals to the evaluator. The Joint Utilities will work with Staff and other stakeholders to put the appropriate rules and protections in place to support public confidence.

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24 Straw Proposal, footnote 39.

Ownership of DER by Utility and Utility Affiliates

Staff cites the Commission's 1998 Vertical Market Power Policy Statement ("VMP Policy Statement") asking whether a policy intended to address market power at the bulk system level is applicable to utility ownership issues at the distribution level. However, the Commission's VMP Policy was never intended to apply to and is not applicable in the context of distribution utilities who may own distributed generation or energy storage. The Commission's VMP Policy Statement was developed under circumstances and for objectives unrelated to those in the REV Proceeding. At the time the policy was adopted, New York's electricity requirements were satisfied almost entirely by large central station generation units owned primarily by utilities. The VMP Policy Statement addressed the ownership of major power plants and other large sources of centralized generation by affiliates of utilities. The policy, however, did not envision nor was it ever intended to apply to the more complicated effort to increase the utilization of DERs and to develop a retail market for DERs by allowing utilities to own distributed generation. Rather, it created a rebuttable presumption that the ownership of generation by an affiliate of a utility would unacceptably exacerbate the potential for market power. The Commission, however, created adequate controls to rebut such a presumption when it allowed affiliates of utilities such as Con Edison to own solar-powered generation notwithstanding the VMP Policy. It can do so again in the REV proceeding to address ownership of DER by utility affiliates.

In sum, the REV Proceeding is directly addressing issues related to the ownership of DERs and the application of a policy adopted outside the proceeding for unrelated reasons and objectives is not appropriate. Specific concerns regarding the potential for unfair treatment of market participants can be effectively addressed by appropriate rules and Commission oversight. Further, the application of the policy to the REV Proceeding would result in the unnecessary expenditure of time and resources to address a rebuttable presumption against utility or utility affiliate ownership of DER that is not justified.

Consequently, the Joint Utilities respectfully recommend that the VMP Policy Statement not be applied in the REV Proceeding with regard to utility ownership of DER.

VII. Implementing REV: Findings and Recommendations

The Joint Utilities believe that a phased approach, along the lines envisioned by Staff in the Straw Proposal, is required to successfully implement REV.

The conclusions and recommendations in the Straw Proposal reflect a completely new vision for the structure of electricity markets in New York that requires significant effort and careful planning to implement. Based on our understanding of the Straw Proposal, Joint Utilities have identified twenty processes, initiatives, and/or actions that they are required to perform in order to introduce, develop, and mature the REV vision. The Straw Proposal does not, however, provide a complete vision regarding how this significant work can be accomplished in an orderly and efficient manner. To move the REV development process forward, the Joint Utilities have considered these twenty items and developed an initial framework describing how this work could be accomplished. As background, Attachment A provides a matrix showing: (1) each of the twenty areas of work; (2) Staff's proposed timing; (3) the Joint Utilities proposed timing; (4) interdependencies of each work activity with the other work requirements identified in the matrix; (5) the Straw Proposal's recommendations; and (6) the Joint Utilities' comments on Staff's proposed schedule. In Attachment A, the Joint Utilities have categorized the timing of these work activities into three phases: immediate actions, near-term actions (dependent in part on the Commission's Order), and longer-term actions.

A number of initiatives in Attachment A are required to begin the transition to REV and are either currently underway or should be started shortly. The Joint Utilities are committed to move forward on these items and have identified the following activities as immediate actions:

(1) REV Proceeding: Track 2 (already underway);

(2) No Regrets Action Plan: Capital Projects (subject to limitations addressed earlier);

(3) No Regrets Action Plan: ETIP;

(4) Demand Response Tariff; and

(5) 1,000 Character Bill Message Evaluation.

Regarding item 2, No Regrets Action Plan, utilities may focus on direct procurement of DER via projects such as Con Edison's Brooklyn-Queens Demand Management program. In time, such an approach could transition to price signals and, ultimately, to functional operating markets. As these immediate actions proceed, it will be necessary to plan for and begin work on near-term actions in the following areas:

(7) Customer Web-Based Tools;

(11) Information Data Exchange (subject to limitations addressed earlier);

(10) Proposals for Interim Actions;

(13) Demonstration Project Proposals;

(14) BCA Stakeholder Process;

(8) 1,000 Character Bill Message Implementation; and

(6) Demand Response Promotion.

It will be critical that the BCA Stakeholder Process commence and make significant progress because this process is required to inform at least six future work activities including: (15) Technical Platform Design Stakeholder Process; (16) Market Design Stakeholder Process; (17) DSIP Methodology Stakeholder Process; (18) DSIP Plan; (19) Uniform DSP Plan; and (20) Market Oversight and Auditing. Moreover, while the Straw Proposal envisions the NYSERDA Energy Efficiency Data Management Stakeholder Process (9) as something that should start during the first quarter, the Joint Utilities for reasons noted earlier in Section V, recommend deferral of that project and the continued use of the EEPS scorecard for reporting energy efficiency results.

Once the immediate and near-term actions are underway, it will become possible to begin certain implementation activities that were dependent on earlier actions and other transitional work (longer-term actions):

(9) NYSERDA Energy Efficiency Data Management Stakeholder Process;

(12) Main Tier Renewable Resource Procurement;

(15) Technical Platform Design Stakeholder Process;

(16) Market Design Stakeholder Process;

(17) DSIP Methodology Stakeholder Process;

(18) DSIP Plan;

(19) Uniform DSP Plan; and

(20) Market Oversight and Auditing.

The dependent items listed in the matrix also highlight the importance of three actions which will have a direct impact on the ability to move subsequent work items forward: (1) timely Commission orders on Track 1 and Track 2; (2) progress of the initial BCA work; and (3) completion of the DSIP Methodology Stakeholder Process.

CONCLUSION

The Joint Utilities appreciate the opportunity to provide these comments on the Straw Proposal and look forward to continuing collaboration with Staff, the Commission, and stakeholders on this important reform.

WHITEMAN OSTERMAN & HANNA LLP

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Albany, New York

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Attachment A: Utility Initiatives Outlined in the Straw Proposal

	Work Item	Staff Phase	The Joint Utilities Phase	Dependencies	Staff Straw Proposal	The Joint Utilities Preliminary Comments on Staff's Proposed Timeline
1	**REV Proceeding: Track 2**	NA	I	None	Track 2 Schedule	• Track 1 and Track 2 must be more closely tied together as the implementation of various initiatives contemplated in Track 1 are contingent upon appropriate funding mechanisms being developed in Track 2.
2	**No Regrets Action Plan: Capital projects likely to be deferred**	I	I	Track 1 Order	• Identify significant capital projects most likely to be deferred or avoided through the procurement of DER alternatives. (p. 79) • The plan should also include a competitive DER procurement process and for making available customer usage data sufficient to allow potential DER providers to effectively participate and offer viable solutions. (p.79)	• The identification of initial capital projects that are deferred through DER will be pursued through a phased approach. • The Joint Utilities will benefit from the lessons learned and experiences from projects such as Con Edison's Brooklyn-Queens Demand Management program.
3	**No Regrets Action Plan: ETIP**	I	I	BCA analysis will be required for the ETIP but will not be dependent upon the BCA stakeholder process.	• The ETIP will put in place a plan for how the utility will procure energy efficiency starting in 2016, as a transition from procurement via the Clean Energy Fund. (p. 64-65) • ETIP plans need to be submitted no later than March 31, 2015. (p. 51) • ETIP implementation would begin January 1, 2016. (p. 53) • Implementation of the ETIP plan will occur until the DSIP plan is in place. (p. 53)	

	Work Item	Staff Phase	The Joint Utilities Phase	Dependencies	Staff Straw Proposal	The Joint Utilities Preliminary Comments on Staff's Proposed Timeline
4	**Demand Response Tariff**	I	I	NYISO rules will require change, cost recovery mechanisms will need to be identified.	• Staff recommends a statewide expansion of existing utility-offered demand response programs in the near term. (p. 64) • Straw proposal recommends requiring Utilities to file a tariff. (p. 80)	• The Joint Utilities support an initiation of a joint process with NYISO, Utilities, DR participants, and, as necessary, FERC to determine the most appropriate transition plan in consideration of court decision on FERC Order 745.
5	**1K Character Bill Message**	I	I	Track 1 Order	• Staff proposes that utilities make available approximately 1,000 characters on their bills for ESCO bill messages concerning DER or other energy-related value-added products. (p. 29) • Conceptually, ESCOs could develop customer-specific messages based on the energy usage of their customers, and use EDI to transmit that information to utilities for printing on CUB. (p. 29)	
6	**Demand Response Promotion**	I	II	Demand response tariff	• Staff recommends Utilities file a proposal to inform customers of new or expanded DR programs using state–of-the-art marketing tools and methods to increase DR options. (p. 64)	
7	**Customer Web-based Tools**	I	II	Track 1 and Track 2 Order May require JU governance/corporate structure for jointly-owned infrastructure	• Staff recommends utilities should jointly design and develop web-based tools to enable customers to shop for, and purchase, DERs and other energy-related value-added services. (p. 80)	

	Work Item	Staff Phase	The Joint Utilities Phase	Dependencies	Staff Straw Proposal	The Joint Utilities Preliminary Comments on Staff's Proposed Timeline
8	**1k Character Bill Development Implementation**	I	II	Track 1 Order	• Staff proposes that utilities make available approximately 1,000 characters on their bills for ESCO bill messages concerning DER or other energy-related value-added products. (p. 29) • Changes should be implemented within six months after issuance of a Commission Order directing such actions. (p. 29)	
9	**NYSERDA Energy Efficiency Data Management Stakeholder Process**	I	III	ETIP Plans	• Staff recommends that a joint utility-NYSERDA effort, in consultation with Staff, be formed to research "off-the-shelf" systems that may be available, identify the pros and cons of each, develop specifications for an adaptable system, and have NYSERDA issue a RFP by the third quarter 2015 to procure this system. (p. 55)	• Full development of a RFP to provide statewide data-management services would need to include the scope of proposals developed for program years 2017 and 2018, therefore, this initiative should be deferred.
10	**Proposal for Interim Actions**	I/T	II	Track 1 and Track 2 Orders Individual rate case timing	• Staff proposes utilities file Proposals for Interim Actions that summarize how the utility intends to achieve near-term and transitional recommendations. (p. 65)	
11	**Information Data Exchange**	T	II	Track 1 Adoption of rules toward making distribution system data and customer usage data available to market participants	• The Commission should require the utilities to develop and expand universal and transparent access to system data through information exchange. (p. 76) • DSP market information exchange be designed and established in 2015. (p. 26)	• The Joint Utilities support deferring implementation with further consideration in regards to scope, customer data privacy and system security. Activities envisioned in the Immediate and DSIP plan would address the Commission's objectives of giving DER Providers the information they need to target investments in areas and ways that will increase overall system efficiency.

	Work Item	Staff Phase	The Joint Utilities Phase	Dependencies	Staff Straw Proposal	The Joint Utilities Preliminary Comments on Staff's Proposed Timeline
12	**Main Tier Renewables Resources**	T	III	Completion of separate track	• Staff recommends that procurement of supply-side large scale renewable resources become the responsibility of the utilities. (p. 51) • Staff recommends that the REC-only program approach should transition to bundled contracts for energy and RECs between the utilities and competitively selected projects. (p.53) • A new mechanism for procuring these resources must be in place by early 2016 with Main Tier contracts in place by 2016. (p. 52)	• The Joint Utilities recommend a separate track for the Main Tier comments and plan to submit further comments on this topic by the Commission's October 26, 2014 deadline.
13	**Demonstration Project Proposal**	T	II	Timing of review in rate cases or separate filings	• Demonstration project plans should be filed with the Commission and initially include a part of Proposal for Interim Action. (p. 80).	• The Joint Utilities recommend Utilities should be allowed to propose demonstration projects at any time as technologies, system conditions, and customer needs evolve.
14	**BCA Stakeholder Process**	T	II	Track 1 Order	• Staff proposes a stakeholder process be established to design the BCA framework. (p. 65) • Such a process should include an appropriate number of technical conferences to solicit stakeholder input, and may require utility or third-party support to create an initial straw proposal and subsequent iterations. (p. 65)	• The Joint Utilities recommend this effort become one of the first REV-related stakeholder process to begin, and anticipate use of a phased approach which considers the timing and progress of other REV activities.

	Work Item	Staff Phase	The Joint Utilities Phase	Dependencies	Staff Straw Proposal	The Joint Utilities Preliminary Comments on Staff's Proposed Timeline
15	**Technical Platform Design Stakeholder Process**	M	III	Track 1 Order Preliminary BCA process has been initiated	• A Technical Platform Design Stakeholder Process should be designed and launched to facilitate multi-stakeholder engagement and recommendation creation for design parameters and standardization. (p. 66)	• The Joint Utilities recommend a phased approach to this effort which considers the timing and progress of other REV activities.
16	**Market Design Stakeholder Process**	M	III	Track 1 Order Preliminary BCA process has been initiated Technology Platform Design Process	• A Market Design Stakeholder Process should be designed and launched to facilitate multi-stakeholder engagement and recommendation for market design parameters and standardization. (p. 66)	• The Joint Utilities recommend a phased approach to this effort, and a slight staggering which considers the timing and progress of other REV activities.
17	**DSIP Methodology Stakeholder Process**	T	III	Track 1 and Track 2 Orders BCA framework process Technology Platform Design Process	• DSIP methodology should include the BCA framework, a list of what components must be included in the DSIP, and any guidance on specific approaches or inputs to be used. (p. 65)	• The Joint Utilities recommend this effort begin several months after the Technology Platform Design stakeholder process so initial findings can inform the DSIP methodology development.
18	**DSIP Plan**	T	III	Track 1 and Track 2 Orders DSIP methodology	• The DSIP should indicate how the utility proposes to implement REV actions over the next five years. (p. 65) • The plan should reflect the utility's entire system plan. (p. 65)	• The Joint Utilities recommend allowing flexibility for an initial DSIP that would cover a two to three year time frame following the Proposal for Interim Action. This would allow sufficient time for Stakeholder Processes to be completed and for learning to be incorporated into future plans more efficiently.

	Work Item	Staff Phase	The Joint Utilities Phase	Dependencies	Staff Straw Proposal	The Joint Utilities Preliminary Comments on Staff's Proposed Timeline
19	**Uniform DSP Plan**	M	III	Track 1 and Track 2 Orders BCA Framework Technology and Market Design DSIP Methodology Individual DSIP Plans Filed	• Jointly filed Uniform DSP Plan that describes the system and technologies to be deployed that will allow for the desired functionalities envisioned under REV, with the standardization needed to enable a statewide market. (p. 66) • The Uniform DSP Plan should encompass both technology platform and market design issues. (p. 66)	
20	**Market Oversight and Auditing Strategy**	M	III	Track 1 and Track 2 Orders BCA Framework Technology and Market Design	• A market oversight and auditing strategy for providing process and timeline for a comprehensive review of progress toward REV should be established by the Commission. (p. 66)	• The Joint Utilities recommend a phased which considers the timing and progress of other REV activities.

Staff Phase: Immediate (I), Transition (T), Mature (M)

Joint Utility Phase: Immediate (I), Near Term (II), Longer Term (III)

Please note that the information in the table represents the Joint Utilities' summary and compilation of the initiatives included in the Straw Proposal and represents the Joint Utilities' interpretation of this information. The table also includes the Joint Utilities' preliminary recommendations for some of the initiatives. This is a first review of the information and therefore is not comprehensive. Based on further review and comments from key stakeholders, the Joint Utilities plan to present further recommendations to Staff regarding the timeline and dependencies of various initiatives.