NECHPI
NORTHEAST CLEAN HEAT AND POWER INITIATIVE

July 18, 2014

Hon. Kathleen H. Burgess
Secretary to the Commission
New York State Public Service Commission
Three Empire State Plaza
Albany, NY 12223

Re: Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision

Hon. Secretary Burgess,

Please accept the attached responses for filing on behalf of the Northeast Clean Heat and Power Initiative (NECHPI) in response to Track 1and Track 2 questions in Case No. 14-M-0101.

Respectfully submitted,

_____/s/____

Timothy Banach, Executive Director
Northeast Clean Heat and Power Initiative (NECHPI)

State of New York

Public Service Commission

Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision

Case 14-M-0101

Comments on Behalf of the Northeast Clean Heat and Power Initiative (NECHPI)

Track 1 Policy Questions

July 18, 2014

INTRODUCTION:

This document contains the Northeast Clean Heat and Power Initiative's ("NECHPI") responses to the ruling issued by Administrative Law Judges Bielawksi and Stein on June 4th, 2014 titled "Posing Questions on Selected Policy Issues and Potential Outcomes" as part of the Reforming the Energy Vision (REV) Case 14-M-0101. NECHPI is a non-profit organization that promotes policies and practices conducive to the deployment of clean combined heat and power (CHP) applications where high overall efficiency and economic and environmental benefits may be achieved.

NECHPI generally supports the stated goals that the Commission is seeking and appreciates the magnitude of potential outcomes and impacts being considered in the REV process.. NECHPI appreciates the opportunity to provide responses to the policy questions posed for party comment, listed below.

I. POTENTIAL REV OUTCOMES

Please comment on whether the anticipated outcomes identified in the outcomes matrix are the appropriate results that the Commission should be striving for in this effort. Once the Commission has established the appropriate outcomes, parties will be asked to weigh in on the metrics to be used to most effectively achieve those results.

Response: In general, NECHPI believes the anticipated outcomes identified in the outcomes matrices are appropriate results for the REV effort.

Under Category I (Advancement of Clean Energy), NECHPI strongly supports the goals of reducing greenhouse gases and regulated air contaminants, improving the uptake of energy efficiency measures, and installing new renewable power sources. We note that clean combined heat and power (CHP) systems are effective tools for reducing greenhouse gas emissions and criteria air pollutants by simultaneously producing useful electric and thermal energy at fuel efficiency rates far above what can be achieved by the centralized grid. While NECHPI supports the installation of new renewable power sources (e.g. solar, wind) under the "clean generation" outcome, we believe that the installation of highly efficient, reliable, and dispatchable CHP systems should also be included in this goal.

Under Category II (Customer Engagement), NECHPI again supports the stated outcomes but believes reducing the *costs* of interconnection (in addition to time) should be included under the "interconnection" goals. As an example, NECHPI has recently noted that interconnection issues associated with the status of utility network protectors, create undue barriers to CHP development even after the application of the Reliability Performance Mechanism. Potential CHP projects can be stymied if located near over-duty circuit breakers because the utility may require the project to bear the costs of upgrading this equipment in order to interconnect with the main grid. We believe that changes under REV should also focus on interconnection connection issues that can increase project costs and delay development, such as issue previously described.

NECHPI generally supports the the outcomes and goals stated under the remaining Categories III - VI.

II. OPTIMAL OWNERSHIP STRUCTURES FOR DISTRIBUTED ENERGY RESOURCES

Please comment on the framework of analysis presented in the Staff Report, see pages 26-28, and discuss which of the potential approaches to utility engagement in DER and other models is preferable to ensure a robust DER market, and why.

The Staff Report introduces the notion of expanding utility relationship with DERs to ownership, financing, operation, or contracting. Presumably, utility engagement with DERs beyond their current role of coordination and interconnection would ONLY be allowed if the utility were to compete on terms equal to private sector DER service providers. This includes equal access to customer energy data for the purposes of DER feasibility review, equal treatment under utility tariffs and rates, and interconnection application requirements, processes, and timeframes equal to those experienced by private developers and DER owners. Assuming the utility has no unfair advantage over the private sector, it's unclear how utility ownership of DERs would support deployment.

If the goal is to leverage the expertise of the utility towards expanded deployment of DERs, this could currently be achieved through improved coordination and cooperation between the utility and private sector DER service providers and a commitment to reduce market barriers currently in place. For example, upgrading the distribution system in a manner that would allow greater penetration of DERs; reducing timelines for interconnection application review and approval; and reviewing and revising current standby tariffs are strategies that could be pursued to support DER deployment without expanding the utility's current engagement with DERs.

III. DSPP IDENTITY

Please address the analysis contained in the Staff Report, see pages 24-26, as related to the question of whether incumbent utilities, or an independent entity, should serve as the DSPP.

The Staff Report indicates that the DSPP will "plan, design, construct, operate, and maintain" needed modifications to existing distribution facilities to allow greater deployment of DERs. NECHPI recognizes that the level of distribution modifications proposed requires careful planning and significant resources. Regardless of the entity chosen to serve as DSPP, it should be given the authority to achieve its directive - to improve distribution facilities to allow for greater deployment of DERs - and should be required to report progress towards quantifiable goals to the Commission. In addition to technical improvements in the distribution system, significant barriers to DER deployment may be eliminated through review and modifications of standby tariffs and that such review should fall within the purview of the DSPP. Specifically, standby tariffs should be applied in such a manner that standby customers do not pay demand charges greater than they would have otherwise paid as non-standby customers. A role in which the DSPP reduces the transaction costs for DERs to participate in energy services markets may assist in supporting DER development.

IV. BENEFITS AND COSTS

Discuss the preferred analytical framework to assessing benefits and costs, with particular attention to the different ways that benefits and costs may need to be considered in various stages of this initiative, and the methodologies and tools that may be appropriate to each. For example, what benefits and costs related to environmental externalities should be monetized in considering DER pricing? Consider that the outlook on broad, long-term benefits and costs that informs a Commission policy decision may be different from the business case supporting a utility investment plan, which may in turn differ from the analysis supporting a particular

investment, or supporting the pricing of products and services that contribute to DSPP objectives.

Response: Essential to any analytical framework for assessing costs and benefits is the the need to align distribution system capital investments with the expected outcomes of REV. The REV outcomes anticipate a future scenario where DERs function as a dynamic asset on the grid, and where it is enhancing customer responsiveness and improving the productivity of the existing distribution system. In order to achieve that outcome, the distribution system will require a different functionality than it currently has today. To plan for such a future scenario, benefit and costs analysis will need to appropriately value the costs today for the increased functionality that we expect and need to have in a future with dynamic DERs functioning on the grid. To that end, there should be a mechanism for monitoring the increased functionality of the grid over time, and perhaps for assessing penalties for distribution systems whose functionality remains as status quo over time. The metrics currently used in assessing distribution system performance and guiding distribution system investments are not likely to give appropriate signals as how amenable the grid is to incorporating DERs effectively and how the functionality of the grid is evolving with respect to many of the goals stated in the REV outcomes matrix including resiliency, efficiency, and system intelligence.

Any analytical framework employed by the Commission should be able to quantify fully and accurately the benefits and costs DERs provide and incur, respectively, to the grid and society as a whole. Currently, many benefits provided by DERs are not accounted for and therefore remain non-monetized by DER owners resulting in lost opportunities for potentially beneficial DER development. By accurately quantifying these benefits, DER owners can receive compensation (and new revenue streams) for the various benefits they provide. These benefits include, but are not limited to, the reduction of harmful air emissions such as greenhouse gases and criteria air pollutants; generation, transmission, and distribution infrastructure investment deferral and avoidance; and distribution level ancillary services; increased system resiliency; and reductions in system peak load. The quantification of benefits and costs should not be impacted by the type of technology employed to ensure an even playing ground for all technologies.

As an example, the benefits of DER greenhouse gas reductions should be determined on a net avoided emissions basis. When a no-carbon (e.g. solar, wind) or low-carbon (e.g. CHP) generator produces energy, the greenhouse gas reduction benefit is dependent on the emissions of the energy source(s) displaced by that generator. Since the main grid's emissions profile changes with both time and location, the displaced energy generation will therefore depend upon both the location of the DER in the electrical grid and the times that it displaces other generation. This means, for example, that the greenhouse gas reduction value of a solar kWh during the day may be different than the value of a wind kWh during the night. Calculating the value of greenhouse gas reductions on a net avoided emissions basis will ensure that various DER technologies will be fairly compensated for this societal benefit as well as incentivize DERs that provide the most cost effective reductions.

V. TRANSITION FOR CLEAN ENERGY PROGRAMS

The Staff Report (see page 21) envisions the integration of distributed energy resources into DSPP system planning to maximize system value, with NYSERDA's portfolio expected to refocus on market and technology transformative strategies to provide temporary intervention to

overcome specific market barriers while continuing to provide access to clean energy for low-income customers. How can we ensure the transition from current renewable and energy efficiency programs without backsliding on the State's environmental goals?

Response: Any transition from NYSERDA's current renewable and energy efficiency programs and market and technology transformative strategies should be closely monitored for its impact on the state's energy goals. NYSERDA's current programs were put in place to help achieve certain goals and these goals should not be sacrificed during the course of any transition. Baseline metrics should be recorded for the efficacy of current programs, which can then be measured against any new strategies employed by NYSERDA in the future as a result of the current REV and Clean Energy Fund proceedings. There should be mechanisms in place to ensure current programs are not reduced or eliminated without assurance that any new strategies are effectively supplanting current programs in achieving state energy goals.

Many DER assets have operational lives spanning decades and the decision to develop DER assets is affected by one's confidence in the future stability of incentives and/or DER revenues available at the time of investment. Eliminating or restructuring the landscape of incentives and available market revenues for DERs can cause uncertainty in the market. In addition to quantifying and compensating DERs for the benefits delivered, establishing incentives and markets for DER revenues more in line with the operational lives of the DER assets will increase confidence in the market at the time of investment.

VI. ENHANCED SERVICES

The Staff Report (see page 61) describes the potential for a regulated utility offering enhanced services to create revenues, some or all of which may accrue to revenue requirements. Please discuss the regulatory issues related to this potential, e.g. the definition of basic services, and the relationship between enhanced services offered by a regulated utility and the monopoly function of the utility.

Response: Any enhanced services offered by the utility should not be at the detriment of standard services.

VII. ACCESS TO DATA

Issues concerning access to data are currently the subject of a formal comment period Case 12-M-0476, pursuant to a Notice Seeking Comments issued February 25, 2014. Initial comments were filed June 2, 2014, and reply comments are due June 16, 2014, as detailed in a Notice issued April 3, 2014. Staff will review those comments before determining whether additional written input on issues related to access to data should be obtained through separate comments in this proceeding as well.

Response: Access to and review of customer load data is essential for understanding customer load profiles, energy usage, and for determining the feasibility of DER on site. Access and review of such data by third parties for the purposes of DER feasibility should be restricted without the customer's consent. The customer's access to their own energy usage data as recorded by the utility should be allowed.

Answers to Track II Questions Submitted by NECHPI

As noted in the Commission Order, the goals of REV include improvements in system efficiency, greater customer choice, greater penetration of clean generation and energy efficiency technologies, and reduction in air pollution and greenhouse gas emissions. An important component of REV is the Distribution System Platform Provider (DSPP). The role of the DSPPs will be to create markets, tariffs, and operational systems to enable Distributed Energy Resource (DER) providers to monetize products and services that will provide value to the utility system and thus to all customers. Resources provided could include energy efficiency, predictive demand management, demand response, distributed generation, energy storage, building management systems, microgrids, and more.

The end vision of REV is a fully animated market for DERs which allows the DSPPs to optimize operations and planning of the electric distribution system. However, this optimization is contingent on the availability of adequate DERs and the proper valuation of such resources. To achieve the minimum level of DER penetration to create a functional DER market, barriers to entry must be eliminated and proper regulatory incentives must be established.

The following are answers and observations on the questions provided for Track II of the REV proceeding.

Outcomes-Based Ratemaking

1. Incentives and disincentives in current ratemaking
    a. How should existing incentive mechanisms (reliability, service, safety or other targeted performance incentives) be modified? Should any be eliminated?
    b. Should rewards (revenue adjustments) be provided for superior reliability, service, or safety performance?
    c. How would superior performance be defined and measured?

It is apparent that in an environment of rapidly increasing penetration levels of distributed energy resources and bi-directional flow of information and energy, a traditional utility "volumetric rate structure" is increasingly ineffective as a means to compensate a utility. Rocky Mountain Institute ("RMI") points to existing rates and incentives fail to provide accurate economic signals to align distributed generation investment with system costs and benefits over the long term and to more accurately reflect the costs and values associated with each particular resource, which in its estimation will require some degree of price unbundling (i.e., charging separately for different cosThe t components).

Are there modifications or more fundamental changes to traditional cost-of-service regulation that would be beneficial for achieving 21st century goals for the power sector?

The first step is to establish goals for the New York State power sector to set the stage for possible performance objectives such as below (America's Power Plan):

Goal	Possible Performance Objectives
Cost	Minimize overall energy service costs to customers; ensure equitable allocation of costs; optimize resource allocation; improve company productivity through innovation
Reliability	Fewer outages; shorter duration of outages; fewer customers impacted by outages
Environmental Performance	Minimize pollution; minimize land use impacts; minimize water consumption
Customer Service	Transparent billing process; adequate response to customer complaints; delivery and support of new value-added products and services (from the utility or from third-party service providers)

Most regulators are familiar with such goals and the tradeoffs between them. However, they are not always made explicit at the beginning of a traditional cost-of-service ratemaking process. Tools such as Integrated Resource Planning have made strides towards a more forward-looking regulatory process; however, traditional cost-of-service regulation is still a "backward-looking" exercise predominantly based on incurred costs of utility assets and utility operations.

"As one recent report observed, U.S. regulatory regimes typically focus on the central question: "Did we pay the correct amount for what we got?" In contrast, other regulatory regimes have emerged (e.g., performance-based ratemaking) that place performance objectives at the forefront, thereby changing the focal question to: "How do we pay for what we want?" In other words, the regulatory regime becomes predicated more on value provided by serving electric customers rather than simply the cost of providing service." (*New Regulatory Models*, Sonia Aggarwal, Energy Innovation and America's Power Plan, March 2014)

Thus, traditional ratemaking involves the development of a utility's revenue requirements and ultimately its rates to recover a utility's costs in the "test" year (including taxes) plus a reasonable return on its rate base. In contrast,

performance-based ratemaking decouples a utility's profits from its costs and ties utility profit to performance relative to specific benchmarks.

RMI makes specific proposals on how to reduce disincentives and reward performance with respect to distributed resource deployment, including new pricing models and methods of cost allocation to realign resource investments with system costs and benefits over short-term (operational) and long-term (planning) horizons.

Examples include:

- Unbundled pricing for reliability, standby, and power quality services;
- Temporally or locationally differentiated prices for energy or distribution services; price structures that reflect how costs are incurred (e.g., demand-based, fixed, energy-based, etc.); and
- Incentive payments for dispatchable demand response or ancillary services to the grid.

We believe that there are key underlying conditions which need to be addressed and implemented before regulators and utilities are able to address performance-based issues associated with specific rates, incentives and penalties. The most critical ones in our estimation are the following:

- Mandated integrated resource planning
- The adoption of standardized and transparent cost/benefit and valuation methodologies for all energy resources across the grid, including distributed energy resources, which form the coherent and justifiable basis for the development of new rate-setting and other compensation mechanisms such as special tariffs, bilaterally negotiated contracts, competitive bids and new grid services to be developed in the future

There is an emerging regulatory model called results-based or performance-based regulation. Performance-based ratemaking starts with the outcomes that matter to customers, utilities, regulators and other power-sector industry participants. These goals might include objectives such as minimizing costs, maximizing reliability, maximizing environmental performance, and enhancing the value of customer service. It aims to align the goals of customers, regulators and utilities. In PBR, the utility is rewarded based on its achievement of specific performance targets, providing an opportunity to earn a higher return if the company is able to perform on the objectives identified.

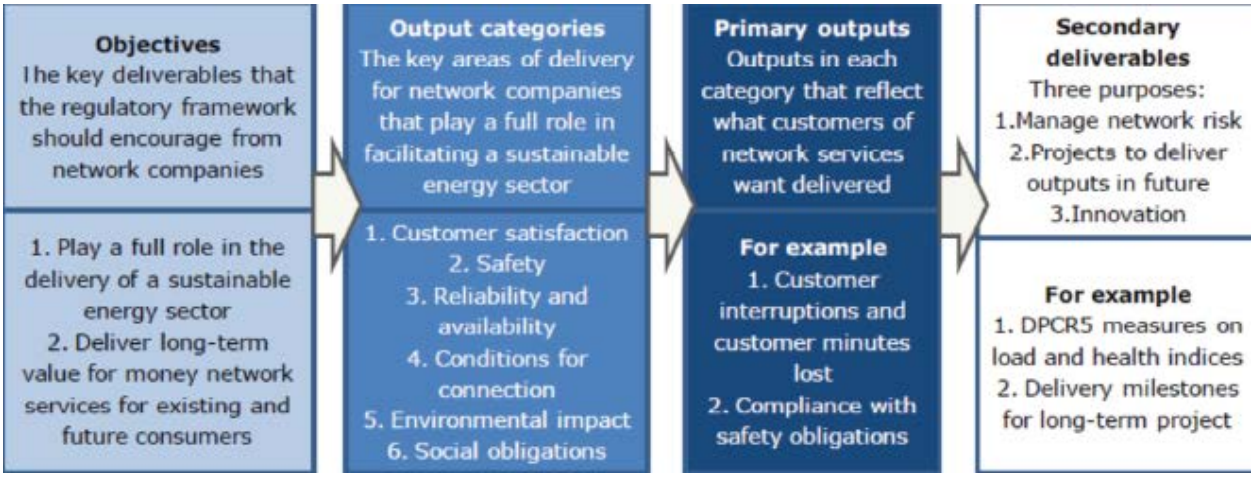
Well-designed performance-based ratemaking includes both incentives for over-performance and penalties for underperformance. This system of paying for performance broadens the scope of options utilities can call on to run their business.

A discussion of performance-based cost recovery naturally leads to a conversation about how performance should be measured and what measures should be used. The variation by state is quite significant. For example, Maryland developed 90 implementation metrics and 36 on-going performance metrics to evaluate IOU smart-grid deployment status and value creation. Regulators in other states need to develop their own performance measures based on their specific goals and objectives, e.g., for distributed energy resource deployment, meeting RPS standards, carbon emissions reductions, etc.

Examples of performance-based ratemaking including the following:

- Fort St. Vrain, Colorado for a new nuclear facility
- Revenue-sharing for Off-System REC Sales: Xcel Energy in Colorado
- Massachusetts Statewide Plan of Performance Incentives for Energy Efficiency
- Revenue Sharing for Off-System Sales: MidAmerican Iowa
- Smart Grid Investment: Illinois' Energy Infrastructure Modernization Act
- Full-scale Performance-based Ratemaking: the UK's RIIO Model

The RIIO model is the most forward-thinking of all of the above-listed models. RIIO includes six primary output categories: customer satisfaction, reliability and availability, safe network services, connection terms, environmental impact, and social obligations, each with measurable targets. The program also allows utilities to propose higher rates to meet secondary deliverables to manage network risk, deliver outputs in the future and innovate. See the below figure.



There is a significant amount of available information on the RIIO, which is too complicated to discuss within this context, but NECHPI believes that the its highly adaptable approach, based on policy changes and experience over time through implementation, offers an innovative model which should at least be investigated thoroughly and possibly implemented as a pilot for a period of time.

The New Regulatory Models report provides the following principles for designing performance-base ratemaking, and NECHPI would recommend the adoption of such an approach, with some modifications tailored to New York State's particular circumstances:

PRINCIPLES FOR DESIGNING PERFORMANCE-BASED RATEMAKING

1. Define goals and outcomes. Then, set a quantitative standard for performance; include incentives for exceptional performance and penalties for missing the standard.
2. A clear methodology for measuring performance and a counterfactual should be defined at the outset of the program. Simply beginning to measure performance can reveal substantial opportunities for savings.
3. Shift an appropriate amount of performance risk to the utility, in exchange for longer-term regulatory certainty and perhaps incentive compensation. Reward entrepreneurialism.
4. Establish a long enough time horizon for the utility and third-parties to make investment decisions with certainty and innovate to meet performance targets.
5. Revenue sharing can align utility performance with customer benefits. Structure programs so there is enough upside potential for the utility to drive innovation.
6. Build on an existing framework, but aim to find holistic solutions that go far enough to align incentives and simplify the regulatory process. Adding piecemeal performance-based ratemaking to existing regulation—without carefully adjusting the terms and conditions of each—can add complexity and undermine both.
7. Single performance incentives can be designed to achieve multiple objectives.
8. Mid-course correction can be built in, but the need for any changes must be announced well in advance of implementation, in order to minimize uncertainty.
9. Engage with customers and power sector participants early to find out which outcomes they care about. Both the Commission and the utility can be proactive on this.
10. Learn from experience with energy efficiency standards and incentive programs. Apply these approaches to achieve other system goals that produce customer value.

2. New outcomes/metrics
    a. What new targeted performance incentive approaches should be considered?
    b. What specific outcomes of REV should be incentivized? What percentage of utilities potential earnings or how many basis points of earnings should be tied to these incentives at standard and superior performance levels?

c. Should metrics tied to new outcomes be generic across all utilities or utility specific?

d. How should a distribution system efficiency incentive be designed? What performance measures and targets need to be developed for a distribution system efficiency incentive?

e. Can utility incentives stimulate changes in customer behavior? Should incentives be used in this way?

f. Can utility performance targets and incentives be helpful in ensuring reasonable working relationships between distribution utilities and market participants such as ESCOs or DER providers, for example facilitating interconnections or encouraging microgrids?

g. What utility incentives are necessary to promote comprehensive integrated resource planning at the distribution level that would consider all DER alternatives to satisfy system expansion, system replacement, and / or to meet clean energy goals? Are there examples for multi-year performance metrics which would be superior in providing value to customers compared with an annual metric?

3. Inputs

a. Are there instances where utility inputs are a proper metric to assess performance? For example, employees per MW served, cost per distribution MWh, cost per customer, or some other metric (please specify).

4. Accommodating bridge investments. Bridge investments are long term projects that may require several years or levels to achieve.

a. Should the Commission incent utilities to build/acquire bridge investments?

b. If so, what incentives will engage utilities in "bridge investments" necessary to meet the Commission's goals for the new system? (For example, one incentive approach is to establish incentives to achieve milestones along the path to conclusion rather than establish an incentive at the conclusion of the project.)

c. What ratemaking should apply to bridge investments that do not produce complete results during the term of the incentive period?

Clearly there has to be a transition period to the ultimate goal of a utility business model dominated by earnings driven by performance metrics. Transformations do not occur over night, and utilities, regulators, rate payers and other stakeholders will need time to adjust to new market realities. There are numerous examples around the country of regions that have successfully tested and adopted new rate-setting approaches, and we believe that, once standardized and transparent cost-benefit and valuation methodologies are

developed and used for valuing all energy resources, compensation mechanisms will be able to be tailored to the particular circumstances of a utility. Some states such as Vermont and Minnesota have been successful at adopting controversial energy policies with significant stakeholder approval.

The establishment in New York State of a technology-agnostic state "green bank" fully supportive of all distributed energy resources ("DERs"), including CHP, will be critical in implementing "bridge" investment strategies and an excellent first step in providing the means for clean-energy market expansion since we are a firm believer in public-private partnerships ("P3") and leveraging private capital to complement/supplement public and utility longer-term capital expenditure programs; however, without coordination between the green bank and all of New York State's inter-related mandates, rules and regulations, many developed incrementally and in isolation to one another, the current environment, in spite of specific, articulated goals to support the growth of CHP both locally and nationally, is not sufficiently robust or supportive to allow CHP to help the State achieve these stated goals.

As key CHP stakeholders in New York State, we believe that the current regulatory environment will not lead to the desired result as stated in the state's current policy goals in regards to CHP, and the following recommendations highlight the initiatives and actions needed to ensure that those stated policy goals are achieved.

1. Develop and implement transparent, standardized processes, procedures and documents in all aspects of clean-energy projects to ensure that federal and state economic, social, energy-policy and environmental goals, regulations and legislative mandates are met while simultaneously attracting high-quality sources of capital throughout the clean-energy value chain.

2. Adopt technology-agnostic technical and financial underwriting approach to ensure a level playing field, enabling long-term financial support on competitive terms for all distributed-generation assets in the emerging energy-resource mix required to meet state goals and mandates.

3. Continue to drive down "soft" costs associated with clean-energy project implementation, including design, permitting and inspection, legal and interconnection costs, through the required standardization as much as possible of certain of the associated activities. In particular, CHP siting and permitting processes can be costly, time-consuming and onerous, and some states are already beginning to adopt statewide procedures for DG siting and permitting, helping to drive down their costs.

4. Help overcome one of the largest constraints to long-term financing, namely, up-front construction financing, through a revolving fund approach designed to fund short-term needs, which in turn is rolled into long-term permanent financing based on the standardized and transparent technical and financial underwriting mechanisms based on industry best practices approved by high-quality financing sources. This will provide revolving funds, which will continue to support clean-energy projects on an on-going basis.

5. Focus policy initiatives to support the alignment of legislative and regulatory requirements, both at the utility- and the New York ISO level, which have developed over time as a patchwork of rules in response to incremental developments in the energy industry over the last decade in particular. As the energy mix is changing fairly dramatically to include a wide array of distributed-energy resources and as the transmission and distribution systems continue to expand and improve, these rules need to be upgraded and aligned to guide the production, transmission and delivery of electricity, most particularly at the distribution level.

6. Improve the state's RPS and EEPS standards, net metering rules and utility rate structures to be more robust and supportive of DER and CHP in particular. CHP is receiving a great deal of public support in New York State as well as through NYSERDA, but there are countervailing trends and mechanisms that reduce the effectiveness of those initiatives and efforts. The combined effects of the three policies undermine the ability of CHP to compete with other clean-energy resources on a level playing field.

7. Ensure the development and implementation of policies that aim as much as possible for a uniform set of rules and requirements for all distributed energy resources, including CHP. We advocate for the clear delineation and coordination of federal and state authority for utility regulation and that New York should take maximum advantage of new FERC rules that actively support the participation of distributed energy resources in wholesale power markets across the board. There are still unclear boundaries but ones that could be to the advantage of states that seek to address FERC's orders proactively.

8. Adopt rules and regulations aligned with, and maximized for the successful implementation of FERC's performance-based compensation orders for all technically-qualified resource types, including CHP, in wholesale markets.

9. Ensure that the NYISO supports CHP participation in its programs. CHP is currently precluded from revenue streams that could dramatically alter the economics of CHP plants and operations, which lowers investor interest. Other markets, such as PJM Interconnection and ISO – New England are much more supportive of CHP resources, including behind-the-meter

implementations of all DERs. As an example, NYISO does not allow behind-the-meter participation in regulation services if the site has on-site generation. This is a significant issue as most industry observers are clearly seeing the emergence of what is being referred to as a "transactive" energy market that will form the underpinning of the electric grid in the not-too-distant future.

5. Symmetry options
    a. What are the advantages and disadvantages of symmetrical, penalty only and asymmetrical incentives relative to the Commission's goals in this proceeding?
    b. In order to achieve the Commission's objectives, how should the Commission determine which metrics and associated value to tie to such incentives?

6. Benchmarking

NYS DPS envisions over the longer term the electric grid to be a bidirectional, transactive, and situationally-aware system that supports:

- Transactive nodes across the grid, with bidirectional interconnections and "prosumers" (producer-consumers) buying and selling energy products and services;
- The elimination of barriers to entry, allowing new technologies to participate in the electric grid and ensuring that the batteries and energy storage are not excluded;
- The valuation of products and services based on transparent and standardized methodologies, procedures and processes through the unbundling of the costs and benefits of energy resources in providing products and services to the grid, ensuring that each DER's value streams are appropriately and fairly captured; and
- The elimination of competitive barriers so that each resource can participate on a level playing field.

We believe that DPS's vision requires a framework and methodology for developing a long-term implementation plan that is built on a robust, secure, real-time transactive-energy platform, which is able to create value streams systematically and transparently for all distributed energy resources based on detailed costs/benefits analyses that level the playing field. The methodology should be based on sound financial and technical planning principles; is able to be phased in over time; and provides a means for distributed energy resources ("DERs") to participate in all products and services based on their

capabilities, performance and other attributes, not on artificially created support mechanisms or penalties, which advantage or disadvantage certain technologies over others.

Value essentially equates to a price. However, how it is expressed can be through any number of different compensation mechanisms as follows:

- Organized markets
- Procurements
- Competitive RFPs
- Tariffs (FITs, specialized tariffs for solar, energy storage, microgrids, etc.)
- Over-the-counter bilateral contracts
- A customer's or other entity's self-optimization process.

NECHPI supports the development and implementation of a variety of approaches as long as they are based on standardized and transparent valuation methodologies and documentation adhered to by utilities and which inform the development and implementation of all compensation mechanisms and retail rates.

Thus, we strongly urge the development and adoption of standardized, transparent, replicable and scalable processes, procedures, methodologies such as those proposed by RMI in the valuing of costs and benefits of DERs to enable the development of compensation mechanisms that are consistently applied and allow any resource to participate at the level appropriate to its abilities. We believe that, by adopting standardized, transparent processes, procedures and documentation, all energy resources will benefit and all stakeholders will be able to assess the validity, equity, fairness and applicability of the assumptions underlying the models to their particular issues and requirements.

We also adhere to the principle of technology agnosticism and that with the development of open, standardized costs/benefits analyses underpinning value streams for products and services created as part of a transactive energy framework, all stakeholders will benefit.

7. Utility as DSPP and as DER-owner: neutralizing incentives
    a. Can ratemaking or structural mechanisms be established to remove the utility bias in favor of DER investments owned by the utility or its affiliates?
    b. If the utility owns DER investments, is it better if they are rate based and rate regulated, or owned by unregulated affiliates? Is there another option? Does this provide utility incentives to misallocate costs between regulated and unregulated products?
    c. What, if any, incentives are required for the utility to make the necessary up front investments in the DSPP?

8. Removing bias toward increasing capital expenditures
    a. What ratemaking mechanisms or incentives would encourage the most efficient mix of capital expenditures and operational expenses?
    b. Should the Commission employ any mechanisms to eliminate the bias in favor of managing operating expenses (O&M vs. capital issue)? Should the Commission develop mechanisms to treat capital savings the same as O&M savings?
    c. The current ratemaking paradigm provides utilities with earnings based on the size of the rate base (amount of infrastructure investment). Are there other ways to provide utilities with earnings that would not be dependent upon/linked to the size of a utilities rate base?

Long Term Rate Plans

1. Pros and cons of long term rate plans
    a. What are the pros/cons of an extended rate plan term (i.e., greater than three years)?
    b. How can long term planning and priorities be better encouraged under the current rate making approach?
    c. Are longer term rate plans a preferable way to enable utilities to achieve identified strategic outcomes?

    d. Optimal number of years
        i. What is the optimal length for a long term rate plan? Are there any impediments to achieving the recommended term, or negative aspects to such terms, and how can they be mitigated?

    e. Baseline cost-of-service recovery; ROE
        i. For current multi-year rate agreements, the Commission sets rates (including the ROE) for the initial rate year. What are the challenges you expect in setting initial rates under outcome-based ratemaking?
2. What are the advantages and disadvantages of setting initial rates under outcome-based ratemaking?
    a. How should the Commission set initial rates under outcomes-based ratemaking?
    b. Earnings sharing mechanisms are a key feature in the current ratemaking system. They provide for the sharing of efficiency gains during the term of the rate plan, and potentially militate against unintended consequences. Should these be retained, modified, or eliminated?
    c. What are the advantages and disadvantages of maintaining the Commission's current methodology for setting the ROE in multi-year rate plans under outcome-based ratemaking? What, if any, modifications should the Commission make to its return on equity methodology in the new incentive environment?

2. Interim investment provisions (avoiding deterioration)
    a. Capital expenditure reconciliations are an important feature in the Commission's current ratemaking system. They provide for the capture of under spending during the term of the rate plan as a secondary measure which potentially militates against unintended future service or reliability consequences. Should these be retained, modified, or eliminated?

b. Should there be additional upside protections against capital spending in excess of forecasts?
c. Should downward only capital expenditures mechanisms be modified to allow utilities to keep the benefits of efficiencies implemented in capital budgeting (projects completed at lower cost than expected)? How?

3. Reopening conditions
    a. What sort of mid-term reopeners are needed to evaluate long term plans?
    b. Should a long term rate plan be terminated if certain performance targets are not met mid-way through the rate-plan period?

4. Exogenous factors and reconciliations
    a. What uncertainty mechanisms would be needed for long term plans to deal with unexpected costs or new governmental requirements?
    b. Typically, utilities are provided with protections against certain risks during long term rate plans (e.g., commodity pass through, uncontrollable costs provisions, etc.). In return, the utility must absorb any deficient returns. Should this type of approach be retained or modified? What costs should be included?
    c. Should we consider changing the existing pass through recovery of electric commodity costs by electric utilities? Explain.
5. Reporting requirements
    a. What level of financial monitoring is necessary during a long term plan? What reporting requirements are necessary under a long term plan?
    b. What level of service quality and other performance reporting and monitoring is necessary?
    c. How should the Commission monitor cost allocations to other subsidiaries including unregulated subsidiaries?

6. Application of RIIO concepts (to the extent not addressed above)
    a. Should the Commission focus more on outputs and less on inputs? If so, by which means should the Commission accomplish this? Which outputs and inputs would be appropriate?
    b. If the NY Commission were to focus on outputs as is done in RIIO, which outputs should we focus on? Which ones should we ignore or add?
    c. What are your thoughts (pros/cons) on the 8 year rate plan length?

7. 11-month suspension period and establishing a long-term plan

a. Is it a reasonable expectation that an extended rate plan can be redesigned within the statutory 11 month suspension period or will it take more time (how long)?

8. Financial implications of ratemaking changes
    a. How can we insure that any new incentives do not adversely affect the utility's credit rating?
    b. Under US GAAP Accounting Standards Codification (ASC) 980-Regulated Operations utilities are permitted to record regulatory deferrals. Would a revised regulatory regime focused on performance-based ratemaking impact utility qualification under ASC 980? To what extent is that a concern?
    c. Would there be any concerns about asset impairment under a revised regulatory regime focused on performance based ratemaking? How much of a concern is that and how can any concern be mitigated?

Rate Design

1. How do the customer incentives and disincentives under current rate design affect DER participation?
2. Tariffs for DSPP products
    a. How should non-monetized benefits and costs (e.g., carbon) be accounted for in rates, if at all?
    b. Which non-monetized benefits should be accounted for, if any?

A goal of these proceedings should be to establish valuation methodologies that systematically address all costs and benefits of each DER to: 1) provide a framework for comparing all DERs on an apples-to-apples basis and 2) monetize those benefits and costs not yet monetized or accounted for in rates. We take as a first principle that we should go back to the drawing board and rigorously establish these foundational values which will inform the development of new rate-setting methodologies. While this can be phased-in over time, it will not work until the whole approach to rate-setting is revisited. We believe that the methodology promulgated by RMI, and as adopted in the Minnesota VOST discussed in a separate of these Track II questions, should be developed and implemented across the board for all energy resources, not just DERs, and should be one of the required methodologies used in a mandated utility IRP process.

3. For each of the products and services to be *procured* by the DSPP, how should the pricing be determined? (If the answers differ by product, please specify to the extent possible)

Under a new utility business model, the utility could also likely fill a number of clear roles:

- Distribution system operations coordinator;
- Provider of reliability/standby and power quality services for customers that do not self-provide these services;
- Integrator of large-scale supply resources, distributed energy resources and storage, all under circumstances in which regulation creates a level playing field for the utility to combine these resources for least cost overall.
- Integrated Distributed Resource Manager (DER Dispatcher)
- Distributed Resource Finance Aggregator (DER FinanceCo) (providing on-bill financing, as an example, for customers choosing to invest in certain

types of qualifying DERs, coupled with a new tariff structure that applies for participating customers);

- Utility as an active director investor responsible for siting distributed resources and managing deployment through price signals.

- Utility as owner of distributed resources as long as a competitive environment is maintained locally; and

- Utility as a platform to create peer-based transactive energy grids that allow distributed resources to interact directly with each other through network-based, local energy markets in close to real time.

Once the new utility business model is agreed upon, which includes the kinds of services to be delivered, then evaluating appropriate pricing mechanisms would follow. As we have said in other sections of these questions, as long as there is a standardized cost/benefit and valuation methodology employed for all resources and which is applied across the board, we believe that any number of mechanisms could be used to support the state's longer-term clean energy goals.

4. For each of the products and services to be *offered* by the DSPP, how should the pricing be determined?
    a. Should delivery services be unbundled into reliability, power quality, ancillary services components and other value added services? What value added services need to be unbundled?
    b. Should pricing be based on embedded cost of service?

Once based on standardized and transparent valuation methodologies, markets for DERs should be open, unbundled and competitive, encouraging competition to increase efficiency, reduce both cost and price and allowing participants to profit from superior performance. An embedded cost of service model, which is an old cost-of-service rate-setting methodology, is not appropriate under a new rate design.

    c. Should pricing be determined through a market mechanism which might reflect locational based marginal pricing?

The value of energy and capacity is highly related to location. It is therefore important that market mechanisms are created that value locational as well as temporal benefits. Note that this applies to both load reductions as well as providing energy and capacity. We also believe that there is a host of grid-flexibility products as yet development and implemented which should be integrated into rate-setting methodologies. In the long-run, we should achieve

competitive, transactive-driven markets that fully value all of the benefits associated with local and temporal energy and capacity. Initially, prior to sufficient DER penetration to establish robust markets, other pricing mechanisms that incorporate locational and temporal value should be adopted.
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A key issue today is that utilities do not understand what it costs them to serve each customer. What is needed is a "value signal" that shows cost by customer and by location. This signal must jointly value both grid-side and supply-side simultaneously. Tom Osterhus, the founder of Sageview Associates and the CEO of Integral Analytics, has developed the concept of what he calls the "distributed marginal price" to reflect that it is to the distribution network what the locational marginal price is to the transmission network.

Locational marginal price is the hypothetical incremental cost to produce more power to a particular node in the network at a particular time and reflects the value of energy at a specific location at the time that it is delivered. PJM describes the LMP as follows: "When there is transmission congestion (that is, heavy use of the transmission system in an area), energy cannot flow freely to certain locations. In that case, more expensive and advantageously located electricity is ordered to meet that demand. As a result, the LMP is higher in those locations."

The DMP in contrast simultaneously and jointly values both supply-side (kW) avoided costs and grid-side costs (KVAR, voltage, power factor). It forces collaboration within the utility across siloes and reveals a single price signal per house, per customer, for third parties to see with certainty. This in turn should spark considerable innovation and do so in the right place, the right time and the right amount.

Mr. Osterhus believes that DMPs can change the industry by:

- Providing a transparent and efficient value signal that reflects the true cost to the utility;
- Providing a value signal to "aim" and assess third-party innovation; and
- Jointly valuing grid-side and commodity-side costs in an integrated fashion, providing a common metric for utilities, regulators and third parties.

We believe that the NYS PSC should actively pursue investigating this approach as part of its analysis of new standardized and transparent valuation methodologies.

d. Should pricing be determined via request for proposals and individually negotiated contracts? Should individually negotiated contracts be made available for public inspection?

In its simplest terms, value equates to a price – whether it is the market price of generating, transporting and consuming power across the system or the price of maintaining, protecting and optimizing the power lines and transformers, energy storage and demand response assets and other equipment that aids the task. (Grid Wise Alliance Council)

Value realization can take place through a variety of market-based approaches including the following, all of which are viable alternatives as long as transparent and standardized valuation methodologies are employed:

- Organized markets
- Procurements
- Competitive RFPs
- Tariffs (FITs, specialized tariffs for solar, energy storage, microgrids, etc.)
- Over-the-counter bilateral contracts
- A customer's or other entity's self-optimization process.

e. Should pricing be administratively determined to provide an incentive to achieve a predetermined outcome? If so, what level of granularity is needed (e.g., peak/off-peak vs. hourly)

With the emergence of close-to-real-time IT and network communications technologies, incentives should be as granular as possible but transparent. This will require, however, an automated metering infrastructure, which New York does not have. AMI has evolved fairly dramatically over the last five years, and many utilities that have been involved in its implementation state that they are now realizing substantial benefits through the ability to receive granular usage information allowing them to measure and monetize the data as well as develop pricing mechanisms able to take advantage of the granularity.

The State should actively consider the implementation of an AMI infrastructure. Without it, it will not be able to adopt advanced price-responsive mechanisms in close to real time for individual consumers as well as classes of them.

f. Should the pricing vary by time and/or geographic location?

Per the above answers, we believe that new pricing schemes should be developed to reflect temporal and locational values.

g. Should the pricing be differentiated for products related to reliability, economics, or public policy?

As we have stated in other sections, these are important performance metrics which need to be tailored to the particular clean-energy and other state policy requirements. As part of the cost/benefit and valuation methodologies developed by RMI, all of these are part of the approach taken to value all DERs in a comparable fashion.

5. New rate designs (This is the same language from the first section but relevant.)

It is apparent that in an environment of rapidly increasing penetration levels of distributed energy resources and bi-directional flow of information and energy, a traditional utility "volumetric rate structure" is increasingly ineffective as a means to compensate a utility. Rocky Mountain Institute ("RMI") points to existing rates and incentives fail to provide accurate economic signals to align distributed generation investment with system costs and benefits over the long term and to more accurately reflect the costs and values associated with each particular resource, which in its estimation will require some degree of price unbundling (i.e., charging separately for different cost components).

Are there modifications or more fundamental changes to traditional cost-of-service regulation that would be beneficial for achieving 21st century goals for the power sector?

The first step is to establish goals for the New York State power sector to set the stage for possible performance objectives such as below (America's Power Plan):

Goal	Possible Performance Objectives
Cost	Minimize overall energy service costs to customers; ensure equitable allocation of costs; optimize resource allocation; improve company productivity through innovation
Reliability	Fewer outages; shorter duration of outages; fewer customers impacted by outages
Environmental Performance	Minimize pollution; minimize land use impacts; minimize water consumption
Customer Service	Transparent billing process; adequate response to customer complaints; delivery and support of new value-added products and services (from the utility or from third-party service providers)

Most regulators are familiar with such goals and the tradeoffs between them. However, they are not always made explicit at the beginning of a traditional cost-of-service ratemaking process. Tools such as Integrated Resource Planning have made strides towards a more forward-looking regulatory process; however, traditional cost-of-service regulation is still a "backward-looking" exercise predominantly based on incurred costs of utility assets and utility operations.

"As one recent report observed, U.S. regulatory regimes typically focus on the central question: "Did we pay the correct amount for what we got?" In contrast, other regulatory regimes have emerged (e.g., performance-based ratemaking) that place performance objectives at the forefront, thereby changing the focal question to: "How do we pay for what we want?" In other words, the regulatory regime becomes predicated more on value provided by serving electric customers rather than simply the cost of providing service." (*New Regulatory Models*, Sonia Aggarwal, Energy Innovation and America's Power Plan, March 2014)

Thus, traditional ratemaking involves the development of a utility's revenue requirements and ultimately its rates to recover a utility's costs in the "test" year (including taxes) plus a reasonable return on its rate base. In contrast, performance-based ratemaking decouples a utility's profits from its costs and ties utility profit to performance relative to specific benchmarks.

RMI makes specific proposals on how to reduce disincentives and reward performance with respect to distributed resource deployment, including new pricing models and methods of cost allocation to realign resource investments with system costs and benefits over short-term (operational) and long-term (planning) horizons.

Examples include:

- Unbundled pricing for reliability, standby, and power quality services;
- Temporally or locationally differentiated prices for energy or distribution services; price structures that reflect how costs are incurred (e.g., demand-based, fixed, energy-based, etc.); and
- Incentive payments for dispatchable demand response or ancillary services to the grid.

We believe that there are key underlying conditions which need to be addressed and implemented before regulators and utilities are able to address performance-based issues associated with specific rates, incentives and penalties. The most critical ones in our estimation are the following:

- Mandated integrated resource planning
- The adoption of standardized and transparent cost/benefit and valuation methodologies for all energy resources across the grid, including distributed energy resources, which form the coherent and justifiable basis for the development of new rate-setting and other compensation mechanisms such as special tariffs, bilaterally negotiated contracts, competitive bids and new grid services to be developed in the future

There is an emerging regulatory model called results-based or performance-based regulation. Performance-based ratemaking starts with the outcomes that matter to customers, utilities, regulators and other power-sector industry participants. These goals might include objectives such as minimizing costs, maximizing reliability, maximizing environmental performance, and enhancing the value of customer service. It aims to align the goals of customers, regulators and utilities. In PBR, the utility is rewarded based on its achievement of specific performance targets, providing an opportunity to earn a higher return if the company is able to perform on the objectives identified.

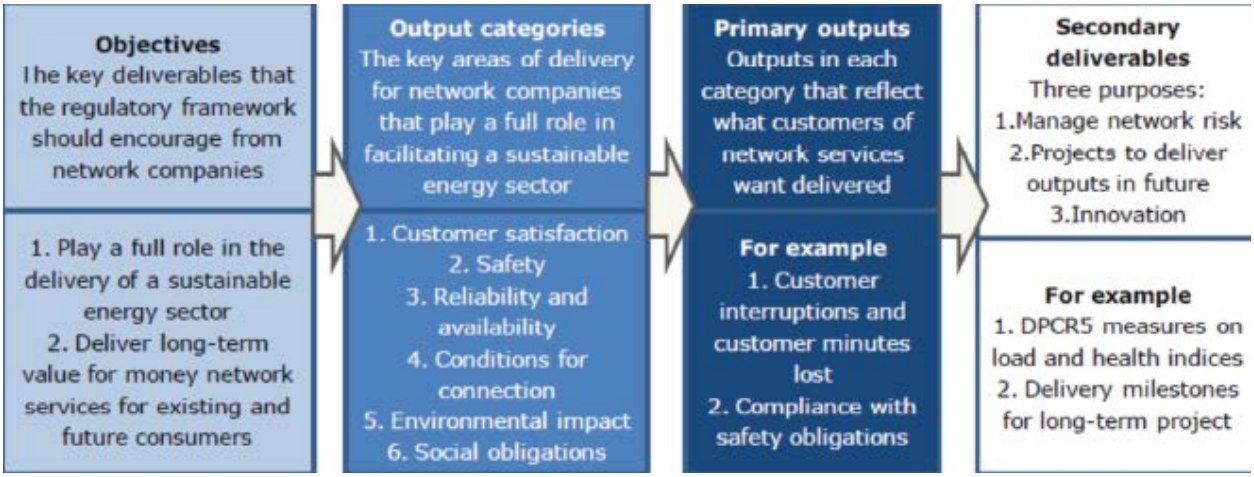
Well-designed performance-based ratemaking includes both incentives for over-performance and penalties for underperformance. This system of paying for performance broadens the scope of options utilities can call on to run their business.
A discussion of performance-based cost recovery naturally leads to a conversation about how performance should be measured and what measures should be used. The variation by state is quite significant. For example, Maryland developed 90 implementation metrics and 36 on-going performance metrics to evaluate IOU smart-grid deployment status and value creation. Regulators in other states need to develop their own performance measures based on their specific goals and objectives, e.g., for distributed energy resource deployment, meeting RPS standards, carbon emissions reductions, etc.

Examples of performance-based ratemaking including the following:

- Fort St. Vrain, Colorado for a new nuclear facility
- Revenue-sharing for Off-System REC Sales: Xcel Energy in Colorado
- Massachusetts Statewide Plan of Performance Incentives for Energy Efficiency
- Revenue Sharing for Off-System Sales: MidAmerican Iowa
- Smart Grid Investment: Illinois' Energy Infrastructure Modernization Act
- Full-scale Performance-based Ratemaking: the UK's RIIO Model

The RIIO model is the most forward-thinking of all of the above-listed models. RIIO includes six primary output categories: customer satisfaction, reliability and availability, safe network services, connection terms, environmental

impact, and social obligations, each with measurable targets. The program also allows utilities to propose higher rates to meet secondary deliverables to manage network risk, deliver outputs in the future and innovate. See the below figure.



There is a significant amount of available information on the RIIO, which is too complicated to discuss within this context, but NECHPI believes that the its highly adaptable approach, based on policy changes and experience over time through implementation, offers an innovative model which should at least be investigated thoroughly and possibly implemented as a pilot for a period of time.

The New Regulatory Models report provides the following principles for designing performance-base ratemaking, and NECHPI would recommend the adoption of such an approach, with some modifications tailored to New York State's particular circumstances:

PRINCIPLES FOR DESIGNING PERFORMANCE-BASED RATEMAKING

1. Define goals and outcomes. Then, set a quantitative standard for performance; include incentives for exceptional performance and penalties for missing the standard.
2. A clear methodology for measuring performance and a counterfactual should be defined at the outset of the program. Simply beginning to measure performance can reveal substantial opportunities for savings.
3. Shift an appropriate amount of performance risk to the utility, in exchange for longer-term regulatory certainty and perhaps incentive compensation. Reward entrepreneurialism.
4. Establish a long enough time horizon for the utility and third-parties to make investment decisions with certainty and innovate to meet performance targets.
5. Revenue sharing can align utility performance with customer benefits. Structure programs so there is enough upside potential for the utility to drive innovation.
6. Build on an existing framework, but aim to find holistic solutions that go far enough to align incentives and simplify the regulatory process. Adding piecemeal performance-based ratemaking to existing regulation—without carefully adjusting the terms and conditions of each—can add complexity and undermine both.
7. Single performance incentives can be designed to achieve multiple objectives.
8. Mid-course correction can be built in, but the need for any changes must be announced well in advance of implementation, in order to minimize uncertainty.
9. Engage with customers and power sector participants early to find out which outcomes they care about. Both the Commission and the utility can be proactive on this.
10. Learn from experience with energy efficiency standards and incentive programs. Apply these approaches to achieve other system goals that produce customer value.

a. Should rate designs reflect different levels of service, e.g. essential monopoly service versus non-essential value-added competitive service? Can fees from non-monopoly services constitute a portion of the incentives otherwise provided through ratemaking?

b. Should the products and services procured and offered by the DSPP be offered on a service class basis or uniform pricing for all customers? If the answer differs by product, please specify.

c. Should rates for products or services procured to achieve certain incentives, like more efficient utilization of the distribution system through peak load reductions, be set by the Commission or allowed to be set by the utility companies as necessary?

d. Should the current volumetric rate designs used to recover embedded costs be revised to move toward fixed pricing? What are

the tradeoffs or unintended consequences of moving towards fixed pricing that should be considered?

e. To what extent should the existing revenue decoupling mechanisms (RDM) continue to be applied and what modifications would be necessary?

f. Should lost revenues due to customer bypass be fully, partially, or not included and recovered in the RDM, or some other, reconciliation process?

g. What payment structure would facilitate distribution utility ownership of DER behind customers' meters? For example, should a customer be provided with a direct payment for allowing the utility to locate the DER on its property or should the customer be allocated a portion of the ongoing DER benefit?

h. How can rates best be structured to equitably share system benefits among participating and non-participating customers (i.e. customers without DER onsite)?

i. Should rate designs reflect different levels of service, e.g. essential monopoly service versus non-essential value-added competitive service? Can fees from non-monopoly services constitute a portion of the incentives otherwise provided through ratemaking?

j. Should the products and services procured and offered by the DSPP be offered on a service class basis or uniform pricing for all customers? If the answer differs by product, please specify.

k. Should rates for products or services procured to achieve certain incentives, like more efficient utilization of the distribution system through peak load reductions, be set by the Commission or allowed to be set by the utility companies as necessary?

l. Should the current volumetric rate designs used to recover embedded costs be revised to move toward fixed pricing? What are the tradeoffs or unintended consequences of moving towards fixed pricing that should be considered?

m. To what extent should the existing revenue decoupling mechanisms (RDM) continue to be applied and what modifications would be necessary?

n. Should lost revenues due to customer bypass be fully, partially, or not included and recovered in the RDM, or some other, reconciliation process?

o. What payment structure would facilitate distribution utility ownership of DER behind customers' meters? For example, should a customer be provided with a direct payment for allowing the utility to locate the DER on its property or should the customer be allocated a portion of the ongoing DER benefit?

p. How can rates best be structured to equitably share system benefits among participating and non-participating customers (i.e. customers without DER onsite)?

6. Enhanced service and basic service
   a. How should default service be defined?
   b. Should the DSPP offer default service and if so what products and services should be included and what rate design should be employed?
   c. Should there be different levels of default service, for example basic and enhanced and what features would each have?

7. Standby rates

Standby rates can be a barrier to adoption of DERs and are a manifestation of a utility-system view that DERs must be fully backed up at all times. At the heart of the REV process is a transformation of this system view to consider DERs integral system assets. We believe that once standardized and transparent valuation methodologies are adopted, many of these issues will go away since each individual energy resource will be compared on an apples-to-apples basis, allowing the development of compensation mechanisms based on readily visible metrics. This, we believe that the question of DER reliability should not be address by standby charges, but instead, DERs should be fully integrated into the integrated resource planning process and that tariff structures be fully reassessed to address not only the costs but the multiple benefits of DERs and to properly compensate utilities for the value of the interconnection to the grid.

In terms of CHP, utility rate structures are generally not supportive of CHP and in fact, can make many projects unviable economically and therefore, unfinanceable; for all intents and purposes, only CHP under 10 kW in size are allowed to participate in New York State's net metering program, which places it at a significant disadvantage relative to other DG assets. In our estimation, it should be on an equal footing with all other DG assets; and the RPS should fully include CHP as an eligible resource or should have a carve-out in the RPS as a "critical-infrastructure" resource.

Standby rates in particular can pose a substantial barrier to adoption of CHP systems when they are not designed to closely preserve the nexus between charges and cost of service. (Everyone knows all of the arguments for why they are so bad. I am focused on features that should be incorporated into utility tariffs and rates going forward.)

Standby rates that incorporate the following features encourage customer-generators to use electric service most efficiently and minimize costs they impose on the electric system:

- Reduce use of demand charges and replace with more energy-specific charges (e.g., under full requirements rates, demand charges can comprise 30% of a yearly bill whereas they comprise upwards of 50% for a partial service customer);
- Have peak demand charges that are not ratcheted (or, at most, have a one-month ratchet charge);
- Establish contract demand or reservation charges that are small in relation to the variable charges for peak demand and energy;
- Have energy-based (instead of demand-based) charges to collect capacity costs;
- Offer daily or monthly as-used demand charges for backup power and shared transmission and distribution facilities;
- Reflect load diversity of CHP customers in charges for shared-delivery facilities;
- Provide an opportunity to purchase economic replacement power;
- Allow customer-generators the option to buy some or all of their backup power at market prices and/or bi-laterally;
- Allow the customer to provide the utility with a load-reduction plan;
- Offer a self-supply option for reserves.

Utility Avoided Rate as Evaluation Measure for Standby Rates

Avoided rate compares the cost per kWh on a full requirements basis to the avoided cost per kWh on a standby tariff. In other words, the avoided cost is a kWh price for the electricity not purchased due to on-site generation. The concept is considered important because the reduction in electricity price should be commensurate with the reduction in purchased electricity. When the avoided rate closely matches the full requirements rate, the user experiences increased savings.

According to the EPA/RAP standby rate study, avoided costs that fall below 90% of the full-service retail rate generally indicate standby rates that are unfavorable towards DG/CHP installations. In fact, rates that fall below 85% are thought to actively prevent CHP systems from achieving the desired savings necessary to make projects more economically viable. One of the largest structural culprits to self-generating customers that contribute to the low avoided rate scores is demand ratcheting, including contract demand charges.

a. How can the current standby rate design be revised to reflect the diversity of DER and the unlikelihood that all DER resources would fail at once and all during the system peak hour?
b. How can the current standby rate design be revised to reflect environmental or system values of certain types of DER?
c. How would the current standby rate design need to change to be applicable to multi-customer microgrids?
d. How should the prices for products and service reflect the additional system and environmental values represented by technologies that are currently eligible for net metering?

8. Gas and steam rate implications
    a. How do the current gas and steam rate designs encourage or discourage the installation of DER, specifically gas fired DG and CHP?
    b. Which aspects should be eliminated, expanded, or redesigned, and how?

The issue of the increasing interdependencies of the gas and electric utility industries is becoming readily apparent, and even though it is not part of the REV proceeding per se, it affects many of the issues we are addressing in terms of energy pricing and the ripple effects across the grid. In the case of microgrids and CHP, a critical and integral source of dispatchable energy in microgrids, is

particularly susceptible to gas-price risks, which can radically change the economics of a microgrid project.

Over the last decade the electric power industry has been on an unprecedented rollercoaster ride through a whirlwind of market ups and downs, regulatory twists and turns and environmental swings resulting from major changes in the fundamental business models in place for the last 100 years, including major government support of renewable energy. Compounding the strains is the unprecedented growth in natural gas-fired generation and that is leading to something completely new, namely, the coordination and possible integration of both the natural gas and electric systems.

The growth is being driven first by the increase in shale gas production in the U.S., leading to an abundance and failing prices for the fuel and making it one of the least costly forms of generation compared with other alternatives. Natural-gas-fired generators also offer one of the most flexible modes of operation, providing probably the best support for intermittent renewable power sources such as wind and solar and providing the ability to ramp up quickly when demand is high.

The Northeast's worrying trend of the growing interdependency of the electric and gas sectors is leading to challenges to reliable power system operation. The issue is magnified during the winter months when there is a simultaneous demand for natural gas for both heating purposes and for electric generation. At times, this causes constraints on the natural gas supply coming into the region because there is not enough pipeline capacity to satisfy both heating and electric demand.

Companies that procure natural gas for heating purposes pay for and receive firm, priority contracts with the pipelines for natural gas delivery, but this can limit deliveries to some natural-gas-fired generators in the region, which typically do not pay for firm service and purchase their fuel using a just-in-time delivery system. The current wholesale electricity design does not provide adequate incentives for generators to provide electrical energy when called on by the ISO during stressed conditions, in particular, for gas generators who have not made adequate and reliable arrangements for fuel supply. Because natural gas generators generally have a short- to medium-term financial horizon and are a diverse group with diverse market interests, they are a group of "fragmented" buyers who are unlikely to enter into long-term fuel arrangements on a large-scale, particularly with the current market design.

This does not align with the long-term commitment preferred by investors in gas pipelines and gas storage infrastructure.

Market changes that provide the economic incentives necessary to ensure that generators have adequate and reliable fuel supplies include:

- Changes in wholesale markets to improve electricity price formation, improve the ability of generators to reflect the true cost of fuel in their offers to sell electricity, and strengthen performance incentives for generators and demand resources;
- Changes to the timing of the electricity market to provide additional time for generators to secure fuel from the gas market to meet their obligations in the electricity market and to provide system operators additional time to call on non-gas-fired generators if needed; and
- Expanding the amount of resources held in reserve to respond to the sudden loss of generation due to a system contingency.

Additional flexibility in the natural gas industry would also help address the challenges of increasing interdependency between the two industries. Power generation is rapidly becoming the largest customer for natural gas pipelines, and the gas sector could assist with reliability efforts if gas suppliers provided generators with additional opportunities to obtain fuel outside of normal business hours, and if pipelines would offer more flexible scheduling, additional services and provide real-time information on the status of the pipeline system.

Thus, key to increased coordination is to solve the serious problem arising from non-aligned communication and operational processes between the two sectors. While FERC mandates that communication protocols be established between interstate pipelines, power plant operators and transmission owners/operators, this communication is mostly limited to emergency situations. In addition, resource planning approaches are quite different between the two systems, thereby creating friction when it comes to aligning resource adequacy practices. The situation is exacerbated because the electric industry is designed to be flexible while the natural gas industry is highly reliable on firm contracts. As a result, pipeline capacity closely matches the requirements of firm customres.

The Potential Business Case for Synergies Between Natural Gas and Renewable Energy

A key element of the discussion about microgrids is that, in spite of the fact that natural gas and renewables are often considered competitors in markets, in actuality, natural gas and renewable energy each contribute to economic growth, energy independence, and carbon mitigation, sometimes independently and sometimes collectively. I believe the paper provides a framework for solutions we could recommend for organizing, managing and financing microgrids.

A recent paper commissioned by the Joint Institute for Strategic Energy Analysis and written by the National Renewable Energy laboratory, entitled *Exploring the Potential Business Case for Synergies between natural Gas and Renewable Energy*, focuses on how can compelling business models be created where these two domestic forms of energy work in greater concert. The paper explores revenue opportunities that emerge from system-level perspective in bulk energy and four distribution-edge subsectors: industrial, residential, commercial and transportation end uses.

A key underlying concept in my estimation is that a rising share of variable generation in the system increased the need for the remainder of the capacity – both on the supply and demand side – to complement flexibly the variable output. In systems with a high share of variable renewables, lower predictability in the market as well as for network operators implies a **high need for flexibility** to cope with this volatility.

On an individual asset level, flexibility is the modification of generation injection and/or consumption patterns in reaction to an external signal (price signal or activation) in order to provide a service within the energy system. The parameters used to characterize flexibility include the amount of power modulation, the duration, the rate of change, the response time, the location, etc.

A key concept going forward will be **aggregation**. Aggregation is a commercial function of pooling decentralized generation and/or consumption and other energy assets to provide energy and energy services to actors within the system. Today a number of technologies can provide flexibility, including both centralized and decentralized generation, demand-side participation and energy storage. However, only very large customers find it easy to sell their flexibility on an individual basis and participate in the market today. Smaller customers face high barriers in accessing these markets. Transaction costs of such

participation are too high if managed at the individual asset level. Aggregation offers the opportunity for smaller customers to exploit their flexibility potential.

Aggregators can be retailers or third parties that may act as an intermediary between customers who provide flexibility and procurers of this flexibility. This could be done via flexibility products or simply selling and buying aggregated energy (kWh) at optimal points in time. The key challenge is establishing the basic requirements for aggregated products and how they are integratd in to the intraday and balancing markets.

This is only a summary of the paper though I have typed up sections without referencing them), but the paper is well worth reading. It emphasizes that synergies between natural gas and renewable energy are found at multiple levels – from hybrid systems that optimize assets (e.g., smart buildings with both PV and CHP to transmission corridors that serve both technologies. The business models that capitalize on both renewable energy and natural gas can access new revenue streams, including wholesale market opportunities for the distribution edge (e.g., demand response aggregation), upstream and downstream arbitrage opportunities from shared infrastructure, and energy services that offer the customer resiliency, reliability and reduced costs.

Synergies in Bulk Energy

Natural gas and renewable energy investments have different risk profiles and offer complementary portfolio benefits. These complementarities generally relate to financial risk hedging and reliability. Power generation based on natural gas offers the flexibility and increased dispatchability that complements variable and uncertain renewable energy power generation with no fuel risk but at the risk of increased fuel price volatility and the challenge, in some regions, of ensuring adequate and timely gas delivery. Planning tools that incorporate portfolio risk are one option that may lead to more complementary natural gas and renewable energy use, obviously of interest to the microgrid community.

Other synergistic “bulk energy” opportunities include the following:

- **Joint transmission corridors** for pipelines, roads and wires for both gas and renewables industries
- **Colocation** of gas and renewable plant generation can boost capacity factors and returns on investment. LBNL has recently demonstrated that the addition of solar to a gas-fired plant can improve efficiency by 20%, for example.

- **Hybrid energy systems**, integrating gas, solar, wind and other technologies, to increase overall plant efficiency and flexibility, to manage renewable variability and decrease fuel price risk.
- **Wholesale power markets** creating new market products and associated structures to combine variable renewable energy and flexible gas generation into a single firm, low-emissions product. New market products could also be created to ensure the availability of flexible natural gas-fired generation to support a high level of renewable penetration. A dispersed portfolio of diverse generating assets including as and renewables might be managed using an integrated operations optimization strategy and be bid into wholesale spot markets to maximize revenue and manage risk. Microgrids could be viewed as a portfolio of assets to maximize revenues, provide grid services and manage portfolio risk.
- **Increased coordination** of the gas and utility industries to avoid stranded capital and to maximize returns on limited investments as well as to benefit from better coordination of day-ahead dispatch scheduling of power markets and gas procurement scheduling in gas markets (per the above discussion).
- **Joint financing,** to create opportunities that build onsynergies between natural gas and renewable energy. Investments in renewable energy generation have generally been project-specific, illiquid, and primarily limited to investors who can utilize the tax credit benefits. Natural gas project financing spans broad mechanisms across the supply chain, from production-sharing-for-equity arrangements to collateralized debt obligations or master limited partnerships for midstream infrastructure projects, to asset and debt securitization, to synergistic joint ventures between equity or institutional investors and experienced power plant operators. For renewables, new financing models, such as securitization, expand the types of capital available to finance renewable energy.

  These financing models offer opportunities to build on the synergies between the two classes of generating assets. For example, co-located assets could be financed and securitized together, with the utility as the "offtaker" or on-site distributed generation with PV with large commercial entities as the offtaker. In addition, independent investments in renewable energy and natural gas can be pooled and securitized, reducing systematic portfolio risks (e.g., from changes to fuel prices or regulations). Large asset owners have been spinning off public companies that specialize in renewable energy and natural gas under a YieldCo

structure (e.g., NRG YieldCo). The YieldCo owns a mix of renewable energy and natural gas generation assets, which will pay regular dividends. **This could be an innovative approach to financing microgrids.**

Synergies at the Distribution Edge

A different set of potential business drivers leverages gas and renewable use at the distribution edge. There are multiple technology solutions available that build from the potential synergies, such as islandable energy systems, microgrids, on-site CHP, alternative transportation fuels, and others. Questions concerning maximizing value streams of the synergies between the two at the distribution edge include the following:

- What technology pathways are most promising for optimizing natural gas and renwable options for industry, commercial sites, homes, vehicles, communities and others?
- What combination of natural gas and renewable energy services address multiple, or all, energy services demands? What are the business case and impact metrics for these versus non-coupled energy services?
- How can larger industries optimize the use of natural gas, renewable energy and industrial demand to increase financial performance?
- What are the synergies from distributed renewable energy with distributed natural gas and how can firms prepare for changes in their business models?

Industrial Cogeneration – Optimization of Multiple Markets

On-site cogeneration, which can be fueled by natural gas or a renewable fuel, is typically sized to provide on-site thermal needs. However, there are many opportunities to optimize plant size and operational characteristics to participate in wholesale power markets and provide other energy services. DOE estimates (2012) that untapped technical potential to expand CHP at existing industrial facilities is GW GWs when sized to thermal needs; however, if sized to thermal needs but with no cap in power output and an ability to export power, the untapped technical potential is estimated to be 130 GWs.

Potential revenue streams from optimizing cogeneration include:

- Providing power during times of peak pricing and participating in ancillary service markets
- Combining cogeneration with energy services that can occur during periods of low power prices

- Participating in economic demand response markets
- If fueled with biogas or another renewable fuel, participating in renewable energy credit markets

Residential Smart Hybrid Systems/ Community Energy Systems

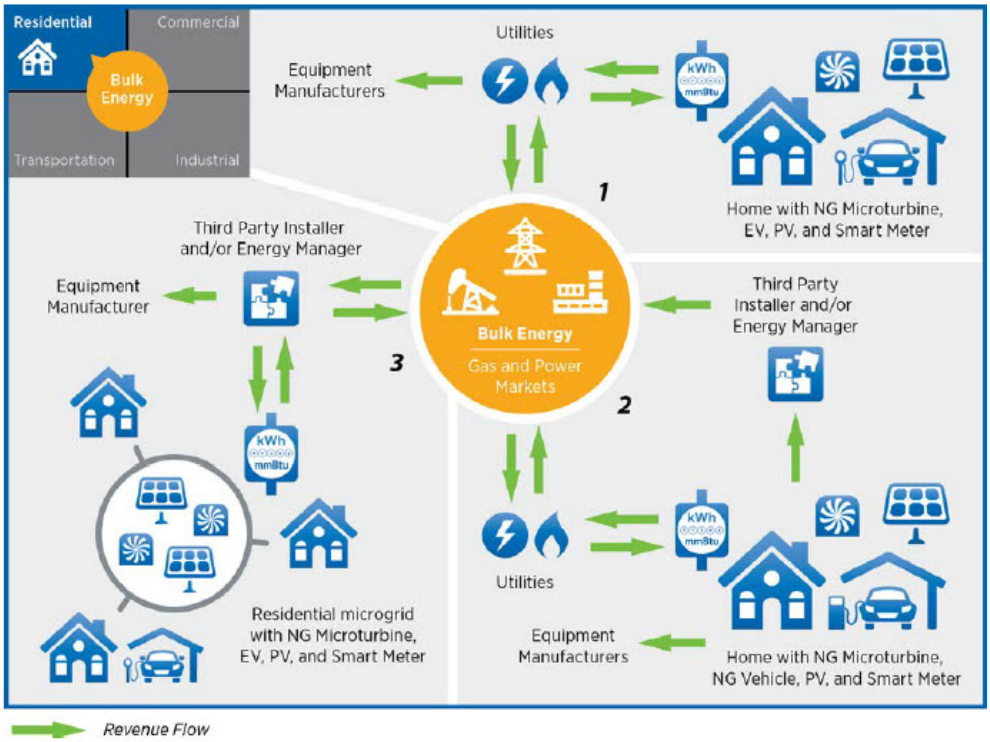
Smart hybrid energy residential systems could use multiple fuel sources, smart energy infrastructure, and on-site generation optimized to provide both low-cost, reliable clean energy for the home and energy services for the distribution grid. An aggregation of homes (e.g., community energy system) could use a combination of on-site solar, a natural gas or fuel cell CHP system, energy storage including plug-in vehicles with so-called vehicle-to-grid capabilities, natural gas vehicle refueling or other technologies.

Smart energy infrastructure would allow the home to sell electricity to the utility or participate in electric markets(including demand response) and, potentially, a natural gas demand response model. Natural gas demand response, in conjunction with other neighborhood participants, could relieve congestion on the gas pipeline system.

The paper provides three different revenue/ownership models as illustrated in the below chart:

- Utility-managed and financed distributed generation and demand response programs;
- Privately owned/leased, third-party managed residential energy system; and
- Neighborhood microgrid managed and operated by third-party energy management company for participation in power markets.

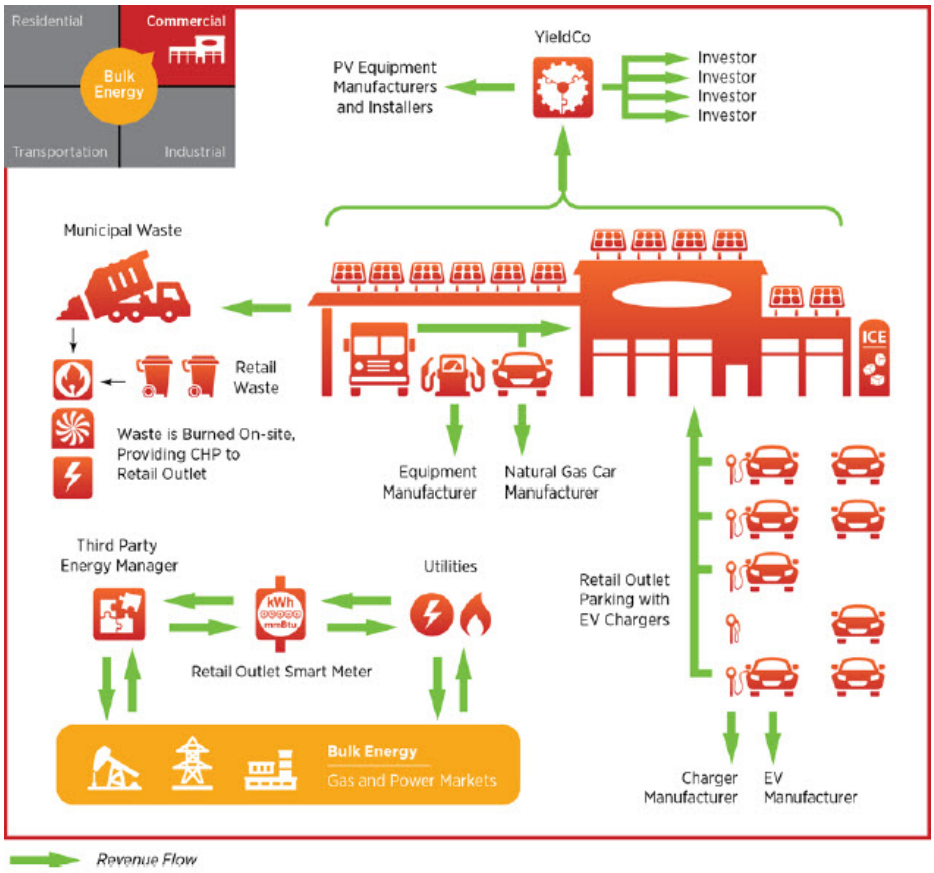
The green arrows represent revenue flows.



Commercial Distributed Generation Hybrid Energy Systems

There are numerous synergies at the commercial level for entities to generate, consume, store and sell energy and energy services. A building or big box store could have a combination of on-site PV, flex fuel CHP, waste-to-energy combustion and energy storage. For the CHP, the business can procure waste from a local municipality and, in combination with waste generated on-site, use waste to provide fuel for an on-site flex fuel CHP turbine, which can also consume natural gas. The size and types of generating equipment are optimized for the site, power market, and intended operational strategy.

Without going into detail here, the model presented has multiple different entities owning or leasing different pieces of the equipment. The following chart depicts various revenue streams potentially available in the commercial sector.


Residential
Commercial
Bulk Energy
Transportation
Industrial
YieldCo
PV Equipment Manufacturers and Installers
Investor
Investor
Investor
Investor
Municipal Waste
Retail Waste
Waste is Burned On-site, Providing CHP to Retail Outlet
ICE
Equipment Manufacturer
Natural Gas Car Manufacturer
Third Party Energy Manager
Utilities
kWh
Retail Outlet Smart Meter
Retail Outlet Parking with EV Chargers
Bulk Energy
Gas and Power Markets
Charger Manufacturer
EV Manufacturer
Revenue Flow