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July 18, 2014

By Electronic Mail

Hon. Kathleen A. Burgess
Secretary
NYS Public Service Commission
Three Empire State Plaza
Albany, New York 12223

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

Dear Secretary Burgess:

In accordance with the schedule adopted in this proceeding, enclosed for filing with the Commission please find the *Track 1 and Track 2 policy issue comments of the Retail Energy Supply Association.*

Thank you for your assistance in this matter.

Respectfully submitted,

Retail Energy Supply Association

By: *Usher Fogel, Counsel*
Usher Fogel, Counsel

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 14-M-0101
Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision.

COMMENTS OF THE RETAIL ENERGY SUPPLY ASSOCIATION

A. PRELIMINARY STATEMENT

The Retail Energy Supply Association (RESA)[1] submits these comments with respect to the Track 1 policy issues identified in the *Ruling Posing Questions On Selected Policy Issues and Potential Outcomes, Establishing Comment Process And Revising Schedule* issued on June 4, 2014 by Eleanor Stein And Julia Smead Bielawski, Administrative Law Judges.

B. RESA RESPONSE TO TRACK 1 POLICY ISSUES

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.

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[1]RESA's members include: AEP Energy, Inc.; Champion Energy Services, LLC; Consolidated Edison Solutions, Inc.; Constellation NewEnergy, Inc.; Direct Energy Services, LLC; GDF SUEZ Energy Resources NA, Inc.; Homefield Energy; IDT Energy, Inc.; Integrys Energy Services, Inc.; Interstate Gas Supply, Inc. dba IGS Energy; Just Energy; Liberty Power; MC Squared Energy Services, LLC; Mint Energy, LLC; NextEra Energy Services; Noble Americas Energy Solutions LLC; NRG Energy, Inc.; PPL EnergyPlus, LLC; Stream Energy; TransCanada Power Marketing Ltd. and TriEagle Energy, L.P. The comments expressed in this filing represent only those of RESA as an organization and not necessarily the views of each particular RESA member.

RESPONSE:

The anticipated outcomes set forth in the matrix do in a very broad sense identify appropriate results for which parties should strive to achieve. However, it is difficult to address this question with a high degree of certainty without first identifying clearly the exact practices, measures, policies and actions the Commission specifically intends to implement. Until the parties know what specific actions are contemplated it is difficult to fashion the specific desired results or outcomes.

In connection with "Customer Information", the goal should be to increase accessibility in a timely and cost effective manner.

II. Optimal Ownership Structures for Distributed Energy Resources (DER)

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. In this context, we are interested in party comments on the implications of the D.C. Circuit Court of Appeals decision on May 23, 2014 (*Electric Power Supply Association v. FERC,* Case No. 11-1486) concerning state jurisdiction with respect to demand response.

RESPONSE:

The goal of this proceeding should center on developing and sustaining a competitive retail market for value-added services and products. These products and services are and will be offered by competitive vendors consistent with extant market conditions. Consequently, the ownership and operation of these products and services are best left entirely to the domain of the competitive vendors that will be selling the products to the end-use consumer or business. The role of the utility is more properly centered on providing information/education, facilitating relationships between customers and vendors, and other such types of supporting roles. The utility should not be engaged in the ownership and operation of these products or in any other way compete with competitive vendors. Further, the utilities should not risk ratepayer funds on the purchase and sale of competitive products and services.

In carrying out this approach the Commission should ensure that applicable reliability standards are met and that there is consistency with the State and Federal environmental standards.

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.

RESPONSE:

In the short term given the Commission's expressed intent to move forward in an expeditious manner, it is most likely that the DSPP role would be met by the incumbent utilities. However, in the longer term the goal should be to transition to an independent entity.

In this context whatever role is developed for the DSPP it is most important that its activities mesh seamlessly with that of the NYISO at the wholesale level and not distort the wholesale markets.

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:

It is difficult to address the matter of cost/benefit without first identifying the specific measure, product or action is contemplated. There is no one-size-fits all analytical framework that is readily applicable to the entire universe of actions that may be taken as part of the Commission's initiative in this proceeding. Further, it will be necessary for the Commission to also identify the desired goals to be achieved from each action and if necessary develop a hierarchy of goals and outcomes. Once the action is identified and the specific goals are delineated a meaningful cost/benefit framework can be established.

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:

As a general rule, the public will be best served in the long run by enabling all forms of renewable and energy efficiency products and services to compete on an economic basis and are not dependent on subsidies and other governmental benefits that distort the operation of competing market forces.

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:

A definitive response to this question requires clear identification of the specific enhanced service that the utility will provide and other factors such as the cost thereof, etc. Only after this information is provided can it be reasonably determined if the utility should offer this service, what are the related costs, what will be the fee and who should pay the fee.

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: None required

VII. Other Issues

This initial list of issues is drawn largely from the Staff Report, but contains other issues in response to concerns raised in the working groups or directly by parties, as we want to ensure that we include for consideration those policy issues of concern to the parties. Although the questions listed above are very broad, parties should use this section to raise their concerns not encompassed by our specific questions.

RESPONSE

It is important to emphasize that the vision presented by the Commission will be most effectively achieved through the adoption of policies and practices that support and do not hinder the continuing development of growth of competitive markets for products and services. Ultimately, enabling the provision of energy to become "customer centric" is dependent upon and must be supported by a robust competitive market that presents customers with meaningful competitive opportunities and choices. To this end, the Commission should avoid command and control models that stifle choice, avoid picking winners and losers in the competitive marketplace or conferring subsidies, benefits, or preferences to any a particular vendor, approach, practice or product.

C. CONCLUSION

RESA appreciates the opportunity to submit these comments and assist the Commission in its efforts to address the needs and concerns of ratepayers.

Respectfully submitted,

Retail Energy Supply Association

By: *Usher Fogel, Counsel*
Usher Fogel, Counsel

Dated: July 18, 2014

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 14-M-0101
Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision.

COMMENTS OF THE RETAIL ENERGY SUPPLY ASSOCIATION

A. PRELIMINARY STATEMENT

The Retail Energy Supply Association (RESA)[1] submits these comments with respect to the Track 2 policy issues identified in the *Ruling Issuing Track 2 Questions and Establishing A Response Schedule* issued May 1, 2014 4, 2014 by Eleanor Stein, Administrative Law Judge.

B. RESA RESPONSE TO TRACK 2 POLICY ISSUES

I. 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?

2) New outcomes/metrics
a. What new targeted performance incentive approaches should be considered?

[1]RESA's members include: AEP Energy, Inc.; Champion Energy Services, LLC; Consolidated Edison Solutions, Inc.; Constellation NewEnergy, Inc.; Direct Energy Services, LLC; GDF SUEZ Energy Resources NA, Inc.; Homefield Energy; IDT Energy, Inc.; Integrys Energy Services, Inc.; Interstate Gas Supply, Inc. dba IGS Energy; Just Energy; Liberty Power; MC Squared Energy Services, LLC; Mint Energy, LLC; NextEra Energy Services; Noble Americas Energy Solutions LLC; NRG Energy, Inc.; PPL EnergyPlus, LLC; Stream Energy; TransCanada Power Marketing Ltd. and TriEagle Energy, L.P. The comments expressed in this filing represent only those of RESA as an organization and not necessarily the views of each particular RESA member.

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?

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

a. Should the Commission consider cost and performance benchmarking to determine utility performance on pre-established metrics?

b. If so, what measurements/metrics should the Commission benchmark and how should the benchmarks be developed (e.g., across the entire state, outside the state, level of benchmarking complexity)? Should non-utility companies or utility companies from outside the state be included? Does benchmarking require a sophisticated statistical model?

c. The U.K. Ofgem's RIIO approach employs some benchmarking techniques in determining utility rates. What are the advantages and disadvantages of adopting a similar benchmarking approach to meet the Commission's goals? If adopted, what, if any, modifications should the Commission consider?

d. Societal values – are there appropriate metrics over which the utility has less than full control that can be useful in promoting public policy goals (e.g. fuel diversity, CO_2 reduction, new market development) while also being manageable for the PSC?

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?

RESA Response:

The goal of this proceeding should center on developing and sustaining a competitive retail market for value-added services and products. This policy should adhere to applicable reliability and environmental standards. These products and services are and will be offered by competitive vendors consistent with extant market conditions. Consequently, the ownership and operation of these products and services are best left entirely to the domain of the competitive vendors that will be selling the products to the end-use consumer or business. The role of the utility is more properly centered on providing information/education, facilitating relationships between customers and vendors, and other such types of supporting roles. The utility should not be engaged in the ownership and operation of these products or in any other way, compete with competitive vendors. Further, the utilities should not risk ratepayer funds on the purchase and sale of competitive products and services.

The use of outcome-based ratemaking if properly developed and executed can help sustain this competitive model. However, any incentives or outcome based measures are to be focused on buttressing the utility role as a facilitator and help promote and ensure a reasonable working relationships between distribution utilities and market participants such as, for example, ESCOs or DER providers. To this end there is no generic formulation or outcome standard that would necessarily be ideal for every situation of DER resource the Commission seeks to promote. It makes more sense to tailor incentives or outcome standard to the particular measure. Thus, for example, if DG is sought to be promoted, the incentive can be based on the amount of electricity associated with DG or the number of DG installations or some combination of the two.

The Commission should not establish any incentives for the utility to own any DER investments. As noted these are measures and types of equipment that are or will be available in the competitive marketplace and therefore have no place in the utility investment portfolio or rate base. The customer should be directed to purchase all such investments directly from the competitive vendor and the utility role that of a facilitator as directed by the Commission. It is important to underscore that given the rapidly changing market and technological advances, these forms of new equipment can become outdated and have the potential to become stranded costs if incorporated in the utility rate base. Consequently, it would be imprudent for the utility to engage in any way in the ownership of DER measures. However, an example of a "disconnect" which is currently in place exists which discourages and even can prevent an ESCO from offering DER products in deference to the utility lies within the current provisions described in the net-metering tariffs at each of the electric utilities in NY. The current net-metering tariffs do not enable ESCOs to participate fully and on a comparable basis as the utility in the net-generation credit process. This in turn prevents ESCOs from cost effectively offering supply products in combination with distributed generation products (which of course require net-metering). The major shortcoming in the current net-metering tariffs is that the utilities report a 'zero' to the ESCO and to the NYISO when a customer's net-generation credit is actually negative. This causes the *utility* to receive the credit on its NYISO settlement statement (as opposed to the *ESCO*) and consequently requires the utility (and not the ESCO) to offer the supply credit on these occasions.

Since the ESCO does not have the net-generation reported on its NYISO settlement statement, the ESCO cannot provide the energy credit that the customer earned. If the tariffs and business practices were amended to enable the utilities to report a negative net-generation value on the ESCO's NYISO settlement statement, this would allow the ESCO to take responsibility for providing the customer it serves with the net-generation credits and enable ESCOs to structure combined distributed generation/commodity supply products accordingly.

In connection with grid hardening and public purpose micro grids that benefit consumer quality of life during emergency events, the affected customer groups such as hospitals, pharmacies, gas stations, ATMs, typically shop for electricity from ESCOs. Consequently the laudable public policy goal of grid hardening which targets electricity customers who are already in the market for competitive services is best achieved with ESCOs and not utilities.

II. 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?

2) Optimal number of years
a. 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?

3) Baseline cost-of-service recovery; ROE
a. 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?

b. What are the advantages and disadvantages of setting initial rates under outcome-based ratemaking?

c. How should the Commission set initial rates under outcomes-based ratemaking?

d. 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?

e. 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?

4) 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?

5) 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?

6) 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.

7) 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?

8) 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?

9) 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)?

10) 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?

RESA Response:

The structural model supported by RESA, which views the utility as a facilitator to enhance the penetration of DEP products and services among consumers and businesses, and leaves the role of ownership and operation of DER to the competitive vendor, and not aligned or directly related to traditional utility rates plans. Under this model, the utility may initially incur some broader infrastructure costs to support its role as facilitator and thereafter apply discreet fees and charges for use by customers of particular utility services. The underlying infrastructure costs can be recovered in a traditional manner either by inclusion in rate base (capitalization) or as an expense recovery or some combination of the two. The rates should include recovery from those classes who benefit from the incurrence of the cost. The fee structure would essentially offset direct costs and thus generally have no impact on rates. In this environment the better approach is to allow quick recovery of the requisite infrastructure costs through delivery rates and allow some expedited deferral and recovery mechanism for on-going costs and expenses.

III. 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?

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)

a. Should pricing be based on embedded cost of service?

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

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

d. 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)

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

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

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?

c. Should pricing be determined through a market mechanism which might reflect locational based marginal pricing? If so, how should any remaining revenue requirement be collected?

d. Should pricing be determined via request for proposals and individually negotiated contracts?

e. Should pricing be administratively determined to provide an incentive to achieve a predetermined outcome?

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

5) New rate designs

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)?

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

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?

RESA Response

As envisioned herein, the utility will act as a facilitator to enhance the penetration of DEP products and services among consumers and businesses, and leave the role of ownership and operation of DER to the competitive vendor. In this new role the application of traditional rate design mechanisms and categories is not particularly germane. Rather the rates and design associated with the utility role as a facilitator will need to accommodate two primary costs: (i) the recovery of the infrastructure costs required to provide the entire body of consumers with the benefits of REV; and (ii) the fees and charges associated with providing consumers and vendors with particular services not covered in the basic infrastructure costs. The former are best incorporated in base delivery rates and recovered (either as an expense or capital item) from all ratepayers consistent with equitable revenue allocation principles; the latter would be set forth in tariff and charged on a non-discriminatory basis to all applicable customers and vendors. This system has been used with positive results with respect to the retail access program,

Traditional rate design is also not geared or designed to sell and recover costs for products obtained in the competitive market which can be subject to many on-going price changes and other modifications that necessitate modifications and other price variations. Traditional rates and tariffs are static whereas the market is continuously in flux.

The current volumetric rate designs used to recover embedded costs should be retained in connection with to commodity service. With respect to other products and services it would be necessary to review the appropriate delivery rate design on a case by case basis.

The overarching goal is the REV proceeding to establish a customer centered model that relies upon the competitive market for the provision of REV products and services. In the real competitive world costs, prices and other charges are not fixed or static but change over time. It is therefore that the rate designs employed by the utility reflect this reality which is accommodated by the use of variable rates. Moreover, in moving to a more market based structure it will be necessary to build flexibility into the system due to the inherent uncertainties associated with a market based structure and the vagaries inherent in creating a materially new regulatory model. In this environment maintaining variable rate structures for recovery of embedded costs increases flexibility and better reflects a market and regulatory model that focuses on the market.

Further, the Commission also has not had a positive experience with utility sponsored fixed price options for commodity. Whenever it has been tried, it has been discontinued due to its negative impacts on consumers and the market. NYSEG and RG&E had offered a fixed price option to small customers. After reviewing the performance of this price option and the attendant financial costs and rewards, the Commission as recommended by Staff discontinued this program. (See Case 05-E-1222, New York State Electric & Gas Corporation, *Order Adopting Recommended Decision With Modifications* (issued August 23, 2006)(NYSEG Rate Order). Similarly, Central Hudson had offered a fixed price option to residential customers but discontinued it after the Commission curtailed the financial charges that could be recovered through this option.(See, Case 05-G-0311, Small Customer Marketer Coalition, *Order Directing the Future Termination, Subject to Conditions, of a Fixed-Price Offer* (issued July 22, 2005).

A similar untoward experience occurred with respect to the situation when the Commission allowed NYSEG to offer a fixed gas price option. From October 1998 until October 2002, the residential gas rates (commodity and transportation) of NYSEG were fixed pursuant to a rate agreement between NYSEG and the Commission. Under this rate agreement, the utility charged a fixed gas rate and in return was allowed to retain any profits it accrued in the event actual costs were lower than estimated and obligated to cover any losses in the event actual costs exceeded the level of costs incorporated in the fixed rate.[2] The Company did not complain as long as gas costs remained low and did not exceed the level of commodity costs included in the fixed rate.

However this view towards fixed rates changed in 2001 with the upsurge in market gas costs. Due to the placement of fixed rates, NYSEG incurred substantial financial losses from below-cost commodity sales to its customers and reflecting the substantial losses it incurred on its gas hedges. In response, NYSEG sought to recover from ratepayers, losses of $36.9 million for the year ending September 30, 2002, resulting from the below-cost commodity sales.[3] Furthermore, NYSEG sought to terminate the existing fixed rate and in its place install a Gas Supply Charge that fluctuated monthly in response to the actual market cost of the utility's gas supplies.[4] Thereafter, the Company was authorized to recover $10.5 million of its asserted loss from below-cost residential sales, terminate the fixed residential gas rate, and institute a variable gas rate.[5]

In summary, previous history demonstrates that implementing a utility fixed rate option for commodity related service would not be a prudent policy approach.

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[2] Case 98-G-0845 - Petition of New York State Electric & Gas Corporation for Approval of Multi-Year Agreement Concerning Gas Rates, *Opinion and Order Adopting Settlement Terms Subject to Modification and Conditions,* Opinion No. 98-17 (issued September 29, 1998), and Opinion Modifying Opinion No. 98-17 (issued December 2, 1998).

[3] Case 01-G-1668 – Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of New York State Electric Corporation and Case 01-G-1683 – Petition of New York State Electric &Gas Corporation Pursuant to Section 312.4 of the Uniform System of Accounts to Defer Expenditures Associated with Residential Gas Costs, *Order Establishing Rates* (issued November 20, 2002).

[4] *Id.,* Appendix C, p. 11.

[5] *Id.,* pp. 2-3.

C. CONCLUSION

RESA appreciates the opportunity to submit these comments and assist the Commission in its efforts to address the needs and concerns of ratepayers.

Respectfully submitted,

Retail Energy Supply Association

By: *Usher Fogel, Counsel*
Usher Fogel, Counsel

Dated: July 18, 2014