October 17, 2008

Honorable Jaclyn Brilling
Secretary Public Service Commission
Agency Building 3
Albany, New York 12223

RE: Case 07-M-0548 – Proceeding on Motion of the Commission Regarding and Energy Efficiency Portfolio Standard. Working Group VIII – Demand Response and Peak Reduction Report.

Dear Secretary Brilling:

On behalf of the participants in the deliberations of Working Group VIII and in compliance with the presiding administrative law judges' Ruling Revising Work Group Schedule, issued October 10, 2008, we, the undersigned conveners, respectfully submit an original and five copies of the Working Group VIII – Demand Response and Peak Reduction Report. The Report includes a summary of recommendations, a full discussion of the relevant issues with recommendations that enjoy widespread support, an appendix, letters representing alternative viewpoints or dissents, and a list of participants. This full transmittal will be distributed electronically in PDF format to all parties using the Energy Portfolio Standard-list serve, and we request that it be posted on the Commission's web site on the Case 07-M-0548 page.

Sincerely,

John D. Barnes,
P.E. Environmental Engineer 2
New York State Department of
Environmental Conservation

Aaron Breidenbaugh
Senior Manager of Regulatory
Affairs and Public Policy – New
York
ENERNOC

Sigmund F. Peplowski
Principal Utility Financial Analyst
New York State Department of
Public Service

Peter Savio
Senior Project Manager
New York State Energy Research
and Development Authority

cc: Judges, List Serve Parties

Energy Efficiency Portfolio Standard
Working Group VIII – Demand Response and Peak Reduction
Summary of Recommendations
October 17, 2008

The primary recommendations presented in Working Group VIII's report are outlined in the following seven sections. Unless otherwise noted, these recommendations represent the general consensus of WG VIII.

A. Integration of Energy Efficiency (EE) and Demand Response (DR)
   1. Encourage the Program Administrators to develop cost effective combined DR and EE programs which complement their proposed EEPS Program offerings. Such integrated programs may then be submitted as supplements to their existing EEPS filings.
   2. Using the existing avoided cost models for EE as a starting point, incorporate a calculation of the avoided costs for DR and monetize other direct societal benefits (such as reduced wholesale prices) from a range of demand response programs and actions so that the programs and measures can be appropriately screened for possible inclusion in SBC or EEPS funded offerings.

B. Commercial & Industrial (C&I) and Residential Demand Response Programs
   1. Program Administrators should be directed to consider supplementing their 90-day filings with additional C&I DR RFPs to address peak load, local constraint, or other needs, as appropriate to their individual situations. Following this RFP process, Program Administrators may enter into contracts to retain existing resources and attract such new resources as are required at a minimum to maintain or improve system load factors, as recommended by Staff in Phase I of this proceeding.
   2. The utilities should be directed to consider, consistent with competitive policies under retail commodity access rules, including in their compliance filings proposals to allow for co-marketing and co-branding opportunities with third party DR providers. These opportunities can be separate or a part of the long term RFP process recommended above. Alternative viewpoints or dissent submitted by: Con Edison Solutions, Constellation NewEnergy, Direct Energy, Hess Corporation

C. Advanced Metering and Advanced Metering Infrastructure (AMI)
   1. WG VIII supports and encourages swift Commission and DPS action in their ongoing Advanced Metering Proceeding (Case #) We specifically support the cost-effective provision of advanced metering capabilities that foster greater penetration and MV&E confidence of energy efficiency, demand response, and dynamic pricing programs.

D. Time Variant Tariff Rate Proposals
   1. The Commission should encourage Program Administrators to work jointly to test three dynamic pricing options: Time of use pricing that has a peak period that is narrowly focused to address the system peak; a voluntary residential Real Time Pricing (RTP) with prices based on real-time wholesale energy market prices; and a peak time rebate program that would give customers rebates for reducing their consumption during system peak.
   2. The Commission should continue to expand hourly pricing where it finds it to be beneficial. The Commission should encourage utilities to investigate changes to their MHP tariffs to recover capacity charges over fewer hours.

E. Distributed Generation/Combined Heat & Power (DG/CHP)

1. Permit EEPS and SBC funds to be deployed for support of cost-effective, efficient DG/CHP installations, including Micro-CHP, that have lower net emissions than the average fossil-fuel central generation in New York State and encourage Program Administrators to include incentives as part of their current and future EEPS programs.
2. Adopt an efficiency standard of 60% average annual efficiency and the ability to be dispatched during electric system peaks and or when called upon for reliability events for DG/CHP participating in EEPS programs, recognizing that micro-CHP installations and larger installations may merit distinct standards.
3. Encourage Program Administrators jointly or individually to develop and implement programs for micro-CHP installations in 1-4 family homes, including low-income homes, and smaller commercial installations, and to propose intermediate-scale (1,000 + units) pilot demonstration projects if cost effective.
   Alternative viewpoints or dissent submitted by: Alliance for Clean Energy New York (ACENY)

F. Environmental Justice (EJ) Communities

1. As of October 17, 2008, WG VIII is not in a position to provide specific recommendations to the Commission regarding the EJ charges. After a technical study group completes work outlined in the WG VIII report, a steering committee will develop recommendations that will be submitted to ALJ Stein and ALJ Stegemoeller on December 1, 2008. The form of such recommendations could include further study, targeted demand side management incentives, a pilot program or other mechanisms that will reduce emissions and resulting health impacts to EJ communities.
   Alternative viewpoints or dissent submitted by: Independent Power Producers of New York, Inc. (IPPNY), New York Independent System Operator (NYISO)

G. One overarching concern identified is a need for additional attention to measurement, verification and evaluation (MV&E) provisions and Benefit/Cost (B/C) approaches. We urge that these issues be addressed by the Evaluation Advisory Group (EAG) created as a result of the June 23, 2008 Commission Order.

CASE 07-M-0548

ENERGY EFFICIENCY PORTFOLIO STANDARDS PROCEEDING

WORKING GROUP VIII - REPORT

DEMAND RESPONSE AND PEAK REDUCTION

October 17, 2008

WORKING GROUP VIII – DEMAND RESPONSE AND PEAK REDUCTION EXECUTIVE SUMMARY

Preface

The role of peak load reduction (and demand response) and its relationship to energy efficiency program design and delivery has evolved significantly over the course of the proceeding. Initially, there was little to no focus on the role or value of peak load reduction or mega watt (MW) reductions, the focus being nearly exclusively on MW-hour (MWh) energy reductions. Since that time the importance of MW reductions and the relationship to MWh reductions has grown to be more widely understood by Working Group VIII (WG VIII), as well as a number of other active parties including Program Administrators, DPS Staff, Transmission Owners, the environmental community and end users. The ongoing attention and understanding has evolved over the course of the Proceeding and, as described below, the focus of WG VIII has necessarily evolved in parallel.

In the July 3, 2008, Procedural Ruling concerning EEPS Design Issues[1], Administrative Law Judges Stein and Stegemoeller (ALJs) noted that the Commission's June 23, 2008 Order in the EEPS proceeding left open other policy issues with regard to the EEPS proceeding and identified them as outstanding policy issues. In the Procedural Ruling, the ALJs laid out their objective to develop a record, afford parties the opportunity to comment, and bring the remaining EEPS design issues before the Commission. The ALJs labeled some of these open issues as Critical Path Issues.

Critical Path Item 6, at page 4 of the Ruling, was labeled "Demand Response and Distributed Generation." The ALJs stated that defining the role of demand response and distributed generation in the EEPS proceeding is a Critical Path Issue because gains can be made in reducing peak load in constrained areas, while at the same time realizing significant energy savings. The Commission's EEPS Order at pages 9-10 included consideration of demand effects, in particular in constrained areas, in the criteria for program approval. Likewise, the August 22 Order Concerning Utility Incentives also highlighted the need for peak load reduction, especially in constrained areas, such as New York City.

---

[1] Case 07-M-0548 – Proceeding on Motion of the commission Regarding an Energy Efficiency Portfolio standard (EEPS).

As stated by the ALJs, the principal issue for WG VIII discussion and recommendations is to identify specific measures that are not presently achievable through New York Independent System Operator (NYISO) and Systems Benefit Charge (SBC) programs, utility programs, or EEPS initiatives as recently ordered by the Commission. In addition, the Environmental Justice Roundtable requested consideration of a study to assess health impacts on communities that host peak generation facilities to a disparate extent, and of opportunities to render those facilities obsolete through the acquisition of energy efficiency resources.

A scope of work for WG VIII was developed and submitted to the ALJs on August 18th. WG VIII worked within the broad scope of the ALJ's charge and presents recommendations for a cost- effective role for peak load reduction and DR. The following section is a summary of our work to date and key findings.

Our task began with an effort to identify those issues that were: (1) within the primary jurisdiction of the Commission and (2) not adequately addressed by other programs or funding sources. We did this using the criteria identified in the EEPS Order, subsequent Rulings and additional guidance from the ALJs and by examining the support opportunities currently provided by the NYISO, utilities or SBC. WG VIII found the following six topics warranted further discussion and investigation that resulted in recommendations:

- Integration of Demand Response and Energy Efficiency
- Commercial & Industrial (C&I) and Residential DR
- Advanced Metering and Advanced Metering Infrastructure (AMI)
- Time Variant Tariff Rate Proposals
- Distributed Generation/Combined Heat & Power (DG/CHP)
- Environmental Justice Communities

In addition the group identified a need for: a) accurate, verifiable measurement, verification and evaluation (MV&E) that is critical to the success of DR, and b) additional attention to cost/benefit approaches (methods, inputs, etc.) in order to accurately capture the value streams provided by DR[2]. This latter discovery highlights the need for the EEPS Evaluation Advisory Group (EAG) to identify, develop, or have developed for it, avoided cost metrics (including time and location specific data) and cost/benefit approaches that better capture the attributes of peak load reduction, demand response, DG/CHP and load shifting. For example, subject to adequately rigorous MV&E, peak load reductions and DR can defer or eliminate transmission and distribution investments and this value should be included in B/C calculations. However, utilities may be unwilling to include peak load reduction and DR measures absent clear direction as far as MV&E and B/C. WG VIII has raised these issues as something that we urge the EAG to undertake.

A Summary of Recommendations is presented at the end of this Executive Summary.

The following sections provide an overview of Demand Response and Peak Load Reduction and Environmental Justice Communities.

Demand Response and Peak Load Reduction

DR refers to customers temporarily reducing their electric demand in response to a signal, be it a notification to reduce load or pricing conditions, for example, having electricity customers reduce their consumption or increase on site generation at critical times or in response to market prices. This is complimentary to energy efficiency, which can provide a permanent reduction in energy use, but typically with less consideration for peak reduction benefits. DR participants, often through the use of dedicated control systems, shed loads in response to a request by a utility, system operator or market price conditions.

Under conditions of tight electricity supply, demand response can significantly reduce the peak price, electricity price volatility, and reduce strain on electric systems. Since

---

[2] See for example "Demand Response Valuation Frameworks", Heffner, Grayson, Demand Response Resource Center at 1: ***"The impetus for the paper was recognition that the economic analysis methods for quantifying the benefits of Demand Side Management (DSM) are insufficient to capture the value of Demand Response (DR)"*** in turn citing "Towards a New Paradigm for Valuing Demand Response", R. Earle and A. Faruqui", The Electricity Journal, May 2006. v. 19. # 4. Downloadable at: http://www.puc.state.nh.us/Electric/06-061/epact%20articles/EJ%20Toward%20a%20New%20Paradigm%20for%20Valuing%20Demand%20Response.pdf

electrical systems are generally sized to correspond to peak demand (plus margin for error and unforeseen events), lowering peak demand reduces overall plant and capital cost requirements. Depending on the configuration of generation capacity, however, demand response may also be used to increase demand (load) at times of high production and low demand. Some systems may thereby encourage energy storage to arbitrage between periods of low and high demand (or low and high prices). As the proportion of intermittent power sources such as wind power in a system grows, demand response may become increasingly important to effective management of the electric grid.

In the June 23, 2008 Commission Order Establishing the Energy Efficiency Portfolio Standard and Approving Programs, the Commission at page 9 stated that:

> In addition to the near-term efficiency targets adopted in this Order, we emphasize the importance of demand reduction as a critical objective of this proceeding. Reducing peak demand will moderate commodity prices, improve system reliability, and potentially reduce – or at least defer – the need for construction of generation, transmission and distribution facilities. We will require that impact on demand, particularly in constrained areas, be an important criterion in selecting efficiency programs. (Footnote 8: Although the role of demand response programs – versus permanent energy efficiency programs – remains an issue, it is clear that this proceeding will not encompass demand response that substitutes one generation source for another without regard to efficiency or emissions).

There is an opportunity for DR to be integrated into program administrator program design and implementation, incorporating the value of peak load reduction benefits at the times and in the locations of maximum impact on enhanced reliability, avoided or deferred electrical infrastructure investments, reduced emissions and lower overall costs to consumers.

As described in the section of this report entitled *Integration of Demand Response and Energy Efficiency*, WG VIII believes that there are important synergies between DR and energy efficiency (EE) and that any demand side initiative that considers both in a balanced way will necessarily be more cost-effective and yield larger benefits than a program that considers either in isolation. This is not an expansion of the proceeding or even an expansion of the traditional EE business model; rather it is a reflection of strong, effective and cost-effective program design and delivery. Any number of the Energy Service Companies (ESCOs) that will be critical to efficiency program delivery already operate business models that integrate commodity, EE/DR, and many contractors that are critical to EEPS program success already bundle DR/EE - to do otherwise splinters program delivery, invites lost opportunities and adds to program. This relationship is discussed further in the sections which follow.

Environmental Justice Policy

In the early 1980s, environmental justice emerged as a concept in the United States. It is difficult to pinpoint a particular date or event that launched the Environmental Justice Movement, as the movement grew organically out of dozens, even hundreds, of local struggles and events and out of a variety of other social movements.[3] In DEC's Commissioner Policy 29, EJ is defined more simply as the fair treatment and meaningful involvement of all people regardless of race, color, or income with respect to the development, implementation, and enforcement of environmental laws, regulation and policy. Fair treatment means that no group of people, including a racial, ethnic or socio economic group should bear a disproportionate share of the negative environmental consequences resulting from industrial, municipal, and commercial operations or the execution of federal, state, local and tribal programs and policies.

As noted previously EJ advocates (during Round-table discussions held in December 2007) had requested consideration of a study to assess health impacts on communities that host peak generation facilities to a disparate extent, and of opportunities to render peaking facilities "obsolete" through the acquisition of energy efficiency resources. WG VIII was tasked with addressing these requests.

The complexity of this issue and the variety of perspectives represented resulted in controversy that WG VIII was considering "shutting down peakers" without regard to reliability. This was never the case. WG VIII has always proceeded from the assumption that no recommendation that would result in the reduction of reliability would be advanced to the ALJs. WG VIII unanimously agreed that the reliability of the electric system was of paramount importance.

Summary of WG VIII Recommendations

The primary recommendations are outlined in the following seven sections. Organizations that submitted alternative viewpoints or dissenting opinions are noted under the respective recommendations, and are included at the end of this report.

[3] Wikipedia definition.

A. Integration of Energy Efficiency (EE) and Demand Response (DR)

1. Encourage the Program Administrators to develop cost effective combined DR and EE programs which complement their proposed EEPS Program offerings. Such integrated programs may then be submitted as supplements to their existing EEPS filings.

2. Using the existing avoided cost models for EE as a starting point, incorporate a calculation of the avoided costs for DR and monetize other direct societal benefits (such as reduced wholesale prices) from a range of demand response programs and actions so that the programs and measures can be appropriately screened for possible inclusion in SBC or EEPS funded offerings.

B. Commercial & Industrial and Residential DR

1. Program Administrators should be directed to consider supplementing their 90-day filings with additional C&I DR RFPs to address peak load, local constraint, or other needs, as appropriate to their individual situations. Following this RFP process, Program Administrators may enter into contracts to retain existing resources and attract such new resources as are required at a minimum to maintain or improve system load factors, as recommended by Staff in Phase I of this proceeding.

2. The utilities should be directed to consider, consistent with competitive policies under retail commodity access rules,including in their compliance filings proposals to allow for co-marketing and co-branding opportunities with third party DR providers. These opportunities can be separate or a part of the long term RFP process recommended above.

   Alternative viewpoints or dissenting opinions were filed by: Con Edison Solutions, Constellation NewEnergy, Direct Energy, Hess Corporation.

C. Advanced Metering and Advanced Metering Infrastructure (AMI)

1. WG VIII supports and encourages swift Commission and DPS action in their ongoing Advanced Metering Proceeding (Case 00-E-0165) We specifically support the cost-effective provision of advanced metering capabilities that foster

greater penetration and MV&E confidence of energy efficiency, demand response, and dynamic pricing programs.

D. Time Variant Tariffs Rate Proposals

1. The Commission should encourage Program Administrators to work jointly to test three dynamic pricing options: Time of use pricing that has a peak period that is narrowly focused to address the system peak; a voluntary residential Real Time Pricing (RTP) with prices based on real-time wholesale energy market prices; and a peak time rebate program that would give customers rebates for reducing their consumption during system peak.

2. The Commission should continue to expand hourly pricing where it finds it to be beneficial. The Commission should encourage utilities to investigate changes to their MHP tariffs to recover capacity charges over fewer hours.

E. Distributed Generation/Combined Heat & Power (DG/CHP)

1. Permit EEPS and SBC funds to be deployed for support of cost-effective, efficient DG/CHP installations, including Micro-CHP, that have lower net emissions than the average fossil-fuel central generation in New York State and encourage Program Administrators to include incentives as part of their current and future EEPS programs.

2. Adopt an efficiency standard of 60% average annual efficiency and the ability to be dispatched during electric system peaks and or when called upon for reliability events for DG/CHP participating in EEPS programs, recognizing that micro-CHP installations and larger installations may merit distinct standards.

3. Encourage Program Administrators jointly or individually to develop and implement programs for micro-CHP installations in 1-4 family homes, including low-income homes, and smaller commercial installations, and to propose intermediate-scale (1,000 + units) pilot demonstration projects if cost effective.

   Alternative viewpoints or dissent submitted by: Alliance for Clean Energy New York (ACENY).

F. Environmental Justice (EJ) Communities

1. As of October 17, 2008, WG VIII is not in a position to provide specific recommendations to the Commission regarding the EJ charges. After a technical study group completes work outlined in the WG VIII report, a steering committee will develop recommendations that will be submitted to ALJ Stein and ALJ Stegemoeller on December 1, 2008. The form of such recommendations could include further study, targeted demand side management incentives, a pilot program or other mechanisms that will reduce emissions and resulting health impacts to EJ communities.

Alternative viewpoints or dissenting opinions were filed by: Independent Power Producers of New York, Inc. (IPPNY), New York Independent System Operator (NYISO).

G. One overarching concern identified is a need for additional attention to measurement, verification and evaluation (MV&E) provisions and Benefit/Cost (B/C) approaches. We urge that these issues be addressed by the Evaluation Advisory Group (EAG) created as a result of the June 23, 2008 Commission Order.

A. Integration of Energy Efficiency and Demand Response

Overview

From the customer's viewpoint, demand response and energy efficiency are similar services in that they are designed to lower energy costs. They serve a common purpose but have significantly different delivery mechanisms in the state and have been promoted separately. While energy efficiency has been fully supported through retail rates for many years and has evolved into a mature and successful industry, the same cannot be said for demand response. Demand response has been supported primarily through NYISO and NYSERDA programs, and has grown significantly over the past few years in the large and mid-sized C&I sectors but less so in the residential and small C&I sector. In addition, to date, many of the demand response actions taken by end users are manual and/or related to the use of emergency generators during capacity shortages. Integration of the energy efficiency and demand response programs would facilitate expansion of DR into the smaller customer sectors and provide greater opportunity for automation in all customer sectors.[4]

WG VIII believes that there are important synergies between DR and EE and that any demand side initiative that considers both in a balanced way will necessarily be more cost-effective and yield larger benefits than a program that considers either in isolation. This is not an expansion of the proceeding or even an expansion of the traditional EE business model; rather it is a reflection of strong, effective and cost-effective program design & delivery. Any number of the Energy Service Companies (ESCOs) that will be critical to efficiency program delivery already operate business models that integrate commodity, DR/EE, and many contractors that are critical to EEPS program success already bundle DR/EE - to do otherwise splinters program delivery, invites lost opportunities and adds to program.

[4] It is our belief that the goal should be to automate these actions over the long term to as great an extent as is practical. This would provide two benefits. First, it would increase confidence in the reliability of such actions. Second, it would increase the number of small C&I end-users and importantly, residential end-users that participate in such programs. The latter group is especially important since residential A/C use has represented such a large portion of the increase in summer peak demand over the past few years.

The integration of energy efficiency and demand response offers an opportunity to cost effectively combine these attributes:

- demand side management
- peak demand and energy reduction
- electric system optimization and efficiency
- promotion of new technologies to customers
- vendor facilitation and market transformation
- financial mechanisms to bridge gaps in the value chain
- common marketing and implementation structures
- MV&E processes

If the fully developed energy efficiency program model is leveraged to deliver demand response services, the resulting synergies will be significant and enable them to better realize their full potential. In addition, by providing these services comprehensively, there may also be other cross fertilization benefits as has been experienced with comprehensive energy efficiency projects.

Challenges

There are several challenges to integrating these services. First, in terms of cost effectiveness, it will be important to separately account for the energy efficiency benefits and demand reduction benefits from a combined delivery platform. This will require careful development of an MV &E protocol and analysis. As an example, in most cases, current cost effectiveness models lump all peak energy into a single bucket as opposed to placing a higher value on so called 'critical peak' energy. Second, it is important to allow either or both programs to be subject to competitive procurement while preserving the synergies. This will require careful crafting of request for proposals (RFPs) issued by the utilities and/or New York State Energy Research and Development Authority (NYSERDA).

Recommendations

1. Encourage the Program Administrators to develop cost effective combined DR and EE programs which complement their proposed EEPS Program offerings. Such integrated programs may then be submitted as supplements to their existing EEPS filings.

Components of an Integrated Program may include:

- Offer DR audits as a part of energy audits for all customer classes
- Co-market EE and DR programs
- Cross-train technical staff installing EE measures to be able to install DR technology at the same time or as part of the same project
- Evaluate DR potential as part of SBC and EEPS funded customer technical assistance studies
- Educate customers about DR programs and their economic benefits
- Combine or align incentives for DR with EE program offerings, e.g. added incentives or condition incentives for adding control technology to EE projects eligible for SBC and EEPS funding.

This program design should be developed as part of the overall collaborative approach to program design currently underway within the state.

2. Using the existing avoided cost models for EE as a starting point, incorporate a calculation of the avoided costs for DR and monetize other direct societal benefits (such as reduced wholesale prices) from a range of demand response programs and actions so that the programs and measures can be appropriately screened for possible inclusion in SBC or EEPS funded offerings.

This model must be flexible so as to allow screening of wide ranging activities such as residential direct load control or industrial demand response with variable event hours that may be proposed. The model may also consider the value of demand response in different geographic regions in the state, such as high load growth vs. negative load growth regions – capturing system optimization benefits.

3. Develop appropriate MV&E protocols.

B. Commercial and Industrial (C&I) and Residential Demand Response Programs

Overview

As described above in this report, DR programs, such as those administered by the NYISO for energy, ancillary services, and/or capacity/reliability should be an important component of the State's 15 X 15 strategy[5]. As noted in the preface, DR is at one end of a customer-centric demand-side continuum that extends through load shifting, to "pure" energy efficiency. WG VIII elsewhere refers to these collectively as demand side management (DSM). WG VIII believes that a balanced, economically efficient, approach to DSM must include all of the relevant pieces, in proportions that vary according to the needs of the state and relevant Program Administrator. Using a generator analogy, an efficient DSM portfolio must have a combination of "peakers" (DR) "load following" (price responsive), and "baseload" (EE.) To date this proceeding has focused very much on the EE end of the DSM spectrum. WG VIII's efforts, specifically those addressed below, have sought to expand the focus to more fully include DR and thus encompass the entire DSM spectrum.

Questions are often raised about why the current DR offerings in the state by the NYISO, NYSERDA, and some utilities are not sufficient to achieve the level of demand response desired to improve system efficiency while meeting the energy reduction goals. The purpose of this section of the report is to address those questions, describe the challenges to achieving increased DR potential in the state and provide recommendations for solutions to those barriers. These barriers apply to DR programs across all customer classes. The differences between the programs for each sector relate to the level of penetration but not the barriers, i.e. achieving greater C&I participation and launching residential programs on a full scale basis for the first time.

DR programs have been available for large to medium commercial and industrial (C&I) customers in the state for many years. Funding from NYSERDA has been available for partial reimbursement of communication, metering, and other capital costs. Payments from the NYISO through its Special Case Resource, Emergency Demand Response reliability programs, and its Day-Ahead Demand Response economic programs have been the primary source of revenues to encourage participation in DR. In addition an

[5] The New York State's long term goal of reducing electricity usage by 15% statewide by 2015.

emergency distribution load relief program is available in Con Ed's service territory under its Rider U tariff.

These sources of support have created a competitive market among third party providers of DR to the medium and large C&I sectors. Notwithstanding these facts, there remain a number of barriers to greater participation in this sector. On the other hand, the residential and small C&I sector has been virtually untapped. Yet this sector is a major contributor to load growth, primarily through air conditioning. Therefore, it is imperative to get started on DR programs for the residential and small C&I sectors and to address the remaining barriers to increased participation by larger C&I customers.

WG VIII recommends that program administrators be directed to consider supplementing their "90-day" proposals with DR programs. Increase the use of DR, so as to reduce the overall cost to consumers, while maintaining safe and environmentally sound and reliable service. Those programs should include the following goals and objectives, applicable to each PA:

- Reduce the need for new generation and expansion of transmission and distribution systems.
- Reduce emissions from peaking generation.
- Realize load reductions as soon as practicable.
- Introduce and expose customers to wholesale pricing of energy and capacity markets.
- Investigate and evaluate new DR technologies for potential use by customers.
- Leverage related energy efficiency measures to provide additional demand response benefits, as discussed in the Integration of EE and DR section.
- Minimize the cost to rate payers by maximizing the use of wholesale market revenues.

In addition to the MV&E discussion and advanced metering discussion in the preface, key barriers to DR expansion are: revenue certainty, adequacy of market-based revenues, and the cost of access to customers. As presented below, the solutions to these barriers are long-term contracts, which provide adequate and predictable revenue over the life of the contract and offer co-branding and marketing synergies between third party providers, utilities, and program administrators.

Challenges

Certainty and Adequacy of Revenue

Capacity prices in New York are set by a demand curve intended to reflect the value of capacity beyond the reserve margin. The capacity markets in New York are short term by design and the associated prices do not necessarily represent the long term value of capacity. They are insufficient to stimulate significant additional participation in the capacity markets by DR resources.[6]Adequate price signals are needed to ensure that providers continue and expand their participation in demand response programs. Further, providers need certainty as the level of revenue they will receive over the longer term. A provider may be willing to accept prices below the market price at any one given point in time, if over the longer term, the revenue derived from their investment provide a sufficient return. The current market for DR in the state provides neither of these things – price stability nor revenue assurance. Absent long-term revenue certainty, WG VIII expects demand response to remain static or decline, creating potential capacity shortfalls and eroding system load factors.

Recommendation

Prior to the implementation of a statewide Forward Capacity Market that accommodates DR on a basis comparable to generation, Program Administrators should be directed to consider supplementing their 90-day filings with additional C&I DR RFPs to address peak load, local constraint, or other needs, as appropriate to their individual situations. Following this RFP process, Program Administrators may enter into contracts to retain existing resources and attract such new resources as are required, at a minimum to maintain or improve system load factors, as recommended by Staff in Phase I of this proceeding.

PA RFPs should seek to acquire such resources at, or below, forecasts of applicable avoided costs and be offset by the revenues that can be garnered from the competitive market. Avoided cost in this context should be reflective of the Evaluation Advisory Group's expected efforts to better quantify the benefits or DR that are not captured by traditional EE cost/benefit tests.

WG VIII anticipates that the contracts referenced above will be for terms greater than the current six-month commitments available in the NYISO ICAP markets, and likely for

[6] The recent substantial fluctuations in three localities raises significant question as to whether the current level of DR in the state will remain much less stimulate expansion.

significantly longer (i.e. multi-year) terms. However, PAs should be responsible for proposing these, along with all other terms. The Commission should indicate that long-term contracts will be considered on a case-by-case basis, including factors such as whether they are necessary in view of market conditions, the relevant benefits and/or negative impacts of specific proposals, the consistency with applicable NYISO markets, minimization of the risks and costs to consumers, conformance with applicable public policies, and the degree to which the proposed structure of the contract impacts the competitive markets.

With respect to residential and small C&I customers, WG VIII recommends the introduction of one or more direct load control (DLC) programs. If the PAs and the Commission conclude that a statewide program is advisable, WG VIII supports and encourages that approach. If not, these programs should be of sufficient scope to have a meaningful impact on peak loads and should be coordinated between the PAs in such a way as to maximize synergies to the extent possible while minimizing entry barriers for competitive suppliers..

Just as funds have been invested in the past for large C&I DR participation, funds can and should be expended to support the development of one or more large scale DLC program. WG VIII suggests that the program(s) would initially focus on controlling central air conditioning, pool pumps, water heaters, and other uses that can be easily controlled remotely with existing technology. As advanced technology is implemented the control technology can be upgraded and expanded to allow for greater sophistication and complement other demand strategies such as dynamic pricing[7].

Components of a Residential Program

The following are the components of a residential DR program that should be considered by PAs and the Commission:

1. Program Size – a load reduction potential analysis should be performed for each service territory or region of the state. An initial program size to allow for immediate ramp up could be established based on known load and customer data.
2. Control Technology – technology used should facilitate migration to direct load control and AMI communication technologies.

[7] The Commission's decisions whether and how to proceed with its Advanced Metering initiative is highly relevant in this context.

3. Customer incentives – the incentives to be provided to customers need to be established so as to determine the cost of the program
4. Administration – the program should be competitively procured on a pay for performance basis so as to maximize the benefits and ensure the lowest cost of the program
5. Cost effectiveness – PAs should attempt to design the programs so as to maximize the benefits, consistent with the need to assure M&V adequate to the value assumed.

Cost of Customer Acquisition & Customer Education

Utilities hold much information that is critical to target and prioritize electric customers for Demand Response. This data includes such information as contact information, usage history, and facility details. Utilities also have direct, trustworthy relationships with their customers. These are all things that competitive providers can develop as well, but the costs to do so are significant that they act as barriers to acquiring smaller customers. While utilities appear to be in the best position to be DR providers, they face inherent limitations in their ability to provide these services, among these being the ability to manage customer risk through aggregation. WG VIII agrees that competitive procurement will ensure the most effective penetration in the market at the least cost.

Demand Response providers use tremendous resources in market research and marketing to uncover the best DR candidates. Customers may rightly have reservations about receiving information about DR, a new product to them, from a company they are not familiar with. Current DR marketing strategies may be inefficient and ineffective in attracting a high percentage of high-potential DR customers. Existing programs have limited exposure and mixed information because the programs are typically administered / implemented by different entities and there is no central location to view all programs. NYSERDA, NYISO and Con Edison websites offer examples of how different entities provide some information about differing programs.

Co-Branding consists of two or more entities promoting or endorsing the same marketing platform for a product. Utilities could create DR collateral with their branding on it, which could be used by DR providers to show prospects that their local utility approves of this offering. Also, utilities could provide a list of DR providers with links on their websites, similar to competitive supplier info that is currently provided.

With respect to residential and small C&I customers, the cost of customer acquisition is far too high for a third party to deliver a DR program without the support of the local utility – even with a long-term contract. The best way to reach these customers effectively is through a marketing arrangement between the utility and the third party provider. Under such an agreement, incremental utility costs should be absorbed by the provider as part of an overall long term contract. DR providers have expressed their willingness to pay for such services, so long as they are provided at cost-based rates.

Recommendation

The utilities should be directed to consider, consistent with competitive policies under retail commodity access rules, including in their compliance filings proposals to allow for co-marketing and co-branding opportunities with third party DR providers. These opportunities can be separate or a part of the long term RFP process recommended above.

C. Advanced Metering and Advanced Metering Infrastructure (AMI)

Overview

It has long been recognized that average cost energy pricing based on totalized monthly usage fosters highly inefficient energy use patterns by most electricity consumers, and particularly by consumers that contribute most to peak demands. Dynamic pricing and the advanced metering that enables the timely exchange of pricing and other information between consumers and service providers are expected to be key components in achieving substantial gains in more efficient energy use. Support for deployment of AMI where and when it is cost effective can help ensure that the 15 X 15 strategy can be achieved.

Benefits of AMI

Advanced Metering Infrastructure (AMI) is not a specific technology; but rather, AMI generally describes a metering system that provides more timely transfer of data between the customer and the utility. AMI can also provide finer granularity of data such as hourly or sub-hourly usage data that could be used for both demand response verification and hourly pricing. With rapidly evolving technology, various forms of AMI may also integrate directly with other services such as data and voice communications, direct load control and other value added services.

AMI can reduce the implementation and/or verification costs of energy efficiency, dynamic pricing and demand response opportunities. AMI can also provide the added benefit of providing consumers access to detailed information about their usage patterns; information that can be linked to the variable cost of energy at different times. This allows consumers to better understand the cost of their current energy habits as well as how much they might save by altering those habits. With such detailed information available, ESCO's and other suppliers will be able to offer competitive retail rates that more closely align with the industry's costs, resulting in higher overall system efficiencies. Depending on the specific AMI technology implemented, there can be additional benefits to customers, distribution companies, suppliers, and energy services companies.

A primary benefit of AMI is the ability to more quickly access and process large amounts of pricing and usage data, making such data available to both the customers and service providers. This could provide a platform by which consumers can see and respond to the continually changing wholesale cost of generation supply as well as to system conditions such as capacity deficiencies. While, AMI is not a prerequisite for most demand response or energy efficiency programs contemplated in the EEPS, it could help extend the reach of implementation and evaluation strategies and foster price-responsive behavior which together support cost-effective achievement of the long term 15 X 15 strategy.

To move forward with a plan to achieve aggressive energy reduction goals without including demand response and advanced metering would limit the opportunity to maximize conservation of electricity during peak periods. Approximately 2,000 MW of generating capacity are needed to address the highest 60 hours of peak load of the NYISO system[8]. Targeting these highest peak hours can have the greatest impact on the need for new generation and Transmission and Distribution infrastructure, enhanced system reliability, and facilitate the retirement of higher emitting generation.

Recommendations

WG VIII supports and encourages swift Commission and DPS action in their ongoing Advanced Metering Proceeding (Case 00-E-0165 – In the Matter of Competitive Metering) We specifically support the cost-effective provision of advanced metering capabilities that foster greater penetration and Measurement, Verification and Evaluation (MV&E) confidence of energy efficiency, demand response, and dynamic pricing programs.

[8] David Patton, PhD. and Pallas Lee VanSchaick, PhD., 2007 State of the Market Report, New York ISO, p. 9. (available at http://www.nyiso.com/public/webdocs/documents/market_advisor_reports/NYISO_2007_SOM_Final.pdf)

D. Time Variant Tariff Rate Proposals

Overview

The Commission should encourage Program Administrators to work jointly to test three dynamic pricing options: 1) Time Of Use (TOU) that has a peak period that is narrowly focused to address the system peak; 2) a voluntary residential Real Time Pricing (RTP) with dynamic prices (based on real-time and/or day-ahead wholesale energy market prices); and 3) a peak time rebate program that would give customers rebates for reducing their consumption during system peak.

The overriding objective of dynamic pricing programs is to create a financial incentive for electric customers to reduce consumption on the grid when the electric system peaks-by either conserving energy, shifting use to off-peak periods or by generating electricity on site. Demand response is usually done by providing an incentive (or payment) to loads to reduce load. Decisions on the size and structure of these incentives can get very complicated. Dynamic pricing attempts to induce demand response by more closely tying the price of electricity to its marginal cost in the wholesale market. By giving customers information on the cost of electricity, they can change their consumption patterns to lower their cost and possibly lower their consumption of electricity. Dynamic pricing can also provide signals to consumers when to recharge plug-in electric vehicles and to provide electricity to the grid from on-sight generation sources.

Challenges

Residential Customers in New York

Some dynamic rates are available to residential customers in New York. New York State Electric and Gas Corporation (NYSEG) has had a residential day/night rate since the 1930s to which customers respond. All of the state's investor owned utilities offer voluntary TOU rates for residential customers. These rates were designed for the largest residential customers, with some rates having explicit demand or kWhr thresholds. These rates also tend to target large blocks of time similar to day/night rates. These rates recover the cost of more expensive metering through higher customer charges or explicit meter charges. NYSEG has been the most successful in promoting TOU rates and has approximately 140,000 customers on the rate.

The Commission tried to make the TOU rates mandatory for large residential customers. That started a controversy which led to the New York Legislature taking away the Commissions powers to mandate TOU rates[9] in 1997.

In 2005, NYSERDA funded a dynamic pricing pilot in Westchester County with approximately 130 customers. Under this pilot, an ESCO, ECONnergy developed new, variable residential rates. These rates were arranged into four unchanging time blocks (6 am to 11 am, 11 am to 4 pm, 4 pm to 10 pm and 10 pm to 6 am) and the block prices changed daily based on the wholesale cost of electricity in the ISO Day Ahead Market. The hourly blocks were constant throughout the year, but the price in each block changed daily. The pilot was successful in demonstrating that customers were willing to adapt to the rate structure and reduce or shift usage as a result. The pilot could not demonstrate the transfer of customer load data from the ESCO to Consolidated Edison of New York (ConEd) due to the utility's billing system constraints and procedures of accepting meter data from a third party. There were also some technical problems with the meters. The deployment of the meters by the utility's metering shop was at a rate of three (3) to eight (8) homes per week.

Dynamic Pricing Experiences in Other States

In the past several years there has been a great deal of experimentation with dynamic pricing. Advances in meter technology have meant a drop in the cost of hourly interval meters and much greater flexibility in designing dynamic rates. Recent pilots have examined TOU rates that feature more than simple peak and off-peak time periods, critical peak rates that allow prices to go up especially high on peak event days, hourly pricing rates, and peak time rebates which provide customers a rebate for cutting back their usage on peak days. A recent paper by the Brattle Group[10] reviews evidence from the fourteen most recent pricing experiments with dynamic pricing and finds:

> On average, customers respond to higher prices by lowering usage. The magnitude of price response depends on several factors, such as the magnitude of the price increase, the presence of central air conditioning and the availability of enabling technologies such as two-way communicating thermostats and gateway systems. For the average customer, time-of-use rates are likely to induce a drop in peak

---

[9] L. 1997, c. 307, amended Public Service Law section 66(27) (a).

[10] Faruqui, Ahmad and Sanem Sergici, The Power of Experimentation New Evidence on Residential Demand Response, The Brattle Group, A Discussion Paper, May 11, 2008.

usage of under 5% while critical peak pricing tariffs a drop of around 10-25%. Customers with central air conditioning are likely to display responses in the 15-20% range while those with enabling technologies in the 25-45% range.

Some of the largest pilots have been the California Statewide Pricing Pilot, the Illinois RTP Program, and the New Jersey PSE&G Residential Pilot. Further information on these pilots can be found in the appendix.

Benefits of Dynamic Pricing

The Commission noted that hourly pricing programs provide price signals that

would facilitate efforts to reduce the electric system's peak period demand and to shift load to off-peak, less expensive time periods. The potential benefits for customers are reductions to peak period prices, enhanced peak period reliability, wholesale market power mitigation, and a reduction in the State's dependence on peak generation units. Additionally, hourly pricing programs, through more detailed pricing, assign costs to customers in a fair and more equitable manner.[11] The benefits of other dynamic pricing programs are similar to MHP, but because the Commission is limited in its ability to mandate dynamic rates for residential customers, it must determine if there are dynamic rates that residential customers will volunteer for and find beneficial.

Recommendations

The Commission should encourage Program Administrators to work jointly to test three dynamic pricing options: 1) TOU that has a peak period that is narrowly focused to address the system peak; 2) a voluntary residential Real Time Pricing (RTP) with prices based on real-time wholesale energy market prices; and 3) a peak time rebate program that would give customers rebates for reducing their consumption during system peak.

The purpose of such a joint effort would be to get a better understanding of the benefits and cost effectiveness of such tariffs in New York. Some lessons learned from other pricing pilots that should guide Program Administrators in designing and testing these dynamic prices are:

---

[11] CASE 03-E-0641 - Expedited Implementation of Mandatory Hourly Pricing for Commodity Service, Order Denying Petitions for Rehearing and Clarification in Part and Adopting Mandatory Hourly Pricing Requirements., (Issued and Effective April 24, 2006), pp. 1-2.

- Load control devices can double DR but the technology should be tested to make sure it works as expected. The Westchester pilot relied on customer behavior to shift load to lower priced periods of the day. The test should incorporate some forms of direct load control to determine if greater net benefits are achieved with direct load control devices.
- A significant portion of the New York retail electric market is served by Energy Service Companies (ESCOs) that have provided dynamic prices. A methodology for retrieving load data and sharing it between ESCOs, DR providers, and Transmission Owners (TOs) should be tested in a pilot.
- If an ESCO customer's electric usage is measured by hourly meters, then the ESCO needs to be billed on their customer's actual load shape instead of a class average load shape. Using a class average load shape takes away any incentive the ESCO has to do Energy Efficiency and DR by not giving the customer or the ESCO credit for altering their load shape.

Program administrators should work collaboratively with the Commission Staff and the EAG to determine a common understanding of the "benefits" of dynamic pricing, so that it can be properly valued and used by TOs to evaluate advanced metering proposals.

Improving Hourly Pricing Programs

Overview

The Commission should continue to expand hourly pricing where it finds it to be beneficial. The Commission should encourage utilities to investigate changes to their MHP tariffs to the recovery of capacity charges into fewer hours. This would give customers a more accurate price signal and encourage them to reduce their consumption during system peaks.

The hourly prices that utilities pass through to customers in their mandatory hourly pricing programs ("MHP") programs do not always send the strongest signals to Up-State customers at the time of the New York State system or zonal peak in electricity use. Day-ahead price signals in some parts of downstate New York are also weaker than one might expect at the time of the system peak.

Large Customers in New York

New York has led the country in exposing the largest customers to dynamic pricing. Some of the New York's large customers began to face TOU rates in 1978, and now all the largest utility customers have mandatory hourly pricing (MHP) rates, National Grid[12] and Central Hudson[13] were the first to implement MHP tariffs. On April 24, 2006, the NYPSC issued an Order[14] directing utilities to file Hourly Pricing tariffs, outreach and education plans and plans for making meters available to implement MHP for their largest customer classes[15]. National Grid, which already has mandatory MHP for its largest customers, was directed to expand its MHP to other large TOU customers with demand greater than 500 kW. The Commission ordered Staff to report in the first quarter of 2009 on the experience of the utilities implementation of MHP and make recommendations on how the program should be changed and whether the program should be expanded.

While large C&I customers have the option to purchase electricity from ESCOs to avoid variable rates, ESCOs are responsible for their customer's actual load shape. This requirement gives ESCOs the incentive to reduce their customers' use of on-peak power in order to reduce the ESCO's cost of procuring that power. It has also given ESCOs the incentive to offer a wide range of time sensitive pricing options to customers.

---

[12] CASE 94-E-0098 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation for Electric Service.(issued August 26, 1998)

[13] CASE 00-E-1273 – Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service. Tariff filing by Central Hudson Gas & Electric Corporation to eliminate the Market Price Charge and Market Price Adjustment pricing option for Service Classifications Nos. 3 and 13. (Issued April 18, 2005)

[14]CASE 03-E-0641 - Expedited Implementation of Mandatory Hourly Pricing for Commodity Service, Order Denying Petitions for Rehearing and Clarification in Part and Adopting Mandatory Hourly Pricing Requirements., (Issued and Effective April 24, 2006).

[15]The threshold for MHP rates vary by utilities: Consolidated Edison 1.5 MW, O&R 1MW, NYSEG 1 MW, RG&E 1 MW, National Grid 500 kW and Centra Hudson 1 MW.

Since the original order to implement MHP several utilities have lowered the threshold for MHP. In 2007, NYSEG agreed to expand MHP to customers with demand greater than 300 kW[16] over the course of the next three years. ConEd agreed to expand MHP to customers with demand greater than or equal to 500 kW[17]. Orange &Rockland's (O&R) three-year rate plan, as modified by the Commission, expands the applicability for mandatory hourly pricing (MHP) to those customers with demand in excess of 500 kilowatts (kW), instead of demand in excess of 1,000 kW to allow for greater participation in O&R's MHP program[18].

Voluntary TOU rates have been offered to the medium commercial and industrial classes. Some utilities have also offered voluntary hourly pricing to these customers. These rates have not been popular with customers.

Challenges

The lack of strong price signals reduces the financial incentive for customers to make their operations more flexible and reduce load during peak periods. The lack of strong price signals, therefore, undermines a key objective of implementing hourly pricing programs to provide customers a load curtailment incentive based on strong price signals.

One way to send strong and persistent signals to customers at the time of the system-peak is for utilities to collect capacity costs in their retail commodity rates in a way that

---

[16]CASE 07-E-0479 - Tariff Filing of New York State Electric & Gas Corporation to Offer Customers a Single Fixed Supply Service., ORDER ESTABLISHING COMMODITY PROGRAM, (Issued and Effective August 29, 2007).

[17]CASE 07-E-0523 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service.,ORDER ESTABLISHING RATES FOR ELECTRIC SERVICE,(Issued and Effective March 25, 2008).

[18] CASE 07-E-0949 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service.,ORDER ESTABLISHING ELECTRIC RATE PLAN FOR ORANGE AND ROCKLAND UTILITIES, INC.,(Issued and Effective July 23, 2008).

accurately reflects when these capacity costs are incurred and the role that customers play in driving capacity costs higher.

In large part, capacity costs are determined by the amount of electricity that customers jointly demand during the hour of the system peak, since each TO or ESCO (Load Serving Entity or LSE) must purchase enough unforced capacity for the next year to cover the peak demand of their customers in that hour plus a minimum reserve margin. LSEs in New York State have complete discretion over how to collect capacity costs from retail customers. New York State Utilities currently employ a variety of rate designs to collect capacity costs from customers. Some designs send a stronger signal at the time of the system peak than others. But each design is sufficiently malleable to send an even stronger signal at the time of the system peak if such action is deemed appropriate.

Recommendation

The Commission should continue to expand hourly pricing where it finds it to be beneficial. The Commission should encourage utilities to investigate changes to their MHP tariffs to recover capacity charges over fewer hours.

This would give customers a more accurate price signal and encourage them to reduce their consumption during system peaks.

E. Distributed Generation/Combined Heat and Power (DG/CHP)

Overview

Properly designed and implemented DG/CHP (including residential micro-CHP[19]) programs can offer efficiency and emissions reduction benefits that could meet thermal and electricity needs throughout New York State, particularly in electrically constrained areas such as load pockets, networks, and/control zones. DG/CHP systems can reduce peak demand as well as reduce overall energy consumption [20]

While there have been standard offer programs from NYSERDA to help encourage CHP deployment, these offerings have primarily focused on larger (500 kW and larger) systems. However there are several opportunities for smaller sized systems in New York's constrained areas, and as the Final Generic Environmental Statement ("FGEIS") (p. 37) points out, may represent some modest potential load growth for natural gas distribution systems.

The efficiency potential of smaller systems, including residential CHP, has been recognized in Massachusetts where recent legislation provided various incentives for CHP with an energy efficiency of 60% or above and defined micro-CHP as 60 kW and below. Also, both Massachusetts and Vermont encourage micro-CHP utilizing natural gas as part of their renewable and energy efficiency portfolio programs. The inclusion of DG/CHP systems in energy portfolios has also been recognized in Connecticut, New Jersey, Pennsylvania, California, and most recently in part of the Recovery and Tax Credit Act signed by President Bush on October 3, 2008. This Act sets a 10% business tax credit for CHP less than 15,000 kW in size, but not an individual tax credit for residential CHP.

---

[19] Micro-CHP is here defined as 60 kW and below with an annual energy efficiency of 60%. Larger combined heat and power systems are included as well, although the primary focus of the recommendations here addresses systems 500 kW and under

[20] The accepted conventional rule of thumb is 33% efficiency for conventional central generation. See Con Edison Slide No. 5 in presentation at July 17, 2008 Technical Conference in Case no. 08-E-0751.

Specifically, with respect to micro-CHP, it is generally recognized as being sized approximately for a single-family residence, therefore, being in the range of 1 to 5 kW, or thereabouts. A limited number of vendors currently offer such a product, and NYSERDA is currently working with two such vendors to make improvements to their equipment and/or demonstrate/validate their products with early adopters in NYS.

Since 2000, NYSERDA has offered a CHP Demonstration Program which does not have any size limitation, and has supported projects with generators as small as 30 kW and site installations as large as 30 MW. Over the years, this program indicates a clear marketplace desire trending toward larger systems, and has garnered marketplace intelligence which reveals that smaller systems have exceptional financial difficulty due to a disproportional burden of costs which do not scale linearly with size (e.g., project marketing/sales to customer, engineering design). To specifically address this marketplace hurdle, NYSERDA has recently created a program (CHP Fleet) which is geared toward smaller-scale projects and has a built-in mechanism to specifically address these disproportional cost burdens. Adequate time is needed to assess the influence of the program, especially how it may function to secure initial customer participation which could result in follow-on CHP opportunities.

Benefits

DG/CHP programs can foster net conversion efficiency improvements, lower net emissions, and improved optimization of infrastructure when compared to producing only thermal on-site and obtaining electricity from remote generating stations.

CHP systems offer the potential to reduce demand on the grid by the amount of electricity they are generating plus the reduction in line losses. This benefit is magnified during peak periods when line losses can reach as high as 20%.

Additionally, CHP systems with absorption chillers or other thermally driven cooling systems, could reduce the strain on the grid further by cutting or reducing the electrically driven cooling load that would otherwise require additional grid capacity[21].

[21] www.westgov.org/wga/initiatives/cdeac/CHP-full.pdf.

In addition to peak demand reductions, DG/CHP offers potential to help mitigate the increased electric costs that rate-payers are currently experiencing and make fuller use of the natural gas distribution system. CHP may: reduce congestion in constrained areas, increase reliability, reduce real power losses and reactive power consumption, and reduce or defer T&D expenditures[22]. Furthermore these benefits are not necessarily limited to peak load conditions and in fact, in some cases can be greater at times other than the summer peak[23].

Challenges

- Obtaining recognition that DG/CHP (and DR for that matter) provide benefits that go beyond the Commission's existing Total Resource Cost (TRC) framework that is based on criteria developed twenty years ago. For example, in the case of CHP they do not recognize societal emissions reduction benefits.
- Existing standard funding offers generally limit opportunities to systems larger than 500 kW. The lack of standard offer funding for residential micro-CHP and DG/CHP systems smaller than 500 kW has been a stumbling block to the deployment DG/CHP in these markets.
- MV&E costs become such a large percentage of project costs that smaller projects are no longer economically viable. As a result, there are many projects that are otherwise cost-effective that are not eligible, i.e., microturbines, micro-CHP, and smaller hybrid systems employing CHP, DR, and EE.
- There is no universally applicable energy efficiency standard for CHP in New York. **Differences in** such standards could lead to increased overall MV&E costs. **One** challenging issue is determining annual efficiency when end-users don't have year- round thermal loads. (One question is how to determine efficiency when operating.)

Recommendations

WG VIII recommends the following actions with regards to CHP systems of all sizes, including Micro-CHP systems:

---

[22] Optimal Portfolio Methodology For Assessing Distributed Energy Resources Benefits for the Energynet CEC-500-2005-061-D.

[23] CEC-500-2005-061-D, page 11.

- Permit EEPS and SBC funds to be deployed for support of cost-effective, efficient DG/CHP installations, including Micro-CHP, that have lower net emissions than the average fossil-fuel central generation in New York State and encourage Program Administrators to include incentives as part of their current and future EEPS programs.
- Adopt an efficiency standard of 60% average annual efficiency and the ability to be dispatched during electric system peaks and or when called upon for reliability events for DG/CHP participating in EEPS programs, recognizing that micro-CHP installations and larger installations may merit distinct standards.
- Encourage PAs jointly or individually to develop and implement programs for micro-CHP installations in 1-4 family homes, including low-income homes, and smaller commercial installations, and to propose intermediate-scale (1,000 + units) pilot demonstration projects if cost effective.

- Encourage the Evaluation Advisory Group (EAG) to review the current Total Resource Cost Test and recommending ways to update it so that it takes into account improvements in environmental and thermal benefits, among other factors, provided by DG/CHP and DR but not now considered.
- Encourage the Evaluation Advisory Group to establish DG/CHP Measurement, Verification, and Evaluation (MV&E) processes that:
  - are appropriate and scalable to the size of the DG/CHP projects.
  - recognize all fuel sources in evaluating cost-effectiveness.
  - compare net efficiency and net emissions improvements to "before" local thermal conversion and remote fossil-fuel electricity generation in a benefits analysis.
  - consider whether the comparison is being done with summer peaking vs. winter peaking.
  - recognize and appropriately value multiple benefit streams.

F. Environmental Justice Communities

Overview

Certain low income neighborhoods in New York, and very often communities of color, host peak generation facilities that are among the higher emitting and most inefficient units in the state. In some cases these units have no emission controls and stacks as short as 30 feet from ground level. These units are posited to have negative health impacts on the local populace. Environmental Justice advocates have asked the Commission to determine whether there are opportunities to render those facilities obsolete through the acquisition of energy efficiency resources. This was one of the charges given to WG VIII, which has interpreted it as a request to identify whether the output from such units could be 1) fully or 2) partially replaced or displaced with clean demand response, load shifting technologies and energy efficiency (collectively demand-side management (DSM)).

In addition, WG VIII was directed to consider the need for a study to assess the health impacts on communities that host peak generation facilities to a disparate extent. Although WG VIII's charge is limited to evaluating impacts to communities from peak generation facilities, there are other sources of air pollution that impact the communities surrounding the facilities evaluated by this working group.

Challenges

It is generally accepted that, in the most general terms, DSM resources can act as substitutes for generation, with certain types of DSM resources being better suited to substitute for certain types of generators. However, whether or not specific generators can be replaced, or their operations significantly reduced, by clean DSM resources is a very technical question and one which WG VIII is not capable of answering in isolation.

This is especially true for peaking generation facilities in New York City with its complex and highly loaded electrical network. For example, in order to meet reliability criteria, 80 percent of the generation needs of New York City must be met by generators physically located within the city. Similarly, certain generators may be required for voltage support, black start, or other system operation needs. Whether one or more peaking units could be replaced by clean DSM resources would depend on the units in question, their location, and the availability of sufficient DSM resources within that area.

It may be possible that the output of some units could be replaced or displaced by appropriate DSM resources located anywhere in Zone J (NYC) while the output of others could be replaced or displaced with DSM resources outside of Zone J. However, the output of other units might be replaced or displaced only by DSM resources in the same local area, raising the question of whether sufficient DSM resource potential exists to serve that function. Finally, other units might not be replaceable by DSM resources at all because they are needed for functions that usually cannot be provided by DSM resources.

Working Group VIII is unanimous in its view that whatever may come out of the investigations and recommendations regarding this charge, no reduction in system reliability from established standards can be tolerated. If it is determined that DSM resources can replace or displace the output of the peaking facilities, such actions must be done in a way that maintains or improves the reliability of the system through compliance with all applicable reliability rules.

Finally, WG VIII recognizes that generators in New York are dispatched in accordance with established market rules that currently do not incorporate environmental considerations except insofar as environmental compliance costs are reflected in generator bids and in constraints on when and for how long certain units can be operated. Absent specific agreements or requirements outside the market to limit the operation of the facilities in question, there is no guarantee that added demand resources will displace output from the intended units.

Further Study

An analysis needs to be conducted in order to determine whether the output from peak generation units[24] within a half-mile of an Environmental Justice community could be fully or partially replaced or displaced with clean DSM resources. Working Group VIII suggests that a technical study group be convened with staff from the New York Independent System Operator (NYISO), the Department of Public Service, the Consolidated Edison Company (Con Ed), and the Department of Environmental Conservation. The technical study group will make an initial assessment whether the output from peak generation units within a half-mile of an Environmental Justice community could potentially be fully or partially replaced or displaced with clean DSM

[24] The peak generation units under consideration by WG VIII are simple-cycle turbines that, in general, have a capacity factor less than 10 percent during the ozone season and do not have environmental controls.

resources. In addition, a steering committee, consisting of interested parties would be responsible for reviewing and advising the work of the technical study group. The units that would be evaluated would be selected based upon criteria such as:

1. Emissions from the units; (lbs per MWh, NOx and PM)
2. Actual or modeled impacts of those emissions on ambient air quality on the identified EJ Communities
3. Role of the facilities for providing the reliable operation of the transmission system;
4. Electricity generated (MWh/year and MWh/ozone day);
5. Number of residents within a half-mile of the facilities;
6. Age of the units; and
7. Future plans for the units.

The results of this assessment will be presented in a report to ALJ Stein and ALJ Stegemoeller by December 1, 2008.

Recommendation

As of October 17, 2008, Working Group VIII is not in a position to provide specific recommendations to the Commission regarding the EJ charges. After the technical study group completes its assessment, the steering committee will develop recommendations based on the results of the assessment and will present the recommendations to ALJ Stein and ALJ Stegemoeller on December 1, 2008. Ultimately, recommendations may advise the Commission to maximize DSM resources in Environmental Justice communities, create incentives for targeted DSM resources that would specifically compete with the dispatch of peaking turbines located within one-half mile of an Environmental Justice community, initiate, a pilot program, conduct additional technical analysis, or recommend other mechanisms that will reduce emissions and resulting health impacts to environmental justice communities.

Appendix to Time Variant Tariff Rate Proposals

California Statewide Pricing Pilot

One of the lessons gleaned from California's energy crisis in 2000/2001 is that the lack of demand response in retail markets makes it very difficult to equilibrate (or balance) wholesale markets at reasonable prices.[25] In the absence of demand response, the normally downward sloping demand curves become vertical, since customers do not change their demand for electricity in response to changes in the wholesale price of electricity. Studies have shown that economic efficiency in the allocation of scarce capital, fuel and labor resources can be realized by introducing demand response in retail markets. One method for introducing demand response in retail markets is time-varying pricing. With this in mind, the California Public Utilities Commission (CPUC) initiated a proceeding in July 2002 designed to introduce demand response in California's power market.[26]

The Statewide Pricing Pilot (SPP) involved roughly 2,000 residential and small commercial and industrial (C&I) customers[27] located in the service territories of Pacific Gas & Electric Company, San Diego Gas & Electric Company and Southern California Edison. Most customers enrolled in the pricing pilot were either placed on experimental dynamic pricing tariffs or given dynamic pricing information to encourage demand response. Other customers were selected as a control group and were kept on their existing tariffs and monitored at the same time.

The tariffs being tested in the SPP include a time-of-use (TOU) rate and two types of critical peak pricing (CPP) rates. The TOU rate offers customers an on-peak

---

[25] James L. Sweeney, The California Electricity Crisis, Hoover Institution Press, 2002.

[26] Order Instituting Rulemaking on policies and practices for advanced metering, demand response and dynamic pricing, R. 02-06-001.

[27] Small C&I customers are divided into two segments, those with billing demand less than 20 kW and those with billing demand between 20 kW and 200 kW.

price that is higher than the average price for the standard rate and an off-peak price that is lower than the current average price.[28] The two CPP rates (CPP-F and CPP-V) include a substantially higher on-peak price (about 50 to 75 cents/kWh) for 15 "critical" days of the year and a TOU rate on all other days. CPP-F features a fixed, on-peak period on both critical and non-critical days with day-ahead customer notification, while CPP-V features a variable-length on-peak period on critical days, and customers may be notified on the day of the critical peak event.

Illinois – Commonwealth Edison's Residential RTP Program

Pursuant to a 2006 law, the Illinois utilities were directed to offer an optional real-time pricing program to all residential customers. See, 220 ILCS 5/16-107. Commonwealth Edison (ComEd) launched their program in January 2007, building on an existing day-ahead pilot they had initiated in 2003. That law also required the program to be administered by a third party responsible for the development, implementation, operations and marketing of the program. Under this program, energy prices vary on an hourly real-time basis and reflect actual hourly wholesale real time prices (PJM's LMP). Interval meters are installed for customers without charge and rented at a subsidized cost to the first 110,000 participants at the charge of $2.25/month or about 50% of the costs. All residential customers are charged 14 cents per month to support the remaining costs of the program.

Under this program, participants are notified of the predicted "day ahead" PJM market prices. Real-time "day of" high price alerts are sent when the LMP reaches or exceeds certain price thresholds for 30 consecutive minutes. In addition, there is an optional automated price response service available called "Load Guard" which will automatically cycle the customers' air conditioning at certain price thresholds. The two pricing thresholds for controls are 10 cents and 14 cents . During 2007, real time hourly prices hit or exceeded 10 cents per kWh for 160 hours and 29 hours at 14 cents per kWh. The real time price of energy for the remainder of the hours was below those prices.

---

[28] The peak period for all tariffs is from 2 pm to 7 pm on weekdays. The critical peak period for the CPP-F rate is also from 2 pm to 7 pm on CPP-event days. The critical peak period for the CPP-V tariff varies between 2 hours and 5 hours during the period from 2 pm to 7 pm on CPP-event days.

The program has a web portal called "WattSpot.com" which provides customers with educational materials, including savings tips, as well as access to the real-time and predicted prices and online bill summaries and comparison with fixed rates and usage information. Load Guard customers can also access their thermostats and set points online. As of April 2008, there were 6,000 customers on the program. According to the utility's 2007 annual report, 95% of the customers saved money last year. The majority of customers who participated for a full year experienced annual savings between 7 to 12%.[29] In sum, the ComEd program is a good example of a dynamic pricing program that can test price responsive demand with and without automation.

New Jersey – PSEG's myPower Pricing Pilot[30]

Starting in the summer of 2006, Public Service Electric & Gas (PSEG) in New Jersey, initiated a dynamic pricing pilot which tested both technology and price response. It consisted of two types of programs. Both included the same time-of-use (TOU) and critical peak (CPP) pricing designs but one included a controllable programmable thermostat. Those customers were also given an in-home education briefing about saving money on-peak a during critical peak periods. This program was called the myPower Connection program. The other program did not include the thermostat and was called myPower Sense program. PSEG also established a control group which consisted of a comparable group of residential customers for which interval meters were installed but they received no price signals or control technology. Customers were notified the night before a critical peak event and the program was designed to call a maximum of 8 events during the year – 5 in the summer and 3 in the non-summer months.

---

[29] A copy of the report can be found at http://www.icc.illinois.gov/docket/files.aspx?no=06-0617&docId=123573

[30] See Schedule FAL-3 of the Petition and supporting documents of Public Service Electric and Gas Company (PSE&G) in the New Jersey Board of Public Utilities Docket No. EO08050326, Filed August 5, 2008. Avaliable at http://www.state.nj.us/bpu/pdf/energy/PSEGdemandresponse.pdf

According to a report prepared for PSEG by Summit Blue Consulting, LLC dated December 21, 2007, the program produced a reduction in demand on peak for all customer groups and the vast majority of customers on both programs believed that they saved money being on the rates (71%). The report made the following findings:

- myPower Critical Peak Pricing does produce measurable and statistically significant reductions in participant's energy use during high and critical peak price periods. myPower Connection customers regularly reduced their on-peak demand on summer peak days by 21%, while myPower Sense customers reduced their demand by 3 to 6%. myPower Connection customers reduced their demand by an additional 26% on CPP days, creating a total demand reduction of 47%. This is equivalent to an average reduction of 1.33 kW over the on-peak period.
- Customers who received enabling technology as part of the program...showed greater reductions in demand, both in response to the TOU rates and the CPP events.
- On the hottest summer days, myPower Connection customers reduced their average hourly demand during the 1:00 p.m. to 6:00 p.m. period by 21% (0.59 kW) in response to the TOU on-peak rate, and they reduced their demand by an additional 26% (0.74 kW) if a CPP event was called. This is a total reduction of 47% (1.33kW).
- On the hottest summer days, myPower Sense customers with central air-conditioning reduced their average hourly demand during the 1:00 p.m. to 6:00 p.m. period by 3% (0.07 kW) in response to the TOU on-peak rate, and they reduced their demand by an additional 14% (0.36 kW) if a CPP event was called. This is a total reduction of 17% (0.43 kW).

ACE NY
ALLIANCE FOR CLEAN ENERGY NEW YORK, INC.
Promoting Clean Energy, A Healthy Environment
And A Strong Economy For The Empire State.

Dissent of the Alliance for Clean Energy New York
re: WG VIII's Recommendation on DG/CHP

The Alliance for Clean Energy New York (ACE NY) respectfully disagrees with Work Group VIII's recommendations on Distributed Generation/Combined Heat and Power.

ACE NY believes the Energy Efficiency Portfolio Proceeding (EEPS) must include Demand Response and Peak Reduction efforts since these are important initiatives to lower peak load even further than efficiency measures alone can do and can avoid the need for costly and polluting peaking power resources to maintain reliability. We also realize that in some circumstances Demand Response providers may use distributed generation to replace the grid power their clients are foregoing. However, we do not consider micro turbines a "renewable" resource nor an efficiency measure per se. Simply replacing central station generation with more efficient but fossil fuel (natural gas) based distributed generation is not, we believe, the goal of the EEPS. Therefore, we do not support the recommendation that EEPS funds be used directly for deployment of micro-CHP.

[illegible] Washington Avenue
Suite [illegible] Albany, NY 12210
Ph 518.432.1405
Fx 518.432.1407
www.aceny.org

ConEdison Solutions
An Energy Services Company

More than just power...

VIA ELECTRONIC MAIL
Mr. Sigmund Peplowski
Staff Contact – EEPS Working Group VIII
New York Department of Public Service
Three Empire State Plaza
Albany, New York 12233-1350

RE: Case No. 07-M-0548 – Proceeding on Motion of the Commission Regarding An Energy Efficiency Portfolio Standard – **Comments of Consolidated Edison Solutions On the Working Group VIII Commercial and Industrial and Residential Demand Response Programs Proposal**

Dear Mr. Peplowski:

Consolidated Edison Solutions, Inc. ("CES"), is an active party in the above-referenced proceeding and submits this letter to point out concerns with the Commercial and Industrial ("C&I") and Residential Demand Response Programs proposal developed by Working Group VIII. Specifically, CES is concerned that Working Group VIII's proposal to implement a C&I Demand Response Request For Proposals would result in mandatory long-term contracts for DR resources that would potentially conflict with the existing bilateral market for DR resources.

While CES does not dispute that volatility in the capacity markets may make it difficult to attract DR resources, the same concerns also apply to traditional generation resources. CES' does not believe a separate market mechanism for DR resources is necessary and could in fact deter such resources from participating in bilateral or NYISO administered markets. It is CES' experience that an active bilateral market already exists where DR resources can sell their capacity for terms longer than the NYISO's 6 month strip auction duration.

In the event that Commission elects to approve a mechanism like the Working Group VIII proposal, CES would recommend that the costs of a C&I DR RFP program be recovered in a competitively neutral manner. In addition, the procurement should be structured where winning suppliers receive a premium payment over an above the capacity revenues they would receive from the bilateral or NYISO administered market. Such a structure would at least reduce the disruption to the existing market mechanisms.

CES deeply appreciates the hard work and efforts of Working Group VIII and the opportunity to offer comments to the collaborative.

Respectfully Submitted,

Stephen Wemple
Vice President, Regulatory Affairs
Consolidated Edison Competitive Shared Services, Inc.
For Consolidated Edison Solutions, Inc.
701 Westchester Ave. Suite 201 West
White Plains, NY 10604
914-993-2149

October 16, 2008

810 Seventh Avenue
Suite 400
New York, New York 10019
212.885.6400
212.883.5888 Fax
www.newenergy.com

Constellation NewEnergy

October 16, 2008

Sigmund Peplowski
New York Department of Public Service
Three Empire Plaza
Albany, NY 12233

RE: Case 07-M-0548 – Proceeding on Motion of Commission Regarding An Energy Efficiency Portfolio Standard – Working Group VIII, Demand Response Recommendations – **Dissenting Comments of Constellation NewEnergy, Inc. and Constellation Energy Commodities Group, Inc.**

Dear Mr. Peplowski,

Constellation NewEnergy, Inc. and Constellation Energy Commodities Group, Inc. ("Constellation") has been an active party in this proceeding since its inception as well as an active member in the activities of Working Group VIII. Constellation would like to acknowledge the hard work of staff and other working group members in the development of these demand response recommendations. Constellation believes demand response is a critical resource for maintaining system reliability and improving the overall functioning of the wholesale markets in New York. While Constellation does support the current recommendations on residential programs and utility co-marketing initiatives, we would like to make the following suggestions in regard to the long-term contracting recommendations.

1. **New demand response programs should be designed to leverage the strengths of New York's competitive market, not compete with it.** The Working Group identified no regulatory barriers to the ability of demand response providers to achieve long-term revenue stability by entering into bilateral contracts for capacity and/or energy with other non-utility market participants. In fact, over the last few years, the generation sector has demonstrated that these long-term contracts can be readily obtained through the competitive marketplace with no threat of stranded costs for rate payers. Given the fact that demand response providers already have access to such contracts Constellation suggests that allowing utilities or NYSERDA to offer similar contracts is duplicative and imposes additional program complications as well as unnecessary risks to rate payers.

2. **If it is determined that supplemental payments for demand response resources beyond current wholesale market revenues (capacity, energy, and ancillaries) are needed to achieve desired demand response levels, those payments should be made on a stand-alone basis.** In other words, rather than combining supplemental payments, or subsidies, with an energy and capacity procurement contract, payments should be made separately thus allowing demand response resources to participate directly in wholesale markets as they currently do. This approach not only provides maximum cost and price signal transparency for market participants, and particularly rate payers, but also minimizes the risk of these programs undermining or distorting wholesale markets. A good example of a program with stand-alone supplemental payments is Con Edison's Distribution Load Relief Program. Con Edison's program has successfully increased demand response enrollment levels in a relatively short period of time by building on the NYISO's existing demand response programs and compensating resources only for the incremental benefit they provide in maintaining the reliability of the distribution system. Constellation would highlight Con Edison's program as a model that should be expanded and replicated in other territories.

3. **The costs of new demand response programs should be recovered in a competitively-neutral manner.** In order to be competitively neutral the costs of demand response programs should be recovered through the SBC or some other non-bypassible delivery charge. This type of recovery mechanism is appropriate both because the programs would be driven by public policy goals and because the programs would benefit all rate payers.

Constellation appreciates the opportunity to offer these dissenting comments and looks forward to its ongoing participation in the Energy Efficiency Portfolio Standard proceeding.

Sincerely,

Tim Daniels
Director, Energy Policy

Direct Energy

October 16, 2008

VIA ELECTRONIC MAIL
Mr. Sigmund Peplowski
Staff Contact, EEPS Working Group VIII
New York Department of Public Service
Three Empire State Plaza
Albany, New York 12233-1350

RE: Case No. 07-M-0548 – Proceeding on Motion of the Commission Regarding an Energy Efficiency Portfolio Standard

Dear Sig:

In response to your email of October 15, 2008 regarding the proposed Working Group VIII report, Direct Energy Services, LLC ("Direct Energy") hereby notifies the group that it respectfully dissents from the proposed recommendation contained in the section of the report entitled "Commercial and Industrial (C&I) and Residential Demand Response Programs." Specifically, we dissent from the recommendation that Program Administrators issue RFPs for additional demand response resources "to address peak load, local constraint, or other needs, as appropriate to their individual situations," which resources would be secured through long-term (that is, multi-year) contracts with Program Administrators.

We object to this recommendation on the same grounds identified by Hess Corporation and ConEdison Solutions, and so will no recapitulate those arguments in detail here, other than to say that the proposal is unwarranted and could be counter-productive should it interfere with the continued development of the bilateral voluntary market for demand response. Moreover, while we appreciate the argument the report makes regarding possible deficiencies in the New York capacity market's ability to assess the long-term value of capacity (a deficiency that could have equal effect on non-demand response capacity resources), we do not believe hard-wiring a certain level of demand response into the system through Program Administrator-based long-term contracts is an appropriate response at this time.

Further, the specific condition that results from this perceived deficiency in the capacity market (namely, insufficient revenue to give demand response providers a sufficient return on their investment) is too generic as currently described in the report to warrant the commitment of ratepayer funds as a remedy. Before such a commitment is made (especially on a long-term basis) the benefits of any particular measure as they relate to the fundamental goals of this proceeding must be firmly established, and it should be clear that these benefits cannot be reasonably obtained through means other than ratepayer funding.

Thank you for your and the group's continued hard work in addressing the important issues at hand in this proceeding.

Yours truly,

JW for CK

Christopher H. Kallaher
Director, Gov't and Regulatory Affairs
Direct Energy Services, LLC

162 Cypress Street
Brookline, MA 02445
(617) 879-0668 (voice)
(617) 879-0661 (fax)
(617) 549-3002 (cell)
chris.kallaher@directenergy.com
www.directenergy.com

HESS

HESS CORPORATION
1 Hess Plaza
Woodbridge, NJ 07095

JAY L. KOOPER
Director of Regulatory Affairs
Energy Marketing
(732) 750-7048
FAX: (732) 750-6670

October 16, 2008

VIA ELECTRONIC MAIL
Mr. Sigmund Peplowski
Staff Contact – EEPS Working Group VIII
New York Department of Public Service
Three Empire State Plaza
Albany, New York 12233-1350

RE: Case No. 07-M-0548 – Proceeding on Motion of the Commission Regarding An Energy Efficiency Portfolio Standard – **Dissent of Hess Corporation On the Working Group VIII Commercial and Industrial and Residential Demand Response Programs Proposal**

Dear Mr. Peplowski:

Hess Corporation ("Hess"), an active party in the above-referenced proceeding submits this letter to respectfully register its dissent on the Commercial and Industrial ("C&I") and Residential Demand Response Programs proposal developed by Working Group VIII. Specifically, Hess dissents from Working Group VIII's proposal to implement a C&I Demand Response Request For Proposals that would result in mandatory long-term contracts for DR resources.

It is Hess' position that such a mechanism is neither necessary nor warranted. First, Working Group VIII, based on a review of their report, has not identified barriers to C&I demand response providers seeking voluntary long-term contracts through the competitive market in the same way as generators do. In fact, Hess can speak to this from experience from its Hess Demand Response product deployment that began in January 2008 and has made considerable progress in penetrating the New York market. Such contracts procured on the competitive market can provide the price signals and price stability that the demand response providers – including Hess – need to grow the DR industry.

Second, marshalling C&I demand response into a utility-based RFP process that in turn begets a mandatory long-term contract regime runs the grave risk of interfering with DR growth in New York through the competitive industry just as this avenue is beginning to hit its stride. At minimum, Hess would urge the Working Group to specifically identify and analyze any specific barriers to C&I DR providers seeking long-term contracts through the competitive markets before recommending an RFP process that will involve ratepayer liability and a mandatory long-term contract regime that could step on efforts to grow DR through the competitive industry.

In the event that Working Group VIII decides to proceed with the current recommendation under consideration, Hess advises that the costs of a C&I DR RFP program be recovered in a competitively neutral manner. In addition, Hess recommends that if the Commission determines that a premium should be paid to these DR resources beyond revenue from wholesale markets then as an alternative to utility contracts the Commission should consider implementing direct payments of the premium. It is Hess' understanding that the Renewable Portfolio Standards currently operates under a similar construct and that this structure will have less potential for disrupting wholesale energy and capacity markets.

Hess deeply appreciates the hard work and efforts of Working Group VIII and the opportunity to offer comments to the collaborative. Hess looks forward to continuing to work with all stakeholders in this proceeding.

Sincerely,

Jay Kooper

Jay L. Kooper
Director of Regulatory Affairs

PSC Case 07-M-0548 -Energy Efficiency Portfolio Standard Proceeding

Working Group 8 – Demand Response and Peak Reduction

IPPNY's PROPOSAL

October 10, 2008

Overview

The focus and scope of the proceeding are to establish an Energy Efficiency Portfolio Standard (EEPS). The July 3rd procedural ruling concerning EEPS design issues noted that defining the role of demand response and distributed generation in this proceeding was a critical path issue towards achieving gains in peak load reduction and the associated energy savings. It is peak load reduction and energy savings that are the main objectives of the proceeding and the ruling states that the principal issue for working group discussion and recommendations is to identify specific measures that are not presently achievable through ISO and SBC programs, utility programs, or EEPS initiatives as recently ordered by the Commission. Issues related to environmental justice (EJ) and peaking power plants have been raised and a July 3 ruling by the Administrative Law Judges in this case noted that "the environmental justice roundtable requested consideration of a study to assess health impacts on communities that host peak generation facilities to a disparate extent, and of opportunities to render those facilities obsolete through the acquisition of energy efficiency resources." The word "obsolete" does not appear in the roundtable's report, and this proceeding is not the proper venue to determine if certain resources can be rendered obsolete, given the potential negative impact on electric system reliability needs.

At most the acknowledgement of the EJ request is a recognition that a recommendation for further study may be appropriate, yet some members of Working Group (WG) VIII have gone to great lengths to interpret the Judges' language as a direct request to identify whether specific peaking facilities could be fully or partially replaced with demand-side management (DSM), which seems to include demand response, load shifting technologies, and energy efficiency, as well as potentially lower-emitting distributed generation. Such a determination is beyond the scope of this proceeding and should be made in the context of a reliability proceeding, where the analysis and decision-making is focused on maintaining system reliability as opposed to being focused on improving energy efficiency.

Because New York City is a constrained load pocket, a requirement exists that a minimum of 80 percent of its capacity must be purchased in New York City. Given the significant fluctuations in load in New York City, peaking units are a great benefit to the system in terms of providing reliability services. Studies must be done to determine whether New York City would continue to be able to meet its minimum locational reserve requirements, if the output of peaking facilities were to be reduced.

The concern about the disparate impacts of peak generation facilities on local communities is a legitimate concern. In regards to the health impacts assessment mentioned in the Judges' ruling, analyses of the relative health impact of these facilities already have been conducted. For example, a report on air emission impacts was completed by Synapse Energy Economics (in the 2003-2007 timeframe). The scope of work and final product are the result of a collaborative effort which included Citizens Helping Organize a (K)leaner Environment (CHOKE), the Natural Resources Defense Council (NRDC), and other stakeholders. According to the report's estimate of direct $PM_{2.5}$ emissions in New York City, point sources account for 17 percent of emissions. Point sources are facilities such as electric power plants, manufacturing, refineries, and steel mills. The majority of emissions come from other sources. The report's chief recommendation to address emission reductions is increased investment in energy efficiency programs, which is the focus of the EEPS proceeding.

Peaking generation facilities, almost all of which were sold by Consolidated Edison (Con Edison) in 1999 (and some still are owned by Con Edison), are operated in full compliance with very stringent emission regulations and dispatched to operate by the New York Independent System Operator (NYISO) based on economics and reliability needs. IPPNY Member companies who purchased peaking units have made subsequent investments in improvements, amounting to hundreds of millions of dollars, to maintain and improve reliability and efficiency, to integrate the use of lower-emitting fuels, and to reduce emissions from the entire portfolio of units. IPPNY Members are reviewing potential additional actions and investments to improve the operations of their facilities. However, the development of market based price signals that encourage investments to meet the goals of this proceeding is essential to further improvements.

Challenges

DSM resources can help meet load under peak conditions, and, in order to avoid any reliability issues, these resources must be properly targeted, measured, and verified. Moreover, the NYISO has indicated that some generating units in load pockets may be needed, even if demand is lower. Similarly, certain generators may be required for voltage support, black start, or other system operation needs. According to the NYISO, questions about whether DSM can replace the output of peaking units cannot be answered by an easy analysis, and WG VIII is not capable of answering this very technical question in isolation.

The suggestion by some members of WG VIII that DSM efforts in the EEPS proceeding can render particular peaking units "obsolete" is unlikely to succeed and is not backed by any evidence or analysis. To the extent that DSM programs can reduce peak load and provide other system support, then peaking units in general will run less. However, trying to target a particular unit is a more complicated challenge and goes beyond the EEPS proceeding.

If the goal of some members of WG VIII is to replace completely the existing peaking generation units in New York City, so the EJ communities are impacted as little as possible, then WG VIII should recommend consideration of this goal by another initiative that goes beyond the reasonable scope of the EEPS proceeding, such as the New York State Energy Planning Process. That other process should create a competitive solution to the replacement goal that provides incentives for not only demand side management initiatives but also repowering to modern, state-of-the-art generation with very low emission rates.

Recommendations

The IPPNY members of WG VIII recommend that prior to the development of a DSM program promoting energy efficiency in a constrained area, the following actions should be taken in order to understand and promote the maximum overall public benefits of such a program:

1. A study should be conducted to assess what levels of DSM penetration can be accommodated while respecting the level of peaking facility support that will still be required in order to ensure system reliability is maintained.

2. The results of this study can then be used to quantify the emissions reductions and relative value of the environmental benefits that might be achievable through such a program.

3. Finally, assuming both energy efficiency and environmental benefits are the desired outcomes, a program should be designed to encourage increased DSM and the repowering of peaking facilities in order to achieve the maximum combined benefits of peak load reduction, energy savings and emission reductions. Such a program must work in concert with the NYISO markets and its reliability planning processes. As such, we recommend that the PSC work together with the NYISO, NYSRC and market participants to determine what market-based price signals are needed to (1) make this increased reliance on DSM possible and economic and/or (2) to repower facilities to modern, state-of-the-art generation that meets New Source Performance Standards. The market solutions to incent repowering could be in the form of (1) Request for Proposals (RFPs) (2) market-based credits (similar to the REC market for wind capacity) or (3) Long-term forward capacity market contracts.

NEW YORK INDEPENDENT SYSTEM OPERATOR

10 Krey Blvd. Rensselaer, N.Y. 12144

October 16, 2008

Honorable Jaclyn Brilling
Secretary Public Service Commission
Agency Building 3, 19th floor
Albany, New York 12223-1350

Re: Comments Of The New York Independent System Operator, Inc. on Working Group VIII's October 16, 2008 Environmental Justice Recommendation

Dear Secretary Brilling;

The New York Independent System Operator, Inc. ("NYISO") respectfully declines the invitation of the EEPs Working Group VIII that it participate in a "technical study group" to assess, with staff from the Department of Public Service, the Consolidated Edison Company (Con Ed), and the Department of Environmental Conservation:

> [W]hether the output from peak generation units within a half-mile of an Environmental Justice community could potentially be fully or partially replaced or displaced with clean DSM resources.... The units that would be evaluated would be selected based upon criteria [omitted].... The results of this assessment will be presented in a report to ALJ Stein and ALJ Stegemoeller by December 1, 2008.

The NYISO strongly believes in Demand Side Management and appreciates the efforts of all concerned to look for opportunities to improve programs and expand eligibility for participation in the NYISO's existing programs. With this goal in mind, the NYISO has participated in Working Group VIII's efforts.

The NYISO, however, must decline to participate in this proposed technical study group. There are many reasons for the NYISO's position but most significant among them is the due date of December 1, 2008 for the technical study group report when the units proposed to be studied have not yet been identified. Serious analysis requires more than six weeks. Serious analysis also requires a scope of work that is significantly more concrete and thought out than is the charge enunciated by the Working Group at this point.

Although the NYISO is unable to participate in the technical study group as it is currently envisioned, the NYISO stands ready to continue to work with the Commission and any interested parties in understanding whether there are greater opportunities for DSM participation.

Respectfully yours;

Mollie Lampi
Assistant General Counsel
New York Independent System Operator, Inc.

Name	Affiliation
Aaron Breidenbaugh	EnerNOC
Aisha Kutter	NYPA
Alison Kling	NYC Econ. Dev. Corp.
Anthoy Grey	NYSDOH
Arthur Pearson	E Cubed Company
Brett Feldman	Constellation
C Pasch	Energy Spectrum
Carole J	NYSDOH
Chris Graves	NYSDPS
Chris Holmes	Current
Chris Kallaher	Direct Energy
Cindy Acrcate	Comverge
Dan Rosenblum	Pace Energy and Climate Center
Dan Zaweski	LIPA
Daniel P. Duthie	MicroPlant Technology Corp.
Dave Sampson	NYSDEC - OGC
David Bomke	NYECC
David Hepinstall,	Assoc. for Energy Affordability
David M. Ahrens	Energy Spectrum
Donna Pratt	NYISO
Doug Smith	National Grid
Ed Gray	Elster
Elena Futoryan	Con Edison
Elizabeth Fennell	ConEd
Elizabeth Weiner	Conservation Service Group
Francis J. Murray, Jr.	Pace Energy Law Project
Garrett E. Bissell	Integrys Energy Services
Giuseppe Zeppieri	Con Edison Solutions
Heather Adams	Central Hudson
Heather Hunt	UTC Power
James W. Brew	Nucor Steel Auburn
Jamie Stein	Sustainable South Bronx
Jeff Irish,	Hudson Valley Clean Energy
Jeffrey N. Barat,	D & B Engineering

Name	Affiliation
John Allen	RGE
John Barnes	NYSDEC
John Little	Navigant Consulting
John Rathbun	Keyspan Energy
Joy Zimberlin	NYISO
Karl Mayer	ECR International
Keith Christensen	EarthKind Energy, Inc.
Larry Simpson	Everwild Enterprises
Lee Smith	NYSERDA
Leka Gjonaj	NYSDPS
Lisa Garcia	NYSDEC
Marie Pieniazek	Consumer Powerline
Mark Marini	NYSEG/RG&E
Martha Sickles	Association for Energy Affordability, Inc.
Mary Coleman	Reliant Energy
MaryEllen Burns	NYS AG
Michael J. Delaney	The City of New York
Michael Spector	Central Hudson
Michael Vecchi	Cellnet Hunt
Michael W. Caufield,	Alcoa, Inc.
Michael W. Reville,	NFG
Micheal Jaeger	ECS
Monica Kreshik	NYSDEC EJ Office
Paul Peter Jesep,	NYSTAR
Pete Carney	NYISO
Pete Savio	NYSERDA
Peter Washburn	NYSOAG
Radmila Miletch	IPPNY
Randy Bowers	NYISO
Richard B. Miller	Consolidated Edison and Orange and Rockland
Richard Hackman	NYPA
Rick Struck	O&R
Robert Pike	NYISO
Robert Sliwinski	NYSDEC

Name	Affiliation
Ruben Brown	Joint Supporters
Saul Rigberg	NYSDPS
Sam Brewer	Capstone Turbine Corp.
Sandra Reulet	NYSDPS
Scott DeBroff	Elster, Sensus, Trilliant, and Walmart
Scott Smith	Trilliant
sharper	EnerNOC
Sheldon Rekant	IDT Energy
Sig Peplowski	NYSDPS
Stacy Palm	Site Controls
Stephen B. Wemple	Con Edison Solutions
Steve Cowell	Conservation Services Group
Steve Keller	NYSDPS
Tanja M. Shonkwiler	Duncan, Weinberg, Genzer & Pembroke, P.C.,
Thomas McGuire	NYSDEC
Tim Roughan	National Grid
Timothy Daniels	Constellation
Timothy Sheehan	NYPA
Tom Barone	NYSERDA
Usher Fogel	RESA
Benjamin Mastaitis	Read & Laniado
Jamie Stein	Sustainable South Bronx
Liam Baker	US Power Generating
Gail Suchman	Stroock Stroock & Lavan
Roger Caiazza	NRG Energy, Inc