UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Demand Response Compensation in Organized Wholesale Energy Markets	**)** **)**	**Docket No. RM10-17-000**

COMMENTS OF ISO NEW ENGLAND INC.

On March 18, 2010, the Federal Energy Regulatory Commission ("Commission") issued a Notice of Proposed Rulemaking on Demand Response Compensation in Organized Wholesale Energy Markets in Docket No. RM10-17-000 ("NOPR"). ISO New England Inc. ("ISO-NE") respectfully submits these comments in response to the NOPR.

I. INTRODUCTION AND EXECUTIVE SUMMARY

In the NOPR, the Commission proposes that:

> Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) with tariff provisions permitting demand response providers to participate as resources in energy markets by reducing consumption of electricity from their *expected levels* in response to price signals be required to pay to demand response providers, *in all hours*, *the market price for energy* for such reductions.[1]

Specifically, the Commission proposes that ISOs and RTOs be required to pay demand response providers "the market price for energy, *i.e., full LMP*, for demand reductions made in response to price signals."[2] The Commission reasons that "paying demand response resources the LMP in all hours

[1] NOPR at P 1 (emphasis added). The NOPR states that this provision would apply only to demand response acting as a resource in organized wholesale energy markets and not to demand response receiving payments to respond in reliability or emergency conditions, or participating in ancillary service markets. NOPR at fn. 4 and P 7.

[2] NOPR at P 11 (emphasis added).

will compensate those resources in a manner that reflects the marginal value of the resource to each RTO and ISO, comparable to [the] treatment of generation resources."[3]

An efficient wholesale energy market requires active demand participation in which the demand side of the market responds to market-clearing energy prices. To achieve this end, ISO-NE has been working with the New England Power Pool ("NEPOOL") and the New England Conference of Public Utilities Commissioners ("NECPUC") to develop and implement a variety of demand response initiatives that provide financial incentives to demand response providers whose demand resources respond to wholesale energy prices or to system reliability events. New England's experience demonstrates the value of initiating and evolving demand response programs. Since the time ISO-NE introduced both Locational Marginal Prices ("LMPs") and a number of demand response initiatives in 2003, the region's demand response capability has grown over 11-fold. Ultimately, ISO-NE's objective is to fully integrate demand resources into the wholesale market. This will improve overall market efficiency and ensure that demand resources compete on a comparable basis with generation resources.

While the NOPR proceeding presents an opportunity to increase the integration of demand resources into the wholesale energy market, the proposed rule will lead to inefficient outcomes in the energy markets unless the Commission addresses these inefficiencies through other means. Paying full LMP to demand resources that have reduced consumption relative to an estimated baseline as required by the proposed rule will encourage the dispatch of higher-cost demand resources that will displace lower-cost generation in the wholesale energy markets. This is inefficient, runs counter to the fundamental least-cost resource dispatch procedure of the energy markets, and will ultimately raise consumer costs. ISO-NE developed these views after careful consideration informed by over 19

[3] NOPR at P 12.

months of analysis and discussions with stakeholders and state regulators on the topic of achieving price-responsive demand in New England.

The proposed rule appears to be based on the false assumption that demand resources and generators are equivalent, and that demand response providers should participate in energy markets like generators by submitting supply offers reflecting the marginal cost of their resource.[4] Demand resources, however, are physically different from generators – demand resources reduce consumption whereas generators serve consumption. Because demand resources reduce consumption, a demand response provider's reaction to energy market price signals will consider savings in the consumer's energy bill plus any incentive payments from the wholesale energy market. By paying the full LMP to demand response providers without taking into account the bill savings produced by demand resources, demand response providers are given a significant financial incentive to dispatch demand resources with marginal costs exceeding LMPs. By dispatching higher-cost demand resources, lower-cost generating resources are displaced, which is inefficient and increases total resource costs in the energy market. In contrast, payment of the full LMP to generators does not produce inefficient results because generators have no bill savings to consider. To efficiently integrate demand resources into wholesale energy markets where all energy resources (generators and demand resources) are economically dispatched in order of increasing marginal costs, the financial incentives provided to demand resources must be made comparable and symmetric to the financial incentives provided to generation resources. Comparability and symmetry are achieved by netting out the bill savings from

[4] See NOPR at P 15. "Given that the LMP represents the marginal value of the resource being used by the RTO or ISO to balance supply and demand, it follows that the LMP should be paid to any resource clearing in the RTO's or ISO's energy market. In balancing supply and demand, a one megawatt reduction in demand is equivalent to a one megawatt increase in energy for purposes of meeting load requirements and maintaining a reliable electric system. The ISO or RTO is able to avoid dispatching suppliers with higher bids, be they generation or demand response, by accepting a lower bid to either reduce consumption or increase generation."

the full LMP payment made to a demand response provider for demand reductions, for demand resources that have reduced consumption relative to an estimated baseline.

Further, the proposed rule appears to be based on the notion that the goal of demand resource participation in the energy market is to produce the lowest LMPs.[5] While such a notion may be appealing from a short-term cost perspective, demand resource participation in energy markets should serve a greater purpose – that is, to contribute to a more reliable electrical energy system at the lowest total resource cost. The use of demand resources to achieve a least-cost electrical energy system is consistent with cost-effectiveness principles that have been developed and used by the states over the past three decades to guide demand resource planning, program design, and procurement.

The proposed rule also introduces baseline estimation and cost allocation problems, neither of which is addressed in the NOPR and both of which must be fully addressed before any final rules can be issued. The Commission's proposed requirement that those who reduce consumption of electricity from *expected levels* in response to price signals be paid the full LMP for such reductions *in all hours* creates a situation in which baseline estimation becomes a substantial challenge. There is no baseline estimation technique that can accurately and reliably estimate what a customer's energy usage pattern would have been if that customer responds frequently to price signals. With respect to cost allocation, the NOPR and proposed rule do not address how the costs resulting from payments to demand response providers ought to be allocated among market participants. Analysis conducted by ISO-NE found that some cost allocation schemes raise the overall costs charged to end-use consumers more than other schemes. While the payment rate for demand reductions was certainly the most

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[5] *See* NOPR at P 4. "Demand response acting as a resource in organized wholesale energy markets helps to improve the functioning and competitiveness of such markets in several ways. *First, demand response can lower prices.* When bid directly into the wholesale market, demand response – which results in lower demand – can result in lower clearing prices…. Demand response *can also lower prices* in the organized wholesale energy markets by reducing the need to dispatch higher-priced generation, or construct new generation, in an effort to satisfy load." (emphasis added)

controversial subject in the New England stakeholder process, allocation of these costs was a close second. Any final rule must address cost allocation. If the full-LMP construct is ultimately adopted the payments to demand response providers should be split into components for cost allocation purposes. The first component, the so-called LMP − G component, should be charged to the load-serving entity that is providing the energy; the second component, the excess over the LMP − G (*i.e.*, the "G" component), should be charged to network load (which is billed to the transmission owners) so that those entities can pass these excess costs through to all customers. Analysis conducted by ISO-NE indicates that splitting the costs between load-serving entities and transmission owners as described above minimizes cost impacts on final customers.

While the proposed rule creates inefficiencies, these inefficiencies can be corrected. These comments provide two alternatives. First, if the objective is payment of the full LMP in all hours in which the consumption of electricity was reduced from expected levels in response to price signals, then the day-ahead purchase of expected energy use, or some other advance purchase requirement, should be required. This is efficient, avoids the need for an estimated baseline, and avoids the need to allocate costs of payments to demand resources. If the Commission does not wish to impose a day-ahead or other advance purchase requirement for expected energy usage, then payment of the LMP net of the retail generation rate (i.e., "LMP – G") is appropriate. Costs of these payments should be borne by the associated load-serving entity whose load was reduced by the demand response. Both the "day-ahead purchase"[6] approach and the LMP – G approach are supported here and in other comments supported by ISO-NE.[7]

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[6] These comments will use the term "day-ahead purchase" to refer to the purchase of expected energy usage in the day-ahead energy market. However, this term should not be read to exclude other forms of advance purchase requirements. For example, efficient results could also be achieved through an advance purchase established in the retail market through a "demand subscription" service.

[7] *See* Hogan, William, "Demand Response Pricing in Organized Wholesale Markets," May 13, 2010, prepared for the Comments of the ISO/RTO Council in Response to the Federal Energy Regulatory Commission's Notice of

(continued...)

The remainder of these comments is structured as follows:

After summarizing the extensive New England stakeholder process addressing the issue of how to best achieve price-responsive demand in the region, ISO-NE's comments explain, first, why economic efficiency (which the states have called the "total resource cost" perspective) is superior to other criteria in ensuring maximum societal benefit from demand resources. The comments demonstrate how the proposed rule could create inefficiencies and increase total resource costs by allowing a demand response provider to benefit by dispatching a demand resource with a marginal cost exceeding the LMP. The comments also describe the day-ahead purchase approach to implementing the NOPR's "full LMP in all hours" payment principle that satisfies the total resource cost perspective. These comments build upon the work conducted by ISO-NE in the review of different approaches to achieve price-responsive demand in New England, as well as the extensive body of knowledge developed by the states and by the more recent National Action Plan for Energy Efficiency.

The comments also address an alternative approach to evaluating demand resource cost-effectiveness that has been proposed by some New England stakeholders. In the price-responsive demand stakeholder process initiated by ISO-NE, some stakeholders championed the view that the appropriate test of demand resource cost-effectiveness is the net impact of the demand resource on the rates paid by consumers. These stakeholders stated that a demand resource is cost-effective if the reduction in LMP caused by the dispatch of the demand resource is sufficient to offset the payment to such demand resources. This is not consistent with the principle of economic efficiency and has previously been rejected by most demand resource advocates and states in the development of state-

(...continued)
Proposed Rulemaking on Demand Response Compensation in Organized Wholesale Energy Markets, Docket No. RM10-17-000, May 13, 2010 (the "Hogan Paper"). *See also* Comments of the ISO-NE Internal Market Monitor being filed today in this proceeding.

sponsored demand resource programs. The primary test of resource cost-effectiveness should not be based on the distributional effects of resources on different stakeholders – rather, the primary test of resource cost-effectiveness ought to promote the use of the least-cost resources available at each moment in time.

ISO-NE's comments explain that, second, if the Commission does not agree with the day-ahead purchase requirement recommended by ISO-NE to ensure that full LMP is paid efficiently, or if the Commission agrees that the full LMP minus the retail generation rate should be paid for reductions from an estimated baseline, other policy issues will need to be considered by the Commission. These policy issues have been the subject of much discussion in the New England price-responsive demand stakeholder process and, after the question of what is the appropriate payment rate for demand resources, are the largest demand resource-specific market design issues facing the region. These issues include (1) the measurement and verification of demand reductions (*i.e.*, the customer baseline issue), and (2) the issue of how to allocate among market participants the costs associated with payments to demand response providers. In addition to ensuring that only cost-effective resources are scheduled and dispatched in the energy markets, the market rules filed in response to the final rule must require that the demand reductions produced by demand resources be accurately and reliably measured and verified, and that any resulting costs associated with payments to demand response resources should be allocated to market participants so as to minimize cost impacts on final consumers.

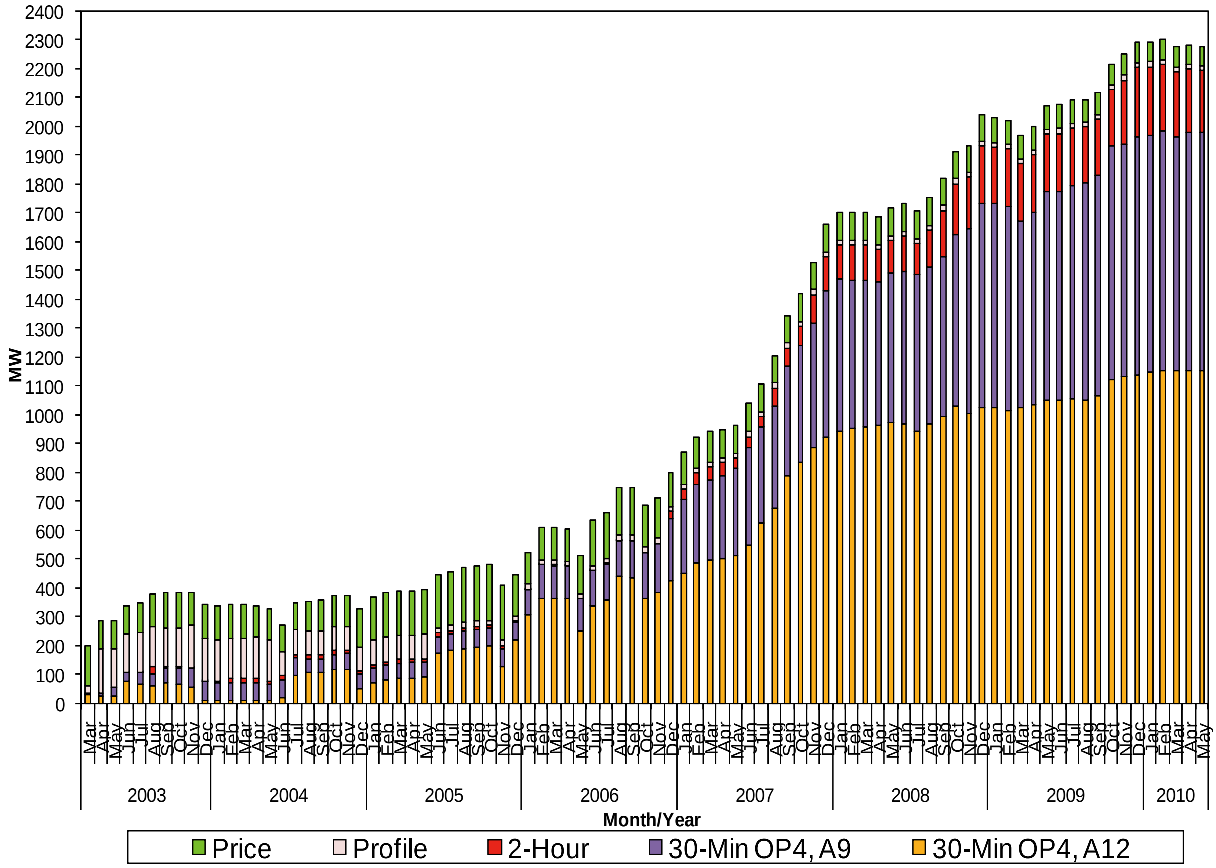
The comments explain why each of these requirements is necessary and the means by which each of these requirements can be met in order to achieve comparable treatment of resources participating in the energy markets. Because different approaches can achieve cost-effective results, the Commission should allow each ISO/RTO to work with its stakeholders to put in place market rules that best fit the circumstances of each region, subject to the requirements mentioned above.

II. BACKGROUND: ISO-NE AND THE NEW ENGLAND STAKEHOLDER PROCESS REGARDING PRICE-RESPONSIVE DEMAND

ISO-NE is the private, non-profit entity that serves as the RTO for New England. ISO-NE operates the New England bulk power system and administers New England's organized wholesale electricity market pursuant to ISO-NE Tariff, which is regulated by the Commission, and operating agreements with transmission owners. In its capacity as an RTO, ISO-NE has the responsibility to plan for and operate the New England bulk power system according to reliability standards established by the Northeast Power Coordinating Council and the North American Electric Reliability Corporation.

ISO-NE has implemented, in consultation with state utility regulators and other stakeholders, a variety of initiatives over the last several years that have been successful in "jump-starting" the demand resource industry. As a result, demand resource capability has grown substantially from the 200 MW that existed at the time ISO-NE implemented the major market restructuring in 2003 that introduced locational marginal pricing and multi-settlement markets (day-ahead and real-time). Figure 1 shows the increase in demand response capacity from the time the Load Response Program was implemented in March 2003 to the present.

Figure 1: ISO-NE Demand Response Resource Enrollment – March 2003 to April 2010[8]



Key drivers to the growth of demand resources in New England include:

- Establishing a Demand Resources Department in 2002;

[8] In Figure 1, "Price" refers to the energy-based Real-Time Price Response Program. All other programs indicated in Figure 1 are capacity-based programs. Figure 1 suggests that the enrollment of demand response resources in wholesale markets responds well to capacity price signals, but not to energy price signals. Similar to peakers, low-capacity factor demand response resources receive most of their value from capacity markets and not from energy markets because demand response resources are dispatched infrequently. Figure 1 shows that the escalation of demand response resource enrollment is coincident with the escalation of capacity prices – for example, demand response enrollment escalated substantially at the end of 2006/beginning of 2007 coincident with the start of the ICAP Transitional Period, the predecessor to the Forward Capacity Market, in which capacity prices of $3.05/kW-month increasing to $4.10/kW-month were paid to capacity resources including capacity-based demand response resources. Prior to this time, capacity prices were near zero. Meanwhile, participation in energy-based programs such as the Real-Time Price Response Programs steadily declined even though the program has not changed since its implementation in 2003. Today, less than 70 MW participate in the Real-Time Price Response Program. Many Real-Time Price Response Program participants switched their enrollment to programs receiving capacity payments as capacity prices escalated, suggesting that demand response participation in wholesale markets will be affected more by the design of capacity markets than energy markets.

- Opening energy markets that establish day-ahead and real-time Locational Marginal Prices ("LMPs") in 2003, which enabled load-serving entities to purchase energy on a price-sensitive basis;
- Implementing the existing Load Response Program, which is a broad menu of demand response programs addressing system reliability and price responsiveness, in 2003;
- Issuing a gap Request For Proposals to maintain reliability in Southwestern Connecticut from 2004 through 2008, through which ISO-NE administered contracts involving 260 MW of demand resources;
- Establishing a winter supplemental demand-response program in reaction to the potential loss of natural gas supplies that may have resulted from the devastation of Hurricanes Katrina and Rita;
- Implementing a Demand Response Reserves Pilot Program in 2006 to determine how small demand response resources (less than 5 MW) can provide a functionally equivalent reserve product;
- Commencing transition payments related to the Forward Capacity Market ("FCM") in 2006 for which demand response program participants, energy efficiency resources, and distributed generation resources were eligible; and
- Executing the first three Forward Capacity Auctions in which demand resources successfully competed with traditional generation resources. As a result, demand resources will provide up to approximately 2,900 MW of capacity annually to the New England region.

While much has been done to expand the region's demand resource capability, ISO-NE, NEPOOL and NECPUC believe that more can and should be done. In October 2008, ISO-NE initiated a stakeholder process to develop new approaches to achieve price-responsive demand ("PRD") in New England. The stakeholder process complied with the requirements of Section III.E.1.3 of the ISO New England Inc. Transmission, Markets and Services Tariff (the "ISO-NE Tariff")[9] and the Commission's 2008 order regarding ISO-NE's Day-Ahead Load Response Program ("DALRP").[10] That order required, *inter alia*, a review of the customer baseline methodology used in the DALRP.

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[9] Capitalized terms not otherwise defined herein have the meanings ascribed thereto in the ISO-NE Tariff.

[10] *ISO New England Inc.*, 123 FERC ¶ 61,266 (2008) (the "DALRP Order").

To encourage greater price responsiveness of demand resources in the region, ISO-NE had previously developed and implemented, in consultation with stakeholders, a Real-Time Price Response Program ("RTPRP") and the DALRP. Both programs were set to expire on May 31, 2010, coincident with the first Capacity Commitment Period of the Forward Capacity Market. Section III.E.1.3 required undertaking a stakeholder process to consider whether to allow the RTPRP and the DALRP to expire, continue the programs in their current form, or implement modified programs or other market designs.

To facilitate full consideration of the options for PRD, ISO-NE and NEPOOL made a filing, accepted by the Commission in October 2009,[11] extending the expiration date of the RTPRP and the DALRP from May 31, 2010 to May 31, 2012 and modifying the DALRP eligibility requirements to allow Real-Time Demand Response Assets (a type of Demand Resource participating in the Forward Capacity Market) to participate in the DALRP starting June 1, 2010.[12]

During the period between October 2008 and March 2010, the region's stakeholders and state regulators met over 24 times to develop new approaches for achieving PRD in the New England region. These efforts were reported to the Commission in a series of filings dated March 27, 2009, July 31, 2009, and December 18, 2009.[13] As explained in the December 18, 2009 report of ISO-NE and NEPOOL regarding the PRD stakeholder process, the process produced a design basis document ("DBD"), which:

> outlined two options available for market participants with demand resources to participate in the region's wholesale energy market, a "Supply-Side Option" and a

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[11] See delegated letter order issued in Docket No. ER09-1737-000 (October 29, 2009).

[12] The first Capacity Commitment Period of the Forward Capacity Market commences on June 1, 2010.

[13] *See* Report of ISO New England Inc. and New England Power Pool Regarding Treatment of Price-Responsive Demand in the New England Electricity Markets, Docket No. ER08-830-000, filed March 27, 2009, July 31, 2009, and December 18, 2009.

> "Demand-Side Option." As described in the PRD DBD, under the Demand-Side Option, Market Participants could purchase a voluntary wholesale product in which the energy component is priced on an hourly, real-time basis. Under the Supply- Side Option, Market Participants could offer load reductions into the wholesale energy markets in a manner similar to supply offers of generation resources, which would be integrated into the market-clearing, price-setting, and resource-scheduling algorithm. In stakeholder deliberations, the major area of disagreement regarding the Demand-Side Option concerned the pricing of capacity in the voluntary wholesale product. Some of the major areas of disagreement regarding the Supply-Side Option concerned the payment levels for demand resources, the thresholds for participation, and allocation of costs resulting from payments to suppliers of demand resources.[14]

In response to the December 18, 2009 filing, the Consumer Demand Response Initiative ("CDRI") submitted a request to the Commission for policy guidance with respect to the Supply-Side Option being discussed in the New England stakeholder process. In ISO-NE's answer to the CDRI request, ISO-NE informed the Commission of its plan to prepare an initial set of market rules for PRD (the "Phase 1" rules), vet them through the stakeholder process, and file them with the Commission under Section 205 of the Federal Power Act on or before April 30, 2010.[15] Further, ISO-NE planned to file a second set of rules (the "Phase 2" rules) reflecting the Commission's rulings on the Phase 1 rules. The Phase 2 rules would have built upon the Phase 1 rules and would have completed the set of market rules needed to enable demand response resources to participate directly in the supply-side of the New England energy markets.[16] The Phase 1 rules would have addressed product definition, eligibility, payment rate and cost allocation. The Phase 2 rules would have addressed demand reduction offer parameters, real-time scheduling and dispatch of demand resources, asset enrollment requirements, measurement

[14] *See* Report of ISO New England Inc. and New England Power Pool Regarding Treatment of Price-Responsive Demand in the New England Electricity Markets, Docket No. ER08-830-000 (filed December 18, 2009).

[15] *See* filing of ISO-NE and NEPOOL in Docket No. ER08-830-000, at 6 (February 12, 2010).

[16] *Id*., at 6-7.

and verification of demand reductions, rights and obligations of demand resources, and internal market monitoring review of demand reduction offers.

The NEPOOL Markets Committee was preparing to vote on ISO-NE's proposed Phase 1 rules at its March 23, 2010 meeting. Just prior to that meeting, however, the Commission initiated the NOPR on Demand Response Compensation in Organized Wholesale Energy Markets. The NOPR addresses some of the key issues that the Phase 1 rules would have addressed, particularly the payment rate and participation threshold issue. Because the Commission will be addressing these key issues generically in the NOPR proceeding, ISO-NE withdrew its request for a stakeholder vote on the proposed Phase 1 market rule language.

As this background indicates, ISO-NE's comments in this proceeding have been informed by almost 19 months of analysis and discussions with the region's stakeholders and state regulators on issues concerning the participation of demand resources in the energy markets.

III. APPROACHES TO ENSURING COST-EFFECTIVENESS OF DEMAND RESOURCES IN THE ENERGY MARKETS

A. The ISO-NE Energy Market is Designed to Achieve Economic Efficiency by Minimizing Total Resource Costs

The wholesale energy market administered by ISO-NE is designed to achieve economically-efficient outcomes by dispatching the least expensive resources available to meet the demand for energy, subject to reliability constraints.[17] To achieve this, resources are scheduled in the order of the lowest to highest cost of supply – *i.e.*, those with the lowest operating costs should be scheduled first, with increasingly higher cost resources being scheduled next to meet increasing levels of consumption. To determine generator operating

[17] See Market Rule 1, Section III.1.7.6 (a). Market Rule 1 is Section III of the ISO-NE Tariff.

costs for the purposes of scheduling, generators submit supply offers to ISO-NE – *i.e.*, the price at which the generator is willing to supply an amount of energy to the wholesale energy market. Competition among generators drives the price of these supply offers to reflect each generator's marginal cost of production.[18]

To achieve comparability between generators and demand resources participating in the energy markets, supply offers submitted by demand resources into the wholesale energy market must also reflect the marginal cost of each resource. In this way, the costs of all resources (generators and demand resources) can be compared and scheduled such that economic efficiency is maintained – that is, the lowest cost resources are used first and most frequently. If a demand resource has a lower marginal cost than a generator, that demand resource should be scheduled first and more frequently than that generator. While the marginal cost of a generator is driven primarily by fuel and variable operating and maintenance costs, the marginal cost of a demand resource is driven by the marginal opportunity cost of consumption, which could be driven by one or more factors such as:

- The marginal cost of a distributed generator operated by the consumer (*i.e.*, the fuel and variable operating and maintenance costs of the distributed generator);
- The marginal cost of a substitute form of energy (e.g., gas-fired steam chillers instead of electricity for air conditioning);
- The marginal cost of implementing an energy efficiency, load control, or load shifting strategy, or

[18] In a competitive market design in which the market-clearing price is set by the last accepted supply offer used to meet consumption, suppliers have a strong incentive to submit supply offers equaling their true marginal operating costs. Because only those generators that are scheduled and dispatched earn energy revenues, generators submitting supply offers that exceed their marginal operating costs – in an attempt perhaps to increase profit by inflating prices above costs – run the risk of being out-competed by other generators that submit lower-priced offers. Generators submitting above-cost supply offers in a competitive market, therefore, reduce their opportunity to earn revenue. On the other hand, a generator that submits a supply offer that is less than its marginal operating cost – in an attempt perhaps to out-compete other generators and be dispatched more frequently to increase its chances of earning greater revenues – runs the risk of being scheduled and dispatched when the market-clearing price is less than its operating costs, which would erode its profits.

- The marginal value that the consumer places on electricity consumption that is foregone when the consumer interrupts its end-use energy consumption.

B. Economic Efficiency is the Basis by Which States Evaluate Demand Resource Planning, Program Design, and Procurement

The use of economic efficiency as the basis for demand resource program design is consistent with the resource cost-effectiveness principles that have been developed by state regulatory bodies over the past three decades to guide demand resource planning, program design and procurement. Consumer advocates have similarly emphasized that, when a demand resource is "fairly projected to be the *least cost resource*, it should be the preferred resource in a prudent resource planning and acquisition practice."[19] The New England states have been leaders in the development of regulatory policies guiding the development of demand resources and the design of demand resource programs based on the principle of cost-effectiveness. Today, some New England states are committed to capturing *all cost-effective* demand resources within fairly aggressive timeframes.[20] Also, the recent National Action Plan for Energy Efficiency – developed by a group of over 60 gas and electric utilities, state agencies, energy consumers, energy service providers, and environmental/energy efficiency organizations under the auspices of the U.S. Department of Energy and the U.S. Environmental Protection Agency – has as its primary goal the achievement of "*all cost-effective* energy efficiency by 2025."[21] The approach utilized in the development of the National Action Plan

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[19] *See* The National Association of State Utility Consumer Advocates Principles for Energy Efficiency Programs, Resolution 2009 – 02 , *available at* http://www.nasuca.org/archive/res/index.resoltuions.php (emphasis added).

[20] For example, see "2010-2012 Massachusetts Joint Statewide Three-Year Electric Energy Efficiency Plan," October 29, 2009, available at http://www.ma-eeac.org/docs/DPU-filing/ElectricPlanFinalOct09.pdf. Page 11 notes that "…this Plan seeks to capture *all available cost-effective energy efficiency* for the three-year period beginning January 1, 2010 with the consideration of factors and concerns noted at the Council, including, but not limited to, bill impacts, environmental benefits, and the need for a reasonable ramp-up schedule" (emphasis added).

[21] *See* http://www.epa.gov/cleanenergy/energy-programs/napee/index.html. ISO-NE was a member of the leadership group.

for Energy Efficiency is being considered by the Commission for the development of the National Action Plan on Demand Response.[22]

Tests used by demand resource program administrators to evaluate the cost-effectiveness of demand resources in the electricity industry are based on the fundamental principle that a demand resource is cost effective when its cost is less than the cost of producing an equivalent amount of energy. That is, a demand resource participating in the energy market is cost-effective when its marginal cost is less than the ***"avoided cost of energy."*** For example, the total resource cost test ("TRC"), the most commonly used primary metric of demand resource cost-effectiveness among the states, is based on this fundamental principle.[23] In a competitive energy market such as the one administered by ISO-NE, the avoided cost of energy equals the LMP.

The TRC perspective is consistent with the economic efficiency principles supported by ISO-NE for the design of the energy market in general, and for the integration of demand resources into the energy market in particular. In New England, Maine, Massachusetts, New Hampshire and Vermont use the TRC or the societal cost test[24] as the primary test of demand resource cost-effectiveness.[25] Connecticut uses the TRC as a secondary consideration,[26] though more recent information suggests that Connecticut is now using the societal cost variant of the

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[22] *See* National Action Plan on Demand Response, Federal Energy Regulatory Commission Staff, Docket No. AD09-10, March 11, 2010, at pp. 21, 23, and 81-82.

[23] See the paper developed for the National Action Plan for Energy Efficiency: *Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers*, Energy and Environmental Economics, Inc. and Regulatory Assistance Project at pp. ES-2 and 5-1 (2008), *available at* http://www.epa.gov/cleanenergy/documents/cost-effectiveness.pdf ("National Action Plan for Energy Efficiency").

[24] The societal cost test ("SCT"), or simply the "societal test," is a variant of the TRC that includes consideration of non-energy benefits and costs that are not priced in the market such as environmental externalities.

[25] National Action Plan for Energy Efficiency, at p. 5-1.

[26] In Connecticut, demand resource cost-effectiveness is based primarily on the program administrator cost test ("PACT"), which examines the costs and benefits of a demand resource program from the perspective of the entity implementing the program (*e.g.*, utility, government agency, nonprofit, or other third party). National Action Plan for Energy Efficiency, at pp. 5-1, 5-2 and 6-2.

TRC approach as its primary test of demand resource cost-effectiveness.[27] Rhode Island's primary cost-effectiveness test is not specified.[28]

C. The Proposed Rule Will Produce Economic Inefficiencies in the Energy Markets

Because a demand resource simultaneously affects both supply and demand, a demand response provider working with a consumer can receive both a payment for reducing demand and accrue savings in its energy bill for the same reduced energy consumption. If the market design does not take into account the combined impact of both incentives in its construction, a demand response provider might earn full-LMP payments for demand reductions while the customer simultaneously accrues energy bill savings for the same demand reductions. The total financial benefit in this case from dispatching a demand resource exceeds the LMP. This makes it profitable to dispatch a resource with a marginal cost exceeding the LMP, which is inefficient and raises total resource costs. Recognizing that both incentive payments and bill savings are relevant to the decision of a demand response provider to reduce consumption is essential to achieving an efficient market design.

Demand response providers would consider the sum of incentive payments from the market administrator and savings in the consumer's energy bill resulting from reductions in energy consumption. The demand response provider would compare this "double benefit" to the marginal cost of its demand resource in its decision to dispatch its demand resource capability; the demand response provider would dispatch its demand resource capability if total benefits exceed the costs. The double benefit produced by a full-LMP payment approach gives demand

[27] *See* Integrated Resource Plan for Connecticut, January 1, 2010. Prepared by: The Brattle Group, Connecticut Light and Power, and United Illuminating Company.

[28] National Action Plan for Energy Efficiency, at p. 5-1.

response providers the incentive to dispatch a demand resource whose marginal cost exceeds the LMP. In a report shared with the region's stakeholders and state utility regulators in February 2009, ISO-NE found that approaches that pay full LMP without requiring the advance purchase of power could result in high-cost demand resources displacing low-cost resource available in the wholesale market:

> The combination of bill savings and payments received by [demand response] program participants gives them the incentive to defer consumption whose value may exceed the LMP, and/or to switch to alternative energy sources that cost more than the LMP. Such a program design, therefore, results in an inefficient market outcome that inefficiently utilizes society's resources. For example, if the retail rate is $80/MWh and the LMP is $90/MWh, a customer who is paid the LMP to reduce consumption would be able to earn an additional $20/MWh by using a $150/MWh on-site generator ($80 bill savings plus $90 payments - $150 generator = $20 net gain) to reduce its net metered load. Thus, the program incentive payment results in an inefficient utilization of society's resources by encouraging the use of a more expensive $150/MWh resource even though a less expensive $90/MWh resource in the wholesale market was available to serve the customer's load. This example applies whether an on-site generator is used or consumption valued at the same $150/MWh is foregone.[29]

In contrast to demand resources, wholesale generators dispatched in the energy market receive only the LMP since they do not accrue bill savings. Under a policy of full-LMP payment for both generated energy and demand reductions, generators receive the *single* benefit of the full-LMP payment whereas demand response providers receive the *double* benefit of the full-LMP payment and bill savings. In this sense, demand resources and wholesale generators are fundamentally different, warranting different treatment in the energy markets to achieve comparable and symmetric incentives that minimize total resource costs. Failing to recognize the fundamental difference between a wholesale generator and a demand resource in the design

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[29] *See* http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2009/feb202009/a2_iso_status_report_prd_draft_version_1_02_13_09.pdf, p. 8. On the other hand, if the customer first purchased its expected energy requirements at, say, the $80/MWh retail rate, the customer's decision to dispatch its demand resource would be based on a comparison between the full LMP and the marginal cost of its demand resource – *i.e.*, the customer would compare the cost of its demand resource to the LMP in a manner comparable to all other resources participating in the energy market. Under these circumstances, the customer would not dispatch its demand resource, which is the efficient solution in this case, since its cost at $150/MWh would be higher than the LMP at $90/MWh.

of incentive payments for demand response would result in the inefficient utilization of society's resources under a full-LMP payment approach – *i.e.,* higher-cost demand resources would displace lower-cost generation resources available at that time. Such a result violates the fundamental principle that a demand resource is cost-effective only when its cost is less than the avoided cost of energy (*i.e.,* the LMP).

D. Example of Efficient and Inefficient Market Designs and Outcomes with Payment of the Full LMP

The following examples illustrate how economically-efficient wholesale market rules can be designed – which is consistent with the TRC perspective – to support the fundamental principle that the least expensive resources (whether generation or demand response) should be scheduled in the wholesale energy market. These cases show that:

- Payments for load reductions from demand resources are justified to drive down total resource costs when the marginal cost of a demand resource is less than the LMP. Conversely, payments for load reductions from demand resources are not justified when the marginal cost of a demand resource exceeds the LMP because such payments would raise total resource costs;

- The primary motivation of a wholesale generator is to earn revenue in excess of costs, while the primary motivation of a participant with a demand resource is to reduce its net energy bill.

- If a participant with a demand resource is not required to purchase its expected energy requirements at, for example, the day-ahead LMP, but is paid the full LMP for reductions in expected energy use, the participant is presented with the opportunity to reduce its net energy bill by dispatching a high-cost demand resource and displacing lower-cost resources available on the grid. That is, the private incentive presented to the participant rewards behavior that is not consistent with an efficient market outcome.

- To achieve comparable treatment of all resources (generation and demand resources) in the energy markets in which all resources are dispatched in economic-merit order, participants with demand resources must purchase their consumer's expected energy consumption at, for example, the day-ahead LMP.

The following examples assume that a 10 MW consumer decides to participate in the wholesale energy market by utilizing its demand resource capability.[30] This market participant determines that it is not worth buying energy if the cost of that energy exceeds $200/MWh. This $200/MWh figure could be the result of an evaluation of the marginal opportunity cost of the energy, which could be based on the foregone value of energy consumption, the cost of a substitute form of energy, the marginal cost of implementing an energy efficiency measure, a load control device or a load shifting/management strategy, or the marginal cost of distributed generation with a dispatch cost (*i.e.*, a fuel and variable operations and maintenance cost) of $200/MWh.[31] Further assume that the participant is able to purchase energy (either directly or through a retail customer aggregator) from the day-ahead energy market at the day-ahead LMP, which is $100/MWh in these examples.

Table 1 shows how this participant would behave depending on how incentive payments for PRD are designed. The examples include: no incentive payment (Base Case), incentive payment with day-ahead purchase (Case 1), incentive payment with day-ahead purchase and a lower real-time LMP (Case 2), and incentive payment with no day-ahead purchase (Case 3). In all cases other than the Base Case, the incentive payment is the full real-time LMP. For simplicity, Table 1 illustrates only a single hour, though these results could be generalized across numerous hours.

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[30] This consumer could participate in the wholesale market either directly or through an aggregator. The examples that follow do not depend on how the consumer participates in the wholesale market.

[31] While marginal costs may be difficult to estimate and may shift over time, it is difficult to imagine a business consumer willing to pay any price for an input to its production process – at some point the price of an input could be so high that it eliminates its profits, so a successful consumer would stop buying such a high-priced input and seek lower-priced alternatives. With respect to electricity, a successful consumer (or an agent working on behalf of the consumer) would specify in the day-ahead energy market the most it would be willing to pay for energy based on the marginal cost of the demand resource under the consumer's control, which also happens to equal the consumer's marginal opportunity cost of energy. In this way, the consumer remains in control of its production costs and ultimately its profits.

Table 1: Impact of Demand Response Incentives on Price-Responsive Behavior and Total Resource Costs

Scenario	Was DR dispatched?	Day-Ahead LMP ($/MWh)	Real-Time LMP ($/MWh)	DR Marginal Cost ($/MWh)	Real-Time Energy Use (MWh)	Day-Ahead Energy Bill ($)	Cost of Dispatching DR ($)	DR Payment @ Full RT LMP ($)	Net Energy Bill ($)	Total Resource Cost ($)
Base Case	No	$100	$300	$200	10	$1,000	$0	$0	$1,000	$3,000
Case 1	Yes	$100	$300	$200	0	$1,000	$2,000	$3,000	$0	$2,000
Case 2	No	$100	$150	$200	10	$1,000	$0	$0	$1,000	$1,500
Case 3	Yes	$100	$150	$200	0	$0	$2,000	$1,500	$500	$2,000

a) Base Case – No Incentive Payment is Inefficient

The Base Case – *i.e.*, the first line of Table 1 – assumes no incentive payments for price-responsive demand and a real-time LMP of $300/MWh. Given the lack of incentive payments for dispatching its demand resource, the market participant is more than willing to purchase all of its expected energy requirements from the day-ahead energy market, which cleared at a $100/MWh, than to dispatch its demand resource at a cost of $200/MWh.[32] Accordingly, the participant places 10 MWh of load on the grid and is billed $1,000 (*i.e.*, 10 MWh times the day-ahead price of $100/MWh) – note that in the absence of any offsetting incentive payments (at the full real-time LMP or otherwise) the participant's energy bill would have been $2,000 if it dispatched its demand resource at a cost of $200/MWh (*i.e.*, 10 MWh times $200/MWh demand resource marginal cost). Because the participant does not dispatch its demand resource, there are no demand resource costs (and, of course, no incentive payments). The participant's net energy bill is $1,000.

[32] According to this example, the participant would submit a Demand Bid into the Day-Ahead Market to purchase 10 MWh of energy at a price not to exceed $200/MWh. The fact that the day-ahead LMP clears at a price far lower than its Demand Bid accrues to the benefit of the customer.

However, Table 1 also shows that the total resource cost associated with the participant consuming 10 MWh in this hour is $3,000. This is because the real-time LMP, which represents the actual marginal or avoidable cost of generation, was $300/MWh. Meanwhile, a less expensive resource was available – *i.e.*, the participant's $200/MWh demand resource. The $200/MWh demand resource could have been used instead of the $300/MWh resource on the grid. Had the lower cost demand resource been used, total resource costs would have been $2,000 instead of $3,000. Therefore, the Base Case shows that not using the demand resource under these circumstances violates the fundamental cost-effectiveness principle – *i.e.*, if it is less expensive to save energy than to produce it, society benefits from saving the energy. However, with no incentive payments, the participant will consume high-cost energy from the grid even though the cost of saving energy is less than the avoided cost of energy. The Base Case indicates that the energy market should make payments to participants with demand resources so as to provide incentives for the utilization of cost-effective resources.

b) Case 1 – Incentive Payment with Day-Ahead Purchase is Efficient

In contrast to the Base Case, Case 1 gives the market participant the opportunity to receive the full real-time LMP for dispatching its demand resource. With this incentive payment, the net energy bill paid by the participant is significantly lower when the participant dispatches its demand resource. As in the Base Case, the participant purchases its expected energy requirements at the day-ahead LMP at a cost of $1,000. By dispatching its demand resource, the participant incurs a cost of $2,000; however, the participant also receives the full real-time LMP for reducing its demand in real time. By receiving the full real-time LMP for its reduced demand, the participant receives $3,000 of incentive payments. Therefore, the participant reduces its net energy bill to $0, which is far less than the $1,000 energy bill it would have paid as shown in the Base Case if it did not dispatch its demand resource.

Most importantly, total resource costs are lower in Case 1 than in the Base Case – total resource costs are $2,000 in Case 1, which is $1,000 lower than in the Base Case. This is because the marginal cost of the demand resource at $200/MWh is less expensive than the $300/MWh cost of the marginal resource setting price in the wholesale energy market. That is, using the demand resource under these circumstances is consistent with the TRC perspective and is cost-effective – the marginal cost of the demand resource is less than the marginal cost of the resource setting price in the wholesale energy market. Therefore, the provision of the full LMP incentive payment induces the participant to dispatch a cost-effective resource, resulting in a reduction in total resource costs.

c) Case 2 – Incentive Payment with Day-Ahead Purchase Leads to Efficient Dispatch

Case 2 shows what happens when the real-time LMP changes to $150/MWh, all other things remaining the same as in Case 1. As in Case 1, the participant purchases its expected energy requirements at the day-ahead LMP, which clears at $100/MWh. Further, the participant is offered to be paid the full real-time LMP for any energy it does not consume in real time. However, since the real-time LMP is $150/MWh, it chooses not to dispatch its demand resource. By not dispatching its demand resource, Case 2 shows that the participant's net energy bill for the hour is $1,000. Had the participant dispatched its demand response resource, the participant would have raised its net energy bill to $1,500. That is, the participant would have paid $1,000 for its cleared Day-Ahead Demand Bid, would have incurred a cost of $2,000 for dispatching its demand resource, and would have received an incentive payment of only $1,500 resulting in a net energy bill of $1,500 (*i.e.*, $1,000 +

$2,000 - $1,500 = $1,500). Presumably, participants would not voluntarily raise their net energy bills, so they would not dispatch a $200/MWh demand resource in this instance. However, not dispatching the demand resource in this instance is the right solution from a TRC perspective. The cost of dispatching the resource was $200/MWh, but the cost of the marginal resource on the system was $150/MWh – *i.e.*, the marginal cost of the demand resource exceeds the avoided cost of energy, so it is not cost-effective to dispatch the demand resource in this instance.

Some stakeholders may argue that a participant should be able to offer demand reductions into the wholesale energy market as a supply resource without needing to purchase its expected energy requirements from the day-ahead energy market or from an aggregator securing energy from the wholesale energy market on its behalf. That approach, however, would not comply with the TRC perspective, as demonstrated in the discussion of Case 3, below.

d) Case 3 – Incentive Payment without Day-Ahead Purchase is Inefficient

Case 3 shows what would happen if a market participant in a price-responsive demand program were not required to purchase its expected energy requirements in the day-ahead energy market (or from an aggregator purchasing energy from the wholesale energy market on behalf of the participant). By not requiring the participant to purchase its expected energy requirements from the day-ahead energy market, its day-ahead energy bill is $0. Additionally, by dispatching its demand resource and demonstrating a demand reduction of 10 MWh, the participant receives a payment at the full real-time LMP equaling $1,500.   However, the participant incurs a cost of $200/MWh for dispatching its demand resource for a total cost of $2,000. Under this approach, Case 3 shows that the participant's net energy bill (*i.e.*, the difference between the $2,000 cost for dispatching its demand resource and the $1,500 incentive payment) is $500.

For obvious reasons, a wholesale generator would refrain from submitting a supply offer that would obligate it to produce energy at a cost exceeding its revenue. While Case 3 shows that the cost of dispatching the demand resource is greater than the incentive payment, it would be incorrect to assume that the participant with a demand resource would behave like a wholesale generator – while generators do not have the incentive to dispatch resources whose cost exceeds the LMP, *participants with demand resources that are not required to purchase their expected energy requirements will have an incentive to dispatch a demand resource whose cost exceeds the LMP.* Note that the customer's net energy bill in Case 3 is half that of Case 2 with the same day-ahead and real-time prices. Whereas the primary motivation of a wholesale generator is to earn revenue that exceeds its cost, *the primary motivation of a participant with a demand resource is to reduce its net energy bill.* Therefore, if a participant with a demand resource is not required to purchase its expected energy requirements, the participant is presented with the opportunity to reduce its net energy bill by dispatching a high-cost demand resource and displacing lower-cost resources available on the grid.[33]

The approach illustrated in Case 3, therefore, disrupts the comparable treatment of resources in the energy markets. While wholesale energy markets schedule the dispatch of generation resources in economic-merit order – *i.e.*, in the order of increasing resource marginal costs – paying full LMP without requiring a participant with a demand resource to purchase its expected energy requirements could very well result in a high-cost demand resource being dispatched before a lower-cost generation resource.[34] Further, and most importantly, Case 3 shows that dispatching the demand resource increases total resource costs from $1,500 to $2,000. Therefore, not requiring the participant to

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[33] In fact, the participant would have the incentive to dispatch a demand resource that costs up to $250/MWh (even though the real-time LMP is only $150/MWh) all other things equal. The participant would have the incentive to dispatch a demand resource as long as the difference between the cost of the demand resource and the real-time LMP did not exceed the day-ahead LMP.

[34] If the real-time LMP is lower than the day-ahead LMP, the participant would certainly not be encouraged to dispatch its demand resource in real time, but may instead decide to take advantage of the low real-time price and consume more energy at the lower price, which increases the consumer's value.

purchase its expected energy requirements gives the participant the incentive to dispatch demand resources that are not cost-effective relative to the marginal resource available on the grid, resulting in higher total resource costs. That is, when a participant is not required to purchase its expected energy requirements but is paid the full LMP for reductions in expected energy use, the private incentive presented to the participant rewards behavior that is not consistent with an efficient market outcome.

To avoid this perverse outcome, participants must purchase their expected energy consumption at the day-ahead LMP or from a retail customer aggregator purchasing energy from the wholesale energy market on behalf of the participant. By requiring that a participant purchase its expected energy consumption, participants would improve their financial position only by dispatching a demand resource that is cost effective. Conversely, not requiring participants to purchase their expected energy consumption gives participants the incentive to take actions that increase total resource costs, which violates the fundamental test of demand resource cost-effectiveness.

E. Basing Resource Cost-Effectiveness on LMP Reduction is Inconsistent with Economic Efficiency Principles, and is Inconsistent with the Views of Most States on What Constitutes a Proper Economic Analysis

Some stakeholders may argue that the appropriate test of demand resource cost-effectiveness should be based on the net impact of the demand resource on the rates paid by consumers. During the price-responsive demand stakeholder process initiated by ISO-NE in October 2008, some stakeholders put forth the view that a demand resource was cost-effective if and only if the reduction in LMPs caused by the demand resource was sufficient to offset the payments to demand response providers. This should not be the basis for demand resource compensation because it is inconsistent with the principle of economic efficiency.

This perspective, where cost-effectiveness of demand-side actions is based on the net financial impact of such actions on all other consumers, was first defined in February 1983 with the publication of the "Standard Practice for Cost-Benefit Analysis of Conservation and Load Management Programs."[35] This perspective is known to the demand-side management community as the "ratepayer impact measure" or "RIM" test, which is also known to practitioners as the "non-participant" or "no-losers" test. Under the RIM perspective, cost-effectiveness is judged on whether the demand resource raises or lowers electricity rates to consumers – that is, a demand resource is cost-effective if it lowers electricity rates and is not cost-effective if it raises rates. In a competitive wholesale market setting, a RIM approach might examine the impact of the demand resource on LMPs relative to the payments made to demand response providers – if the reduction in LMPs offset the payments to demand response providers, this should translate eventually to lower retail electricity rates to all consumers, at least in the short-run. If the reduction in LMPs is sufficient to offset the additional cost of demand resources charged to consumers – particularly to those consumers that do not implement demand resources (*i.e.*, the non-participants) – then the demand resource is considered to be cost-effective.

While the RIM perspective has obvious appeal to consumers of energy, many demand resource advocates and states have rejected the RIM test as a primary test of demand resource cost-effectiveness.[36] The only jurisdiction that reportedly uses the RIM perspective as the primary test of demand resource cost effectiveness is Florida.[37] In New England, only New Hampshire considers the RIM perspective in its review of proposed demand resource programs, though it uses the TRC perspective as its primary consideration.[38] The primary test of resource cost-effectiveness should not be based on the distributional effects of resources on different

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[35] *See* California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects, July 2002, at p. 1, *available at* http://drrc.lbl.gov/pubs/CA-SPManual-7-02.pdf.

[36] National Action Plan for Energy Efficiency, at pp. 5-1, 5-2.

[37] *Id.* at p. 5-1.

[38] *Id.* at p. 5-2.

stakeholders[39] – rather, the primary test of resource cost-effectiveness ought to promote the use of the least-cost resources available at each moment in time. Moreover, a RIM perspective is not consistent with the treatment of other resources participating in the energy markets. For example, generation is not dispatched and paid for only when the generation reduces LMPs – generation is dispatched and paid for when it is cost-effective.

F. RIM Has Unintended Consequences and is Likely to be Counterproductive in the Long-Run

In the current debate, however, some of the stakeholders will advocate a return to the RIM perspective as a measure of cost-effectiveness for demand resources, particularly for demand response resources. The RIM perspective favors low-capacity factor demand response resources[40] that dispatch their demand reduction capability for a few high-priced hours during a season or year. These demand response resources have a relatively low impact on overall energy consumption compared to energy efficiency and base-load distributed generation demand resources. However, the RIM perspective tends to be unfavorable to higher capacity factor resources, such as energy efficiency, that may be more cost-effective from a total resource cost perspective.

Additionally, the Commission's proposed policy that the full LMP be paid in all hours

[39] While the TRC or the SCT is used as the primary test of demand resource cost-effectiveness in most states, some states use the RIM perspective to modify demand response program design to address bill impacts on non-participants. For example, see the recent recommendations of the Integrated Resource Plan for Connecticut, January 1, 2010. While an "All Achievable Cost-Effective" demand resource strategy utilizing a societal cost approach was identified, the plan recommended a more moderate demand resource expansion strategy to address rate impacts on non-participants. The plan found that capturing all cost-effective demand resources would raise the overall rates of non-participants whereas a more moderate and targeted demand resource strategy would reduce generation service charges offsetting the increase in charges to acquire the cost-effective demand resources. *Id*., pp. I-5 – I-6.

[40] A resource with a low-capacity factor is one that produces little output for its size. The capacity factor of a demand resource is defined as: (MWh of demand reduction produced by the demand resource during the season or year) ÷ (MW demand reduction capacity of the demand resource x hours in the season or year).

creates a situation in which demand resources may interrupt demand at times when LMPs are low and the supply curve is relatively flat. A reduction in demand during such hours has little or no impact on LMPs. A RIM perspective, therefore, would find that demand reductions during such hours are not cost-effective. Accordingly, the RIM perspective does not support payment of full LMP in all hours. ISO-NE's recommendation that cost-effectiveness judged by a TRC perspective would not limit the dispatch of demand resources to high-priced hours. Rather, dispatch would occur whenever a resource is cost-effective (*i.e.*, when the marginal cost of the resource is less than the LMP).

In addition to encouraging the dispatch of resources that are not cost-effective, endorsing the RIM perspective because of its focus on reducing LMPs could have numerous unintended consequences such as:

- **LMP reductions are likely to be transient at best.** If the financial returns of suppliers (generation and demand resources) are depressed by suppressing LMPs below market clearing levels in the short-run, existing supply would be encouraged to exit the market and/or new supply would be discouraged from entering the market.[41] As supply becomes more constrained, LMPs would rise. Analysis by ISO-NE demonstrated that, ultimately, any consumer gains from suppression of LMPs in the short-run will result in higher prices and costs in the long-run as investors adjust their resource portfolios over time in response to prices.[42]

- **LMP reductions result in higher capacity payments during Shortage Events.** The interaction between the Forward Capacity Market and the energy market in New England tends to neutralize the savings to consumers from LMP reductions. In the Forward Capacity Market, LMP reductions during high-priced Shortage Events are offset by the Peak Energy Rent ("PER") payment adjustment to capacity resources. That is, when LMPs go down, capacity payments to capacity resources go up because the PER deduction to capacity payments is reduced.

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[41] See Allcott, Hunt (2009). "The Smart Grid, Entry, and Imperfect Competition in Electricity Markets." MIT Department of Economics and MIT Energy Initiative; NYU Department of Economics.

[42] *See* http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2009/feb202009/a2_iso_status_report_prd_draft_version_1_02_13_09.pdf, at pp. 40-43.

- **Discouraging investment in renewable generation technologies that have low or no fuel costs.** A large portion of net revenues earned by many generation projects utilizing renewable resources (*e.g.*, wind, solar, etc.) is in the form of "energy rents" – *i.e.*, the difference between the LMP and the cost of production. Depressing LMPs below efficient market clearing levels would reduce the earnings of such resources. Because these resources have relatively low capacity values, a shift in available revenues from the energy market to the capacity market would reduce the overall incentive to invest in these resources.

- **Non-comparable treatment of generation technologies that reduce LMPs.** Paying demand resources on the basis of LMP reduction discriminates against other types of resources that also reduce LMPs. For example, generators with low or zero short-run marginal costs (*e.g*., nuclear resources and certain renewable resources such as wind) reduce the LMP when they operate. Allowing demand resources to receive both bill savings and full-LMP payment because of their LMP-reducing attributes discriminates against generators that receive only the LMP even though those generators also reduce LMPs across many hours.

- **Reducing the demand of some consumers below optimal levels.** By paying some consumers to reduce demand in order to reduce LMPs, the consumers receiving incentive payments may be encouraged to take economically inefficient actions such as deferring energy consumption the value of which exceeds the cost of producing energy.

- **Increasing the demand of other consumers above optimal levels.** If LMPs are reduced by paying some consumers to reduce demand, the remaining consumers who experience a price decrease are encouraged to increase demand, which negates at least some of the demand reductions achieved by the program.

- **Discouraging investment in higher capacity factor demand resources.** Depressing LMPs below market clearing levels by encouraging the use of demand response resources with marginal costs exceeding LMPs reduces the avoided cost of energy, which in turn reduces the cost-effectiveness of higher capacity factor demand resources such as energy efficiency and base-load distributed generation. As indicated in the National Action Plan for Energy Efficiency:

> The most common primary measurement of energy efficiency cost-effectiveness is the TRC [total resource cost], followed closely by the SCT [societal cost test]. A positive TRC result indicates that the program will produce a net reduction in energy costs in the utility service territory over the lifetime of the program. The distributional tests (PCT [participant cost test], PACT [program administrator cost test], and RIM) are then used to indicate how different stakeholders are affected. *Historically, reliance on the RIM test has limited energy efficiency investment, as it is the most restrictive of the five cost-effectiveness tests.*[43]

[43] National Action Plan for Energy Efficiency, at pp. ES-2 (emphasis added).

Accordingly, ISO-NE strongly urges the Commission to reject an approach that determines cost-effectiveness of demand resources and associated incentive payments based on the RIM perspective. Rather, wise stewardship of society's resources requires that the cost-effectiveness of, and associated incentive payments to, demand resources be based on a total resource cost perspective.

IV. THE PROPOSAL TO PAY FULL LMP IN ALL HOURS CAN LEAD TO SERIOUS MEASUREMENT AND VERIFICATION PROBLEMS

The Commission's proposal requires payment of the full LMP for reductions from expected levels of energy consumption in all hours. Estimating the "expected levels" of consumption, absent a day-ahead purchase requirement or other advance purchase requirement, requires calculation of a customer baseline. The requirement that resources be eligible for full LMP payment in all hours, however, makes baseline estimation a substantial challenge. No baseline estimation methodology that relies upon historical customer meter data can accurately and reliably estimate what an individual customer's energy usage pattern would have been if that customer responds frequently to price signals. Furthermore, statistical estimation of baselines could invite sophisticated market participants to strategically schedule load reduction events so as to manipulate the baseline calculation.

To achieve comparability between generation and demand resources participating in the energy markets, the accuracy and reliability of the energy resource quantity provided by demand resources should be similar to that of generators. Achieving such comparability, however, is a challenge for demand resources. Whereas measuring the energy output of a generator is straightforward – the output is measured using an interval meter – measuring the demand reduction produced by a demand response resource is not as straightforward. No device exists that directly measures energy usage that did not occur, let alone a device that measures reduced consumption of energy in response to price signals. Accordingly, demand reductions need to be measured relative to an estimated baseline. The actual metered consumption of a demand resource is compared to the estimated baseline to establish the amount by which the demand of a market participant was reduced in response to price signals.

Numerous reasonable baseline estimation methodologies currently exist. However, the baseline estimation methodologies of which ISO-NE is aware, which are used to settle load reductions provided by customers participating in demand response programs, rely upon statistical analysis of historical customer meter data. Such baseline estimation methodologies exclude from the computation those days in which load reductions are scheduled to occur. The purpose behind excluding days with scheduled load reduction events is to establish a pattern of energy usage on a "normal" day against which energy usage on an "event" day can be compared. However, if a market participant schedules demand reductions for many consecutive days, that means many days are excluded from the baseline calculation. As a result, baselines can become stale and may not truly estimate a customer's normal energy usage pattern. As mentioned above, no baseline estimation methodology that relies upon historical customer meter data can accurately and reliably estimate an individual customer's normal energy usage pattern if that customer responds frequently to price signals.

Further, a sophisticated market participant could submit bids into the energy markets to strategically schedule load reduction events so as to manipulate the baseline calculation. "Adverse selection" and "moral hazard" give market participants incentives to inflate baseline estimates and extract program payments for essentially normal consumption behavior. Under adverse selection, customers have the incentive to selectively join a demand response program just before the end of their peak usage season. The baseline would be established using load data compiled during the customer's high usage season, which allows the customer to receive demand reduction payments as the customer's load naturally begins to decline because the customer is transitioning into its off-peak season.[44] Under moral hazard, customers may actively manipulate their load to create a higher-than-normal baseline and then receive payments for essentially normal consumption.[45] Behavior associated with adverse selection and moral hazard was observed in the DALRP in the fall of 2007, which prompted changes to the program rules so as to limit the hours in which a demand reduction offer could clear under the program.[46]

Additionally, a calculated baseline is not used symmetrically – *i.e.*, baselines are used to estimate reductions, but not increases, in expected energy consumption. As a result, a participant can receive payments for essentially no reduction in net energy usage. Participants on a *fixed retail rate* would be able to take advantage of the asymmetric use of calculated baselines in the following ways:

- A participant could reduce usage below its baseline in one hour and receive full-LMP payment for that reduction, but then increase usage above its baseline in an adjacent hour without having to pay the full LMP for its increased usage. If the adjacent hours have similar LMPs, such load shifting does not reduce overall energy usage or costs, yet the participant receives payments.

- If baselines are statistically estimated using hourly meter data from previous days, a participant can receive payment for essentially normal consumption behavior through the natural day-to-day variation in load. For example, assume that the baseline is computed as the statistical average of metered loads from five previous days. If the load for a particular hour over the last five days was 5, 4, 3, 2, and 1 MW, the calculated baseline for the hour would be 3 MW. If the load continued to exhibit the same variation going forward, the participant could receive full-LMP payment on the days in which the load was 2 or 1 MW, but not be required to pay the full LMP when the load was 5 or 4 MW. Overall energy usage would not have changed, and this participant would not have to do anything differently to receive payments.

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[44] For example, a customer with high air conditioning usage may join a demand response program at the end of the summer season, and receive payments when its air conditioning load naturally subsides into the fall. A school may join a demand response program in the spring when the school is still in session, and then receive payments through the summer while the school is essentially unoccupied. Ski resorts may join the program just before the end of the snow-making season. A factory may join a program just before its planned seasonal shut down.

[45] For example, a customer with a behind-the-meter, base-load distributed generation unit could temporarily turn off the unit during which time it establishes a baseline. Once the baseline is established, the customer turns the unit back on to extract demand reduction payments.

[46] See *ISO New England Inc.*, Docket No. ER08-538-000; Filing of Changes to Day-Ahead Load Response Program (February 5, 2008).

- A participant with multiple facilities in the same control area could establish baselines for each facility, and then shift production from one facility to another such that overall production and energy usage among all facilities does not change. The facilities with usage falling below its baseline, however, receive full-LMP payment whereas the facilities increasing usage above its baseline would not need to pay the full LMP for increased usage. By definition, overall energy usage would not have changed, yet the participant would receive payments for reduced usage.

There may be other ways in which participants on fixed retail rates could take advantage of the asymmetric use of baselines and receive payments for essentially no change in overall energy usage.

Finally, since baselines are estimates that are not directly observable – *i.e.*, baselines are used to estimate consumption that *did not* occur – it is difficult to verify the legitimacy of a claimed baseline estimate. To the extent that program participants actively modify their energy usage in response to changing LMP levels over many hours of the year, the accuracy of baseline estimates becomes increasingly unreliable.[47] To address this problem, it is necessary to limit the number of hours or days that a demand resource could clear in the energy market so that the customer's "normal" load can be estimated. This approach is utilized in the current ISO-NE price-response programs. Of course, this limits the number of hours that a demand response resource could clear the market, which is contrary to the Commission's proposed rule that demand resources be paid in all hours.

It is preferable to avoid the use of statistical analysis of historical usage data when establishing baselines for demand resources participating in the energy markets. Instead, baselines should comprise hourly MWh quantities acquired through the day-ahead energy market. The approach could be utilized with some other form of advanced purchase, but the

[47] While programs seeking to maximize price-responsiveness across many hours should avoid the use of statistically-estimated baselines, a statistically-estimated baseline can be an effective tool for measuring load reductions that occur infrequently. Research conducted by ISO-NE shows that the current baseline methodology has acceptable accuracy at an event day frequency of about 100 days per year. ISO-NE estimated that Real-Time Demand Response Resources participating in the Forward Capacity Market may be called between 12 – 26 days during the 2011/2012 Capacity Commitment Period. Therefore, ISO-NE concluded that its current baseline methodology is adequate for Real-Time Demand Response Resources participating in the Forward Capacity Market.

discussion here is limited to the day-ahead energy market. This would allow payment in all hours and avoid the need to somehow restrict the hours of payment because of limitations in baseline estimation techniques. To the extent that prices in the day-ahead energy market exceed the cost of dispatching the participant's demand resource capability, the participant would simply not purchase the energy in the day-ahead energy market and would instead plan to deploy its demand resource capability for the next operating day. Deploying demand resources under such circumstances is cost-effective since LMPs exceed the cost of the demand resource.[48]

Formulating a baseline on the basis of a cleared financial position in the day-ahead energy market would not be subject to artificial constraints such as a minimum number of days for which meter data is needed to establish a customer baseline or a maximum number of days that a demand resource could clear to maintain baseline accuracy and reliability. Against such a baseline, the customer can sell any amount of energy in the form of a demand reduction into the real-time energy market at the full real-time LMP for any or all hours that it chooses not to consume.

Not requiring the participant to first purchase its expected energy requirements essentially allows the participant to sell energy into the grid which it did not have to first purchase and own. For example, if a consumer saves two gallons of gasoline by not using his car today and the price is $3.00/gallon, the consumer saves $6.00. The consumer cannot also expect to receive a payment of $6.00 unless he had previously purchased two gallons of gasoline which he does not use and instead sells to someone at the going price of $3.00/gallon. However, if this consumer did not previously purchase two gallons of gasoline, but is paid $6.00 for not

[48] Of course, reducing purchases in the day-ahead energy market would also result in lower prices. If real-time LMPs decrease to a point below the cost of the demand resource, the participant could take advantage of such low prices by turning off its demand resource and consuming energy from the wholesale power grid.

consuming the two gallons, this consumer is being treated as though he is allowed to sell to the market two gallons of gasoline that he never possessed. In contrast to generation resources that physically inject energy into the wholesale power grid, demand resources physically reduce the withdrawal of energy from the wholesale power grid. As a result, allowing a participant with a demand resource to sell reduced energy usage like a supply of energy to the wholesale power grid in a manner comparable to a generator requires the participant to first purchase its expected energy usage before it can sell any unused energy back to the market for payment. To do so otherwise, like in the gasoline example, allows the participant to sell a quantity of energy back to the market which it never possessed. It is difficult to conceive of a well-functioning market for which market participants are allowed to sell goods into the market for which they do not have entitlement.

Formulating a baseline on the basis of a cleared financial position in the day-ahead energy market complies with the Commission's proposed rule that demand resources be paid in all hours while maintaining baseline accuracy and reliability. Further, this approach affords participants with demand resources full flexibility with minimal ISO/RTO oversight. Rather than a one-size-fits-all baseline estimation approach, which may not work well with all types of demand resources, or an approach that allows demand resources to use "customized" baseline methodologies subject to ISO/RTO approval, which would be subject to gaming and be highly burdensome for ISOs and RTOs to administer, use of a participant's financial day-ahead energy market position as the baseline allows participants to establish any type of baseline that fits their individual circumstances with little need for ISO/RTO oversight.

V. THE PROPOSED RULE RAISES COST ALLOCATION ISSUES THAT MUST BE ADDRESSED

Unlike programs that require the day-ahead or other advance purchase of energy, approaches that pay demand resources like supply resources create a unique settlement problem. Because demand resources reduce demand, treatment of demand resources as a supply resource would create a settlement imbalance; payments in the energy markets due to suppliers, both generation and demand resources, would exceed collections from consumers.[49] Allocation of these costs has been a subject of significant discussion in the New England stakeholder process. If the proposed rule is adopted, the Commission must address how payments to demand response providers will be allocated. Since the NOPR did not address this important issue, the Commission will need to propose further rules and seek comment before such rules can be implemented.

In a simple energy market in which supply consists of only generators and demand consists of only consumers, the allocation of energy market costs is straightforward. If a generator produces 100 MWh, that is because 100 MWh of load exists; therefore, settlement consists of paying the generator the market-clearing price for the 100 MWh it produced, and charging the consumers the same market-clearing price for the 100 MWh it consumed. Such an allocation is efficient and non-controversial because only those who consumed energy get charged and only those that produced energy get paid – those who did not consume do not get charged and those that did not produce do not get paid.

In contrast to a generator, however, if a demand resource produces 100 MWh as a supply resource, demand is simultaneously *reduced* by 100 MWh. Settlement in this situation is much more complicated because total supply (including generation and demand resources) exceeds total demand by the amount of demand resources delivered in real time.[50] If the demand resource is paid the

[49] This problem does not exist when baselines are established by financial positions in the day-ahead energy market.

[50] By treating demand reductions as a supply resource, if generators produce 1,000 MW of energy and demand response providers produce 100 MW of demand reductions in a particular hour, a total of 1,100 MW of supply

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market-clearing price for 100 MWh of demand reduction produced, who should be charged to pay for the 100 MWh that had been eliminated? Payment of demand reductions as a supply resource requires ISOs/RTOs to address to whom the resulting cost ought to be allocated. Obviously, market participants have a financial stake in how payments to demand resources are allocated. Within New England, stakeholder discussions about this issue were nearly as controversial as the question of how much to pay for demand reductions. To address this issue, ISO-NE recommends that the Commission require that payments to demand response providers be allocated among market participants in a way that minimizes the overall cost impact on customers.

Under the general approach to meeting the Commission's goals advocated by ISO-NE, whereby the participant purchases its expected energy consumption (*i.e.*, its baseline) at the day-ahead LMP and then is free to resell its position at the full real-time LMP, the cost allocation issue is automatically addressed within ISO-NE's current settlement algorithms. Entities taking a position in the energy markets would be financially responsible to pay for the positions taken, and any benefits produced by demand reductions would be accrued by those producing the demand reductions. Under ISO-NE's recommended approach, allocation of demand resource costs is efficient and non-controversial – those who consume energy get charged and only those who have an entitlement to energy but choose not to consume it get paid.

If the Commission nevertheless declines to require participants to purchase their expected energy requirements at the day-ahead LMP, adopts its rule as proposed, and/or utilizes statistically-estimated baselines rather than those based on the participant's day-ahead energy market position, the

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would exist. Assuming an LMP of $100/MWh, suppliers (i.e., both generators and demand response providers) would be owed a total of $110,000. However, only 1,000 MW of energy were consumed in that hour – recall that physical generation and load on the bulk power system must be equal in real time. If consumers are charged the same LMP for its metered consumption, only $100,000 would be collected, resulting in an under-collection of $10,000, which is equal to the payments owed to the demand response providers.

total amount paid to suppliers (generation and demand resources) at the full LMP would exceed collections from load-serving entities. In this instance, the ISOs/RTOs and the Commission would be faced with the difficult issue of determining how to allocate the costs associated with payments made to demand response providers.

There are numerous factors to consider in determining an appropriate allocation of these costs. A consumer that reduces energy consumption in real-time by utilizing its demand resource capability in response to high LMPs also reduces the amount of high-cost energy that its load-serving entity needs to purchase from the wholesale market, which in turn reduces the costs incurred by that load-serving entity. However, the same reduction in consumption also affects the retail revenue of the load-serving entity – interrupted load means lower retail sales and thus lower retail revenues. Finally, and most importantly, uncertainty in the amount and timing of load reductions produced by demand resources introduces an additional element of risk in serving the load of consumers with demand resources, particularly if the consumer is charged a fixed retail rate by its load-serving entity. For example, a load-serving entity charging a fixed retail rate needs to incorporate into its rate a forecast of how much, and at what LMP level, demand response is likely to occur during the prospective period over which its rate is in effect. However, since the amount and timing of demand response is uncertain, the load-serving entity will likely charge a risk premium to address this uncertainty. Higher risk premiums ultimately result in higher retail rates charged to end-use customers.

Analysis conducted by ISO-NE indicates that different cost allocation schemes expose load-serving entities to different levels of risk that result from uncertainty in the level of and timing of demand reductions from demand resources. Higher risks result in higher retail rates and ultimately higher overall consumer bills. However, the level of the risk that needs to be hedged is also a function of the amount paid to demand response providers, whether a participant is required to purchase its expected energy requirements at the day-ahead LMP, and whether the participant's baseline is based on its day-ahead energy market position. Because ISO-NE cannot presume the outcome of the NOPR proceeding with respect to these issues, it is difficult to recommend a specific cost allocation approach that would minimize the risks introduced by greater penetration of demand resources in the market. To guide ISO/RTO market rule development at the conclusion of the NOPR proceeding, ISO-NE recommends that the Commission require that market rules implementing the Commission's proposed rule allocate costs related to payments to demand response providers in a manner that minimizes cost impacts on final consumers.

If the Commission's rule is ultimately adopted, the simplest means of cost allocation is to split the costs resulting from payments to demand response providers into two components and charge those costs separately. The first component, the so-called LMP – G component, should be charged to the load-serving entity that is providing the energy to the end-use customer. The second component, the excess over the LMP – G (*i.e.*, the "G" component), should be charged to network load, which is the transmission owner portion of the bill. The transmission owner is best situated to simply pass this charge through as part of its rates to all customers to pay the excess costs. Analysis conducted by ISO-NE indicates that splitting the costs between load-serving entities and transmission owners as described above minimizes cost impacts on final customers. This proposal, however, should not be adopted until the Commission has conducted a full proceeding to discuss cost allocation.

VI. PAYMENT OF LMP LESS THE RETAIL GENERATION RATE CAN BE EFFICIENT

If ISO-NE's recommendations for how to implement the Commission's suggested payment of the full LMP in all hours are not adopted, other approaches that produce economically-efficient outcomes ought to be considered by the Commission. These alternative approaches, however, may require the Commission to consider the complex and controversial issues of determining accurate and reliable baselines and allocating costs associated with payments to demand resources.

One such approach would be to pay demand response providers that reduce demand the LMP less the retail generation rate ("LMP – G"). For example, assume a 10 MWh retail customer with a fixed 10¢/kWh retail generation rate and a demand resource with a marginal cost of 20¢/kWh. When the LMP is $300/MWh (*i.e.*, 30¢/kWh), dispatch of the demand resource is cost effective. As demonstrated previously, the dispatch of the demand resource is cost-effective whenever the marginal cost of the demand resource is less than or equal to the LMP. However, given the retail customer's fixed rate of 10¢/kWh, the retail customer has no incentive to dispatch its demand resource, because it could receive energy at a lower cost than the cost of dispatching its demand resource.

However, if this customer were offered an incentive payment of LMP less the retail generation rate, the customer would be paid 20¢/kWh for dispatching its demand resource (*i.e.*, the 30¢/kWh LMP less the fixed 10¢/kWh retail generation rate = 20¢/kWh incentive payment). By dispatching its demand resource, the customer reduces its net energy bill by $1,000. That is, the customer could purchase its energy requirements at its fixed retail rate of 10¢/kWh for a total bill of $1,000 (*i.e.*, 10¢/kWh retail rate x 10 MWh = $1,000). However, the customer's net energy bill would be $0 if it dispatched its demand resource. This is because the dispatch of the demand resource reduces the customer's retail load to 0 kWh, so the customer's retail bill is likewise $0. Further, the incentive payment offsets the cost of dispatching the demand resource (*i.e.*, [20¢/kWh incentive payment – 20¢/kWh demand resource marginal cost] x 10 MWh = $0). Accordingly, the incentive payment of LMP less the retail generation rate incents the dispatch of a cost-effective demand resource.[51]

[51] Because the retail customer still receives its energy commodity at a fixed retail rate under the scenario described here, the customer receives no incentive to increase its consumption in periods with low LMPs. While the approach described here produces an economically efficient result during hours in which LMPs exceed the retail generation rate, it is not as efficient as the approach described in Section IV and V of these comments whereby consumers or

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Paying LMP less the retail generation rate points to a solution for the cost allocation problem. If this payment rate is adopted, costs of payments to demand resource providers should be allocated to the load-serving entity whose load was reduced by the demand resource. Because the load-serving entity serving this customer experiences a net increase in wholesale market revenue in the amount of the reduced load times the difference between the real-time LMP less its retail generation rate,[52] the load-serving entity whose load was reduced by demand resources is in the best position to finance these incentive payments, and it could do so without having to raise its retail rates. Finally, since demand resource costs are not allocated to other load-serving entities, these other load-serving entities do not have to increase their rates to finance demand resource costs. Most notably, the stakeholders representing New England's load-serving entities agreed with ISO-NE that they should receive a direct allocation of demand resource costs to the extent that such costs were based on the LMP less the actual retail generation rates charged by such load-serving entities.

Under this approach, where demand response providers are paid the LMP less the retail generation rate for demand reductions, a statistically-estimated customer baseline appears to be needed, given that the entity taking the position in the wholesale energy market on behalf of the customer (*i.e.*, the load-serving entity) and the entity working with the customer to utilize its demand resource capability (*e.g.*, the demand response provider) are likely to be different entities. However, because demand response providers would not likely produce demand

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their agents purchase the consumer's expected usage and adjust their actual usage in real time as real-time conditions warrant. All price-responsive demand approaches that pay only for *load reductions* fail to realize the gains in customer value and economic efficiency from increasing load during hours with low LMPs.

[52] Under this approach, the load-serving entity sells the demand resource's unused energy back to the real-time energy market at the real-time LMP. The load-serving entity also experiences an erosion of its retail revenue equal to its retail generation rate. However, if the payment to the demand response provider is equal to the LMP less the retail generation rate, the load-serving entity whose load was reduced by the demand response is in a position to fully finance the payment to the demand response provider without having to increase its retail rates.

reductions when LMPs are less than the retail generation rate, and since retail generation rates would likely be higher than LMPs for a majority of hours in the year, statistically-estimated customer baselines are likely to be reasonable estimates of a customer's normal energy consumption behavior.

Some stakeholders may argue that the incentive payment to a participant in the energy market with a demand resource not be reduced by the retail generation rate. But, as noted earlier, this can lead to the dispatch of demand resources that are not cost effective. For example, assume the same customer with the same demand resource as above (*i.e.*, a 10 MWh retail customer with a fixed 10¢/kWh retail generation rate and a demand resource with a marginal cost of 20¢/kWh). If the LMP were $150/MWh, the customer could reduce its net energy bill by dispatching its demand resource even though the cost of the demand resource (20¢/kWh or $200/MWh) is greater than the cost of the marginal resource in the market represented by the LMP ($150/MWh). If the customer does not dispatch its demand resource, it would incur a cost of $1,000 for consuming 10 MWh of energy (*i.e.*, 10¢/kWh retail rate x 10 MWh = $1,000). By dispatching its demand resource, the customer would reduce its net energy bill to $500 (*i.e.*, [$200/MWh demand resource marginal cost – $150/MWh incentive payment] x 10 MWh = $500). Accordingly, if the payment to the demand resource is not reduced by the retail generation rate, the customer is given the incentive to dispatch its $200/MWh demand resource, which displaces a $150/MWh marginal resource in the market. This is not cost effective and does not result in comparable treatment of resources in the energy markets. Accordingly, a payment rate of the LMP less the retail generation rate is efficient and consistent with a total resource cost perspective.

An approach based on the LMP less the retail generation rate combined with the use of a statistically-estimated baseline was being developed in the New England stakeholder process prior to the Commission's initiation of the NOPR proceeding. Whether the Commission modifies the

NOPR's full LMP payment principle or not, ISO-NE recommends that the Commission require that any resulting costs associated with payments to demand response resources be allocated to market participants so as to minimize cost impacts on final consumers.

ISO-NE is also aware of other approaches that are consistent with a total resource cost perspective. For example, Professor William W. Hogan developed an "unbundled transaction model" which also appears consistent with a total resource cost perspective.[53] Professor Hogan (for the ISO/RTO Council) and ISO-NE's Internal Market Monitor will be submitting comments in the NOPR proceeding, which evaluate various alternatives to achieving price-responsive demand in the energy markets.[54] Because there is more than one approach to achieve cost-effective usage of resources in the energy market while achieving comparable treatment between generation and demand resources in the energy markets, the Commission should allow each region to develop an approach that suits its particular circumstances. Such approaches, however, should be consistent with a total resource cost perspective, address the baseline issue adequately, and minimize cost impacts on final consumers.

VII. CONCLUSION

In its current form, the proposed rule does not produce an efficient market outcome – it will encourage the dispatch of higher-cost demand resources in place of lower-cost generation in the energy markets. The proposed rule will have many undesirable effects, including higher consumer costs in the long-run. Further, the proposed rule appears to be based on the assumption that demand resources and generators have similar financial motivations and would participate in the energy market in the same way. This assumption, however, is not true. While generators are motivated to

[53] *See* Motion for Leave to Answer and Answer of the Electric Power Supply Association and White Paper by Professor William W. Hogan, Docket No. EL09-68-000 (October 30, 2009).

[54] *See* Hogan Paper included with ISO/RTO Council comments being filed today in this proceeding. *See also* the comments of the ISO-NE Internal Market Monitor being filed today in this proceeding.

participate in energy markets by earning revenues in excess of costs, demand response providers and the consumers they serve are motivated to participate in energy markets by reducing net energy bills. The fundamental difference between generators and demand resources warrants different treatment in the energy markets to ensure comparable incentives for all energy resources, increase the economic efficiency of energy markets, and reduce total resource costs. Finally, the proposed rule introduces substantial baseline estimation and cost allocation problems, neither of which is addressed in the NOPR. Accordingly, ISO-NE strongly urges the Commission ***not*** to promulgate the proposed rule in its current form.

ISO-NE's views concerning appropriate demand resource program design and the fundamental goal of economic efficiency is both consistent with the design criteria applied to each of the ISO-administered markets and with decades of regulatory policy. An economically-efficient market allocates society's limited resources to their most productive and valuable uses. Rather than promulgating the proposed rule, ISO-NE encourages the Commission to formulate, and permit implementation of, market rules that are consistent with basic principles of economic efficiency. While these comments demonstrated how the proposed rule creates inefficiencies, these comments also suggested how these inefficiencies can be corrected. Further, these comments suggest an approach that establishes accurate and reliable baselines through day-ahead energy purchases, which permits the payment of the full LMP in all hours in which consumption was reduced from expected levels in response to price signals. Finally, these comments ask that the Commission require costs associated with payments to demand response providers be allocated among market participants so as to minimize their impact on end-use consumers.

If the Commission does not require demand response providers to purchase their power in advance before allowing the demand response provider to sell energy into the market in the form of demand reductions, then it is difficult to design an approach in which paying full LMP in all hours for demand reductions is economically efficient. Under approaches developed by ISO-NE as part of its current price-responsive demand stakeholder process, advance purchases are not required. However, efficiency is achieved under this approach by paying the LMP minus the generation portion of the customer's retail rate. This approach also requires the calculation of a customer baseline, which has inherent incentive problems, but could be effectively implemented since fixed retail generation rates are likely to exceed LMPs most of the time, making statistical estimation of "normal" consumption levels more reliable and accurate. Such an approach also results in costs related to payments to demand response providers that must be allocated to market participants in some fashion. Commission guidance on cost allocation in its final rule would assist the ISOs/RTOs in the development of market rules to govern demand resource participation in the energy markets. ISO-NE recommends that the Commission require that such costs be allocated among market participants to minimize cost impacts on end-use consumers.

ISO-NE appreciates this opportunity to address the Commission's proposed rule, and urges the Commission to promulgate a final rule that is consistent with these comments.

Respectfully submitted,

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