EB-2019-__________

ONTARIO ENERGY BOARD

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO

Application for Review of an Amendment to the Independent Electricity System Operator Market Rules

NOTICE OF APPEAL

Nature of the Appeal and Relief Sought

1. The Association of Major Power Consumers in Ontario (AMPCO) applies to the Board for review of the Independent Electricity System Operator's (IESO) amendments of the Ontario Electricity Market Rules (Market Rules) for implementation of a transitional capacity auction (TCA).

2. On September 5th, 2019 the IESO published, pursuant to *Electricity Act, 1998* (*EL Act*) section 33(1), a package of Market Rule amendments[1] (the Amendments) to facilitate expansion of the existing Demand Response Auction (DRA) platform that has been operative in the IESO Administered Market (IAM) since 2015 into a Transitional Capacity Auction (TCA) platform. The Amendments will allow electricity generators to participate in future capacity auctions alongside Demand Response (DR) resources.

3. Generators receive payments for energy services provided to the IAM. DR resources do not (though the IESO has recently indicated that it intends to review the issue of DR resource eligibility for energy payments for services that they provide to the IAM).

4. The effect of implementing the Amendments to broaden the DRA to a TCA without first addressing the inequity in treatment between generation resources and DR resources in

[1] MR-00439-R00-R05.

the IAM energy market is to unjustly discriminate against DR resources, and in favour of generation resources. This is because the Amendments would allow the latter to effectively and unfairly displace the former in the capacity auction platform which was developed for DR resources and through which such resources have been successfully and competitively participating in the IAM since 2015.

5. AMPCO seeks an order from the Board revoking the Amendments effective the date of the Board's decision herein, and referring the Amendments back to the IESO for further consideration, all pursuant to section 33(9) of the *EL Act*.

6. The first TCA facilitated by the Amendments is currently scheduled for early December, 2019. The Amendments were passed in order to allow the first TCA to proceed. Should the first TCA proceed prior to determination by the Board of this application, generators that participate in the new TCA will be provided with an unfair competitive advantage, and DR resources which have historically participated actively and effectively in the DRA will be unduly and unjustly disadvantaged and potentially irreparably harmed.

7. AMPCO will thus also seek an order of the Board, by way of a motion pursuant to *EL Act* sections 33(7) and 33(8) and Rule 8 of the Board's *Rules of Practice and Procedure* (*Rules*), staying the operation of the Amendments pending completion of the Board's review of the Amendments.

8. AMPCO further relies on section 19(4) of the *Ontario Energy Board Act*, 1998, S.O. 1998, c. 15, Sched. B (*OEB Act*), and Rule 17 of the OEB's *Rules*.

Summary of the Grounds of the Appeal

9. The Amendments adopt rules to implement the first phase of a TCA. The IESO explains that Phase 1 of the TCA, *"enables non-committed dispatchable generators to participate in the TCA alongside dispatchable loads and hourly demand response resources. The*

TCA represents an evolution of the demand response auction into a more competitive capacity acquisition mechanism."[2]

10. The Phase 1 December, 2019 TCA was initially proposed as a first step towards transition to an Incremental Capacity Auction (ICA) to be implemented in 2022 in order to address what had been an identified need for capacity following that date. In July 2019 the IESO announced suspension of work on the ICA in light of an updated forecast indicating sufficient baseload and other resources to ensure reliability for the foreseeable future[3]. As such, the first TCA will simply be the first in potentially a series of capacity auction evolutionary steps without any defined end state or particular timing need.

11. While the IESO has indicated that it will address the issue of compensation of DR resources for the value that they provide to the IAM, resolution of this issue is not anticipated prior to the proposed December 2019 implementation of TCA Phase 1. Commandeering the current DRA to a broader auction platform without first addressing the competitive position of DR resources *vis a vis* generators will unnecessarily damage the existing, highly successful DRA market mechanism, which would be unfair to DR resources and counterproductive to robust evolution of the Ontario electricity market.

12. Without ensuring just and reasonable compensation to DR resources, on a comparable basis with other resources which bring similar value to the IAM, the TCA could result in replacement of one set of capacity providing resources with another. This would not enhance competition, but it may well stifle it.

13. The IESO's proposal for developing a broadened capacity auction is part of its overall Market Renewal Program (MRP). The overall objective of the MRP is to encourage and enhance competition[4]:

> *Creating a stable and efficient marketplace that produces value for consumers involves encouraging competition and innovation among suppliers – and is the catalyst behind initiatives to resolve long-standing market design issues.*

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[2] IESO Memorandum to the Board of Directors of the IESO, from Michael Lyle, Vice President, Legal Resources and Corporate Governance Chair, IESO Technical Panel, dated August 20, 2019 re: Recommendation from the Technical Panel on Market Rule Amendment Proposal.
[3] IESO, Energy Payments for Economic Activation of Demand Response Resources, September 25, 2019.
[4] IESO Transitional Capacity Auction, Phase 1 Design Document, April 11, 2019, page 1, 2nd paragraph.

14. Requiring DR resources to compete with generators in a TCA prior to resolution of the eligibility of DR resources for energy payments would:

   a. Undermine competition and market confidence, a result inimical to the IESO's objectives for the capacity auction program and its MRP in general.

   b. Introduce unjust discrimination against DR resources in the expanded auction program by requiring them to compete with generators prior to resolution of the eligibility of such resources for energy payments.

15. Because they discriminate against DR resources and are likely to stifle (not enhance) competition, the Amendments are not only unjustly discriminatory, they are also inconsistent with various of the *EL Act*'s purposes, including:

   a. encouraging electricity conservation and the efficient use of electricity in a manner consistent with the policies of the Government of Ontario;

   b. facilitating load management in a manner consistent with the policies of the Government of Ontario;

   c. promoting the use of cleaner energy sources and technologies, including alternative energy sources and renewable energy sources, in a manner consistent with the policies of the Government of Ontario;

   d. protecting the interests of consumers with respect to prices and reliability of electricity service; and

   e. promoting economic efficiency and sustainability in the generation, transmission, distribution and sale of electricity.

16. Pursuant to subsection 33(9) of the *EL Act*, the Board must revoke and refer back to IESO amendments to Market Rules that are: (i) inconsistent with the purposes of the *EL Act*, or (ii) unjustly discriminatory against a market participant or class thereof. Because the Amendment is both inconsistent with the *EL Act*'s purposes and unjustly discriminatory to DR Resources, the Board must exercise that power in this case.

Background to the Appeal

A. Historical Demand Response Auctions.

17. DR is the changing of electricity consumption patterns by end use consumers in response to market prices.[5]

18. Since 2015 the IESO has held annual DRAs to acquire DR capacity from market participants that are able to provide that capacity to the market in exchange for an availability payment (which is for present purposes essentially a “capacity payment” - i.e. a payment to ensure that capacity is available to supply energy services as and when called upon).

19. Four successful DRAs have been held in Ontario, the most recent in December 2018. The IESO’s report on the most recent DRA underscores the success of the DRA program:

> *This year, 38 organizations were registered as auction participants, the highest number since the auction began in 2015. The successful proponents included four new participants who represent a mix of commercial and industrial consumers.*
>
> *The average annual clearing price for availability payments of $52,810/MW represents a 30% decrease from last year, and a 42% decrease since the first auction in 2015. The auction cleared 818 megawatts (MW) for the 2019 summer commitment period and 854 MW for the 2019/2020 winter commitment period.*
>
> *Moving in to its fourth year, the auction has been established as a valuable and reliable tool for the IESO to secure capacity on the system. Decreasing prices year-over-year demonstrates the ongoing maturity of the demand response market as more consumers participate and competition increases. Lower capacity prices benefit all Ontario consumers, while auction participants benefit by offsetting their energy costs and improving their competitiveness.*
>
> *As the electricity system moves towards competitive electricity auctions under IESO’s Market Renewal project, the participation of consumers providing demand response will increase competition leading to overall lower prices for Ontario consumers.*[6]

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[5] IESO Market Manual, Part 12.0: Demand Response Auction, Issue 6.0, page 4, paragraph 1.
[6] IESO, IESO Announces Results of Demand Response Auction, December 23, 2018.

B. Transition to TCA Without Addressing Compensation for DR Resources Inimical to IESO Objectives and to *EL Act*'s Purposes.

20. Starting in December, 2019 the IESO intends to "transition" the DRA into a broader auction by opening participation to other resources. The TCA will permit non-committed dispatchable generators to participate in the auction alongside dispatchable loads and hourly demand response resources.

21. Generation resources, unlike DR resources, have other revenue opportunities in the IAM, including payments for energy services provided. DR resources do not currently have commensurate revenue opportunities for the energy services which they provide to the market.

22. If the TCA is implemented now (through the Amendments), generators will bid into capacity auctions taking into account their anticipated energy payments. DR resources will have to compete against these bids without an equivalent energy payment stream, putting DR resources at a competitive disadvantage to generators in the capacity market. [7]

23. As long as this is the case, commandeering the currently successful DRA into a TCA will not broaden the existing auction platform, it will only result in driving the DR resources that have successfully participated in that DRA out of the fledgling IESO capacity market, and replacing one set of capacity auction participants (DR) with another (generators). This would actually be a step backward in evolution of the IAM, not a step forward.

24. Requiring DR resources to compete against generators without resolving the comparative value of DR resources and generation resources in the energy market, and how to justly and reasonably compensate the former in a manner comparable to the latter, would undermine the current success of the DRA and handicap DR resources from successfully competing within their own existing market platform. This result is contrary to various of the *EL Act*'s purposes, including:

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[7] Energy payments avoided by the load are not economically equivalent to energy payments for provision of demand reduction to the market, and are not adequately compensatory for the value provided by DR resources to the energy market: 134 FERC ¶ 61,187, 18 CFR part 35, Docket No. RM10-17-000; Order No. 745, *Demand Response Compensation in Organized Wholesale Energy Markets*, March 15, 2011, paragraph 62.

a. encouraging electricity conservation and the efficient use of electricity in a manner consistent with the policies of the Government of Ontario;

b. facilitating load management in a manner consistent with the policies of the Government of Ontario;

c. promoting the use of cleaner energy sources and technologies, including alternative energy sources and renewable energy sources, in a manner consistent with the policies of the Government of Ontario;

d. protecting the interests of consumers with respect to prices and reliability of electricity service; and

e. promoting economic efficiency and sustainability in the generation, transmission, distribution and sale of electricity.

25. This result is also inimical to the IESO's own objectives of enhancing competition for the benefit of consumers.

26. As noted above, the overall objective of the IESO's MRP is to encourage and enhance competition[8]:

> *Creating a stable and efficient marketplace that produces value for consumers involves encouraging competition and innovation among suppliers – and is the catalyst behind initiatives to resolve long-standing market design issues."*

27. The IESO's proposal to evolve the DRA into a broader based capacity auction is to the same end[9]:

> *The ICA will help us to prepare for [a future period of capacity requirement] by allowing more resource types to compete to provide future capacity, enabling the IESO to flexibly meet the province's adequacy needs.*

28. The success of a broadened capacity auction hinges on expanding participation in competition for the provision of capacity:

> *One of the advantages of the ICA is that all eligible sources of capacity – new and existing, on both the supply and demand sides – compete with each other, regardless of resource type. …From the perspective of meeting adequacy needs, there is no functional difference between a megawatt of power from an electricity*

[8] IESO Transitional Capacity Auction: Phase I Design Document, April 11, 2019, page 1.
[9] IESO *Incremental Capacity Auction High-Level Design: Executive Summary*, March 2019, page 1, last paragraph.

generating facility and a megawatt of reduced consumption from demand response. [10]

29. The TCA would start with the DRA, and add non-committed dispatchable generators as eligible capacity auction participants. The IESO's stated intent in so doing is to *"enable competition between additional resource types"*.[11]

30. At the same time the IESO has acknowledged concerns that there are barriers to DR participation in the IESO markets, and that one of these barriers is the unavailability to DR resources of energy payments.[12]

31. The IESO proposes to study the introduction of energy payments for DR resources (i.e. to determine *"whether there is a net benefit to electricity ratepayers if DR resources are compensated with energy payments for economic activations"*). The study proposed is to be concluded *"before the end of 2020"*, with a next step proposed to be to *"[o]btain input from stakeholders on the approach to conducting the analysis required to make this determination"*.[13]

32. Requiring DR resources to compete against generators without resolving the comparative value of DR resources and generation resources in the energy market, and how to justly and reasonably compensate the former in a manner comparable to the latter, would undermine the current success of the DRA and handicap DR resources from successfully competing within their own existing market platform.

33. Requiring DR resources to compete with generators in a TCA prior to resolution of the eligibility of DR resources for energy payments would:

    a. Undermine competition and market confidence, a result inimical to the IESO's objectives for the capacity auction program and its MRP in general.

    b. Introduce undue discrimination against DR resources in the expanded auction program by requiring them to compete with generators prior to resolution of their eligibility for energy payments.

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[10] IESO *Incremental Capacity Auction High-Level Design: Executive Summary*, March 2019, page 3, 3rd paragraph.
[11] *Transitional Capacity Auction Phase I Design Document*, April 11, 2019, p.2, para. 8.
[12] IESO Demand Response Working Group Meeting Materials, June 19, 2019, pages 54 *et seq.*
[13] IESO Demand Response Working Group Meeting Materials, June 19, 2019, page 7.

(The IESO has recently recognized just this sort of issue in respect of DR compensation for out of market (i.e. testing or emergency) Hourly DR resource activations.[14])

34. Premature introduction of a TCA such that it undermines the ability of DR resources to compete in Ontario's competitive electricity market would be a <u>regressive</u> step in the quest for enhanced competition and innovation.

35. Commandeering the current DRA to a broader auction platform without first addressing the competitive position of DR resources *vis a vis* generators and other sources of capacity would unnecessarily damage a highly successful existing market mechanism, which would be unfair to DR resources, counterproductive to robust evolution of the Ontario electricity market, and irresponsible on the part of the IESO.

C. Failing to Compensate DR Resources is Unjust and Unreasonable.

36. It has been definitively recognized that DR resources can provide electricity wholesale market energy services, and that failure to compensate DR resources for such services is unjust and unreasonable. In a Final Rule issued in March, 2011 the United States Federal Energy Regulatory Commission (FERC) determined that:[15]

> *… when a demand response resource participating in an organized wholesale energy market… has the capability to balance supply and demand as an alternative to a generation resource and when dispatch of that demand response resource is cost-effective… that demand response resource must be compensated for the service it provides to the energy market at the market price for energy… This approach for compensating demand response resources helps to ensure the competitiveness of organized wholesale energy markets and remove barriers to the participation of demand response resources, thus ensuring just and reasonable wholesale rates.*

37. In the course of its consideration of the equivalency of DR resources and generation resources in providing energy services, the importance of recognizing and compensating this equivalency appropriately, and the importance of thus reducing barriers to DR

[14] IESO Demand Response Working Group Meeting Materials, June 19, 2019, pages 36 *et seq*.
[15] 134 FERC ¶ 61,187, 18 CFR part 35, Docket No. RM10-17-000; Order No. 745, *Demand Response Compensation in Organized Wholesale Energy Markets*, March 15, 2011, page 1.

participation in wholesale markets, FERC cited an earlier order which included a finding that[16]:

> *A market functions effectively only when both supply and demand can meaningfully participate, and barriers to demand response limit the meaningful participation of demand in electricity markets.*

38. FERC went on to find that:

> *Removing barriers to demand response will lead to increased levels of investment in and thereby participation of demand response resources (and help limit potential generator market power), moving prices closer to the levels that would result if all demand could respond to the marginal cost of energy.*[17]
>
> *…*
>
> *In Order No. 719, the Commission found that allowing demand response to bid into organized wholesale energy markets "expands the amount of resources available to the market, increases competition, helps reduce prices to consumers and enhances reliability."*[18]

39. In its rulemaking deliberations FERC also considered arguments that DR resources are "compensated" by avoiding energy costs when responding to requests to curtail consumption, and accordingly paying such resources for energy thereby effectively supplied would amount to double compensation. On these arguments FERC found as follows:[19] [emphasis in original]

> *Furthermore, Dr. [Alfred E.] Kahn argues that paying demand response [marginal price] sets "up an arrangement that treats proffered reductions in demand on a competitive par with positive supplies; but one is no more a [case of overcompensation*] than the other: the one delivers electric power to users at marginal costs – the other – <u>reductions in cost</u> – both at competitively-determined levels [*Insert in original].*
>
> *… In the absence of market power concerns, the Commission does not inquire into the costs or benefits of production for the individual resources participating as supply resources in the organized wholesale electricity markets and will not here, as requested by some commenters, single out demand response resources for adjustments to compensation. The Commission has long held that payment of [marginal price] to supply resources clearing the day-ahead and real-time energy markets encourages "more efficient supply and demand decisions in both the short*

[16] Ibid, paragraph 57, citing FERC Order No. 719.
[17] Ibid, paragraph 59.
[18] Ibid, paragraph 61.
[19] Ibid, paragraph 62.

run and long run," notwithstanding the particular costs of production of individual resources. Commenters have not justified why it would be appropriate for the Commission to continue to apply this approach to generation resources yet depart from this approach for demand response resources.

40. FERC also recognized in its rule making findings the interrelationship between just and reasonable compensation to DR resources in energy markets and the fairness of associated capacity markets. FERC noted *"how the increased participation by demand resources [in energy markets] could actually increase potential suppliers in capacity markets by reducing barriers to demand resources, which would tend to drive capacity prices down"*, and the need to *"examine the way in which capacity markets already may take into account energy revenues"*.[20]

41. The FERC's conclusions on this topic followed a comprehensive rule making process during which opposing positions on the issue were thoroughly represented (with supporting expert evidence), canvassed and considered.

42. Moreover, the IESO itself has recognized the value DR Resources provide by indicating that it will address the issue of compensation of DR resources for the value that they provide to the IAM.

43. Just and reasonable compensation for DR resources must be addressed, and it must be addressed <u>before</u> the implementation of the TCA so that DR resources are not unfairly driven out of the fledgling capacity market.

D. Instituting a TCA without resolving issues regarding just and reasonable compensation to DR resources is discriminatory.

44. As outlined above, the pre-eminent North American energy regulator – FERC - has carefully and thoroughly considered the role of DR resources in wholesale energy markets, and the issue of just and reasonable compensation of those resources for their participation, and has concluded that:

[20] 134 FERC ¶ 61,187, 18 CFR part 35, Docket No. RM10-17-000; Order No. 745, *Demand Response Compensation in Organized Wholesale Energy Markets*, March 15, 2011, page 67, footnote 167.

a. Failure to compensate DR resources for the value they provide to energy markets in the same manner as compensation is afforded to generation resources for the value which they supply to energy markets results in wholesale prices that are unjust and unreasonable.

b. The fairness of compensation of wholesale energy market participants for energy services provided influences the fairness and efficiency of capacity markets.

45. It follows that expanding the current DRA platform to allow generation resources eligible for energy market compensation to participate in the broadened capacity auction without addressing just and reasonable compensation for DR resources providing energy market services would result in a capacity market that is unfair and inefficient, and effectively anti-competitive and discriminatory.

46. Without resolution of payment to DR resources for energy services that they can and do provide to the IAM in a manner that fairly recognizes the value of these services provided, inviting generators to compete with DR resources in a capacity auction, which will be the effect of the Amendments, will unduly and unfairly prejudice the ability of those DR resources to compete, and would thus be unjustly discriminatory.

E. Market Rule Amendments which, in the result, are unjustly discriminatory or contrary to the purposes of the *EL Act* must be rejected.

47. The *EL Act* governs the authority of the IESO to make Market Rules, and the manner in which the Board oversees that IESO authority.

48. Subsection 33(9) of the *EL Act* requires the Board to consider whether a Market Rule amendment *"unjustly discriminates against or in favour of a market participant or class of market participants"*. If the OEB so finds, it <u>must</u> make an order revoking the amendment, and referring the amendment back to the IESO for further consideration.

49. For the reasons articulated above, Market Rule amendments which have the effect of allowing generation resources to unjustly and unfairly compete against DR resources for the provision of capacity to the IAM would *"unjustly discriminate against a class of market participants"* – i.e. DR resources currently active in the very successful DRA – and <u>must</u> be revoked by the Board.

50. Furthermore, subsection 33(9) of the *EL Act* requires the Board to consider whether a Market Rule amendment "*is inconsistent with the purposes of this Act*". If the Board so finds, it must make an order revoking the amendment, and referring the amendment back to the IESO for further consideration.

51. For the reasons articulated above, Market Rule amendments which implement the TCA without first addressing the unfairness and anti-competitive impact of requiring DR resources to compete with generation resources, but without the assurance of compensation for energy services provided to the IAM, is inimical to fostering competition. Consequently, it is inimical to many of the objectives of the *EL Act*, including:

a. encouraging electricity conservation and the efficient use of electricity in a manner consistent with the policies of the Government of Ontario;

b. facilitating load management in a manner consistent with the policies of the Government of Ontario;

c. promoting the use of cleaner energy sources and technologies, including alternative energy sources and renewable energy sources, in a manner consistent with the policies of the Government of Ontario;

d. protecting the interests of consumers with respect to prices and reliability of electricity service; and

e. promoting economic efficiency and sustainability in the generation, transmission, distribution and sale of electricity.

Relief Sought

52. For all of the foregoing reasons, AMPCO submits that;

a. the Board should find that the Amendments are;

i. inconsistent with the objectives of the *EL Act*; and/or

ii. unduly discriminatory to DR resources; and

b. having so found, it must to revoke the Amendments and refer them back to the IESO for reconsideration.

53. In addition to the materials filed with this Notice of Appeal and any additional relevant materials from those required to be filed by the IESO in response to this Notice of Appeal,

in support of this application AMPCO proposes to file affidavit material as and when permitted by the Board.

54. AMPCO also requests eligibility to seek recovery from the IESO of AMPCO's reasonably incurred costs of this application.

September 26, 2019

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Approved market rule amendments published

September 5, 2019

Further to our August 29 communication on the adoption of two market rule amendment proposals, the final amendments, and the IESO Board's reasons for adopting them, have now been posted online. The two proposals are:

- Transitional Capacity Auction (MR-00439-R00-R05) to evolve the demand response auction into a more competitive capacity acquisition mechanism
- Selection of a mediator or arbitrator other than an IESO Dispute Resolution Panel member (MR-00438-R00) to provide flexibility to parties involved in a market rules dispute.

The effective date of both market rule amendment proposals is October 15, 2019.

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Market Rule Amendment Proposal

PART 1 – MARKET RULE INFORMATION

Identification No.:	MR-00439-R00		
Subject:	Transitional Capacity Auction		
Title:	Changes to Market Rule Definitions		
Nature of Proposal:	☒ Alteration	☒ Deletion	☒ Addition
Chapter:	11	Appendix:	
Sections:	NA		
Sub-sections proposed for amending:			

PART 2 – PROPOSAL HISTORY

Version	Reason for Issuing	Version Date
1.0	Draft for Stakeholder Review and Comment	May 15, 2019
2.0	Draft for Technical Panel Review	June 18, 2019
3.0	Posted for Stakeholder Review and Comment	June 27, 2019
4.0	Submitted for Technical Panel Vote	August 6, 2019
5.0	Recommended by Technical Panel; Submitted to IESO Board	August 14, 2019
6.0	Approved by IESO Board	August 28, 2019
Approved Amendment Publication Date:	September 5, 2019	
Approved Amendment Effective Date:	October 15, 2019	

PART 3 – EXPLANATION FOR PROPOSED AMENDMENT

Provide a brief description of the following:

- The reason for the proposed amendment and the impact on the *IESO-administered markets* if the amendment is not made.
- Alternative solutions considered.
- The proposed amendment, how the amendment addresses the above reason and impact of the proposed amendment on the *IESO-administered markets*.

Summary

The IESO proposes to amend the market rules to evolve the Demand Response Auction (DRA) into the Transitional Capacity Auction (TCA) to address capacity needs in Ontario.

Over its four auctions, the DRA has proven successful in driving down capacity costs and increasing competition. Enhancing the IESO's approach to capacity auctions this year by opening participation to other resources is another step toward a more competitive electricity marketplace; it moves Ontario's electricity marketplace down the path of efficiency, competition, and transparency – the key principles of the market renewal efforts.

This proposal will be discussed as part of the Transitional Capacity Auction stakeholder engagement initiative before consideration by the Technical Panel.

Further information on the Transitional Capacity Auction stakeholder engagement is found here.

Background

The changes to Chapter 11 – Definitions outlined below are being made to clearly define key aspects of the Transitional Capacity Auction, differentiate from previous demand response programs, and to retire definitions that will no longer be in use.

Discussion

Most of the proposed changes to the market rules to enable the TCA are to add, change or delete defined terms. This approach was taken to minimize process changes for existing market participants. The proposed market rules for the TCA are based on newly defined terms with the 'capacity auction' prefix which encompasses both the existing DRA commitment period which ends on April 30, 2020 and the TCA, expected to commence in December, 2019. Because of the overlap of the two auction constructs, the new capacity auction definitions will cover both auctions.

Some 'demand response' definitions remain in the proposed ruleset because they are required to facilitate the existing DRA. It is anticipated that most of the remaining demand response definitions will be removed from the market rules after the DRA commitment period has concluded. This will be a further discussion in phase 2. In the same manner, some 'transitional capacity auction' definitions were added only to help facilitate the first TCA and may change in future phases. Managing any overlapping auction rules within the TCA will be a key consideration for the upcoming phases of change.

This market rule amendment proposal was first circulated to stakeholders and market participants who are participating in the Transitional Capacity Auction stakeholder engagement. In response to feedback received, changes were made to the Capacity Auction Zonal Constraints, Capacity Auction Eligible Generation Resource and Qualified Capacity definitions. Additionally, the definition for Demand

PART 3 – EXPLANATION FOR PROPOSED AMENDMENT

Response Direct Participant has been removed as that definition was used exclusively for the Capacity Based Demand Response Program.

All new defined terms are listed below, and fully defined in the next section.

<u>Chapter 11</u>

- New definitions
  - *auction capacity*
  - *auction period*
  - *availiability window*
  - *capacity auction*
  - *capacity auction deposit*
  - *capacity auction eligible generation resource*
  - *capacity auction offer*
  - *capacity auction participant*
  - *capacity auction zonal constraints*
  - *capacity generation resource*
  - *capacity market participant*
  - *capacity obligation*
  - *capacity prudential support*
  - *capacity prudential support obligation*
  - *capacity transferee*
  - *capacity transferor*
  - *capacity zonal constraints*
  - *demand response resource*
  - *forward period*
  - *non-committed resource*
  - *obligation period*
  - *qualified capacity*
  - *target capacity*
  - *transitional capacity auction*
  - *transitional capacity auction clearing price*
  - *transitional capacity auction reference price*

PART 3 – EXPLANATION FOR PROPOSED AMENDMENT

- Updated definitions
  - *capacity auction deposit*
  - *commitment period*
  - *demand response auction*
  - *demand response capacity*
  - *demand response contributor*
  - *demand response energy bid*
  - *demand response market participant*
  - *demand response prudential support*
  - *demand response prudential support obligation*
  - *demand response transferor*
  - *demand response transferee*
  - *hourly demand response*
- Deleted definitions
  - *capacity based demand response program*
  - *demand response aggregator*
  - *demand response auction clearing price*
  - *demand response auction offer*
  - *demand response capacity obligation*
  - *demand response direct participant*
  - *demand response pilot program*
  - *demand response security*
  - *demand response target capacity*
  - *demand response zonal constraints*

Specific changes to the definitions are listed below. There are five additional rule amendment packages that form the entirety of the proposed rule changes for the TCA.

PART 4 – PROPOSED AMENDMENT

Chapter 11

auction capacity means an amount in megawatts of electricity available to be provided to the *IESO-controlled grid*, by *capacity market participants* pursuant to obligations related to a *capacity auction*;

auction period means, with respect to a *capacity auction*, the length of time commencing with the opening of the window during which the IESO receives *capacity auction offers*, and finishing at the time at which the *IESO publishes* auction results;

availability window means the hours in an *obligation period* during which resources associated with *capacity obligations* are required to be available to provide *auction capacity*;

capacity auction means a *transitional capacity auction* or a *demand response auction;*

capacity auction deposit means the deposit required to be made by a *capacity auction participant* in accordance with section 18 of Chapter 7, as a condition of participating in a *capacity auction;*

~~*capacity based demand response program* means the temporary program used by the *IESO* to transition the former *OPA's* contract based DR3 program into the *IESO-administered market;*~~

capacity auction eligible generation resource means a *non-committed resource* that is a *generation facility*, which is also a *connected facility* at the commencement of the capacity qualification process for a given *capacity auction*, and which is registered as dispatchable with the *IESO* from at least the time a *capacity obligation* is allocated to it;

capacity auction offer means an *offer(s)* from a *capacity auction participant*, in the form of a *price-quantity pair(s)*, to provide *auction capacity* for an applicable *obligation period*, reflecting the amount of *auction capacity* that the *capacity auction participant* can reliably and responsibly provide if received as a *capacity obligation*, and which *offer* amount is no greater than the *capacity auction participant's qualified capacity;*

capacity auction participant means a person that is authorized to participate in a *capacity auction*;

capacity auction zonal constraints means the minimum or maximum amount of *auction capacity* that a *capacity auction* seeks to secure for a specific electrical zone as detailed by the *IESO* in each pre-auction report;

capacity generation resource means a *capacity auction eligible generation resource* with respect to which a *capacity market participant* has allocated a percentage of a *capacity* *obligation* received in the given *capacity auction* in accordance with the applicable *market manual*;

capacity market participant means a *capacity auction participant* that has registered with the *IESO* as a *capacity market participant*, and who satisfies requirements contemplated in Chapter 7, section 18;

capacity obligation means the amount of *auction capacity* that a *capacity market participant* is required to provide during the *availability windows* of an *obligation period*;

capacity prudential support means the collateral provided by a *market participant* with a *capacity obligation in* accordance with the requirements contemplated in Chapter 2, section 5B;

capacity prudential support obligation means the dollar amount of collateral required as specified by the *IESO* as a condition of delivering on a *capacity obligation*;

capacity transferee means a *capacity auction participant* who is willing to accept all or a portion of a *capacity obligation* from a *capacity transferor;*

capacity transferor means a *capacity auction participant* who intends to transfer all or a portion of its *capacity obligation* received through a *capacity auction* to a *capacity transferee;*

commitment period means the ~~length~~period of time for ~~which a *demand response market participant* is required to fulfill its *demand response*~~each *capacity auction* over which it secures *capacity*. It consists of two *obligation* ~~by making its *demand response capacity* available for *dispatch* through the day-ahead commitment process and *energy market;*~~*periods;*

~~*demand response aggregator* means a person that is not a *demand response direct participant* and aggregates at least one *demand response contributor* to provide a portion of the aggregator's monthly contracted MW for the contracted *dispatch* period as outlined in the aggregator's *demand response schedule;*~~

demand response auction means ~~the~~an auction operated by the *IESO* prior to December 31, 2018, to ~~procure~~acquire *demand response capacity*, in accordance with section 18 of Chapter 7;

~~*demand response auction clearing price* means the price at which the *demand response auction* clears for a commitment period and will be quoted in $/MW-day;~~

~~*demand response auction offer* means an offer(s) , submitted by a *demand response auction participant*, in the form of a *price-quantity pair(s)* to provide *demand response capacity* in a *demand response auction;*~~

demand response capacity means the expected ~~quantity of~~*auction capacity* a *dispatchable* *load* ~~reduction a~~or an *hourly demand response resource* can provide during a specified *availability window* and ~~*commitment*~~*obligation period* ~~for~~following a ~~*demand response*~~*capacity auction*, and excludes *energy* transacted through the *energy market*;

~~*demand response capacity obligation* means the amount of *demand response capacity* that a *demand response market participant* is obligated to provide during the applicable availability window and *commitment period*, following a *demand response auction*;~~

demand response contributor means an interruptible load or behind the meter *generator* that is owned by a *demand response direct participant*, or with whom a *demand response aggregator* has enforceable rights, and in either case, who will provide a portion of the monthly contracted MW for the contracted *dispatch* period as outlined in the *demand response schedule*. A *demand response contributor* also means the delivery of a ~~*demand response*~~ *capacity obligation* with an *hourly demand response resource*, in which case a monthly contracted MW is replaced by a ~~*demand response*~~ *capacity obligation*;

~~*demand response direct participant* means a person who is not *a demand response aggregator* and whose *demand response contributors* are owned by the *demand response market participant* and the *facilities* in which the *demand response contributors* reside are controlled by the *demand response market participant;*~~

demand response energy bid means a *bid* in the day-ahead commitment process and the *real-time energy market*, greater than the *demand response bid price threshold* and less than the *MMCP*, by a *demand response market participant* entered for either a *dispatchable load* or an *hourly demand response resource* to fulfill a ~~*demand response*~~ *capacity obligation* availability requirement;

demand response market participant means a ~~person who is a~~ *capacity market participant* ~~that participates only in the *capacity based*~~with a *dispatchable load* or an *hourly* demand response ~~*program*, the *demand response pilot program*, or is a person with a *demand response capacity obligation;*~~*resource;*

~~*demand response pilot program* means a demonstration project, or projects for a *demand* response service referred to in section 16 of Chapter 7;~~

demand response prudential support means ~~the collateral~~*capacity prudential support* provided by a *capacity market participant* in connection with a *demand response* ~~*capacity obligation*~~*auction*;

demand response prudential support obligation means the dollar amount of collateral required as specified by the *IESO* as a condition of delivering on a ~~*demand response*~~ *capacity obligation* received through a *demand response auction*;

demand response resource means, in a *capacity auction*, either an *hourly demand response* resource or a *dispatchable load* and with respect to which a *capacity market participant* has allocated a percentage of a *capacity obligation* received in the given *capacity auction* in accordance with the applicable *market manual;*

~~*demand response security* means the obligations owed to the *IESO* by a third party and other forms of security for the financial obligations of a *demand response market participant*, in the form set forth in section 5A of Chapter 2;~~

~~*demand response target capacity* means the amount of *demand response capacity* which the *IESO* seeks to clear through the *demand response auction*;~~

demand response transferor means a ~~*demand response*~~*capacity auction participant* who intends to transfer all or a portion of its ~~*demand response*~~ *capacity obligation* received through a *demand response auction* to a *demand response transferee*;

demand response transferee means a ~~*demand response*~~ *capacity auction participant* who is willing to accept all or a portion of a ~~*demand response*~~ *capacity obligation* from a *demand response transferor*;

~~*demand response zonal constraints* means the minimum or maximum amount of *demand response capacity* that the *demand response auction* seeks to clear for a specific electrical zone as detailed by the *IESO* in each pre-auction report;~~

forward period means the period of time immediately following a *capacity auction*, to the commencement of an *obligation period*;

hourly demand response means the resource type described in section 19 of Chapter 7, that is a registered facility and used by the *IESO* as a delivery type, on an hourly basis, for a ~~*demand response*~~ *capacity obligation;*

non-committed resource means a *registered facility* that is neither - in whole or in part - rate-regulated, contracted to the *IESO*, contracted to the *OEFC*, or obligated as a resource backed capacity export to another jurisdiction during the entire duration of a given *obligation period;*

obligation period means the period of time for which a *capacity market participant* is required to fulfill its *capacity obligation* through the day-ahead commitment process and *energy market;*

qualified capacity means a quantity in megawatts representing the maximum *capacity auction offer* that a *capacity auction participant* may provide for an applicable *obligation period*, and which corresponds to an amount submitted to the *IESO* by the *capacity auction participant* for qualification during the pre-qualification period of a relevant *capacity auction;*

target capacity means the amount of *auction capacity* which the *IESO* seeks to acquire through *a capacity auction*;

transitional capacity auction means an auction operated by the *IESO* after January 1, 2019 to acquire *capacity*, in accordance with section 18 of Chapter 7;

transitional capacity auction clearing price means the price at which *a capacity auction* clears for an *obligation period* and will be quoted in $/MW-day;

transitional capacity auction reference price represents the price at which resources would be incentivized to enter the market and recover the necessary costs to make their capacity available, recognizing their revenue opportunities and avoided costs in the *energy market*. The reference price is directly associated with the *target capacity* as another key reference point in the demand curve;

PART 5 – IESO BOARD DECISION RATIONALE

Documents presented to the IESO Board of Directors as well as the reasons for adopting the amendments are available online.

Power to Ontario. On Demand.

Market Rule Amendment Proposal

Part 1 – Market Rule Information

Identification No.:	MR-00439-R01		
Subject:	Transitional Capacity Auction		
Title:	Participant Authorization and Facility Registration		
Nature of Proposal:	☒ Alteration	☒ Deletion	☒ Addition
Chapter:	2, 7	Appendix:	
Sections:	Chapter 2, Sections 1.2, 2.1, 3.1, 5.1, 5B, 7.1, Chapter 2 – Appendices, Chapter 7, 2.5.4, 18.1-18.4, 19.1-19.3, 19.6 (new)		
Sub-sections proposed for amending:			

Part 2 – Proposal History

Version	Reason for Issuing	Version Date
1.0	Draft for Stakeholder Review and Comment	May 15, 2019
2.0	Submitted for Technical Panel Review	June 18, 2019
3.0	Posted for Stakeholder Review and Comment	June 27, 2019
4.0	Submitted for Technical Panel Vote	August 6, 2019
5.0	Recommended by Technical Panel; Submitted to IESO Board	August 14, 2019
6.0	Approved by IESO Board	August 28, 2019
Approved Amendment Publication Date:	September 5, 2019	
Approved Amendment Effective Date:	October 15, 2019	

PART 3 – EXPLANATION FOR PROPOSED AMENDMENT

Provide a brief description of the following:

- The reason for the proposed amendment and the impact on the *IESO-administered markets* if the amendment is not made.
- Alternative solutions considered.
- The proposed amendment, how the amendment addresses the above reason and impact of the proposed amendment on the *IESO-administered markets*.

Summary

The IESO proposes to amend the market rules to evolve the Demand Response Auction (DRA) into the Transitional Capacity Auction (TCA) to address capacity needs in Ontario.

Over its four auctions, the DRA has proven successful in driving down capacity costs and increasing competition. Enhancing the IESO's approach to capacity auctions this year by opening participation to other resources is another step toward a more competitive electricity marketplace; it moves Ontario's electricity marketplace down the path of efficiency, competition, and transparency – the key principles of the market renewal efforts.

This proposal will be discussed as part of the Transitional Capacity Auction stakeholder engagement initiative before consideration by the Technical Panel.

Further information on the Transitional Capacity Auction stakeholder engagement is found here.

Background

In order to participate in a TCA, existing market participants or new applicants must become authorized as a capacity auction participant. This participant type will allow organizations to become authorized with the IESO for the purpose of participating in a TCA and be bound by the applicable IESO market rules. There are additional authorization and facility registration requirements for the IESO physical market for those capacity auction participants that obtain a capacity obligation from a TCA. Participants that receive a capacity obligation in a TCA will be required to register their facilities with the IESO.

This proposal also includes the prudential support framework for the TCA which is largely based on the DRA framework.

Discussion

Most additions in this rule amendment proposal are defined term changes, for instance changing demand response to capacity or commitment to obligation. Newly created terms such as capacity auction participant and capacity market participant are described and defined in the definitions package (MR-00439-R00).

This market rule amendment proposal was first circulated to stakeholders and market participants who are participating in the Transitional Capacity Auction stakeholder engagement. No responses to feedback were received pertaining to this proposal.

More specifically, Sections 18.1 and 18.2 add some clarifications to existing language and Section 19.1 adds a generator as eligible to be a capacity auction participant that can secure a capacity obligation.

PART 3 – EXPLANATION FOR PROPOSED AMENDMENT

Section 19.6 is a new section that provides for the eligibility requirements for capacity generator resources. Specific changes to the market rules are listed below. There are five additional rule amendment packages that form the entirety of the proposed rule changes for the TCA.

PART 4 – PROPOSED AMENDMENT

Chapter 2

1.2 Participation

1.2.2 No person shall be authorized by the *IESO* to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* unless the *IESO* is satisfied:

1.2.2.1 on the basis of the certification, tests, and inspections referred to in section 6.2, that the person satisfies the technical requirements referred to in that section applicable to all *market participants*;

1.2.2.2 that the person, if it applies to participate in the *real-time markets*, will either satisfy the *prudential support* requirements of Appendix 2.3 and any other financial requirements set forth in the *market rules* applicable to all *market participants* and the *IESO-administered market* in which the person wishes to participate, or in the case of a ~~*demand response*~~*capacity market participant*, satisfy the ~~*demand response security*~~*capacity prudential support* requirements in section ~~5A~~5B;

2. Classes of Market Participants

2.1.1 The following classes of persons may apply for authorization to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid:*

2.1.1.1 *generators*;

2.1.1.2 *distributors*;

2.1.1.3 *wholesale sellers*;

2.1.1.4 *wholesale consumers*;

2.1.1.5 *retailers*;

2.1.1.6 *transmitters*;

2.1.1.7 *financial market participants*;

2.1.1.8 [Intentionally left blank – section deleted]

2.1.1.9 *demand response market participants*;~~ and~~

2.1.1.10 ~~*demand response*~~[Intentionally left blank – section deleted]

2.1.1.11 *capacity market participants*; and

2.1.1.12 *capacity auction participants*.

3. Application for Authorization

3.1.2 The application for authorization to participate shall be accompanied by:

3.1.2.1 the non-refundable application fee established from time to time by the *IESO* to defray the costs of processing the application; and

3.1.2.2 unless the *application for authorization to participate* is submitted in respect of an applicant that is applying for authorization to participate in the *IESO-administered markets* solely as a *financial market participant* or a ~~*demand response*~~*capacity auction participant*, either:

a. the federal harmonized value-added tax system registration number issued to the applicant by the Canada Customs and Revenue Agency; or

b. where the applicant is resident in Canada and is, by virtue of *applicable law*, not liable to pay the federal harmonized value-added tax under Part IX of the *Excise Tax Act* (Canada), such documentation as may be prescribed in the *Excise Tax Act* (Canada) or described in the policies of the Canada Customs and Revenue Agency to support the exemption from such liability to pay.

5. Prudential Requirements

5.1 Purpose

5.1.1 This section 5 sets forth the nature and amount of *prudential support* that must be provided by *market participants* as a condition of participation in the *real-time* *markets* or of causing or permitting electricity to be conveyed into, through or out of the *IESO-controlled grid*, and the manner in which *market participants* must provide and maintain such *prudential support* on an on-going basis in order to protect the *IESO* and *market participants* from payment defaults. *Market participants* participating in the *IESO-administered markets* solely as a ~~*demand response*~~ *capacity market participant* or ~~*demand response*~~*capacity auction participant* with a ~~*demand response*~~ *capacity obligation* shall be subject only to the ~~*demand response*~~*capacity prudential support* requirements in section 5B.

5B. ~~Demand Response~~ Capacity Prudential Requirements

5B.1 Purpose

5B.1.1 This section 5B sets forth the nature and amount of ~~*demand response*~~ *capacity prudential support* that must be provided by *market participants* that are either ~~*demand response*~~*capacity auction participants* or ~~*demand response*~~*capacity market participants* as a condition of delivering on a ~~*demand response*~~ *capacity obligation*, and the manner in which such *market participants* must provide and maintain ~~*demand response*~~*capacity prudential support* on an on-going basis, in order to protect the *IESO* and *market participants* from payment defaults.

5B.2 Market Participant Obligations

5B.2.1 Each *market participant* shall initially and continually satisfy the obligations set forth in this section 5B.2 with regard to the provision of ~~*demand response*~~*capacity prudential support* as a condition of delivering on a ~~*demand response*~~ *capacity obligation*.

5B.2.2 No *market participant* that is required to provide ~~*demand response*~~*capacity prudential support* shall participate in the *real-time markets* or cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* unless that *market participant* satisfies the requirements of this section.

5B.2.3 Each *market participant* shall provide to the *IESO*, on an ongoing basis, such information as the *IESO* may reasonably require for the purpose of determining that *market participant's* ~~*demand response*~~*capacity prudential support obligation*.

5B.2.4 If ~~*demand response*~~ *capacity prudential support* previously provided to the *IESO* by a *market participant* is due to expire or terminate, and upon expiry or termination of the existing ~~*demand response*~~*capacity prudential support*, the total ~~*demand response*~~*capacity prudential support* held by the *IESO* in respect of that *market participant* will be less than the *market participant's* ~~*demand response*~~*capacity prudential support obligation*, then at least ten *business days* prior to the time at which the existing security is due to expire or terminate, the *market participant* must provide to the *IESO* replacement ~~*demand response*~~*capacity prudential support* which will become effective no later than the expiry or termination of the existing collateral, such that the total ~~*demand response*~~*capacity prudential support* provided is at least equal to the *market participant's* ~~*demand response*~~*capacity prudential support obligation*.

5B.2.5 Where a *market participant's* ~~*demand response*~~*capacity prudential support obligation* has been reduced pursuant to section 5B.5 and the relevant credit rating is revised or the relevant payment history has changed, such as to result in an increase in the *market participant's* ~~*demand response*~~*capacity prudential support obligation*, then within five *business days*, the *market participant* must provide to the *IESO* additional ~~*demand response*~~*capacity prudential support* such that the total ~~*demand response*~~*capacity prudential support* provided is at least equal to the *market participant's* ~~*demand response*~~*capacity prudential support obligation* when calculated on the basis of the revised credit rating or payment history.

5B.2.6 Where any part of the ~~*demand response*~~*capacity prudential support* provided by a *market participant* otherwise ceases to be current or valid for any reason, the *market participant* must immediately so notify the *IESO* and provide to the *IESO*, within two *business days*, replacement ~~*demand response*~~*capacity prudential support* such that the total ~~*demand response*~~*capacity prudential support* provided is at least equal to the *market participant's* ~~*demand response*~~*capacity prudential support obligation.*

5B.2.7 If the *IESO* draws upon part or all of a *market participant's* ~~*demand response*~~*capacity prudential support* in accordance with section 6.3.3.2 of Chapter 3 and the remaining ~~*demand response*~~*capacity prudential support* held by the *IESO* in respect of that *market participant* is less than the *market participant's* ~~*demand response*~~*capacity prudential support obligation*, the *market participant* must, within five *business days* of receiving notice from the *IESO*, provide the *IESO* with additional ~~*demand response*~~*capacity prudential support* such that the total ~~*demand response*~~*capacity prudential support* provided is at least equal to the *market participant's* ~~*demand response*~~*capacity prudential support obligation*.

5B.3 Calculation of ~~Demand Response~~Capacity Prudential Support Obligations

5B.3.1 The *IESO* shall determine, in accordance with the applicable *market manual*, for each *market participant*, a ~~*demand response*~~*capacity prudential support obligation* for each ~~*commitment*~~*obligation period*, based on a percentage of the highest monthly availability payment, less any allowable reductions pursuant to section 5B.5.

5B.3.2 The IESO shall review the ~~demand response~~capacity prudential support obligation of each market participant as follows:

5B.3.2.1 prior to the start of each ~~*commitment*~~*obligation period*;

5B.3.2.2 within two *business days* after it receives notice of any changes to the status of a *market participant* as compared to such status that was in effect when the *market participant's* ~~*demand response*~~*capacity prudential support* was last calculated; or

5B.3.2.3 as a result of either a change in or loss of a *market participant's* credit rating or good payment history reduction calculated in accordance with section 5B.5.

5B.3.3 The *IESO* may change the ~~*demand response*~~*capacity prudential support obligation* for a *market participant* at any time as a result of a review conducted pursuant to section 5B.3.2, and shall promptly notify the *market participant* of any such change. Any change to a *market participant's* ~~*demand response*~~*capacity prudential support obligation* shall apply with effect from such time, not being earlier than the time of notification of the change to the ~~*demand*~~ *market participant*, as the *IESO* may specify in the notice. The *market participant* must supply the *IESO*, within five *business days* of the effective date of the change, any additional ~~*demand response*~~*capacity prudential support* that may be required as a result of an increase in the *market participant's* ~~*demand response*~~*capacity prudential support obligation* that results from such change.

5B.4 Obligation to Provide ~~Demand Response~~Capacity Prudential Support

5B.4.1 Each *market participant* must provide to the *IESO* and maintain ~~*demand response*~~*capacity prudential support*, the value of which is at least equal to the *market participant's* ~~*demand response*~~*capacity prudential support obligation*. The aggregate value of the ~~*demand response*~~*capacity prudential support* shall be equal to the value of the undrawn or unclaimed amounts of ~~*demand response*~~*capacity prudential support* provided by the *market participant.*

5B.4.2 A *market participant's* ~~*demand response*~~*capacity prudential support obligation* must be met through the provision to the *IESO* and the maintenance of ~~*demand response*~~*capacity prudential support* in the following form:

5B.4.2.1 a guarantee or irrevocable commercial letter of credit, which in both cases must be in a form acceptable to the *IESO* and provided by:

a. a bank named in a Schedule to the *Bank Act*, S.C. 1991, c.46 with a minimum long-term credit rating of "A" from an *IESO* acceptable major bond rating agency as identified in the list referred to in section 5B.5.7; or

b. a credit union licensed by the Financial Services Commission of Ontario with a minimum long-term credit rating of "A" from an *IESO* acceptable major bond rating agency as identified in the list referred to in section 5B.5.7.

5B.4.3 The following provisions shall apply to a guarantee or irrevocable letter of credit provided in section 5B.4.2.1:

5B.4.3.1 the letter of credit shall provide that it is issued subject to either The Uniform Customs and Practice for Documentary Credits, 2007 Revision, ICC Publication No. 600 or The International Standby Practices 1998;

5B.4.3.2 the *IESO* shall be named as beneficiary in each letter of credit, each letter of credit shall be irrevocable, partial draws on any letter of credit shall not be prohibited and the letter of credit or the aggregate amount of all letters of credit shall be in the face amount of at least the amount specified by the *IESO*;

5B.4.3.3 the only conditions on the ability of the *IESO* to draw on the letter of credit shall be the occurrence of an *event of default* by or in respect of the *market participant* and a certificate of an officer of the *IESO* that the *IESO* is entitled to draw on the letter of credit, in accordance with the provisions of the *market rules* in the amount specified in the certificate as at the date of delivery of the certificate;

5B.4.3.4 the letter of credit shall either provide for automatic renewal (unless the issuing bank advises the *IESO* at least thirty days prior to the renewal date that the letter of credit will not be renewed) or be for a term of at least one (1) year. In either case it is the responsibility of the *market participant* to maintain the requisite amount of ~~*demand response*~~*capacity* *prudential support*. Where the *IESO* is advised that a letter of credit is not to be renewed or the term of the letter of credit is to expire, the *market participant* shall arrange for and deliver alternative ~~*demand response*~~*capacity* *prudential support* within the time frame mandated by the *market rules* so as to enable the *market participant* to be in compliance with the *market rules*; and

5B.4.3.5 by including a letter of credit as part of its ~~*demand response*~~*capacity* *prudential support*, the *market participant* represents and warrants to the *IESO* that the issuance of the letter of credit is not prohibited in any other agreement, including without limitation, a negative pledge given by or in respect of the *market participant*.

5B.4.4 For the purpose of section 5B.4.2.1, the *IESO* shall establish, maintain, and publish a list of organizations eligible to provide the ~~*demand response*~~*capacity* *prudential support* referred to in section 5B.4.2.1 and shall establish for each such eligible ~~*demand response*~~*capacity* *prudential support* provider, an aggregate limit of the ~~*demand response*~~*capacity* *prudential support* that may be provided by that ~~*demand response*~~*capacity* *prudential support* provider to *market participants*. If aggregate limits are reached for any of these eligible organizations, *market participants* will be required to obtain ~~*demand response*~~*capacity* *prudential support* from other eligible organizations that are still within their respective ~~*demand response*~~*capacity* *prudential support* limits.

5B.4.5 In the event that the ~~*demand response*~~*capacity* *prudential support* provided by a *market participant* is a greater amount than required by the *market rules*, the *IESO* shall, upon written request by the *market participant*, return to the *market participant* an amount equal to the difference between the value of ~~*demand response*~~*capacity* *prudential support* held by the *IESO* and the ~~*demand response*~~*capacity* *prudential support obligation* of the *market participant* at that time. The *IESO* shall return such amount within five *business days* of the receipt of the request for the return of the amount from the *market participant*. In all circumstances, the *IESO* shall return ~~*demand response*~~*capacity* *prudential support* only after all payments and charges for the final month of a *commitment period* have been settled.

5B.4.6 The minimum terms and conditions that shall be included in the ~~*demand response*~~*capacity* *prudential support* in accordance with section 5B.4.2.1 shall be as follows:

5B.4.6.1 ~~*demand response*~~*capacity* *prudential support* shall be obligations in writing;

5B.4.6.2 ~~*demand response*~~*capacity* *prudential support* shall constitute valid and binding unsubordinated obligations to pay to the *IESO* amounts in accordance with its terms which relate to the obligations of the relevant *market participant* under the *market rules*; and

5B.4.6.3 ~~*demand response*~~*capacity* *prudential support* shall permit drawings or claims by the *IESO* on demand to a stated certain amount, including partial drawings or claims.

5B.4.7 Upon the occurrence of an *event of default*, the *IESO* shall be entitled to exercise its rights and remedies as set out in the *market rules*, or provided for at law or in equity. Without limiting the generality of the foregoing, such rights and remedies shall, in respect of the ~~*demand response*~~*capacity* *prudential support* provided by the *market participant*, include setting-off and applying any and all ~~*demand response*~~*capacity* *prudential support* held against the indebtedness, obligations and liabilities of the *market participant* to the *IESO* in respect of the participation by the *market participant* in the *real-time markets*, including the costs, charges, expenses and fees described in section 5B.4.9.

5B.4.8 Each of the remedies available to the *IESO* under the *market rules* or at law or in equity is intended to be a separate remedy and in no way is a limitation on or substitution for any one or more of the other remedies otherwise available to the *IESO*. The rights and remedies expressly specified in the *market rules* or at law or in equity are cumulative and not exclusive. The *IESO* may in its sole discretion exercise any and all rights, powers, remedies and recourses available under the *market rules* or under any document comprising the ~~*demand response*~~*capacity* *prudential support* provided by the *market participant* or any other remedy available to the *IESO* howsoever arising, and whether at law or in equity, and such rights, powers and remedies and recourses may be exercised concurrently or individually without the necessity of any election.

5B.4.9 The *market participant* agrees to pay to the *IESO* forthwith on demand all reasonable costs, charges, expenses and fees (including, without limiting the generality of the foregoing, legal fees on a solicitor and client basis) of or incurred by or on behalf of the *IESO* in the realization, recovery or enforcement of the ~~*demand response*~~*capacity* *prudential support* provided by the *market participant* and enforcement of the rights and remedies of the *IESO* under the *market rules* or at law or in equity in respect of the participation by the *market participant* in the *real-time markets.*

5B.5 Reductions in ~~Demand Response~~Capacity Prudential Support Obligations

5B.5.1 Subject to section 5B.5.2, the *IESO* may reduce the ~~*demand response*~~*capacity* *prudential support obligation* of a rated *market participant*, other than a *distributor*, by an amount equal to the monetary value prescribed by the table below, resulting from a credit rating from a major bond rating agency identified in the list referred to in section 5B.5.7 issued and in effect in respect of the ~~*demand response*~~*capacity* *market participant*.

Credit Rating Category using Standard and Poor's Rating Terminology	Allowable Reduction in Prudential Support
AA- and above or equivalent	100% of the ~~*demand response*~~*capacity* *prudential*

	support obligation before allowable reductions
A-, A, A+ or equivalent	Greater of 90% of the ~~*demand response*~~*capacity prudential support obligation* before allowable reductions or $37,500,000
BBB-, BBB, BBB+ or equivalent	Greater of 65% of the ~~*demand response*~~*capacity prudential support obligation* before allowable reductions or $15,000,000
BB-, BB, BB+ or equivalent	Greater of 30% of the ~~*demand response*~~*capacity prudential support obligation* before allowable reductions or $4,500,000
Below BB- or equivalent	0

5B.5.1A Subject to section 5B.5.2, the *IESO* may reduce the ~~*demand response*~~*capacity prudential support obligation* of a rated *distributor* by an amount equal to the monetary value prescribed by the table below, resulting from a credit rating from a major bond rating agency identified in the list referred to in section 5B.5.7 issued and in effect in respect of the ~~*demand response*~~*capacity market participant*.

Credit Rating Category using Standard and Poor's Rating Terminology	**Allowable Reduction in Prudential Support**
AA- and above or equivalent	100% of the ~~*demand response*~~*capacity prudential support obligation* before allowable reductions
A-, A, A+ or equivalent	Greater of 95% of the ~~*demand response*~~*capacity prudential support obligation* before allowable reductions or $45,000,000
BBB-, BBB, BBB+ or equivalent	Greater of 80% of the ~~*demand response*~~*capacity prudential support obligation* before allowable reductions or $22,500,000
BB-, BB, BB+ or equivalent	Greater of 55% of the ~~*demand response*~~*capacity prudential support obligation* before allowable reductions or $7,500,000
Below BB- or equivalent	0

5B.5.2 Any recommendation to move a *market participant* to "credit watch negative" by any of the major bond rating agencies identified in the list referred to in section 5B.5.7, shall be deemed to automatically result in a one-notch reduction in terms of the credit rating (for example, from BBB+ to BBB) of that *market participant* for the purpose of determining the *market participant's* ~~*demand response*~~*capacity prudential support obligation*.

5B.5.3 Where a *market participant's* ~~*demand response*~~*capacity prudential support obligation* reflects a reduction by reason of the *market participant's* credit rating from a major bond agency identified in the list referred to in section 5B.5.7, the *market participant* shall advise the *IESO* in writing immediately upon the *market participant* becoming aware of either a change in or loss of the then current credit rating or the decision of the bond rating agency to place the *market participant* on "credit watch status" or equivalent.

5B.5.4 Subject to section 5B.5.6, the *IESO* may reduce the *market participant's* ~~*demand response*~~*capacity prudential support obligation* in accordance with sections 5B.5.5 or 5B.5.5A based on the *market participant's* historical good payment history in the *IESO-administered markets*, provided that the *market participant's* payment history includes no *event of default*.

5B.5.5 The *IESO* shall determine the dollar amount of any allowable reduction in the ~~*demand response*~~*capacity prudential support obligation* of an unrated *market participant*, other than a *distributor*, by an amount equal to the monetary value prescribed, by the table below:

Good Payment History Categories for Non-Distributors	**Allowable Reduction in Prudential Support**
≥6 years	Lesser of 50% of the ~~*demand response*~~*capacity prudential support obligation* before allowable reductions or $12,000,000
≥5 years, <6 years	Lesser of 30% of the ~~*demand response*~~*capacity prudential support obligation* before allowable reductions or $7,500,000
≥4, <5 years	Lesser of 25% of the ~~*demand response*~~*capacity prudential support obligation* before allowable reductions or $6,000,000
≥3, <4 years	Lesser of 20% of the ~~*demand response*~~*capacity prudential support obligation* before allowable reductions or $4,500,000
≥2, <3 years	Lesser of 15% of the ~~*demand response*~~*capacity prudential support obligation* before allowable reductions or $3,000,000
<2 years	0

5B.5.5A The *IESO* shall determine the dollar amount of any allowable reduction in the ~~*demand response*~~*capacity prudential support obligation* of an unrated *distributor* by an amount equal to the monetary value prescribed, by the table below:

Good Payment History Categories for Distributors	**Allowable Reduction in Prudential Support**
≥6 years	Lesser of 80% of the ~~*demand response*~~*capacity prudential support obligation* before allowable reductions or $14,000,000
≥5 years, <6 years	Lesser of 65% of the ~~*demand response*~~*capacity prudential support obligation* before allowable reductions or $9,000,000
≥4, <5 years	Lesser of 45% of the ~~*demand response*~~*capacity prudential support obligation* before allowable reductions or $7,500,000
≥3, <4 years	Lesser of 35% of the ~~*demand response*~~*capacity prudential support obligation* before allowable reductions or $6,000,000
≥2, <3 years	Lesser of 25% of the ~~*demand response*~~*capacity prudential support obligation* before allowable reductions or $4,500,000
<2 years	0

5B.5.6 The following restrictions shall apply to the provision of reductions in a *market participant's* ~~*demand response*~~*capacity prudential support obligation* as provided for under sections 5B.5.1, 5B.5.1A, and 5B.5.4:

5B.5.6.1 a *market participant* shall not be entitled to a reduction in its ~~*demand response*~~*capacity prudential support obligation* pursuant to section 5B.5.4 using the payment history of an *affiliate*;

5B.5.6.2 a *market participant* that has a credit rating from a major bond rating agency identified in the list referred to in section 5B.5.7 shall not be entitled to a reduction in its ~~*demand response*~~*capacity prudential support obligation* under section 5B.5.4; and

7. Payment Default Procedure

7.1.1 The *events of default* relating to payment and either *prudential support*~~, *demand response security*, or *demand response*~~ or *capacity prudential support*, as well as the rights and obligations of the *IESO* and *market participants* upon the occurrence of such *event of default*, are specified in section 6.3 of Chapter 3.

Chapter 2 - Appendices

1.3 Dispatch Workstations

1.3.1 Each market participant other than a boundary entity, ~~a demand response auction participant, or a demand response market participant participating in either the capacity based demand response program or with a demand response~~or a *capacity auction participant* with a *capacity obligation* through an hourly demand response resource shall, for the purposes of:

1.3.1.1 the provision to the *IESO* of real-time information required by the *IESO* to direct the operations of the *IESO-controlled grid*;

1.3.1.2 if the person is or will be subject to dispatch by the *IESO*, the receipt of *dispatch instructions*; and

1.3.1.3 the exchange with the *IESO* of other information required to be submitted or received pursuant to Chapter 7 or Chapter 8, other than the submission, receipt of confirmation of and validation of *dispatch data*, *TR bids* or *TR offers* in the *TR market* and *physical bilateral contract data*,

1.4 Participant Workstations

1.4.1 Subject to section 1.6, each *market participant* ~~other than a *demand response market participant* participating only in the *capacity based demand response program*~~ shall, for the purposes of conducting secure communications or transactions with the *IESO* using *IESO*-supplied or approved software, provide, install and maintain a *participant workstation* that meets the specifications, definitions and other requirements set forth in the *participant technical reference manual*.

Chapter 7

2.5 Transfer of Registration of Facilities

2.5.4 Upon completion of the transfer of the *registered facility*, the proposed transferee will have to post with the *IESO* *prudential support* ~~or *demand response*~~and *capacity* *prudential support*, as applicable, equal to the proposed transferee's *prudential support obligation* ~~or *demand response*~~and *capacity* *prudential support obligation*. Until the proposed transferee has done so, the transferring *market participant* shall continue to be liable for the obligations of the proposed transferee in the *IESO-administered markets*. Such obligations shall include, without limitation, the cost of electricity withdrawn from the *IESO-controlled grid* by the proposed transferee and related charges as determined by the *IESO* in accordance with Chapter 9. The *prudential support obligation* and/or ~~*demand response*~~*capacity prudential support obligation* as applicable of the transferring *market participant* shall include all such amounts whether or not the transferring *market participant* has complied with the provisions of this section 2.5.

18. ~~Demand Response~~ Capacity Auctions

18.1 Purpose of ~~Demand Response~~ Capacity Auctions

18.1.1 The ~~*demand response*~~*capacity auctions* will acquire ~~will procure *demand response*~~ *auction capacity* through a competitive auction.

18.1.2 The *IESO* shall specify and *publish* a *target capacity* amount to be ~~procured~~acquired in each ~~*demand response*~~*capacity auction*, as specified in the applicable *market manual.*

18.2 Participation in ~~Demand Response~~Capacity Auctions

18.2.1 No person may participate in a ~~*demand response*~~ *capacity auction* nor receive a ~~*demand response*~~ *capacity obligation* unless that person has:

18.2.1.1 been authorized by the *IESO* as a ~~*demand response*~~*capacity auction participant* in accordance with section 3 of Chapter 2~~;~~ and in accordance with the applicable *market manual*;

18.2.1.2 submitted and ~~has been approved by the~~received *IESO* approval for a *qualified capacity*, using forms and procedures as may be established by the *IESO* in the applicable *market manual*~~, the amount of *demand response capacity* that the *demand response auction participant* is willing to provide~~; and

18.2.1.3 no less than five *business days* prior to the date on which a ~~*demand response*~~*capacity auction* is to be conducted, provided to the *IESO* a ~~*demand response*~~*capacity auction deposit*, in one or both of the forms set forth in section 18.4.

18.2.2 The following provisions of the *market rules* shall not apply to a ~~*demand response*~~ *capacity auction participant* that is authorized by the *IESO* to participate only in a *capacity auction* as an *hourly demand response* ~~*auction*~~*resource*:

18.2.2.1 Chapters 4, 5, and 6;

18.2.2.2 Chapter 7 other than this section 18; and

18.2.2.3 Chapters 8 and 10.

18.2.3 A ~~demand response~~capacity auction participant who obtains a ~~demand response~~ capacity *obligation* shall apply to become authorized by the IESO as a ~~demand response~~*capacity market participant* in accordance with section 3 of Chapter 2.

18.3 Calculation of ~~Demand Response~~Capacity Auction Deposits

18.3.1 Upon receipt of a ~~*demand response auction participant's demand response*~~*qualified capacity* ~~under~~in accordance with section 18.2.1.2, the *IESO* shall determine for each ~~*demand response*~~*capacity auction participant*, a ~~*demand response*~~*capacity auction deposit* for a ~~*demand response*~~*capacity auction* as specified in the applicable *market manual*.

18.3.2 The *IESO* shall review the ~~*demand response*~~*capacity auction deposit* of a ~~*demand response*~~*capacity transferee* upon receipt of a request for a ~~*demand response*~~ *capacity obligation* transfer in accordance with section 18.9.1. As a result of a transfer request, the *IESO* may increase the ~~*demand response*~~*capacity auction deposit* of a ~~*demand response*~~*capacity transferee* and the *IESO* shall notify the ~~*demand response*~~*capacity transferee* of any such increase.

18.3.3 Where the amount of a ~~demand response~~*capacity auction deposit* provided by a ~~demand response~~*capacity auction participant* exceeds the amount required by the *IESO*, the *IESO* shall return the excess amount to the ~~demand response~~*capacity auction participant* within five business days of such a request from the ~~demand response~~*capacity auction participant*. Otherwise, that amount shall be held by the *IESO* and shall form part of that ~~demand response~~*capacity auction participant's* ~~demand response~~*capacity auction deposit* for its participation in a subsequent ~~demand response~~*capacity auction*.

18.4 ~~Demand Response~~Capacity Auction Deposits

18.4.1 A ~~*demand response*~~*capacity auction deposit* shall be in one or both of the following forms:

18.4.1.1 an irrevocable commercial letter of credit provided by a bank named in a Schedule to the *Bank Act*, S.C. 1991, c. 46; or

18.4.1.2 a cash deposit made with the *IESO* by or on behalf of the ~~*demand response*~~*capacity auction participant.*

18.4.2 Where all or part of a ~~*demand response*~~*capacity auction deposit* is in the form of a standby letter of credit, the following provisions shall apply:

18.4.2.1 the letter of credit shall provide that it is issued subject to either The Uniform Customs and Practice for Documentary Credits, 1993 Revision, ICE Publication No. 500 or The International Standby Practices 1998;

18.4.2.2 the *IESO* shall be named as beneficiary in the letter of credit, the letter of credit shall be irrevocable and partial draws on the letter of credit shall not be prohibited;

18.4.2.3 the only condition on the ability of the *IESO* to draw on the letter of credit shall be the delivery of a certificate ~~of~~by an officer of the *IESO* that a specified amount is owing by the ~~*demand response*~~*capacity auction participant* to the *IESO* and that, in accordance with the provisions of the *market rules*, the *IESO* is entitled to payment of that specified amount as of the date of delivery of the certificate;

18.4.2.4 the letter of credit shall either provide for automatic renewal (unless the issuing bank advises the *IESO* at least thirty days prior to the renewal date that the letter of credit will not be renewed) or be for a term of at least one (1) year. Where the *IESO* is advised that a letter of credit is not to be renewed or the term of the letter of credit is to expire, the ~~*demand response*~~*capacity auction participant* shall arrange for and deliver additional ~~*demand response*~~*capacity auction deposits* if the ~~*demand response*~~*capacity auction participant* intends to continue to participate in a ~~*demand response*~~*capacity auction*. If such additional ~~*demand response*~~*capacity auction deposits* are not received by the *IESO* ten (10) *business days* before the expiry of a letter of credit, the *IESO* shall be entitled as of that time to payment of the full face amount of the letter of credit which amount, once drawn by the *IESO*, shall be treated as a ~~*demand response*~~*capacity auction deposit* in the form of cash; and

18.4.2.5 by including a letter of credit as part of a ~~*demand response*~~*capacity auction deposit*, the ~~*demand response*~~*capacity auction participant* represents and warrants to the *IESO* that the issuance of the letter of credit is not prohibited in any other agreement, including without limitation, a negative pledge given by or in respect of the ~~*demand response*~~*capacity auction participant*.

18.4.3 Notwithstanding any other provision of these *market rules*, a person that applies for authorization to participate in the ~~*demand response*~~*capacity auction* and that has not applied for authorization to participate, or is not participating, in any other *IESO-administered market* shall not be required to comply with any requirements for authorization other than those set forth in sections 18.2.1.1 to 18.2.1.3.

18.4.4 In the event a ~~*demand response*~~*capacity auction participant* has not satisfied the applicable eligibility requirements specified in sections 19.2~~ and ~~,19.3, or 19.6 of Chapter 7 and has not elected to buy-out the ~~*demand response*~~ *capacity obligation* in accordance with section 4.7J.3 of Chapter 9, the ~~*demand response*~~ *capacity auction participant*, shall, at the *IESO's* sole discretion, forfeit its ~~*demand response*~~*capacity auction deposit.*

19. ~~Demand Response~~ Capacity Market Participants with ~~Demand Response~~ Capacity Obligations

19.1 Purpose

19.1.1 This section details the delivery of a ~~*demand response*~~ *capacity obligation.*

19.1.2 A ~~*demand response*~~ *capacity market participant* ~~who~~that receives a ~~*demand response*~~ *capacity obligation* shall deliver into the *IESO-administered market* via resources registered as one of the following resources:

19.1.2.1 *hourly demand response*;~~ or~~

19.1.2.2 *a dispatchable load*~~.~~;

19.1.2.3 *generator*.

19.1.3 *generator* authorization types participating in a *capacity auction* must participate using *capacity auction eligible generation resources.*

19.2 Eligibility Requirements for Hourly Demand Response Resources with ~~Demand Response~~ Capacity Obligations

19.2.1 A ~~demand response~~capacity *market participant* is eligible to ~~participate as~~ satisfy its *capacity obligation* with an *hourly demand response* resource provided that the ~~demand response~~*capacity market participant*:

19.2.1.1 demonstrates to the satisfaction of the *IESO* that it can provide the ~~*demand response*~~ *capacity obligation*, as specified in the applicable *market manual*;

19.2.1.2 registers its *facilities* and *demand response contributors* as applicable, to the satisfaction of the *IESO*, in accordance with the applicable *market manual*. The ~~*demand response*~~*capacity market participant* shall not modify, vary or amend in any material respect any of the features or specifications of any ~~resource~~*facility* without first requesting *IESO* authorization and approval in accordance with the applicable *market manual*;

19.2.1.3 satisfies the *connection assessment* requirements in accordance with section 6 of Chapter 4, if required by the *IESO*, in accordance with the *applicable market manual*;

19.2.1.4 has provided *prudential support* and *capacity prudential support* in accordance with section 5 of Chapter 2.

19.2.2 The *IESO* may refuse participation of an *hourly demand response* resource by a ~~*demand response*~~*capacity market participant* if the resource's participation would negatively impact the *reliable* operation of the *IESO-controlled grid*.

19.2.3 The *IESO* may remove a ~~*demand response*~~*capacity market participant's hourly demand response* resource from market participation if the resource's continued participation would negatively impact the *reliable* operation of the *IESO-controlled grid*. The *IESO* may temporarily remove a ~~*demand response*~~*capacity market participant's hourly demand response* resource from market participation if the conditions on the *IESO-controlled grid* are such that the resource's participation would negatively impact the *reliable* operation of the *IESO-controlled grid*.

19.2.4 The following provisions of the *market rules* shall not apply to a ~~*demand response*~~*capacity market participant* that is authorized by the *IESO* to participate only with an *hourly demand response* resource and is not a *wholesale consumer* that is a *non-dispatchable load*:

19.2.4.1 Chapter 2, sections 5A and 8;

19.2.4.2 ~~Chapter~~Chapters 5, ~~other than section 1.2.1 to 1.2.3, 2.3, 2.4, 5.~~6, 8, 10; and ~~5.9;~~

19.2.4.3 Chapter 7 section 7~~; and~~.

~~19.2.4.4 Chapters 6, 8, 10.~~

19.2.5 A *wholesale consumer* that is a *non-dispatchable load* may participate as a *demand response contributor* to an *hourly demand response* resource to fulfill a ~~demand response~~ *capacity obligation*, provided that the *non-dispatchable load* meets all the applicable eligibility requirements of this section 19.2, and the requirements in the *market rules* that are applicable to a *wholesale consumer* that is a *non-dispatchable load*.

19.3 Eligibility Requirements for Dispatchable Loads with a ~~Demand Response~~ Capacity Obligation

19.3.1 A ~~demand response~~ *capacity market participant* is eligible to ~~participate~~satisfy its *capacity obligation* as a *dispatchable load* ~~in satisfying its demand response capacity obligation,~~ provided that the ~~demand response~~*capacity market participant*:

19.3.1.1 demonstrates to the satisfaction of the *IESO* that it can provide the ~~*demand response*~~ *capacity obligation*, as specified in the applicable *market manual*;

19.3.1.2 is authorized as a *wholesale consumer;*

19.3.1.3 registers its *facilities* in accordance with the registration requirements for *wholesale consumers* that are *dispatchable loads*. The ~~*demand response*~~*capacity market participant* shall not modify, vary or amend in any material respect any of the features or specifications of any resource without first requesting *IESO* authorization and approval in accordance with the applicable *market manual*;

19.3.1.4 satisfies the *connection assessment* requirements in accordance with section 6 of Chapter 4, if required by the *IESO* in accordance with the *applicable market manual*;

19.3.1.5 has provided *prudential support* and *capacity prudential support* in accordance with section 5 of Chapter 2.

19.3.2 The *IESO* may refuse participation of a *dispatchable load's* resource by a ~~*demand response*~~*capacity market participant* if the resource's participation would negatively impact the *reliable* operation of the *IESO-controlled grid*.

19.3.3 The *IESO* may remove a ~~*demand response*~~*capacity market participant's dispatchable load* resource if the resource's continued participation would negatively impact the *reliable* operation of the *IESO-controlled grid*. The *IESO* may temporarily remove a ~~*demand response*~~*capacity market participant's dispatchable load* resource if the conditions on the *IESO-controlled grid* are such that the resource's participation would negatively impact the *reliable* operation of the *IESO-controlled grid*.

19.6 Eligibility Requirements for Capacity Generation Resources

19.6.1 A *capacity market participant* is eligible to satisfy its *capacity obligation* as a *capacity generation resource*, provided that the *capacity market participant*:

19.6.1.1 demonstrates to the satisfaction of the IESO that it can provide the *capacity obligation*, as specified in the applicable *market manual;*

19.6.1.2 is authorized as a *generator*;

19.6.1.3 registers *facilities* in accordance with the registration requirements applicable to *generation facilities*. The *capacity market participant* shall not modify, vary or amend in any material respect any of the features or specifications of any *facility* without first requesting *IESO* authorization and approval in accordance with the applicable *market manual;*

19.6.1.4 satisfies the *connection assessment* requirements in accordance with section 6 of Chapter 4, if required by the *IESO* in accordance with the applicable *market manual;*

19.6.1.5 has provided *prudential support* and *capacity prudential support* in accordance with section 5 of Chapter 2.

PART 5 – IESO BOARD DECISION RATIONALE

Documents presented to the IESO Board of Directors as well as the reasons for adopting the amendments are available online.

Market Rule Amendment Proposal

PART 1 – MARKET RULE INFORMATION

Identification No.:	MR-00439-R02		
Subject:	Transitional Capacity Auction		
Title:	Auction Parameters and Publication		
Nature of Proposal:	☒ Alteration	☒ Deletion	☐ Addition
Chapter:	Ch. 7	Appendix:	
Sections:	Ch. 7, 18.5-18.8		
Sub-sections proposed for amending:			

PART 2 – PROPOSAL HISTORY

Version	Reason for Issuing	Version Date
1.0	Draft for Stakeholder Review and Comment	May 15, 2019
2.0	Submitted for Technical Panel Review and Comment	June 18, 2019
3.0	Posted for Stakeholder Review and Comment	June 27, 2019
4.0	Submitted for Technical Panel Vote	August 6, 2019
5.0	Recommended by Technical Panel; Submitted to IESO Board	August 16, 2019
6.0	Approved by IESO Board	August 28, 2019
Approved Amendment Publication Date:	September 5, 2019	
Approved Amendment Effective Date:	October 15, 2019	

PART 3 – EXPLANATION FOR PROPOSED AMENDMENT

Provide a brief description of the following:

- The reason for the proposed amendment and the impact on the *IESO-administered markets* if the amendment is not made.
- Alternative solutions considered.
- The proposed amendment, how the amendment addresses the above reason and impact of the proposed amendment on the *IESO-administered markets*.

Summary

The IESO proposes to amend the market rules to evolve the Demand Response Auction (DRA) into the Transitional Capacity Auction (TCA) to address capacity needs in Ontario.

Over its four auctions, the DRA has proven successful in driving down capacity costs and increasing competition. Enhancing the IESO's approach to capacity auctions this year by opening participation to other resources is another step toward a more competitive electricity marketplace; it moves Ontario's electricity marketplace down the path of efficiency, competition, and transparency – the key principles of the market renewal efforts.

This proposal will be discussed as part of the Transitional Capacity Auction stakeholder engagement initiative before consideration by the Technical Panel.

Further information on the Transitional Capacity Auction stakeholder engagement is found here.

Background

The TCA will determine capacity obligations for the obligation periods and the auction clearing price for successful capacity auction participants. For each obligation period, the IESO will establish a demand curve, and the auction offers will be stacked against the demand curve to determine the capacity obligations that minimize total cost while respecting the parameters of the TCA.

Prior to each TCA, the IESO will establish and publish the demand curve parameters in a public, pre-auction report. The pre-auction report will also identify key milestones for participation and zonal constraints. The outcomes of the TCA will be included in both public reports available to the entire marketplace and private reports send directly to capacity auction participants.

Discussion

Most additions in the rule amendment proposal are defined term changes. Section 18.5.2.4 has been removed as it is no longer required. In this section, the 'transitional capacity auction' defined terms are used to refer specifically to the first TCA to avoid confusion with the ongoing DRA.

This market rule amendment proposal was first circulated to stakeholders and market participants who are participating in the Transitional Capacity Auction stakeholder engagement. No responses to feedback were received pertaining to this proposal.

Specific changes to the market rules are listed below. There are five additional rule amendment packages that form the entirety of the proposed rule changes for the TCA.

PART 4 – PROPOSED AMENDMENT

18.5 ~~Demand Response~~Transitional Capacity Auction Parameters

18.5.1 The *IESO* shall conduct ~~a *demand response auction* on an annual basis~~*capacity auctions* to ~~procure *demand response*~~acquire *capacity* for ~~a~~ one-year ~~period.~~*commitment periods.* In each ~~*demand response*~~*capacity auction* the *IESO* shall ~~procure *demand response*~~ acquire *auction capacity* for each ~~*commitment*~~*obligation period* as specified in the applicable *market manual*.

Demand Curve, Zonal Constraints and Pre-Auction Reports

18.5.2 The *IESO* shall, in accordance with the applicable *market manual*, *publish* a pre-auction report in advance of each ~~*demand response*~~*transitional capacity auction*, including the following ~~*demand response*~~*transitional capacity auction* demand curve reference points:

18.5.2.1 a ~~*demand response*~~ *target capacity* in accordance with section 18.1.2;

18.5.2.2 a ~~*demand response*~~ *transitional capacity auction reference price;*

18.5.2.3 a maximum and minimum ~~*demand response*~~ *transitional capacity auction clearing price*;

18.5.2.4 ~~a minimum *demand response capacity* limit that a *demand response auction* shall clear;~~ [Intentionally left blank – section deleted]

18.5.2.5 a maximum ~~*demand response*~~*auction capacity* limit at the maximum ~~*demand response*~~*transitional capacity auction clearing price* that a ~~*demand response*~~*transitional capacity auction* shall clear; and

18.5.2.6 a maximum ~~*demand response capacity* limit that a *demand response*~~ *auction* *capacity* limit that a *transitional capacity auction* shall clear.

18.5.3 The *IESO* shall define ~~*demand response*~~*capacity auction zonal constraints* for each ~~demand response~~*transitional capacity auction* and the IESO shall publish, in the pre-auction report, those requirements as specified in the applicable *market manual*.

18.5.4 The *IESO* shall specify and *publish* the following timelines associated with a ~~*demand response*~~*capacity auction*:

18.5.4.1 the deadline to submit the amount of ~~*demand response*~~*qualified capacity* the ~~*demand response*~~*capacity auction participant* is willing to provide pursuant to section 18.2.1.2;

18.5.4.2 the deadline for a ~~*demand response*~~*capacity auction participant* to submit a ~~*demand response*~~*capacity auction deposit* in accordance with section 18.2.1.3;

18.5.4.3 the dates in which a ~~*demand response*~~*capacity auction participant* may submit ~~*demand response*~~*transitional capacity auction* offers for a ~~*demand response*~~*capacity auction*;

18.5.4.4 the period over which the *IESO* shall conduct the ~~*demand response*~~*transitional capacity auction*; and

18.5.4.5 the date of ~~*demand response*~~*transitional capacity auction* post-auction reporting in accordance with sections 18.8.1 and 18.8.2.

18.6 ~~Demand Response~~Capacity Auction Offers

18.6.1 A ~~*demand response*~~*capacity auction offer*:

18.6.1.1 may be submitted or revised by the ~~*demand response*~~*capacity auction participant* on the dates specified in accordance with section 18.5.4 and the applicable *market manual*;

18.6.1.2 shall only be applicable to the ~~*commitment period*~~*obligation periods* for which a ~~*demand response*~~*capacity auction participant* has submitted a ~~*demand response*~~*capacity auction offer*, in accordance with the applicable *market manual*; and

18.6.1.3 shall be time stamped by the *IESO* when received.

18.6.2 A ~~*demand response*~~*capacity auction offer* shall only be submitted in respect of a given ~~*demand response*~~*capacity auction* if:

18.6.2.1 the ~~*demand response*~~*capacity auction participant* complies with the ~~*demand response*~~*capacity auction* ~~*participation*~~*participant* requirements in section 18.2.1; and

18.6.2.2 the ~~*demand response*~~*capacity auction participant* has not been disqualified from full or partial participation in the ~~*demand response*~~*capacity auction*~~ in accordance with section~~, pursuant to sections 19.4.8, 19.5.4~~ and the applicable *market manual*~~, or 19.6.4.

18.6.3 A ~~*demand response*~~*capacity auction offer* may include up to twenty *price-quantity* pairs for each ~~*commitment*~~*obligation period* and shall comply with the following:

18.6.3.1 the ~~*demand response*~~*capacity auction offer* shall be for and applicable over an entire ~~*commitment*~~*obligation period* associated with a ~~*demand response*~~*capacity auction*;

18.6.3.2 the ~~*demand response*~~ *capacity auction offer* price in any *price-quantity* pair shall:

- be expressed in dollars and whole cents per MW-day of ~~*demand response*~~*auction capacity* to be provided in each hour of the *availability window* throughout the ~~*commitment*~~*obligation period* associated with that ~~*demand response*~~*transitional capacity auction*;
- be greater than or equal to $0.00/MW-day;
- not exceed the applicable maximum ~~*demand response*~~*transitional capacity auction clearing price*; and
- increase as the associated ~~*demand response*~~*capacity auction offer* quantity increases.

18.6.3.3 the ~~*demand response*~~*capacity auction offer* quantity in any *price-quantity* pair shall be expressed in MW to not more than one decimal place and the total offered quantity shall not exceed the *qualified* ~~*demand response*~~ *capacity* of the resource, determined through the submission of ~~*demand response*~~*auction capacity* that a ~~*demand response*~~*capacity auction participant* is willing to provide in accordance with section 18.2.1.2; and

18.6.3.4 the ~~*demand response*~~ *capacity auction offer* shall indicate whether the ~~*demand response*~~ *capacity auction participant* is willing to clear a~~n~~ *capacity auction* with the full amount of ~~*demand response*~~ *auction capacity offered* in a lamination or a partial amount of the ~~*demand response*~~*auction capacity offered* in a lamination, in accordance with the applicable *market manual*.

18.7 ~~Demand Response~~Transitional Capacity Auction Clearing Prices and Quantities

18.7.1 The *IESO* shall determine a ~~*demand response*~~*transitional capacity auction* demand curve to be utilized for each ~~*commitment*~~*obligation period* in an auction year, based upon the ~~*demand response*~~*transitional capacity auction* parameters detailed in the pre-auction report pursuant to section 18.5 and in accordance with the applicable *market manual*.

18.7.2 The *IESO* shall, in each ~~*demand response*~~*transitional capacity auction*, determine for each ~~*commitment*~~*obligation period* the ~~*demand response*~~*transitional capacity auction clearing price* in accordance with the applicable *market manual*.

18.7.3 The *IESO* shall, in each ~~*demand response*~~ *transitional capacity auction*, determine for each ~~*commitment*~~*obligation period* the ~~*demand response*~~ *capacity obligation* for each ~~*demand response*~~*capacity auction participant* and its resources in accordance with section 18.7.5 and the applicable *market manual.*

18.7.4 The *IESO* shall, for each ~~*demand response*~~*transitional capacity auction*, determine for each ~~*commitment*~~*obligation period* associated with the ~~*demand response*~~*transitional capacity auction*:

18.7.4.1 the ~~*demand response*~~*transitional capacity auction clearing prices* for each electrical zone identified in the pre-auction report; and

18.7.4.2 the zonal ~~*demand response*~~ *capacity obligation* for each ~~*demand response*~~capacity auction participant,in accordance with this section 18.7.

~~in accordance with this section 18.7.~~

18.7.5 If two or more ~~*demand response*~~*capacity auction participants* submit a ~~*demand response*~~*capacity auction offer* at the same price, for the last available quantity, the ~~*demand response*~~ *capacity auction offer* with the earlier time stamp shall be selected as the successful ~~*demand response*~~*capacity auction offer*, in accordance with the applicable *market manual.*

18.8 Post-Auction Notification and Publication

18.8.1 The *IESO* shall, as soon as practicable following the conclusion of a ~~*demand response*~~ *capacity auction*, *publish* the following in accordance with the *applicable market manual*:

18.8.1.1 the ~~*demand response*~~ *transitional capacity auction clearing price*;

18.8.1.2 the amount of ~~*demand response*~~ *auction capacity* that has been ~~procured~~acquired~~;~~ in each electrical zone;

18.8.1.3 those ~~*demand response*~~ *capacity auction participants* who received a ~~*demand response*~~ *capacity obligation* and all respective ~~*demand response*~~ *capacity obligations*; and

18.8.1.4 the *qualified* ~~*demand response*~~*auction capacity* of each ~~*demand response*~~*capacity auction participant.*

18.8.2 The *IESO* shall, following the conclusion of a ~~*demand response*~~*capacity auction*, issue post-auction reports to each ~~*demand response*~~*capacity auction participant* by the date specified in the pre-auction report, to detail the ~~*demand response*~~ *capacity auction offers* that have cleared in the ~~*demand response*~~*capacity auction* and the associated ~~*demand response*~~ *capacity obligations* for each ~~*commitment*~~*obligation period* in accordance with the applicable *market manual*.

PART 5 – IESO BOARD DECISION RATIONALE

Documents presented to the IESO Board of Directors as well as the reasons for adopting the amendments are available online.

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Market Rule Amendment Proposal

PART 1 – MARKET RULE INFORMATION

Identification No.:	MR-00439-R03				
Subject:	Transitional Capacity Auction				
Title:	Energy Market Participation				
Nature of Proposal:	☒ Alteration		☐ Deletion		☒ Addition
Chapter:	3, 7		Appendix:		
Sections:	Chapter 3 – 6.3, 6.3A, & 6.5, Chapter 7 - 3.4, 18.9, 19.4, 19.5, 19.7 (new)				
Sub-sections proposed for amending:					

PART 2 – PROPOSAL HISTORY

Version	Reason for Issuing	Version Date
1.0	Draft for Stakeholder Review and Comment	May 15, 2019
2.0	Submitted for Technical Panel Review and Comment	June 18, 2019
3.0	Posted for Stakeholder Review and Comment	June 27, 2019
4.0	Submitted for Technical Panel Vote	August 6, 2019
5.0	Recommended by Technical Panel; Submitted to IESO Board	August 16, 2019
6.0	Approved by IESO Board	August 28, 2019
Approved Amendment Publication Date:	September 5, 2019	
Approved Amendment Effective Date:	October 15, 2019	

PART 3 – EXPLANATION FOR PROPOSED AMENDMENT

Provide a brief description of the following:

- The reason for the proposed amendment and the impact on the *IESO-administered markets* if the amendment is not made.
- Alternative solutions considered.
- The proposed amendment, how the amendment addresses the above reason and impact of the proposed amendment on the *IESO-administered markets*.

Summary

The IESO proposes to amend the market rules to evolve the Demand Response Auction (DRA) into the Transitional Capacity Auction (TCA) to address capacity needs in Ontario.

Over its four auctions, the DRA has proven successful in driving down capacity costs and increasing competition. Enhancing the IESO's approach to capacity auctions this year by opening participation to other resources is another step toward a more competitive electricity marketplace; it moves Ontario's electricity marketplace down the path of efficiency, competition, and transparency – the key principles of the market renewal efforts.

This proposal will be discussed as part of the Transitional Capacity Auction stakeholder engagement initiative before consideration by the Technical Panel.

Further information on the Transitional Capacity Auction stakeholder engagement is found here.

Background

Capacity market participants with a capacity obligation will be required to deliver on their capacity obligation through participation in the energy market as an hourly demand resource, dispatchable load or non-committed generator. These resource types will be required to submit offers into the energy market (day-ahead and real-time) for every hour of the availability window.

Discussion

Minor changes have been proposed to Chapter 3 to reflect changes to defined terms and to show the shift from demand response programs to the Transitional Capacity Auction.

Significant changes have been proposed for Chapter 7. Defined terms have been updated to show the shift from demand response programs to the Transitional Capacity Auction. New sections have been added in Section 18.9 to further describe qualified capacity, and to provide more clarification on the transfer of auction capacity. Section 19.7 - Energy Market Participation for Capacity Generation Resources has been added. This section outlines the requirements for Market Participants with Capacity Generation Resources to participate in the energy market.

This market rule amendment proposal was first circulated to stakeholders and market participants who are participating in the Transitional Capacity Auction stakeholder engagement. In response to stakeholder feedback, this proposal contains a new section, 18.9.1.5C to allows a transfer of a capacity obligation between zones where the same capacity market participant is both the capacity transferor and the capacity transferee. Additionally, stakeholders noted an incorrect reference in sections 19.7.8 and 19.7.10 which has been corrected in this version.

Specific changes to the market rules are listed below. There are five additional rule amendment

PART 3 – EXPLANATION FOR PROPOSED AMENDMENT

packages that form the entirety of the proposed rule changes for the TCA.

PART 4 – PROPOSED AMENDMENT

Chapter 3

6.3 Events of Default

6.3.1 An event of default occurs if a market participant or the person that has provided prudential support~~, demand response security, or demand response~~ or capacity prudential support in relation to the market participant:

6.3.1.1 does not make a payment in full required under the *market rules* when due;

6.3.1.2 fails to provide payment in full of any amount claimed by the IESO under any prudential support~~, demand response security, or demand response~~ or capacity prudential support;

6.3.1.3 fails to provide and maintain prudential support~~, demand response security,~~ or ~~demand response~~ capacity prudential support required to be supplied under the market rules within the time required;

6.3.2 A *market participant* shall notify the *IESO* immediately upon:

6.3.2.1 the occurrence of an *event of default* or any circumstance that may give rise to an *event of default* referred to in sections 6.3.1.4 to 6.3.1.11; or

6.3.2.2 the appointment of a receiver or receiver and manager or person having a similar or analogous function under the laws of any relevant jurisdiction in respect of any property of the *market participant* or the *market participant's prudential support* provider~~*, demand response security,or demand response*~~ or *capacity prudential support* provider.

6.3.3 Where a *market participant* or a person providing *prudential support*~~, demand response security, or demand response~~ or *capacity prudential support* on behalf of that *market participant* commits an *event of default*, the IESO may:

6.3.3.1 issue to the *market participant* a *notice of intent to suspend* stating that the *market participant* will be suspended unless it remedies the *event of default* within 2 *business days* or such longer period as specified in the notice;

6.3.3.2 immediately draw upon part or all of the *market participant's prudential support*, ~~demand response security, or demand response~~or *capacity prudential support* for either the amount of any money owing to the *IESO* under the *market rules* or where the *market participant's prudential support*~~, demand response security, or demand response~~ or *capacity prudential support* is due to expire or terminate and has not been replaced as required under section 5.2.5, 5A.2.3 or 5B.2.4 of Chapter 2, the undrawn part of the *prudential support* ~~or demand response security~~ notwithstanding the provisions of section 5.7.2.5 of Chapter 2 until such time as the *market participant* has replaced its *prudential support*~~, demand response security,~~ or ~~demand response~~*capacity prudential support*; and

6.3.3.3 set-off any amounts due or credited to the *market participant* under the *market rules*, including those set out in section 4.8.2 of Chapter 9, and any program administered through the billing and *settlement* systems of the *IESO* against any amounts owed by the *market participant.*

6.3A Suspension of a Market Participant

6.3A.2 The *IESO* shall *publish* the details of the *suspension order* and provide a copy of the *suspension order* to the *OEB* and the *transmitter*, *distributor* and/or other *market participant* to whose *facilities* the suspended *market participant* is connected.

6.3A.4 The *IESO* may do one or more of the following to give effect to a *suspension order*:

6.3A.4.1 reject any *bid*, *offer*, *TR bid* or *TR offer* submitted by the *suspended market participant*;

6.3A.4.2 set-off any amounts otherwise due to the *suspended market participant* against any amounts owed by the *suspended market participant* under the *market rules*;

6.3A.4.3 issue a *disconnection order* to the *transmitter*, *distributor* and/or other *market participant* to whose facilities the *suspended market participant's facilities* are connected and provide a copy to the *OEB*; or

6.3A.4.4 make such further order or issue such directions to the *suspended market participant* as the *IESO* determines appropriate.

6.4.2 The *IESO* shall *publish* the details of the *termination order* and provide a copy of the *termination order* to the *OEB* and to the *transmitter*, *distributor* and/or other *market participant* to whose *facilities* the terminated *market participant's facilities* are connected.

6.4.3 When the *IESO* issues a *termination order*, it may at the same time, if it has not already done so, issue a *disconnection order* to the *transmitter*, *distributor* and/or other *market participant* to whose *facilities* the *terminated market participant's facilities* are connected and provide a copy to the *OEB*.

6.5 De-Registration of a Market Participant's Facilities

6.5.3 If the *IESO* deregisters some or all of a *market participant's registered facilities*, it may at the same time issue a *disconnection order* to the relevant *transmitter*, *distributor* and/or other mark*et participant* to whose *facilities* the *market participant's facilities* which is subject of the deregistration are connected and provide a copy to the *OEB*.

Chapter 7

3.4 The Form of Dispatch Data

3.4.1.6 for a demand response market participant with an hourly demand response resource, a demand response energy bid to reduce its energy consumption during a specified availability window and ~~commitment~~obligation period in accordance with the applicable market manual.

18.9 ~~Demand Response~~ Capacity Obligation Transfers

18.9.1 A *~~demand response~~capacity transferor* may, subject to *IESO* approval and in accordance with the applicable *market manual*, request a transfer of all or a portion of its *~~demand response~~ capacity obligation* to a *~~demand response~~capacity transferee* provided that the following criteria are met:

18.9.1.1 the quantity to be transferred does not exceed the difference between the *~~demand response~~capacity transferee's qualified ~~demand response~~ capacity*, and its existing *~~demand response~~ capacity obligation* for the applicable *~~commitment~~obligation period*;

18.9.1.1.1 for the purposes of 18.9.1.1, the *qualified capacity* refers to the *qualified capacity* received by the *capacity transferee* in the *obligation period* for which the quantity is being transferred.

18.9.1.2 the ~~*demand response*~~*capacity transferor* provides written confirmation to the *IESO* from the ~~*demand response*~~*capacity transferee* of its willingness to accept the transfer of a ~~*demand response*~~ *capacity obligation* from the ~~*demand response*~~*capacity transferor*;

18.9.1.3 the *capacity obligation* transfer shall consist of the same attributes (e.g. physical or virtual) and be of the same resource type, as detailed in the applicable *market manual*, as the ~~*demand response*~~*capacity transferor's* ~~*demand response*~~ *capacity obligation*; ~~and~~

18.9.1.4 the quantity to be transferred is in increments of 0.1MW, and the resulting ~~*demand response*~~ *capacity obligations* for both the ~~*demand response*~~*capacity transferor* and ~~*demand response*~~*capacity transferee* following the transfer shall be 0 MW, or greater than or equal to 1 MW;~~.~~

18.9.1.5 the *capacity obligation* to be transferred is within the same zone;

18.9.1.6 if the *capacity obligation* was acquired through a *transitional capacity auction*, the *capacity obligation* may be transferred between zones where the *transitional capacity auction clearing prices* in the two respective zones are equal to the Ontario-wide *transitional capacity auction clearing price*;

18.9.1.7 For the purposes of 18.9.1.6, the *capacity transferor* and the *capacity transferee* may be the same *capacity auction participant;*

18.9.1.8 *capacity obligation* transfers must not result in the receiving zone reaching a *capacity auction zonal constraint.*

18.9.2 For each transfer request that satisfies the criteria in section 18.9.1, the *IESO* shall determine the ~~*demand response*~~*capacity transferee's* revised ~~*demand response*~~*capacity auction deposit* and/or ~~*demand response*~~*capacity prudential support obligation*, as applicable, in accordance with section 18.3.2 and section 5B.3.3 of Chapter 2.

18.9.3 The ~~*demand response*~~*capacity transferee* shall provide the *IESO*, within five *business days* of receiving notification from the *IESO* or within such a longer period of time as may be agreed between the *IESO* and the ~~*demand response*~~*capacity transferee*, any additional ~~*demand response*~~*capacity auction deposit* and/or ~~*demand response*~~*capacity prudential support obligation* that may be required as a result of a transfer request.

18.9.4 After the revised ~~*demand response*~~*capacity* *auction deposits* and/or ~~*demand response*~~*capacity* *prudential support obligations* have been satisfied by the ~~*demand response*~~*capacity* *transferee*, the *IESO* shall notify the ~~*demand response*~~*capacity* *transferor* and ~~*demand response*~~*capacity* *transferee* of its approval or rejection, and the *IESO* shall *publish* updated post-auction reports pursuant to section 18.8.

19.4 Energy Market Participation for Hourly Demand Response Resources

19.4.1 A ~~*demand response*~~*capacity* *market participant* with a ~~*demand response*~~ *capacity obligation* participating with an *hourly demand response* resource shall be eligible for an availability payment in accordance with the applicable *market manual.* Availability payments may be offset by non-performance charges in accordance with section 4.7J of Chapter 9.

Standby and Activation Notices

19.4.2 If an *hourly demand response* resource has a day-ahead *schedule of record* or a *pre-dispatch schedule* less than the resource's total *bid* quantity, or if the applicable pre-dispatch shadow price for an *hourly demand response* resource is equal to or greater than the standby notice price threshold, determined by the *IESO*, for at least one hour during the *dispatch day availability window*, the *IESO* shall issue a standby notice to the applicable ~~*demand response*~~*capacity* *market participant* by 07:00 EST in accordance with the applicable *market manual*.

19.4.3 If the *IESO* does not issue a standby notice to a ~~*demand response*~~*capacity* *market participant* by 07:00 EST, the ~~*demand response*~~*capacity* *market participant* shall remove their *bids* for the *hourly demand response* resource as soon as practicable and before 9:00 EST. A ~~*demand response*~~*capacity* *market participant* that does not remove their *bids* for the *hourly demand response* resource before 9:00 EST shall comply with any corresponding activation notices issued by the *IESO* in accordance with section 19.4.5.

19.4.4 The *IESO* shall issue an activation notice to a ~~*demand response*~~*capacity* *market participant* ahead of the activation period, in accordance with the applicable *market manual* if a standby notice has been issued in accordance with section 19.4.2 or a ~~*demand response*~~*capacity* *market participant* has not removed their *bids* in accordance with section 19.4.3, and the applicable *hourly demand response* resource has a *pre-dispatch schedule* less than the resource's total *bid* quantity for at least one hour during the *dispatch day availability window*.

19.4.5 If a ~~*demand response*~~*capacity* *market participant* receives an activation notice pursuant to section 19.4.4, the ~~*demand response*~~*capacity* *market participant* shall comply with the activation notice, unless such a reduction would endanger the safety of any person, damage equipment, or violate any *applicable law*. In such circumstances, the ~~*demand response*~~*capacity market participant* shall notify the *IESO* as soon as practicable.

19.4.6 A ~~*demand response*~~*capacity market participant* may be subject to non-performance charges, and the *IESO* may take action pursuant to sections 19.2.2 and 19.2.3 if a ~~*demand response*~~*capacity market participant* does not comply with an activation notice pursuant to this section 19, in accordance with the applicable *market manual*. The ~~*demand response*~~*capacity market participant* may also be subject to compliance actions in accordance with section 6 of Chapter 3.

19.4.7 A ~~*demand response*~~*capacity market participant* that expects its *hourly demand response* resource to operate in a manner that differs materially from the activation notice issued to it in accordance with this section 19 shall notify the *IESO* as soon as possible and in accordance with the applicable *market manual*.

19.4.8 The *IESO* may disqualify from future participation in the ~~*demand response*~~*capacity auction* any ~~*demand response*~~*capacity market* ~~*participant's hourly demand response* resource~~*participant* that fails to reduce its consumption when called upon in accordance with this section 19.

Non-performance Events for Hourly Demand Response Resources

19.4.9 ~~A~~ In the event of a material reduction in the *demand response capacity* of an *hourly demand response* resource, associated with a *capacity obligation* acquired through a *transitional capacity auction*, the *capacity market participant* shall ~~submit non-performance events, provided that the *demand response market participant* notifies~~ notify the *IESO* as per the procedures and criteria specified in the applicable *market manual*.

19.4.9A In the event of a material reduction in the *demand response capacity* of an *hourly demand response* resource, associated with a *capacity obligation* acquired through a *demand response auction*, the *demand response market participant* shall notify the *IESO* as per the procedures and criteria specified in the applicable *market manual*.

19.4.10 A ~~*demand response*~~*capacity market participant* shall reduce its *bid* to take into account and reflect the maximum *demand response capacity* that it reasonably expects it can provide due to any non-performance event ~~in a commitment~~related to an *hourly demand response* resource in an *obligation period*.

Activation Testing for Hourly Demand Response Resources

19.4.11 The *IESO* may, in accordance with the applicable *market manual*, direct a ~~*demand response*~~*capacity market participant* with a ~~*demand response*~~*capacity obligation* to perform activation testing for each *hourly demand response* resource up to a maximum of two test activations per ~~commitment~~ *obligation period* to verify that a ~~*demand response*~~ *capacity obligation* is deliverable by the ~~*demand response*~~*capacity market participant*.

19.4.12 If a ~~*demand response*~~*capacity market participant* fails activation testing performed pursuant to section 19.4.11, the ~~*demand response*~~*capacity market participant* shall be subject to non-performance charges in accordance with the applicable *market manual*. Failure during activation testing shall be considered a breach of the *market rules* and may result in sanctions in accordance with section 6.2 of Chapter 3.

19.4.13 The *IESO* shall provide a ~~*demand response*~~*capacity market participant* day-ahead notification of test activations pursuant to 19.4.11 and the test activation shall occur within the *availability window* of ~~a *commitment*~~an *obligation period*.

19.4.14 The test activation shall occur in accordance with the *hourly demand response* resource activation process specified in this section 19.4.

19.4.15 The *hourly demand response* resource shall not be entitled to compensation for any costs related to any valid test activation conducted during a *commitment period* pursuant to this section 19.4.

19.5 Energy Market Participation for Dispatchable Loads with ~~Demand Response~~ Capacity Obligations

19.5.1 A ~~*demand response*~~*capacity market participant* with a ~~*demand response*~~ *capacity obligation* participating as a *dispatchable load* shall be eligible for an availability payment, in accordance with the applicable *market manual*. Availability payments may be offset by non-performance charges in accordance with section 4.7J of Chapter 9.

Dispatch of Resources

19.5.2 The IESO shall schedule a *dispatchable load* with a ~~demand response~~ *capacity obligation* in the *real-time market* and issue a *dispatch instruction* to a *dispatchable load* with a ~~demand response~~ capacit*y obligation* in accordance with Chapter 7.

19.5.3 A *dispatchable load* with a ~~demand response~~ *capacity obligation* shall comply with *IESO dispatch instructions* in accordance with Chapter 7.

19.5.4 The *IESO* may disqualify from future participation in the ~~*demand response*~~*transitional capacity auction* any ~~*dispatchable load facility*~~*capacity* *market participant* that fails to reduce its consumption when called upon in accordance with this section 19.

Outage Notification Requirements for Dispatchable Loads with a ~~Demand Response~~ Capacity Obligation

19.5.5 Each *dispatchable load* with a ~~*demand response*~~ *capacity obligation* shall comply with the *outage* notification requirements of Chapter 5.

19.5.6 A *dispatchable load* with a ~~*demand response*~~ *capacity obligation* shall reduce its *bid* to take into account and reflect the maximum *demand response capacity* that it reasonably expects it can consume due to any *outage*.

Activation Testing for Dispatchable Load Resources

19.5.7 The *IESO* may, in accordance with the applicable *market manual*, direct a *dispatchable load* with a ~~*demand response*~~ *capacity obligation* to perform activation testing for each resource up to a maximum of two activation tests per ~~commitment~~*obligation* *period* to verify that a ~~*demand response*~~ *capacity obligation* is deliverable by the ~~*demand response*~~*capacity* *market participant*.

19.5.8 If a ~~*demand response*~~ *capacity* *market participant* fails activation testing performed pursuant to section 19.5.7, the ~~*demand response*~~*capacity* *market participant* shall be subject to non-performance charges in accordance with the applicable *market manual*. Failure during activation testing shall be considered a breach of the *market rules* and may result in sanctions in accordance with section 6.2 of Chapter 3.

19.5.9 The *IESO* shall provide a *dispatchable load* with a ~~*demand response*~~ *capacity obligation* day-ahead notification of test activation and the test activation shall occur within the *availability window* of ~~a *commitment*~~an *obligation* *period*.

19.5.10 The test activation shall occur in accordance with the *dispatch instructions* for a *dispatchable load facility* specified in this section 19.5.

19.5.11 The *dispatchable load facility* shall not be entitled to compensation for any costs related to any valid test activation conducted during ~~a *commitment*~~an *obligation* *period* pursuant to this section 19.5.

19.7 Energy Market Participation for *Capacity Generation Resources*

19.7.1 A *capacity market participant* satisfying its *capacity obligation* with a *capacity generation resource* shall be eligible for an availability payment, in accordance with this section and the applicable *market manual*. Availability payments may be offset by non-performance charges in accordance with section 4.7J of Chapter 9.

Dispatch of Resources

19.7.2 The *IESO* shall schedule a *capacity generation resource* in the *energy market*, and issue *dispatch instructions* in accordance with Chapter 7.

19.7.3 A *capacity generation resource* shall comply with *IESO dispatch instructions* in accordance with Chapter 7.

19.7.4 The *IESO* may disqualify from future participation in the *transitional capacity auction* any *capacity market participant* that fails to inject *energy* when called upon in accordance with this section 19.

Outage Notification Requirements for *Capacity Generation Resource* with a Capacity Obligation

19.7.5 Each *capacity generation resource* shall comply with the *outage* notification requirements of Chapter 5.

19.7.6 A *capacity generation resource* shall reduce its *offer* to reflect the maximum capacity that it reasonably expects it can inject due to any *outage*.

Activation Testing for Generation Resources

19.7.7 The *IESO* may, in accordance with the applicable *market manual*, direct a *capacity market participant* to perform activation testing for each *capacity generation resource* up to a maximum of two activation tests per *obligation period* to verify that a *capacity obligation* can be satisfied by the *capacity market participant*.

19.7.8 If a *capacity market participant* fails an activation test performed pursuant to section 19.7.7, the *capacity market participant* shall be subject to non-performance charges in accordance with the applicable *market manual.* Failure during activation testing shall be considered a breach of the *market rules* and may result in sanctions in accordance with section 6.2 of Chapter 3.

19.7.9 The *IESO* shall provide a *capacity generation resource* day-ahead notification of test activation and the test activation shall occur within the *availability window* of an *obligation period*.

19.7.10 The test activation shall occur in accordance with the *dispatch instructions* specified in this section 19.7.

PART 5 – IESO BOARD DECISION RATIONALE

Documents presented to the IESO Board of Directors as well as the reasons for adopting the amendments are available online.

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Market Rule Amendment Proposal

PART 1 – MARKET RULE INFORMATION

Identification No.:	MR-00439-R04				
Subject:	Transitional Capacity Auction				
Title:	Non-Performance Charges and Settlements				
Nature of Proposal:	☒ Alteration		☒ Deletion		☐ Addition
Chapter:	Ch. 9		Appendix:		
Sections:	4.7J, 4.8				
Sub-sections proposed for amending:					

PART 2 – PROPOSAL HISTORY

Version	Reason for Issuing	Version Date
1.0	Draft for Stakeholder Review and Comment	May 15, 2019
2.0	Submitted for Technical Panel Review	June 12, 2019
3.0	Posted for Stakeholder Review and Comment	June 27, 2019
4.0	Submitted for Technical Panel Vote	August 6, 2019
5.0	Recommended by Technical Panel; Submitted to IESO Board	August 16, 2019
6.0	Approved by IESO Board	August 28, 2019
Approved Amendment Publication Date:	September 5, 2019	
Approved Amendment Effective Date:	October 15, 2019	

PART 3 – EXPLANATION FOR PROPOSED AMENDMENT

Provide a brief description of the following:

- The reason for the proposed amendment and the impact on the *IESO-administered markets* if the amendment is not made.
- Alternative solutions considered.
- The proposed amendment, how the amendment addresses the above reason and impact of the proposed amendment on the *IESO-administered markets*.

Summary

The IESO proposes to amend the market rules to evolve the Demand Response Auction (DRA) into the Transitional Capacity Auction (TCA) to address capacity needs in Ontario.

Over its four auctions, the DRA has proven successful in driving down capacity costs and increasing competition. Enhancing the IESO's approach to capacity auctions this year by opening participation to other resources is another step toward a more competitive electricity marketplace; it moves Ontario's electricity marketplace down the path of efficiency, competition, and transparency – the key principles of the market renewal efforts.

This proposal will be discussed as part of the Transitional Capacity Auction stakeholder engagement initiative before consideration by the Technical Panel.

Further information on the Transitional Capacity Auction stakeholder engagement is found here.

Background

The following proposed rule changes evolve the settlement processes of the DRA into the TCA.

Discussion

Minor changes have been proposed to reflect changes to defined terms and to show the shift from demand response programs to the Transitional Capacity Auction.

A new sub-section was added (4.7J.2.1) to make a capacity market participant with a capacity generation resource subject to availability payments.

Lastly, sub-sections were removed from 4.8.3 and 4.8.4 to remove references to the CBDR and the former DR Pilots program which no longer exist.

This market rule amendment proposal was first circulated to stakeholders and market participants who are participating in the Transitional Capacity Auction stakeholder engagement. No responses to feedback were received pertaining to this proposal.

Specific changes to the market rules are listed below. There are five additional rule amendment packages that form the entirety of the proposed rule changes for the TCA.

PART 4 – PROPOSED AMENDMENT

Chapter 9

4.7J ~~Demand Response~~ Capacity Obligations

4.7J.1 The *IESO* shall remit an availability payment associated with a ~~*demand response*~~ *capacity obligation*, if any, to the applicable ~~*demand response*~~*capacity market participant*, in the manner specified in the applicable *market manual*.

4.7J.2 A ~~*demand response*~~*capacity market participant* with a ~~*demand response*~~ *capacity obligation* shall, in accordance with the applicable *market manual*, be subject to the following non-performance charges if the ~~*demand response*~~*capacity market participant* does not satisfy the requirements of its ~~*demand response*~~ *capacity obligation*:

~~Demand Response~~Capacity Obligation- Availability Charges

4.7J.2.1 A ~~*demand response*~~*capacity market participant* shall be subject to an availability charge for every hour of the *availability window* it fails to submit *demand response energy bids* in the amount of their ~~*demand response*~~ *capacity obligation* in either the day-ahead commitment process or in the *real-time energy market*.

4.7J.2.1A A *capacity market participant* participating with a *capacity generation resource* shall be subject to an availability charge for every hour of the *availability window* in which it fails to submit *energy offers* in the amount of their *capacity obligation* in the day-ahead commitment process or in the *pre-dispatch* hour specified in Market Manual 5.5

~~Demand Response~~Capacity Obligation Dispatch Charges

4.7J.2.2 A ~~*demand response*~~*capacity market participant* participating with an *hourly demand response* resource shall be subject to a dispatch charge for failure to comply with an activation notice received under section 19.4.5 of Chapter 7.

~~Demand Response~~Capacity Obligation Administration Charges

4.7J.2.3 A ~~*demand response*~~*capacity market participant* participating with an *hourly demand response* resource shall be subject to a *demand* response administration charge for failure to provide *demand* response measurement data to the *IESO*.

~~Demand Response~~ Capacity Obligation-Capacity Charges

4.7J.2.4 Subject to ~~sections~~section 19.4.5 ~~and19.4.12~~ of Chapter 7, a ~~*demand response*~~ *capacity market participant* participating with an *hourly demand response* resource that fails to ~~provide~~satisfy its *capacity* ~~through~~*obligation* in response to an activation ~~notice or activation~~ test~~,~~ shall be subject to a ~~*demand response*~~ *capacity* charge.

4.7J.2.5 Subject to section ~~19~~7.5.~~8~~3 of Chapter 7, a ~~*demand response*~~ *capacity market participant* participating with a either a *dispatchable load* or a *capacity generation resource* that fails to ~~provide~~satisfy its *capacity* ~~through~~*obligation* in response to an activation test shall be subject to a ~~*demand response*~~ *capacity* charge.

4.7J.3 A ~~*demand response*~~*capacity market participant* or a ~~*demand response*~~*capacity auction participant* may elect to be subject to a buy-out charge for all, or a portion of, their ~~*demand response*~~ *capacity obligation* in accordance with the applicable *market manual*, if they are unable to fulfill a ~~*demand response*~~ *capacity obligation* for the remaining portion of ~~a *commitment*~~an *obligation period*.

4.7J.4 At any time, the *IESO* may audit any submitted ~~*demand* response~~ measurement data and supporting information and a ~~*demand response*~~*capacity market participant* shall provide such information in the time and manner specified by the *IESO*. If, as a result of such an audit, the *IESO* determines that actual measurement data and supporting information differed from the submitted measurement data and supporting information, the *IESO* shall recover from or distribute to a ~~*demand response*~~*capacity market participant* any resulting over or under payment, as applicable. Any amounts recovered or distributed to a ~~*demand response*~~ *capacity market participant* shall be distributed to or recovered from *market participants* in accordance with sections 4.8.3 and 4.8.4.

4.8 Additional Non-Hourly Settlement Amounts

4.8.3 The *IESO* shall, at the end of each *energy market billing period*, recover from *market participants*, in the manner specified in the applicable *market manual*, the following amounts:

4.8.3.1 [Intentionally left blank – section deleted]~~any compensation for *demand response market participants* paid in that *energy market billing* period by the *IESO* pursuant to section 4.7H;~~

4.8.3.2 [Intentionally left blank – section deleted]~~any compensation for *demand response market participants* paid in that *energy market billing* period by the *IESO* pursuant to section 4.7I; and~~

4.8.3.3 any compensation for ~~*demand response*~~*capacity market participants* paid in that *energy market billing* period by the *IESO* pursuant to section 4.7J.

4.8.4 The *IESO* shall distribute to *market participants*, in the manner specified in the applicable *market manual*, the following amounts:

4.8.4.1 [Intentionally left blank – section deleted]~~any adjustments to *demand response market participant* payments pursuant to section 4.7H;~~

4.8.4.2 [Intentionally left blank – section deleted]~~any adjustments to *demand response market participant* payments pursuant to section 4.7I; and~~

4.8.4.3 any adjustments to ~~*demand*~~*capacity* ~~*response*~~ *market participant* payments pursuant to section 4.7J.

PART 5 – IESO BOARD DECISION RATIONALE

Documents presented to the IESO Board of Directors as well as the reasons for adopting the amendments are available online.

Market Rule Amendment Proposal

PART 1 – MARKET RULE INFORMATION

Identification No.:	MR-00439-R05		
Subject:	Transitional Capacity Auction		
Title:	Removal of DR Pilots and CBDR Sections		
Nature of Proposal:	☐ Alteration	☒ Deletion	☐ Addition
Chapter:	Ch. 2, 7, 9	Appendix:	
Sections:	Ch. 2 (section 5A, Appendix 2.2), 7 (sections 16, 17), Ch. 9 (section 4)		
Sub-sections proposed for amending:			

PART 2 – PROPOSAL HISTORY

Version	Reason for Issuing	Version Date
1.0	Draft for Stakeholder Review and Comment	May 15, 2019
2.0	Submitted for Technical Panel Review	June 18, 2019
3.0	Posted for Stakeholder Review and Comment	June 27, 2019
4.0	Submitted for Technical Panel Vote	August 6, 2019
5.0	Recommended by Technical Panel; Submitted to IESO Board	August 16, 2019
6.0	Approved by IESO Board	August 28, 2019
Approved Amendment Publication Date:	September 5, 2019	
Approved Amendment Effective Date:	October 15, 2019	

PART 3 – EXPLANATION FOR PROPOSED AMENDMENT

Provide a brief description of the following:

- The reason for the proposed amendment and the impact on the *IESO-administered markets* if the amendment is not made.
- Alternative solutions considered.
- The proposed amendment, how the amendment addresses the above reason and impact of the proposed amendment on the *IESO-administered markets*.

Summary

The IESO proposes to amend the market rules to evolve the Demand Response Auction (DRA) into the Transitional Capacity Auction (TCA) to address capacity needs in Ontario.

Over its four auctions, the DRA has proven successful in driving down capacity costs and increasing competition. Enhancing the IESO's approach to capacity auctions this year by opening participation to other resources is another step toward a more competitive electricity marketplace; it moves Ontario's electricity marketplace down the path of efficiency, competition, and transparency – the key principles of the market renewal efforts.

This proposal will be discussed as part of the Transitional Capacity Auction stakeholder engagement initiative before consideration by the Technical Panel.

Further information on the Transitional Capacity Auction stakeholder engagement is found here.

Background

While reviewing the market rules for TCA Phase 1 changes, there were sections of the rules that were no longer necessary to keep, relating to the Capacity Based Demand Response (CBDR) program, and the former Demand Response Pilots program. The sections in this package, detail the sections of the market rules that will be removed as part of this clean-up effort.

Discussion

This market rule amendment proposal was first circulated to stakeholders and market participants who are participating in the Transitional Capacity Auction stakeholder engagement. No responses to feedback were received pertaining to this proposal.

Each section listed below will be deleted or changed, to remove references to the former Demand Response Pilots program and CBDR. Specific changes to the market rules are listed below. There are five additional rule amendment packages that form the entirety of the proposed rule changes for the TCA.

PART 4 – PROPOSED AMENDMENT

Chapter 2

5A. Capacity Based Demand Response Program – Demand Response Security Requirements

- All sub-sections to be removed

Chapter 2 - Appendices

Appendix 2.2

~~1.1.6A Each *demand response market participant* participating in the *capacity based demand response program* shall provide to the *IESO* and maintain one commercially available telephone and electronic mail address for the purposes of communicating with the *IESO*.~~

1.1.6A [Intentionally left blank – section deleted]

1.4.1 Subject to section 1.6, each *market participant* ~~other than a *demand response market participant* participating only in the *capacity based demand response program*~~ shall, for the purposes of conducting secure communications or transactions with the *IESO* using *IESO*-supplied or approved software, provide, install and maintain a *participant workstation* that meets the specifications, definitions and other requirements set forth in the *participant technical reference manual*.

Chapter 7

16. Demand Response Pilot Program

All sections to be removed

17. Capacity Based Demand Response Program

All sections to be removed

Chapter 9

4.7H Capacity Based Demand Response Program

- All sub-sections to be removed

4.7I Demand Response Pilot Program

- All sub-sections to be removed

PART 5 – IESO BOARD DECISION RATIONALE

Documents presented to the IESO Board of Directors as well as the reasons for adopting the amendments are available online.

Independent Electricity System Operator
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Memorandum

To: THE BOARD OF DIRECTORS
of the Independent Electricity System Operator

From: Michael Lyle, Vice President, Legal Resources and Corporate Governance
Chair, IESO Technical Panel

Date: August 20, 2019

Re: Recommendation from the Technical Panel on Market Rule Amendment Proposal

The IESO is seeking a decision from the IESO Board on the implementation of a Transitional Capacity Auction (MR-00439-R00-R05). The Technical Panel recommended this proposal to the IESO Board for consideration.

Description and Rationale

Ontario is expected to emerge from surplus conditions in 2020 and capacity is required to meet more significant resource adequacy needs starting in 2023. This market rule amendment proposal represents the first phase of the Transitional Capacity Auction (TCA) design, which enables non-committed dispatchable generators to participate in the TCA alongside dispatchable loads and hourly demand response resources. The TCA represents an evolution of the demand response auction (DRA) into a more competitive capacity acquisition mechanism.

The TCA will be implemented in a phased approach, with subsequent phases enabling more resources to participate and new auction design features. Each phase is expected to require changes to the market rules.

Stakeholder Engagement

The IESO has a formal stakeholder engagement initiative to capture and incorporate feedback from stakeholders on the design of the transition to a TCA. Stakeholders from all sectors of the marketplace participated in the initiative. Written submissions were received from generators, demand response aggregators, the Market Surveillance Panel, consumers and associations representing local distribution companies, generators and consumers. During the engagement, stakeholders provided feedback in the following areas.

1. Timelines: In response to stakeholder feedback, the IESO reduced the scope of TCA Phase I changes and adjusted the stakeholder schedule cycle to allow sufficient time for stakeholder input and stakeholder review of draft market rules and manual manuals.
2. Future opportunities: Some stakeholders noted that the expansion of the DRA would create an 'un-level playing field' for existing DRA participants. The IESO recognizes that there may be opportunities to remove certain barriers that demand response resources face in IESO markets and reiterated our commitment to discuss these issues with stakeholders.
3. Target Capacity Approach: Stakeholders raised questions regarding the target capacity amount to be procured and the need for the TCA to be implemented as early as the December 2019 auction. The IESO stated that the resource adequacy needs increase significantly during the TCA planning time frame and the IESO must create an appropriate business environment and confidence in the auction process to sustain and develop resources such that sufficient capacity is available when needed in the years when the capacity requirement increases significantly (2023-2026).
4. Enabling Eligible Resources: There were requests from stakeholders to include other resource types as part of Phase I. The IESO provided a proposed schedule of resource type inclusions for subsequent phases of the TCA.
5. Suggestions for material changes to the Phase I design: Suggestions included expanding capacity transfers between resource types, allowing contingent offers and recognizing economies of scale in auction offer submissions. Within Phase I, the IESO did incorporate stakeholder requests to add a clause to the market rules to transfer auction capacity to the same market participant and to reconsider the proposed changes to non-performance factors. Other suggestions will require a more thorough discussion and time to design. These other suggestions will be considered for subsequent auctions and discussed at appropriate upcoming stakeholder engagement meetings.
6. Alignment of stakeholder engagements: Stakeholders encouraged the IESO to seek efficiencies and alignment between several related stakeholder engagements.

As part of the Technical Panel process, the market rule amendment proposal was published on the IESO public website for stakeholder review and written comment for two weeks. Submissions were received from the Advanced Energy Management Alliance (AEMA), the Association of Major Power Consumers (AMPCO) and Enel X.

Enel X recommended that section 4.8 of Chapter 9[1], which is already in effect as part of the DRA market rule set, be amended and then included in the TCA rule set. The basis of the recommendation was Enel X's expressed concern that the existing market rule language unfairly impacts auction participants who are subject to non-performance charges.

In response to this feedback, the IESO met with Enel X to discuss its concerns, and have since agreed that when read in the broader context of section 4 of Chapter 9, section 4.8 does not unfairly impact auction participants. The IESO explained how it has applied the provisions historically, and Enel X has communicated to the IESO that it is satisfied.

Comments from AEMA and AMPCO relate to the compensation treatment of demand response resources in the TCA. Both organizations provided feedback that energy payments provided to

[1] This section of the market rules pertains to compensation for demand response market participants that is recovered from market participants.

generators without an equivalent revenue stream for demand response resources would "introduce undue and unjust discrimination against DR resources in the expanded auction program by requiring them to compete with generators prior to resolution of their eligibility for energy payments" (quoted from AMPCO's submission). AEMA and AMPCO contend that competition between DR resources and generators could be equalized by making energy payments to DR resources for in-market activations; energy payments would represent DR resource costs on activation. Subsequent to the stakeholder comment period, AEMA and AMPCO provided the IESO with a joint legal brief, further articulating their position, including concerns raised about the proposed implementation date of December 2019. That submission is included in the Board package.

The IESO has taken the position that the proposed Phase I market rules do not unjustly discriminate against DR resources. Phase I initiates a process that will allow more market participants to access a capacity auction, thereby increasing competition and providing the greatest value for ratepayers while meeting a growing reliability need.

The IESO recognizes that issues related to AEMA and AMPCO's position are contentious and complex and the IESO has not taken a formal position on the question as to whether making energy payments might result in a net benefit to ratepayers in a more mature capacity auction. In response to feedback received through the DRWG, the IESO has committed to conducting a broader stakeholder engagement on this question and will complete an in-depth assessment before deciding whether to recommend energy payments in the future.

The IESO has communicated the expectation that for the next few auction periods demand response resources are expected to be economically activated under very limited circumstances and therefore access to energy payments will not be consequential to their participation. The IESO has also communicated that it is important to begin taking steps to address forecasted capacity needs in a more cost-effective and transparent manner. The IESO has also engaged the DRWG in a proposal for cost recovery for out-of-market activations (such as test activations or emergency operating state control action activations. The IESO's intent is to implement this proposal concurrently with the TCA.

I recommend that the Board accept the majority vote and recommendation of the Technical Panel to approve market rule amendment MR-00439: Transitional Capacity Auction with an effective date of October 15, 2019. The details of the Technical Panel vote, and the rationale of each member given with their vote, is included with this package.

I look forward to discussing this item with you.

Michael Lyle

Enc
Cc: IESO Records

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Menu

Sector Participants > Engagement Initiatives > Energy Payments for Economic Activation of DR Resources

Active Engagements

The IESO is committed to an open, two-way dialogue with stakeholders and communities to help understand their views about proposed changes that may affect them.

IN THIS SECTION...

Status of Active Engagements

2019 Conservation Achievable Potential Study

Development of an IESO Competitive Transmission Procurement Process

Energy Storage Advisory Group

Formalizing the Integrated Bulk System Planning Process

Improving Accessibility of Operating Reserve

Innovation and Sector Evolution White Paper Series

Capacity Auction

Energy Payments for Economic Activation of DR Resources

Integrated Regional Resource Plan - Kitchener-Waterloo-Cambridge-Guelph

Regional Electricity Planning – East Lake Superior

Regional Planning – Greater Bruce/Huron

Integrated Regional Resource Plan - Ottawa Area Sub-Region

Integrated Regional Resource Plan - Windsor-Essex

Integrated Regional Resource Plan - York Region

Market Development Advisory Group

Meeting Ontario's Capacity Needs: 2020-2024

Planning Outlook

Regional Planning Review Process

Regional Planning - GTA West

Renewable Distributed Generation Integration (RDGI) Fund

Transmission Asset End-of-Life: Asset Replacement Information Process

Completed Engagements

Energy Payments for Economic Activation of Demand Response Resources

Energy payments (or utilization payments) for the economic dispatch of demand response (DR) resources has been an ongoing topic of discussion at the Demand Response Working Group (DRWG). Stakeholder interest in energy payments was renewed as a result of proposed market rule amendments to enable off-contract, non-regulated dispatchable generators to participate in the capacity auction along with dispatchable loads and hourly demand response resources.

To date, DRWG has been the forum for discussions with stakeholders on energy payments for DR resources – for both economic dispatch and out-of-market activations. However, given that energy payments for economic dispatch of DR resources is a complex issue and would be a substantive change to Ontario's energy market, the IESO has determined that a broader stakeholder engagement is needed to advise on this issue. Energy payments for out of market activations will continue to be discussed through DRWG with the intent to implement the proposal by the December 2019 capacity auction.

Through this engagement, the IESO will seek feedback from stakeholders on:

- The inputs and outputs of the research and analysis required to determine whether there is a net benefit to electricity ratepayers if DR resources are compensated with energy payments for economic activations. The IESO will commission a third party consultant to support the research and analysis.

- The IESO's decision and rationale on whether demand response resources will be compensated with energy payments for economic activations

Additional details on the IESO's plans to engage with stakeholders can be found in the engagement plan. All comments and enquiries on this engagement can be directed to engagement@ieso.ca.

Anticipated timing for this engagement is presented below.

Schedule of Activities

Date	Activities
June 2020	Post IESO final decision and rationale
May 2020	Present draft IESO decision and rationale for stakeholder review
Q1 2020	Post final research findings and analysis
Q1 2020	Present draft research findings and/or analysis for stakeholder review
November 2019	Present final study scope and study plan
October 10, 2019	Meeting to review engagement plan and objectives, draft scope of research and analysis for stakeholder feedback
September 11, 2019	Stakeholder Feedback • AEMA

Date	Activities
August 22, 2019	Engagement launched – stakeholders to provide feedback on engagement plan by September 11, 2019 to engagement@ieso.ca • Communication

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Transitional Capacity Auction

Phase I Design Document

APRIL 11, 2019

Draft Posted for Stakeholder Comment

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Summary

Every minute of every day, the Independent Electricity System Operator (IESO) manages the reliability of the province's electricity grid and administers Ontario's electricity markets so that businesses, communities and consumers have the power they count on to meet their needs – and at the lowest cost.

Creating a stable and efficient marketplace that produces value for consumers involves encouraging competition and innovation among suppliers – and is the catalyst behind initiatives to resolve longstanding market design issues. In 2016 the IESO established a Market Renewal Program (MRP) to introduce fundamental reforms to markets that have remained relatively unchanged since they were introduced in 2002. The rationale for delivering a more efficient, stable marketplace was clear: open electricity markets create transparent price signals, enabling generators and other resources to respond to system conditions. More competition enables efficiencies by opening up opportunities for new ways of doing things, which, in turn, drive down costs and support broader public-policy goals aimed at improving affordability and supporting economic growth.

Emerging capacity needs

In the fall of 2018, the IESO released a forecast showing that Ontario is emerging from a capacity surplus to a period of system need. In particular, it is expected that there will be a signifiant increase in the need for capacity from 2022 to 2023, arising as a result of expiring long-term generation contracts, and nuclear units being refurbished or retired.

In order to ensure that we are able to reliably meet the expected capacity requirement, the IESO is developing an auction mechanism for acquiring capacity in advance of MRP's Incremental Capacity Auction (ICA), the first auction of which will deliver capacity in 2025.

Ensuring adequate capacity requires having sufficient resources available to produce electricity or reduce consumption when needed. This is essential to operating a reliable electricity system.

In Ontario's electricity system, consumers pay for both the actual production of electricity (energy), as well as the capability to generate electricity when needed (capacity). The IESO's MRP will result in energy and capacity being supplied to consumers more efficiently by incorporating enhancements to the existing energy markets and by introducing auctions for securing capacity. The Transitional Capacity Auction (TCA) is a first step toward this more efficient system.

Introducing a Transitional Capacity Auction

The IESO is moving away from long-term fixed-technology contracts toward solutions that emphasize flexibility and put the needs of the system first. This is why the IESO is addressing future capacity needs through predictable, competitive auctions. Auctions help the IESO deliver reliability to customers, in a cost effective manner, by enabling direct competition between resources while allowing the IESO to transparently adjust to changing supply-demand dynamics.

The Transitional Capacity Auction will evolve the existing Demand Response Auction (DRA) to enable competition between additional resource types, starting in December 2019. Introducing the TCA now creates an opportunity to phase-in some of the design features contemplated for the more comprehensive ICA, allowing both the IESO and participants to learn and adjust before the expected period of significant system need. At the same time, the increased competition fostered by the TCA is expected to reduce costs, further benefiting ratepayers in the nearer term.

The DRA has been working well. With each auction, there has been increased participation, new entrants, and decreasing prices – all key elements expected from a competitive auction. But we cannot rely on the DRA to meet expected capacity needs. Building on the proven DRA platform as a transition to the future ICA is the best way for the IESO to help provide a reliable future at a reasonable cost.

How the Transitional Capacity Auction will be implemented

The TCA will transition the DRA to the ICA's broader capacity auction at a measured pace, fostering confidence that the sector is ready to meet capacity needs in the early-2020s. The DRA has proven successful in driving down capacity costs and increasing competition. Enhancing our approach to capacity auctions this year by opening participation to other resources is another step toward a more competitive electricity marketplace; it moves us down the path of efficiency, competition, and transparency – the key principles of our market renewal efforts – as quickly as possible.

TCA Phase I (auction to be held in late 2019) – Will be limited to evolving the existing DRA by adding Noncommitted, Dispatchable Generators as eligible participants alongside Demand Response participants.

TCA Phase II (auctions to be held starting in 2020) – Will focus on enabling more resources such as Imports, Self-Schedulers, and Uprates, and incorporating some ICA design features. The TCA Phase II design will be detailed in a separate design document.

Enabling resources to participate

Providing capacity to meet resource adequacy means that the capacity has to be delivered into the energy market and the IESO recognizes that not all resource types are currently enabled to effectively participate in the current energy market. Through the Market Development Advisory Group, the Demand Response Working Group, and other related efforts, gaps and opportunities will be examined for enabling and enhancing existing, new and emerging resources to deliver services to the IESO.

As more resources are enabled in the TCA, updates will be made to the Market Rules, Manuals, and Tool(s) to incorporate resource specific requirements

Eligibility and participation criteria

Table 1 | Eligibility and Participation Criteria

Resources eligible to participate in Phase I	Resources ineligible to participate in Phase I
• **Demand Response Resources** Response resource that satisfies the registration and authorization requirements for the Transitional Capacity Auction or the Demand Response Auction, respectively • **Phase I-Eligible Generator** An existing generator that is both Noncommitted and a Dispatchable Generator.	• **Capacity from resources contracted wholly or in part for energy or capacity (this includes both the contracted capacity or the merchant component of a resource)** • **Rate regulated facilities** • **Energy efficiency** • **Resources not permitted in Ontario (e.g. coal-fired generation)** • **Imports** • **Self-scheduling resources**

Key Transitional Capacity Auction Periods

The key Auction Periods closely resemble the periods used in the DRA.

Figure 1 | Transitional Capacity Auction Periods for Phase I

Pre-Auction Period

Approximately three months before the auction takes place, the IESO will publish a report stating how much capacity will be targeted through the auction, along with key milestones, auction parameters and zonal constraints. Longer-term outlooks indicating future needs will be shown in an update on Ontario's future capacity needs in the third quarter of 2019.

The IESO will set the target capacity to ensure reliability needs are met at the lowest cost over the longer term. This means the target capacity will be set to reflect the immediate capacity needs, but also set to incent participation from a wider-range of providers to encourage competition. Chapter 3 explains more details of the pre-Auction Period.

Auction Period

The Auction Period is the length of time beginning when the IESO begins accepting auction offers to the time when the IESO posts auction results. Chapter 4 details how the auction is cleared using auction offers

Forward period

The forward period is the time between an auction and the first day participants are obligated to deliver on their Capacity Obligation – which will be five months for the summer Obligation Period and eleven months for the winter Obligation Period for Phase I of the TCA. Chapter 5 provides details of what participants are obligated to do during the forward period.

Commitment period

Participants that clear the auction will receive payments during the commitment period based on their total cleared capacity and the applicable auction clearing price. The amount of capacity that clears in the auction becomes the participant's TCA Capacity Obligation; participant must satisfy an obligation to make its capacity available by participating in the day-ahead commitment process in the energy market, as described in Chapter 6. The TCA, like the former DRA, will continue to use, two seasonal Obligation Periods in each auction year:

- Summer – May 1 to October 31
- Winter – November 1 to April 30

These periods account for seasonal demand characteristics and supply capability over different seasons. Seasonal commitment periods encourage participation by providing demand response resources with the flexibility to offer into the auction in a manner most consistent with their capabilities.

Stakeholder engagement

In TCA Phase I, the IESO is looking for stakeholder feedback on auction elements that inhibit or prohibit an eligible resource's ability to participate and provide capacity in the auction and subsequent commitment periods. In TCA Phase II, the IESO will seek stakeholder feedback on subsequent design improvements to further enable broader participation for future auctions while also incorporating additional features such as qualifying capacity.

Conclusion

The transition from the DRA to the TCA is a phased approach to a much more competitive marketplace and a natural next step in moving to the more comprehensive ICA for Ontario. Taking a balanced approach that minimizes disruption to the existing market, while enabling greater participation where it is cost effective to do so, ensures that reliability needs over the long term will be met at the lowest cost.

This design document is a stepping-off point for stakeholder engagement on the detailed decisions that will need to be addressed before Phase I implementation. Phase II implementation will be presented in separate design documents.

Contents

List of Figures

List of Tables

1. Introduction

The Independent Electricity System Operator (IESO) – as the entity responsible for the reliable operation of the Ontario power system – has identified near-term needs to secure additional capacity before the Incremental Capacity Auction (ICA) can be executed. To meet this objective as effectively as possible, the IESO will evolve the existing Demand Response Auction (DRA), allowing additional resources to participate. This evolved mechanism will be called the Transitional Capacity Auction (TCA), and will serve as a transitional mechanism until the implementation of the enduring and more comprehensive ICA.

This design document describes the first phase of the TCA ("**Phase I**") and reflects the IESO's current expectation of modifications required to effect the evolution from the DRA to this first phase of the TCA.

The TCA will build upon the existing DRA rules and mechanisms, and as such, this document assumes the reader is familiar with the terminology and design of the DRA. DRA design features are used as a starting point for Phase I. For further information about the DRA design, readers are encouraged to review the training guide, Demand Response Auction Market Design, Chapter 7, section 18 of the Market Rules (MR) and Market Manual (MM) 12.0.

1.1 Design Principles

The TCA – beginning with Phase I - will replace the DRA for the December 2019 auction. The design of Phase I was developed with reference to the principles of the Market Renewal Program. The application of these principles to the TCA are described below:

- **Certainty**: Wherever reasonable, maintain consistency with the DRA in order to minimize the administrative challenges and disruption to existing businesses.
- **Competition:** Provide open, fair, non-discriminatory competitive opportunities for participants to help meet evolving system needs by evolving the DRA to enable additional resources.
- **Transparency:** Ensure that accurate, timely and relevant information is available and accessible to market participants to enable their effective participation.
- **Implementability:** Develop design decisions by working together with stakeholders to evolve the DRA in a feasible and practical manner.
- **Efficiency:** Develop a market mechanism that will lower out-of-market payments and deliver efficient outcomes.

1.2 Transitional Capacity Auction Objective

The objective of Phase I is to take a first step toward the ICA by increasing competition and enabling participation from existing, Noncommitted, Dispatchable Generators ("**Phase I-Eligible Generators**") to compete with Demand Response Resources.

In pursuing this objective, the TCA will also seek to:

- Maintain DRA features where they align with the ICA high-level design; and
- Provide assurance that capacity acquired through the TCA produces electricity or reduces consumption in a manner that supports real-time operations through appropriate signals and verification.

1.3 Purpose of the Design Document

This design document provides stakeholders and the IESO with a common understanding of the features of the Phase I TCA design that will inform implementation activities. It describes the key design decisions (i.e. "what" is the design). The information contained herein is intended to inform and allow stakeholders to provide feedback on key challenges, barriers, and opportunities in the design of Phase I implementation activities. The IESO will put this design document into action by completing a number of activities, such as creating or modifying documents (e.g. Market Rules, Market Manuals[1] and internal process documents), and the design and implementation of needed tools and training. Design elements identified in this document may evolve through the implementation phase or otherwise change in response to design challenges, and the IESO will work to continue stakeholdering such changes. Any significant design changes will be documented and stakeholdered separately.

Input and Review

This document is intended to complement and work alongside the stakeholder engagement framework to ensure that stakeholders have appropriate opportunities for input into the TCA design and administration, have visibility into key IESO processes and decision-making, and have adequate opportunity to seek review or consultation concerning certain IESO decisions.

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[1] The Market Rules are the rules governing the IESO-controlled grid (ICG) and establishing and governing the IESO-administered markets (IAM), together with all Market Manuals, policies, and guidelines issued by the IESO, all as amended or replaced from time to time.

Market Manuals and procedures provide more detailed descriptions of the requirements for various activities specified in the Market Rules for the IESO and participants. The documents include the forms and agreements required by market participants. Both Market Rules and Market Manuals can be found on the IESO website.

1.4 Design Document Structure

This design document has been subdivided into chapters that group activities performed in each period of the existing DRA. In general, and as noted in the summary section above, each chapter in this document is structured in a similar manner, starting with an overview section that provides a synopsis of activities performed in each period.

Figure 2 | Transitional Capacity Auction Periods

A section of each chapter is then devoted to the design decisions, with those sections further subdivided as follows:

- **Approach in current market/DRA:** This section describes how the design feature is implemented in the DRA.
- **Approach in Phase I:** This section describes how the design feature will evolve, change or remain the same in Phase I. This section includes a "decision box" which summarizes the decision(s) made in the section. The remainder of this section describes the decision in more detail. Where a TCA design feature materially differs from the DRA, a rationale is provided. If a feature is fundamentally the same as the DRA and changes are required solely to permit participation of Noncommitted Dispatchable Generation, no additional rationale is provided.

At the end of each chapter, there is an additional section titled "**Anticipated Document and Tool Impacts.**" This section lists anticipated changes required to the Market Rules, Market Manuals and IESO tools. Changes to the Market Rules, Market Manuals, and IESO tools will be made so as not to effect participants in the DRA for the current DRA commitment period.

Phase I is intended to introduce minimal changes to the DRA. Most terminology used in this document is consistent with the DRA design laid out in Market Manual 12.0, Issue 6.0 and the Market Rules or defined in Market Rules, Chapter 11, however some terms may differ. Defined terms specific to this document, or which differ from those provided in Market Rules or Market manuals, are set out in the glossary. These terms may also differ from those provided in the ICA design document.

1.5 What resources are eligible to participate in Phase I?

While the ICA is intended to be as resource neutral as possible, the TCA must be mindful of existing capacity market providers (i.e. the demand response community), the investments they have made and commitments to their contributors on the basis of an existing market design, and the significant reliability needs in the future. As a result, the TCA will use a phased in approach to enable participation to a wider range of resources.[2] Taking a balanced approach attempts to minimize disruption to the existing market, while enabling greater participation where it is cost effective to do so, ensures that reliability needs over the long term will be met at the lowest cost. The table below describes the resources that are eligible to provide capacity in the TCA. Eligibility in the TCA is directly linked to eligibility in the energy market as resources have to be able to use their capacity to deliver energy or reduce consumption in the energy market. Consistent with Market Rules Chapter 7, Section 2.2, the minimum capacity resource size in Phase I is 1 MW. Demand Response Resources may aggregate through the contributor management process to meet this requirement.

Table 2 | Eligibility and Participation Criteria

Resources eligible to participate in Phase I	Resources ineligible to participate in Phase I
• **Demand Response Resources** Response resource that satisfies the registration and authorization requirements for the Transitional Capacity Auction or the Demand Response Auction, respectively • **Phase I-Eligible Generator** An existing generator that is both Noncommitted and a Dispatchable Generator.	• **Capacity from resources contracted wholly or in part for energy or capacity (this includes both the contracted capacity or the merchant component of a resource)** • **Rate regulated facilities** • **Energy efficiency** • **Resources not permitted in Ontario (e.g. coal-fired generation)** • **Imports** • **Self-scheduling resources**

[2] Market power mitigation is not described as a design feature in this document. In Phase I, the resources that are eligible to participate are not expected to have the potential to exert market power.

1.6 What is the TCA Capacity Product?

At a high level, the TCA will secure an availability commitment. Committed resources will be required to make the full amount of their cleared capacity available in the day-ahead energy market, during a predefined set of hours.

Participants will set the amount of capacity they wish enter into the auction as available for commitment. The amount of capacity a participant elects to enter must be available for the entire Obligation Period, if cleared.

2. Auction Overview and Timelines

This chapter provides details regarding the purpose of the TCA and the associated timelines, as well as a discussion of changes that are contemplated for Phase I. In general, the TCA will have four major periods – the pre-auction, auction, forward and commitment – each of which involves different IESO and participant activities. These are the same four periods in the DRA.

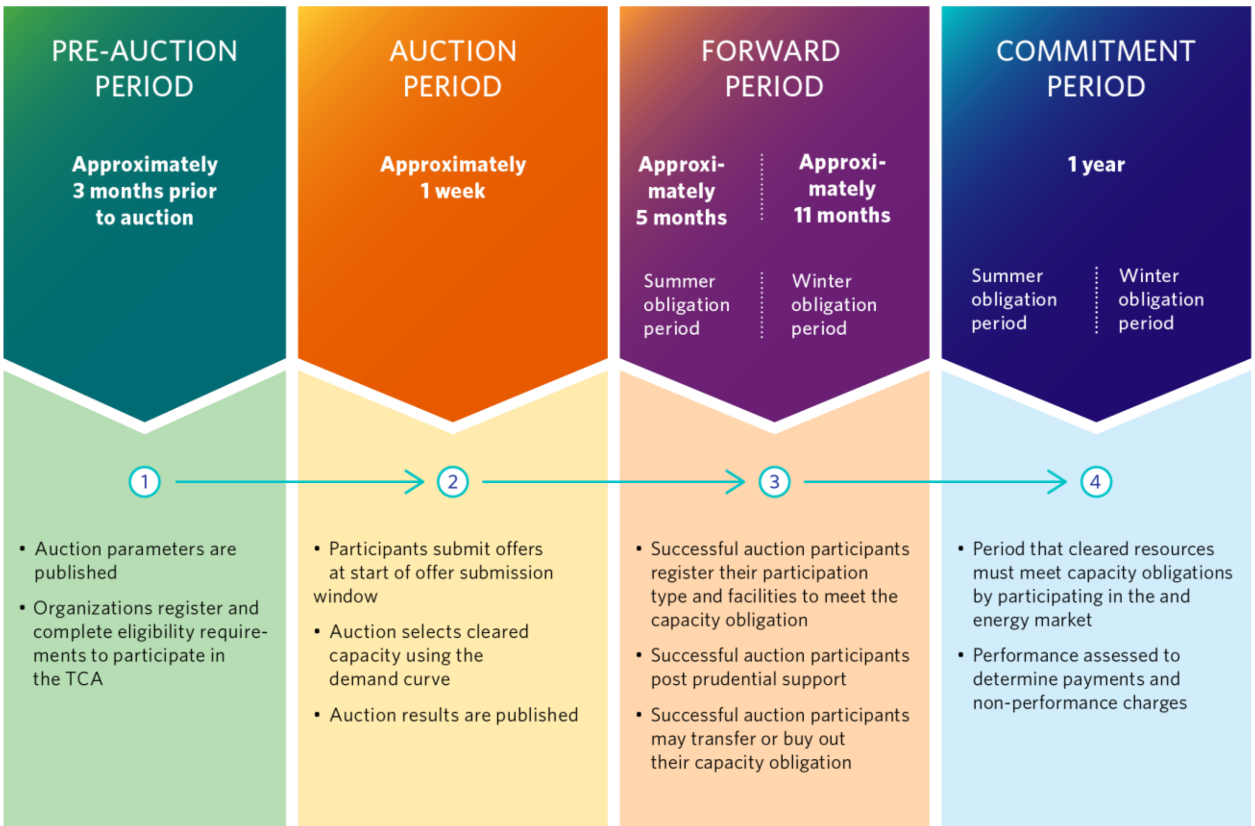

Figure 3 | TCA Activities Overview

2.1 Purpose

2.1.1 Approach in Current Market/DRA

The purpose of the DRA has been to acquire Demand Response Capacity through a competitive auction mechanism.

2.1.2 Approach in Phase I

Decision

The TCA will evolve the DRA as a mechanism for acquiring capacity by adapting it to include Phase I-Eligible Generators. This will represent a first step toward a more comprehensive capacity auction mechanism designed to meet Ontario's capacity requirements.

2.2 Commitment Periods

"Commitment Period" is currently defined in the Market Rules as the length of time for which a Demand Response Market Participant (DRMP) is required to fulfill its DR Capacity Obligation by making its Demand Response Capacity available for Dispatch in the Energy Market.

2.2.1 Approach in Current Market/DRA

The DRA uses two seasonal commitment periods in each auction year:

- Summer – May 1 to October 31
- Winter – November 1 to April 30

These seasonal commitment periods account for seasonal demand characteristics and supply capability over different seasons. Using seasonal commitment periods encourages participation by providing Demand Response Resources with the flexibility to offer into the auction in a manner most consistent with their capabilities.

2.2.2 Approach in Phase I

Decision

There will be no material changes to the DRA commitment period model for the TCA.

Seasonal obligations will continue as part of the TCA in order to support participation from both Demand Response Resources and Phase I-Eligible Generators.

In order to better align with the terminology used in the ICA, the term "Obligation Period" will be introduced in the implementation of the TCA to refer to what the DRA referred to as seasonal commitment periods. The term "Commitment Period" will be reserved in the TCA to reference the entire length of time over which each auction will commit capacity; the TCA will have a 1-year Commitment Period which will consist of two six-month seasonal Obligation Periods. The TCA will, like the DRA, clear each Obligation Period independent of the other.[3]

2.3 Forward Period

A Forward Period is the period of time between an auction and the first day participants are obligated to deliver on their Capacity Obligation.

2.3.1 Approach in Current Market/DRA

The Forward Period for the DRA is five months for the summer commitment period and 11 months for the winter commitment period.

2.3.2 Approach in Phase I

Decision

The Forward Period is expected to be approximately five months for the summer Obligation Period and 11 months for the winter Obligation Period.

If the auction is delayed to allow new participants time to prepare, the forward period will be shortened to ensure that the Obligation Periods begin on May 1 and November 1 for summer and winter, respectively.

[3] The IESO intends to employ co-optimized two-season auction clearing in the auction engine for the ICA, while the TCA will not optimize across multiple seasons in its auction engine.

2.4 Scheduling of the Auction

2.4.1 Approach in Current Market/DRA

The DRA is held annually, starting on the first Wednesday in December of each year.

2.4.2 Approach in Phase I

Decision

The scheduling of the auction may be delayed from the DRA timelines in order to provide new participants sufficient time to prepare. The date of the TCA will be published in the pre-auction report.

2.5 Demand Curve Elements

A demand curve is a representation of the IESO's willingness to buy capacity; it defines the prices that the IESO is willing to pay for varying levels of capacity along the curve. The shape of the demand curve will impact the quantity (MW; the X-axis) and price ($/MW-day; the Y-axis) of capacity that will be secured through an auction.

2.5.1 Approach in Current Market/DRA

The DRA makes use of a straight line downward-sloping demand curve, the shape of which is influenced and defined by the following reference points:

1. **Demand Response Target Capacity (MW):** The amount of Demand Response Capacity which the IESO seeks to secure through the DRA. This can vary for each seasonal commitment period. Typically, the target capacity for each seasonal commitment period was determined based on capacity (in MW) exiting due to the expiration of previous DR programs (e.g. Capacity Based Demand Response, DR Pilot, and Peaksaver Plus).
2. **DRA Reference Price ($/MW-day):** The estimated costs necessary to incentivize new DR resources to enter the market and recover necessary costs to make their capacity available, recognizing revenue opportunities and avoided costs in the energy market. The reference price of $413/MW-day for the auction represents the historical contracting cost in the former DR3 program. It is directly associated with the Demand Response Target Capacity on the demand curve (as shown in Figure 4 | Demand Curve with Elements).

3. **Maximum and Minimum Auction Clearing Price ($/MW-day):** Maximum auction clearing price is the highest amount the IESO is willing to pay for the DR capacity in an auction. In the DRA, reference price is intended to reflect net cost of a new entry into the market as a DR resource; however, there may be instances where the actual cost of a new DR resource is higher than the projected cost. The maximum auction clearing price serves to address this variability by providing some cost flexibility, and, consistent with the design of capacity market demand curves in other jurisdictions, is set at 1.25 multiple of the reference price (refer to MaxCap (MACP) calculation below), rounded to an integer value.

   The minimum auction clearing price is the minimum price at which the auction will clear and is set at $0/MW-day.

4. **Capacity Limits (MW):** The three capacity limits used in the demand curve are: the minimum capacity, the maximum capacity at maximum auction clearing price, and the Maximum Capacity.

   - The minimum capacity is the minimum amount of capacity the auction seeks to clear.[4]
   - The maximum capacity at maximum Auction Clearing Price is derived from the total cost to the market at the DRA Reference Price based on the following formula:

$$MaxCap(MACP) = \frac{Reference\ Price \times Target\ Capacity}{Maximum\ Price}$$

   - The maximum capacity is the maximum amount of capacity the auction seeks to clear. It is determined by forming a straight line between the points for the maximum auction clearing price at maximum target capacity and the Reference price at target capacity and extending this line to intersect the x-axis.

   An example demand curve can be seen in Figure 4 | Demand Curve with Elements.

[4] The minimum capacity input parameter was not used in previous DRAs. Should the IESO require a minimum capacity for reliability purposes, the IESO intends to test and validate its operations prior to setting a non-zero value.

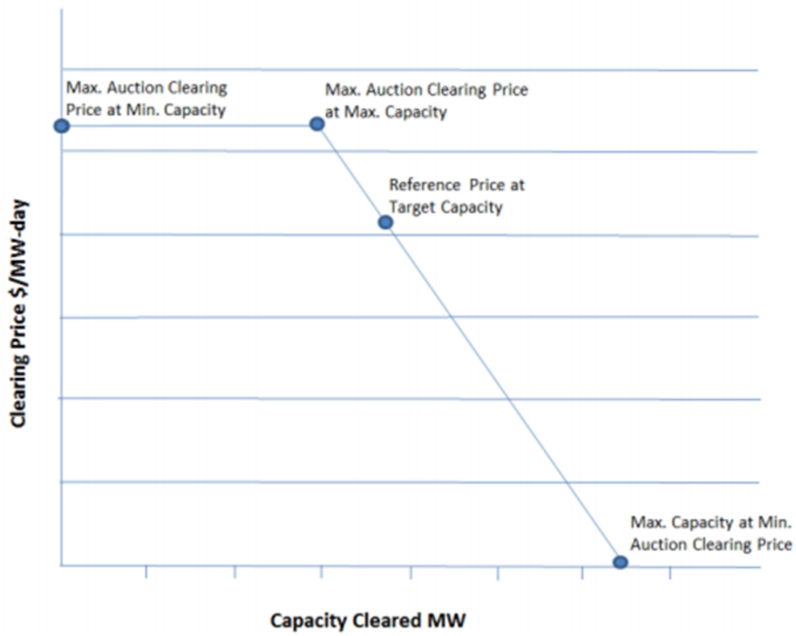

Figure 4 | Demand Curve with Elements

2.5.2 Approach in Phase I

Decision

There will be no changes to the types of demand curve parameters used in the DRA, however, the parameter values will be redefined and updated as appropriate to be inclusive of the Phase I-Eligible Generators.

The IESO will assess the values for these parameters and, using the 2018 DRA parameter values as a base, may alter the value of certain parameters, such as Target Capacity. The IESO will work with stakeholders to develop a methodology that is mindful of the sustainability of the existing DR resources and developing market capability, enabling further competition while respecting resource adequacy needs.

Based on prior DRAs, the IESO has observed that the current DR Reference Price is sufficient to incent supply (from both existing DR resources and Phase I-Eligible Generators) to meet target capacity and so it believes this price should be held constant as the Reference Price for the Phase I auction. In Phase II, the IESO intends to further discuss with stakeholders the reference price and other demand curve elements.

2.6 Zonal Constraints

2.6.1 Approach in Current Market/DRA

In order to ensure capacity can be accommodated while maintaining reliability, the DRA is designed to enforce locational limitations and specific regional needs for each of the 10 electrical zones in Ontario. The zonal limits are used to set the minimum[5] and maximum zonal capacity, respectively, for each zone. This is communicated by the pre-auction report in advance of the auction.

Three types of limits apply to each zone to set the minimum and maximum zonal capacity:

1. **Virtual Zonal Limit[6]** is the maximum amount of virtual DR capacity that can be accommodated from virtual DR resources within a given zone while respecting system security limits. The virtual zonal DR limit does not set the zonal clearing price in the auction. This limit is based on reliability studies, modelling assumptions, and the expiring DR capacity from other DR programs.
    - Virtual resources in a zone are aggregated to a single point for modelling purposes. Allowing excessive disaggregated consumption to be modeled on a single point can introduce dispatch errors and reliability concerns in managing power flows.
2. **Total Zonal Limit** is the maximum amount of capacity from both physical and virtual resources that can be acquired in a zone. This limit is based on transmission availability studies and expiring DR capacity from other DR programs.
3. **Total Zonal DR Minimum** may be set by specific regional needs determined through studies. The limit has not been required in a DRA.

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[5] The minimum zonal capacity has not been used in previous DRAs. Should the IESO require a minimum zonal capacity for reliability purposes, the IESO intends to first test and validate its operations prior to setting a non-zero value.

[6] Virtual DR means the facility does not have IESO registered revenue metering and therefore are non-dispatchable.

2.6.2 Approach in Phase I

Decision

There will be no changes to the types of zonal constraints used in the DRA. The virtual zonal constraints will be applicable only to the virtual Hourly Demand Response (HDR) resources and the total zonal constraint will be applicable to the sum of capacity from physical (Dispatchable Load and Phase I-Eligible Generators) and virtual (HDR) resources.

The values for the constraints in the Phase I TCA are anticipated to be the same as the 2018 DRA Pre-auction Report. Phase I-Eligible Generators will be a physical resource since they have the IESO registered revenue meter installed. For zonal constraints, all DR resources will be continued to be treated the same way as the former DRA.

2.7 Anticipated Document and Tool Impacts

Impacted Market Rules

Market Rules	Description of Change
• Chapter 7, Section 18 Demand Response Auction	• Rename section to Transitional Capacity Auction. • Replace references to *demand response auction* with *transitional capacity auction.* • Add reservation provision with respect to applicability of rules to Demand Response Resources participating in current *demand response auction commitment period*.
• Chapter 7, Section 18.1 Purpose of Demand Response Auctions	• Replace references to *demand response auction* with *transitional capacity auction.*
• Chapter 11 Definitions	• Replace references to *demand response auction* and replace with *transitional capacity auction.* • Change definition of *commitment period.* • Add definition for *obligation period.*

Impacted Market Manuals

Market Manual	Description of Change
• Market Manual 12.0 Section 3.0 Demand Response Auction Overview	• Replace references to *commitment period* with *obligation period.*
• Market Manual 12.0 Section 3.2 Demand Response Auction Overview	• Update start of auction window from the first Wednesday of December to the date specified in the pre-auction report (fourth bullet and diagram).
• Market Manual 12.0 Section 3.3 Commitment Periods	• Replace references to *commitment period* with *obligation period.* • Remove reference to auction date in December and replace with date specified in pre-auction report.
• Market Manual 12.0 Section 3.5.1 Target Capacity	• Revise description of Target Capacity methodology.

Other Impacts

Other Impact (IT Tool, Reporting, etc.)	Description of Change
• Pre-Auction and Post-Auction Reports	• Update terminology used (e.g. replace *commitment period* with *obligation period*).
• Training Guide	• Update training guide with new terminology.

3. Pre-Auction Period

The pre-Auction Period is the first period in an auction cycle. During this period, prospective auction participants and the IESO perform various tasks to ensure that the necessary inputs are prepared to conduct the auction as shown in the diagram below. This chapter provides details regarding activities conducted during this period for the DRA and changes that are contemplated for Phase I.

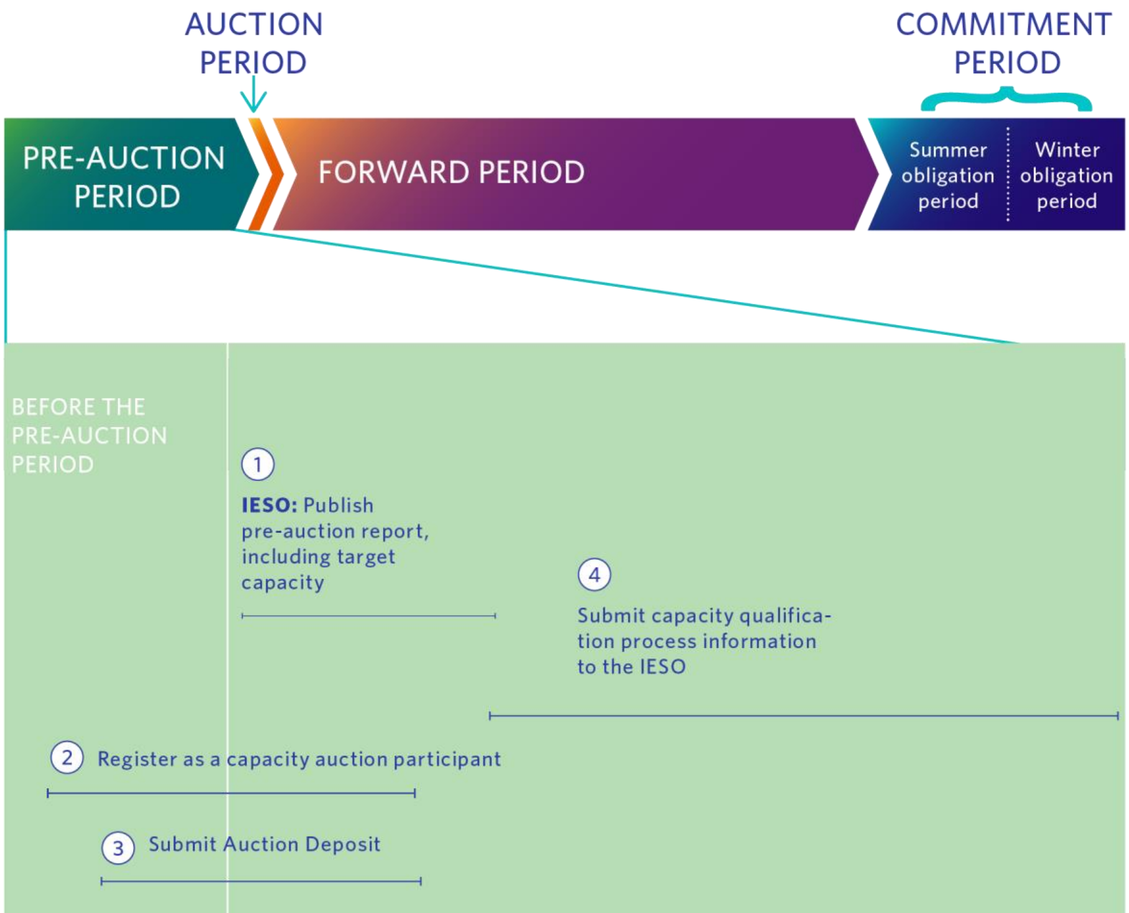

Figure 5 | Transitional Capacity Auction Pre-Auction Period Activities

3.1 Pre-Auction Reporting

The IESO shares information in advance of an auction to help potential auction participants understand capacity needs and prepare for participation in the upcoming auction.

3.1.1 Approach in Current Market/DRA

Prior to the DRA, the IESO publishes the following information:

- A pre-auction report, which is published at least two months in advance of the start of the auction offer submission window. This report includes the following parameters for each seasonal commitment period:
    - Demand Response Target Capacity;
    - Demand Response Auction Reference Price;
    - Minimum and maximum Demand Response Auction Clearing Prices;
    - Minimum (historically set at 0 MW) and maximum DRA capacity limits;
    - Maximum DRA capacity limit at the maximum Demand Response Auction Clearing Price; and
    - Zonal limitations for each electrical zone.
- The timelines for a Demand Response Auction Participant (DRAP) to submit the amount of Demand Response Capacity that they are willing to provide as Demand Response Auction Offers;
- The dates that the IESO will conduct the DRA as well as the date by which the IESO will publish the public and confidential post-auction reports; and
- A link to the IESO's zonal map tool.

3.1.2 Approach in Phase I

Decision

There will be no material changes to the pre-auction reporting.

The IESO will post pre-auction reports for the TCA at least two months prior to the auction. The pre-auction reports will be similar to those currently published to support the DRA. All of the information contained in the DRA Pre-Auction Report will continue to be included in the TCA pre-auction report with updated terminology for the TCA. The TCA pre-auction report will be posted on the Reports section of the

IESO website, however, other information, such as timelines, that was previously shared on the Demand Response webpage will now be posted on a new webpage for the Transitional Capacity Auction. The DR webpage will be archived prior to the TCA auction.

3.2 Authorization Process

The "Authorization Process" is the process through which prospective auction participants inform the IESO of their intent to participate, and the IESO authorizes eligibility for participation, in advance of an auction.

3.2.1 Approach in Current Market/DRA

To offer capacity into the DRA, participants must first register as DRAPs. The authorization process is conducted only once (the first time a prospective participant wishes to participate in a DRA). Participants wishing to offer capacity into the DRA are required to become authorized as DRAPs in advance of submitting information for capacity qualification.

3.2.2 Approach in Phase I

Decision

The IESO will develop a new market participant type, called a Capacity Auction Participant (CAP) that will replace the existing DRAP market participant type. Participants must be registered as a CAP to offer capacity into the TCA. This new CAP participant type will be created in the IESO's existing tools.

For existing DRAPs or any new DRAPs registering prior to the TCA tool changes going into effect for the 2019 TCA auction, the IESO will transfer existing DRAP participants to the new CAP type.

Phase I-Eligible Generators that wish to participate in the TCA will be required to become authorized as a CAP in advance of the start of the TCA Auction Period (i.e. when the offer window opens).

3.3 Auction Deposit

3.3.1 Approach in Current Market/DRA

Submission of a Demand Response Auction Deposit is required to establish the creditworthiness of the participant for auction activities at the outset of an auction process, and to ensure that auction and pre-seasonal commitment period obligations can be fulfilled. The deposit must be submitted by DRAP at least five business days prior to the start of the auction offer submission window. Failure to provide a deposit on time will result in disqualification from participating in an auction.

The deposit must be in one (or a combination of both) of the following forms:

- Irrevocable commercial letter of credit, in a form acceptable to the IESO, provided by an IESO-approved bank; or
- Cash deposits made to the IESO by or on behalf of the authorized market participant. The IESO will not pay interest on cash deposits.

The estimated deposit is a function of the capacity submitted by the participant and the maximum auction clearing price, as given below:

$$DR\ Auction\ Deposit = 3\%\ x\ Qualified\ DR\ Capacity\ x\ Max\ Auction\ Clearing\ Price\ per\ MW\text{-}\ day$$
$$x\ \#\ business\ days\ in\ commitment\ period$$

A higher deposit requirement may be imposed depending on the creditworthiness of the DRAP in the IESO-Administered Markets.

Deposits received from successful auction participants will be released, upon request, once:

- The Demand Response Auction Participant is authorized as a Demand Response Market Participant;
- Sufficient prudential support is posted; and
- At least one resource is registered to meet the DRAP's DR Capacity Obligation awarded to the DRAP for each seasonal commitment period in each of the cleared electrical zones.

Deposits received from unsuccessful auction participants will be released, upon request, after the publication date of the Post-Auction report.

In the case of a DR Capacity Obligation transfer, the IESO will release all or a portion of a Demand Response Transferor's deposit, if requested and a set of criteria are met.

3.3.2 Approach in Phase I

Decision

The process and deadlines for collecting an auction deposit will not materially change. The terminology used in the formula for determining the deposit will be updated.

3.4 Capacity Qualification

3.4.1 Approach in Current Market/DRA

DRAP's specify their own by submitting an amount of Demand Response Capacity they wish to be able to offer into an upcoming DRA. Submissions are made through Online IESO. Because participants are responsible for ensuring that they are able to satisfy any DR Capacity Obligation they ultimately receive in the DRA, a DRAP's should reflect the amount of Demand Response Capacity the DRAP is able to reliably provide.

The capacity qualification process begins when DRAPs who wish to participate in a given DRA provide the following information to the IESO, via Online IESO by the date stipulated in the pre-auction report:

- The amount of Demand Response Capacity, not less than 1 MW per electrical zone, they are willing to provide from each individual resource or aggregated load resource.
- The seasonal commitment period for which they are willing to submit offers. Participants may choose to submit offers for one or both seasonal commitment periods.
- The electrical zone of Demand Response Resources and/or contributors for which they are willing to submit offers (participants choose from the ten electrical zones to submit offers).
- Whether or not the Demand Response Resource is metered by IESO revenue meters (i.e. whether a Physical or Virtual Resource).
- Optional submission of a load reduction plan.
- Confirmation of having submitted the Demand Response Auction Deposit as determined by the IESO.

Upon receipt of the above information, the IESO:

- Verifies that the DRAP has completed the authorization process referenced in Section 3.2;[7] and
- Ensures the DRAP or associated market participant has not been disqualified from auction participation.

[7] Technical data is provided for information purposes only and is not assessed by the IESO. The verification step is *only* a confirmation that the authorization process has completed procedurally.

3.4.2 Approach in Phase I

Decision

The TCA qualification process will mirror the DRA process, but will be updated to enable additional resource types to participate and will require participants to specify whether their resource(s) are Demand Response Resources or Phase I-Eligible Generators.

The qualification process will continue to be facilitated by Online IESO for all CAPs. For Demand Response Resources, the timelines will not be changed. A different time period may be required for Phase I-Eligible Generators to register and qualify capacity. Milestones will be published in an auction timeline posted on the IESO website.

Phase I-Eligible Generators who wish to participate in the TCA will be required, in addition to the other requirements currently set out in the DRA qualification process, to provide an attestation that they are a Phase I-Eligible Generators. They will also be required to submit the amount of capacity not less than 1 MW, that they are willing to submit. In order to enable like-for-like transfers, TCA offers may be required to specify the resource type (i.e. generation or load but not both).

Decision

Load reduction plans will not be included in the capacity qualification process in Phase I, but may be re-introduced in Phase II.

For Phase II, additional design features for capacity qualification may be introduced to better align with the ICA and give IESO greater confidence that resources acquired through the TCA can contribute to the reliability of Ontario's electricity grid when required. Given that the IESO will evolve the capacity qualification process in Phase II, load reduction plans will not be included in the capacity qualification process in Phase I, but may be re-introduced in Phase II.

3.5 Anticipated Document and Tool Impacts

Impacted Market Rules

Market Rule	Description of Change
• Chapter 2, Section 2.1.1.10	• Update the list of classes of market participants by replacing references to *demand response auction participants* with *capacity auction market participants.*
• Chapter 7, Section 18 (throughout)	• Replace references to *demand response auction* with *transitional capacity auction.* • Replace references to *demand response auction participant* with *capacity auction participant.*
• Chapter 7, Section 18.2.2 Participation in Demand Response Auctions; Chapter 11	• Add language to provide definitions for, and differentiate between requirements for demand response resources and eligible generators.

Impacted Market Manuals

Market Manual	Description of Change
• Market Manual 12.0 Section 4.3.1 Demand Response Auction Deposit	• Update formula by replacing the term demand response with transitional capacity auction . • Replace references to demand response auction with transitional capacity auction.
• Market Manual 12.0 Section 4.2 Pre-Auction Authorization Process	• Replace references to *demand response auction participants* with *capacity auction participants.*
• Market Manual 1, Part 1.1: Participation Authorization, Maintenance and Exit	• Update Section 2.3.2 Registration of participation by replacing references to *demand response auction participant* with *capacity auction participant.*
• Market Manual 12.0 (throughout)	• Replace references to *demand response auction participants* with *capacity auction participants.*
• Market Manual 12.0 Section 9 Capacity Obligation Transfer	• Replace references to *demand response auction* with *transitional capacity auction.*
• Market Manual 12.0 Section 4.3 Capacity Qualification	• Add language to differentiate between qualification requirements for demand response and generators and specify additional generator requirements, such as providing certain representations, warranties and agreements. • Remove load reduction plan provisions and references.

Other Impacts

Other Impact (IT Tool, Reporting, etc.)	Description of Change
• Online IESO	• Update formula used for the auction deposit as per Market Manual changes. • Replace references to *demand response auction participant* with *capacity auction participant.* • Update data submission screens to allow capacity auction participants to: 1. For each zone, indicate what type of resources (Load or Generation) will deliver the physical capacity if they secure physical obligation in the auction. This needs to be added only for physical capacity (not needed for virtual capacity). 2. If generation is selected, add an attestation requirement • Remove the field for a load reduction plan
• Auction Engine	• No changes anticipated.
• Pre-Auction Report and Post-Auction Report	• Replace references to demand response to transitional capacity.
• IESO Website	• Create a new TCA webpage. • Archive the DRA webpage.
• Training Guide	• Update training guide with new terminology, formulae and requirements. • Remove references to load reduction plans.

4. Auction Period

The Auction Period is the length of time beginning when the IESO begins accepting auction offers to the time when the IESO posts auction results. This chapter provides details regarding activities conducted during the Auction Period and changes that are contemplated for Phase I.

Figure 6 | Transitional Capacity Auction Period Activities

4.1 Offer Submission

The offer submission and validation window is the period of time during which auction participants are permitted to submit offers into an auction.

4.1.1 Approach in Current Market/DRA

The auction offer submission window, opens on the first Wednesday of December starting at 09:00 EST. The offer submission window closes on the next business day at 23:59 EST. These dates and times are conveyed in the pre-auction report. During this window, DRAPs submit Demand Response Auction

Offer(s) on a zonal basis (can submit in more than one zone) by type of DRAP (physical and/or virtual)[8] for each seasonal commitment period. The requirements regarding submission of Demand Response Auction Offers are as follows:

- Offers are submitted for each of the two-season (summer and winter commitment period), and apply for the entire seasonal commitment period. Participants may offer for one or both periods.
- Submitted offers are for any quantity between 1 MW and the capacity qualified in the pre-auction process, to one decimal place, and uses offer laminations to reflect the price of providing the various levels of capacity.
- A complete Demand Response Auction Offer includes a set of up to 20 monotonically increasing price-quantity pairs, with the total offered quantity across all offers equal to or less than the for that zone. The auction offer quantity is entered as a cumulative value and therefore must increase with every new lamination.
- Each Demand Response Auction Offer must specify, for each price-quantity pair, whether the entire capacity represented in the lamination must be cleared in full or whether it may be partially cleared. A full flag is an indication that the quantity of capacity offered in a given lamination must be fully selected or not selected at all. A partial flag indicates that all, part, or none of the capacity offered in a given lamination may be selected, to a granularity of 0.1 MW.

4.1.2 Approach in Phase I

Decision

There will be no material changes to the structure and requirements in the DRA and offer submission requirements will be applicable to both DR resources (physical and virtual loads) and Phase I-Eligible Generators. Participants will continue to provide offers for each Obligation Period (season).

The TCA offer structure and requirements are effective and flexible to accommodate auction offers from both DR resources and Phase I-Eligible Generators.

[8] Physical resources are those that have IESO revenue meters, whereas virtual DR resources are those that do not.

4.2 Auction Clearing

During this step, the IESO uses certain mechanisms to determine which auction offers are accepted (or "cleared") and the associated clearing price (or "prices paid").

4.2.1 Approach in Current Market/DRA

Once the auction offer submission window closes, the auction engine assesses all the submitted offers to determine the Demand Response Auction Clearing Price(s) and capacity cleared for each zone. For each seasonal commitment period and zone, the auction engine determines the DR Capacity Obligation for each DRAP.

The optimization mathematical model within the auction engine is a mixed-integer linear programming model, with the objective of maximizing the social welfare i.e. optimal selection of resources to maximize consumer and producer surplus. This is shown by the yellow highlighted area above the cleared supply (i.e. auction offers) curve and below the pre-defined demand curve, shown in Figure 7 | Auction Clearing.

Submitted auction offers are cleared against a downward sloped demand curve defined by the parameters described in Section 2.5. The clearing process aims to achieve an auction clearing price for each zone while taking any zonal limitations into account through the maximum capacity constraint in the zone, and determine the unique auction clearing price for any zone in which the zonal limitation has been reached.

The Ontario-wide auction clearing price is equal to the price associated with the last cleared price-quantity pair associated with an DRA offer, and may clear at, below or above the demand curve. When there is an DRA offer not selected, either partially or in full, due to the total maximum zonal constraint, the auction clearing price for that zone will be set at the lesser of:

- the price associated with the next economic quantity from an auction offer in the same zone that would have cleared but for the total maximum zonal constraint; or
- the Ontario-wide auction clearing price.

The total quantity cleared through the auction may clear above the demand curve when doing so will maximize the overall objective function, i.e. increase the social welfare by ensuring more optimal selection of resources.

A downward sloping demand curve allows the auction to clear more or less than the target capacity, when it results in decreased total cost to the consumers.

If two or more auction participants submit an auction offer at the same price for the last available quantity, the auction offer with the earlier time stamp shall be selected as the successful auction offer.

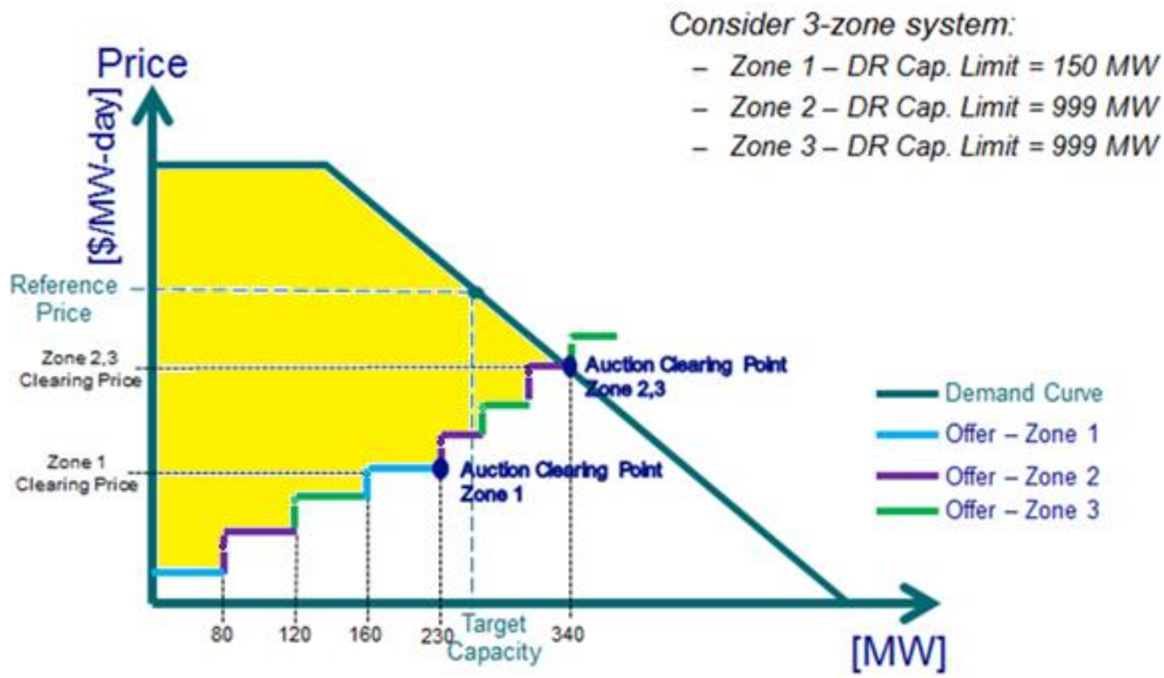

Figure 7 | Auction Clearing

In the example illustrated in Figure 7 | Auction Clearing, Zone 1 has a total maximum zonal constraint of 150 MW. All offers are stacked by increasing price against the demand curve for the seasonal commitment period. After clearing the first offer of 80 MW from Zone 1, the auction engine can only partially clear the second offer (up to 70 MW) at which point the total cleared quantity in Zone 1 is equal to the total maximum Demand Response Zonal Constraints. If the auction engine determines that the un-cleared quantity from the second offer in Zone 1 would have cleared but for the total maximum Demand Response Zonal Constraints, a zonal Demand Response Auction Clearing Price will be determined, in the manner described above. The auction clearing process will continue and the Demand Response Auction Offers will clear until the intersection with the demand curve at 340 MW, which will also set the Demand Response Auction Clearing Price for Zone 2 & 3, and it is also referred to as the Ontario-wide Demand Response Auction Clearing Price.

4.2.2 Approach in Phase I

Decision

There will be no changes to the auction clearing mechanism from the DRA. The auction clearing mechanism will treat capacity offers from both DR resources (physical and virtual loads) and Phase

I-Eligible Generators consistently and clear them with the same price setting mechanism as described above.

The DRA mechanism has proved to be a cost effective way to reliably acquire capacity while sending appropriate signals to the market. By design, the mechanism does not distinguish between offers from generation or load resource and this makes its use ideal for the TCA.

4.3 Post-Auction Reporting Obligations

Post-auction reporting refers to the information published by the IESO to inform the market of the results of the auction.

4.3.1 Approach in Current Market/DRA

Following the auction clearing step the IESO prepares public and private (confidential) post-auction reports to communicate the results. The IESO publishes the post-auction reports within four business days following the day on which the submission window closes.

Both reports are reissued if DR Capacity Obligation s are modified as a result of a buy-out or capacity obligation transfer.

Public Post-Auction Reports

The public reports contain the following information for each seasonal commitment period and are posted on the IESO's reports site:

- The auction clearing price;
- The amount of capacity acquired through the auction for each electrical zone;
- The names of successful DRAP and their DR Capacity Obligation s; and
- The of each DRAP.

Confidential Post-Auction Reports

The confidential post-auction reports are issued to individual auction participants and contain the following information for each seasonal commitment period and are posted on the IESO's confidential reports site:

- The participation type (physical or virtual); and
- The corresponding capacity obligation secured for each electrical zone.

4.3.2 Approach in Phase I

Decision

There will be no material changes to the publishing of both public and confidential post-auction reports. Changes will be made in relevant documentation to ensure the reports are inclusive of all participating resources including the Phase I-Eligible Generators.

The cleared generation capacity will be reported under the physical resources in the post-auction report. To facilitate like-for-like transfer, the report will be updated to separately list surplus generation capacity, similar to the reporting of virtual and physical DR in the existing DR post auction report.

The terms "confidential" and "private" post-auction reports have been used interchangeably within the Market Manuals and training guides. To ensure clarity, these documents will be updated to use only the term "confidential post-auction reports."

4.4 Anticipated Document and Tool Impacts

Impacted Market Rules

Market Rules	Description of Change
• Chapter 7, Section 18.5 Demand Response Auction Parameters	• Update terminology from *demand response to transitional capacity.*
• Chapter 7, Section 18.6 Demand Response Auction Parameters	• Replace *demand response auction* with *transitional capacity auction.*

Impacted Market Manuals

Market Manual	Description of Change
• Market Manual 12.0 Section 4.1 Pre-Auction Reporting Obligations	• Update terminology from *demand response* to *transitional capacity.*
• Market Manual 12.0 Section 3.2 Demand Response Auction Timelines	• Update terminology from *demand response* to *transitional capacity.*
• Market Manual 12.0 (throughout)	• Replace references to private post-auction reports to confidential post-auction reports.
• Market Manual 12.0 Section 5 Auction Mechanics	• Update terminology from *demand response* to *transitional capacity.*

Other Impacts

Other Impact (IT Tool, Reporting, etc.)	Description of Change
• Online IESO	• Allow dispatchable generation resources to offer in the TCA.
• Auction Engine	• No change required.
• Training Guide	• Update training guide with new terminology. • Replace references to private post-auction reports to confidential post-auction reports.

5. Forward Period

This chapter provides details regarding activities conducted during the Forward Period and changes that are contemplated for Phase I.

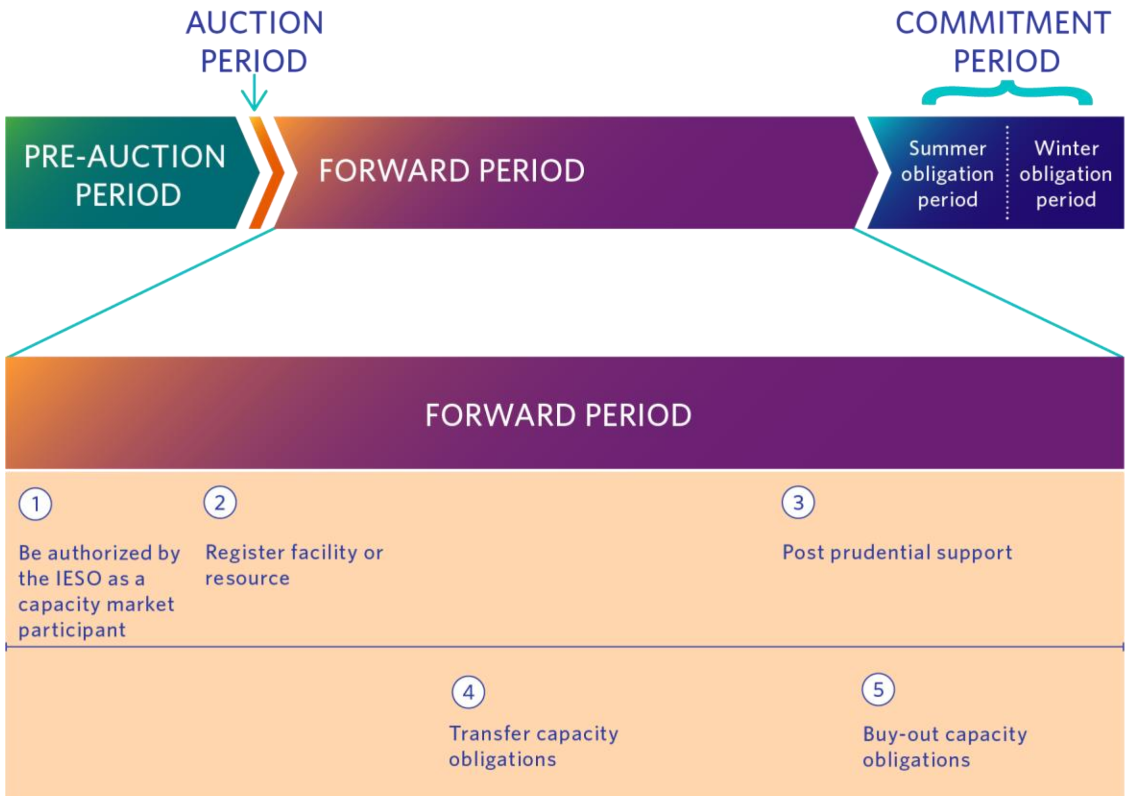

Figure 8 | Transitional Capacity Auction Forward Period Activities

5.1 Participant Authorization in Auction

5.1.1 Approach in Current Market/DRA

DRAP who have secured a DR Capacity Obligation (i.e. cleared the auction) are required to become authorized as a Demand Response Market Participant (DRMP). The authorization enables them to participate in the IESO energy market in order to fulfill their DR Capacity Obligation.

If the DRAP is already operating in the IESO-administered markets as a DRMP, they will need to complete a review of their prudential support as part of the authorization. The prudential support requirements in the post-auction market participant authorization processes are described in Section 5.3.

5.1.2 Approach in Phase I

Decision

The IESO will develop a new participant category, called a Capacity Market Participant (CMP) that will replace the existing Demand Response Market Participant (DRMP) participant category. All Capacity Auction Participants who are successful in the auction will be required to be registered as a CMP, and take on all of the obligations under the Market Rules applicable to a CMP.

Both Demand Response Resources and Phase I-Eligible Generators will be eligible to qualify as a Capacity Market Participant (CMP). For existing DRMPs, the IESO will reclassify them as CMPs prior to the forward period. Phase I-Eligible Generators and Demand Response Resources that were not previously classified as a DRMP with a capacity obligation will be required to register with the IESO as either a DRMP or CMP, depending on the stage of implementation at the time of their registration. All participants will also be required to complete a review of their prudential support as part of the authorization.

5.2 Facility/Resource Auction Registration

5.2.1 Approach in Current Market/DRA

All DRAPs that have received a DR Capacity Obligation in the DRA are required to register their facilities with the IESO to meet their DR Capacity Obligation as either an Hourly Demand Response (HDR) resource or as a Dispatchable Load. Participants begin the registration of their resources at least three months prior to the beginning of a relevant seasonal commitment period to ensure the resource is ready to participate by the start of the seasonal commitment period.

5.2.2 Approach in Phase I

Decision

Phase I-Eligible Generators will be required to register their resources in the same manner as Demand Response Resources.

Dispatchable Generators that participate in the IESO real-time energy market will continue to be subject to a set of requirements in order to register with the IESO (described in Market Manual 1, Part 1.2).

If a Phase I-Eligible Generator that has submitted a written request to the IESO for de-registration of their facility would like to participate in the TCA, they will be required to withdraw their de-registration request prior to the transmitter's receipt of a disconnection order. If the facility has de-registered, they will be treated as an unregistered resource and will not be eligible to participate in the TCA until they have completed the Connection Assessment & Approval and Market Registration processes with the IESO prior to the opening of the auction submission window.

5.3 Prudential Support

5.3.1 Approach in Current Market/DRA

All DRAPs with a DR Capacity Obligation are required to post prudential support for the seasonal commitment period, at least 60 days prior to its commencement.

The IESO calculates the DR prudential support obligation as follows:

[Monthly Availability Payment ($) × 50%] – Allowable Reductions

Where;

Monthly Availability Payment = Σ (Capacity Obligation per zone (MW) for the commitment period × Zonal Clearing Price × 23 days).

The DR prudential support posted by a market participant/DR market participant to satisfy this obligation must be in the form of a guarantee or irrevocable commercial letter of credit, which in both cases must be in a form acceptable to the IESO and provided by a:

- Bank named in a Schedule to the Bank Act, S.C. 1991, c.46 with a minimum Standard and Poor's long-term credit rating of "A" or equivalent from an IESO acceptable major bond rating agency; or
- Credit union licensed by the Financial Services Commission of Ontario with a minimum Standard and Poor's long-term credit rating of "A" or equivalent from an IESO acceptable major bond rating agency.

5.3.2 Approach in Phase I

Decision

The timelines, format and calculation used for prudential requirements will remain unchanged from the DRA. To ensure all participants are treated equally, these requirements will apply to all CMPs, including Phase I-Eligible Generators.

5.4 Capacity Obligation Transfer

5.4.1 Approach in Current Market/DRA

A DRAP with a DR Capacity Obligation may transfer their respective DR Capacity Obligation s. A Demand Response Transferor may request a full or partial DR Capacity Obligation transfer prior to the start of the seasonal commitment period (i.e. during the Forward Period only). The DR Capacity Obligation transfer will be valid for all or some of the seasonal commitment period subject to IESO approval.

In order to initiate a DR Capacity Obligation transfer, a written request must be submitted to the IESO by the Demand Response Transferor. For both parties, the respective resulting DR Capacity Obligation s cannot be between 0 and 1 MW.

The IESO assesses the DR Capacity Obligation transfer request that meets the following criteria, in order to determine whether to approve a transfer request:

- The quantity to be transferred does not exceed the difference between the Demand Response Transferee's qualified demand response capacity, and its existing DR Capacity Obligation for the applicable seasonal commitment period;
- The Demand Response Transferor provides written confirmation to the IESO from the Demand Response Transferee of its willingness to accept the transfer of a DR Capacity Obligation from the Demand Response Transferor;
- The transfer shall consist of the same attributes (e.g. same seasonal commitment period, zone and whether virtual/physical), as the Demand Response Transferor's DR Capacity Obligation ; and
- The quantity to be transferred is in increments of 0.1MW, and the resulting DR Capacity Obligation s for both the Demand Response Transferor and Demand Response Transferee following the transfer shall be 0 MW, or greater than or equal to 1 MW.

The IESO will notify the Demand Response Transferee of any additional deposit or prudential support obligation, if required.

5.4.2 Approach in Phase I

Decision

The steps for completing capacity obligation transfers will remain unchanged from the DRA. In order to ensure adequate time is set aside for the IESO to complete a capacity obligation transfer (including approvals and modelling of resources) prior to the start of the Obligation Period, a CAP with a capacity obligation will be required to request a capacity obligation transfer no later than the milestone on the auction timeline called "last date to register/update contributor management for virtual resources" (approximately 15 business days prior to the start of the Obligation Period).

The capacity obligation transfers support participation in the capacity auctions by providing participating resources with some flexibility to adapt to changing circumstances. Therefore, this feature of the DRA will continue into the TCA and be expanded to permit Phase I-Eligible Generators to transfer capacity.

The requirement that a transfer consist of the same attributes (the "like for like" requirement) will also continue in the TCA (i.e. Phase I-Eligible Generators will be permitted to transfer their capacity obligation only to other Phase I-Eligible Generators, etc.). The post-auction report will include the information required to enable a like-for-like transfers of capacity obligations for both Demand Response Resources and Phase I-Eligible Generators, just as it will continue to be provided to Demand Response Resources. This "like for like" requirement is required to enable the correct modelling in the IESO's market systems. Additional flexibility regarding requirements for Capacity Obligation Transfers may be considered in Phase II.

5.5 Buy-Outs

5.5.1 Approach in Current Market/DRA

DRAP with DR Capacity Obligation s have the option to buy-out their capacity obligation at any time during the Forward Period or the seasonal commitment period. The DRMP may initiate a buy-out by submitting a written request to the IESO identifying the following information in respect of the buy-out request:

- Capacity obligation ID;
- Commitment period (i.e. season);

- Electrical zone;
- Effective date; and
- Amount of capacity.

The IESO processes buy-out requests within one week of receipt. At the end of this review period, the IESO will either approve or reject the buy-out request.

For a full buy-out request during the Forward Period, the pre-auction deposit will be refunded upon request, if applicable, and the prudential support will be reduced to zero after receipt of the buy-out payment. For a partial buy-out request, the prudential support obligation will be revised to reflect the new obligation after receipt of the buy-out payment.

A buy-out charge is applied using the physical markets settlement process for the next available month-end preliminary settlement statement. Buy-out will be valid from the buy-out effective date until the end of the associated seasonal commitment period.

For each buy-out request, the Buy-Out Charge is calculated as follows:

$$50\%\ x \sum_{d=1}^{n} \begin{matrix} DRBOC_k\, x\ DRACP\ x \\ (1 - DRNPF_m) \end{matrix}$$

Where:

'd' is a business day

'n' is the range of business days from the buy-out effective date to the end of the commitment period

'm' is the month that corresponds to the business day

'DRBOCk' is the buy-out capacity

'DRACP' is the DRA Clearing Price

'DRNPFm' is the Non-Performance Factor for the applicable month

The buy-out charge is meant to provide partial compensation to the market from DRMP's vacating their capacity obligation. No availability payment is made to the DRMP from the effective date of the buyout. The 50% charge helps ensure good-faith participation in the DRA while allowing some flexibility/liquidity in lieu of rebalancing auctions. The charge also encourages DRMPs to proactively inform IESO if they will not be able to meet their DR Capacity Obligation s.

5.5.2 Approach in Phase I

Decision

There will be no changes to buy-outs. The charges and process for completing a buy-out will remain the same as the DRA.

The IESO recognizes the short-term need to maintain buy-outs for participants until such time as a more thorough capacity qualification process is developed in Phase II.

5.6 Anticipated Document and Tool Impacts

Impacted Market Rules

Market Rule	Description of Change
• Chapter 7, sections 4.7J.3, 18.2.3, and 18.4.4	• Replace references to *demand response* with *capacity,* as appropriate.
• Chapter 2, section 5B	• Replace references to *demand response auction* with *transitional capacity auction.*
• Chapter 2, Section 5.1	• Replace references to *demand response auction* with *transitional capacity auction.*
• Chapter 7, section. 19 Demand Response Market Participants with DR Capacity Obligation s	• Replace references to *demand response capacity* with *capacity.* • In 19.1.2, add that dispatchable, Noncommitted resources can register.
• Chapter 7, section. 19.6 (New)	• Create a new section that describes the eligibility requirements for generators with a capacity obligation.
• Chapter 7, Section 18.9 DR Capacity Obligation Transfers	• Update terminology to transitional capacity auction.

Impacted Market Manuals

Market Manual	Description of Change
• Market Manual 12.0 Section 6.1 Participant Authorization	• Replace references to demand response with capacity.
• Market Manual 12.0 Section 6.1.1 Prudential Support	• Replace references to *demand response auction* with *transitional capacity auction.*
• Market Manual 12.0 Section 8 Buyout Process	• Replace references from *commitment period* to *obligation period.* • Replace references from *demand response auction participant* to *capacity auction participant.* • Replace references from *demand response capacity obligation* to capacity obligation.
• Market Manual 12, Section 6.2 Registration Requirements	• Add clause that generators may register facilities with the IESO to meet their capacity obligation.
• Market Manual 1.1 Participant Authorization, Maintenance and Exit (throughout)	• Replace references to *demand response auction participant* with *capacity auction participant.*
• Market Manual 5, Part 5.4 Prudential Support	• Replace references to *demand response auction* with *transitional capacity auction.*
• Market Manual 12.0 Section 9 Capacity Obligation Transfer	• Replace references to demand response with capacity. • Update appendix with a sample email request to specify whether virtual, physical or generation. • Add language with the new deadline to request a capacity obligation transfer.

Other Impacts

Other Impact (IT Tool, Reporting, etc.)	Description of Change
• Online IESO	• Update participant authorization and resource registration screens. • Replace references to demand response auction participant with capacity auction participant. • Update rules to permit dispatchable generators to register a capacity obligation for each resource. • Create a validation such that participants must be able to select only the one type of resource (load or generation) that they identified during qualification to deliver a physical obligation. • Update Appian workflow to validate obligation transfers for like-for-like resources.
• Training Guide	• Update screenshots and descriptions of participant authorization, facility/resource registration and eligibility for buy-outs.

6. Commitment Period

This chapter provides details regarding activities conducted during commitments periods, and changes contemplated for Phase I. The diagram below shows the activities during the commitment period.

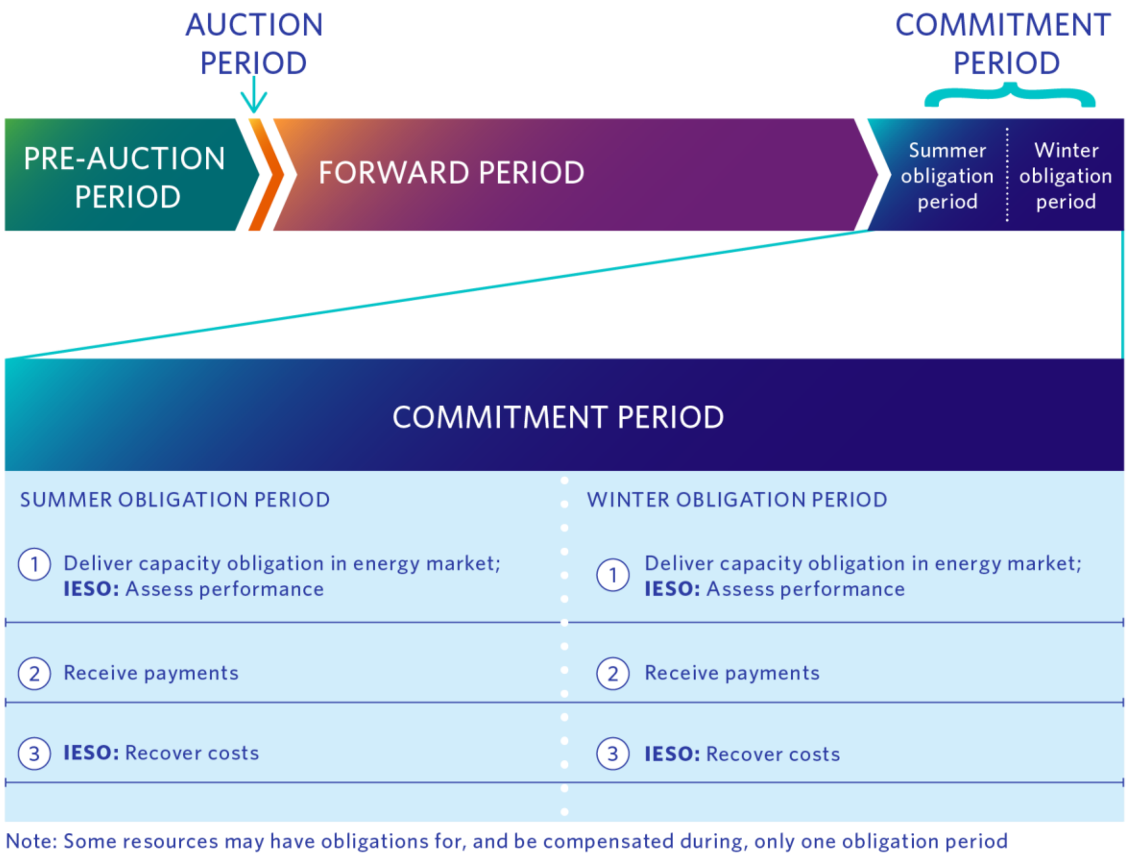

Figure 9 | Transitional Capacity Auction Commitment Period Activities

6.1 Energy Market Participation

Market Participants are expected to meet their capacity obligations by participating in the energy market. Participation activities include:

- Submitting dispatch data in the day-ahead commitment process and in the real-time market;
- Submitting outage requests or non-performance event information, if required; and

- Demonstrating ability to deliver capacity obligations by responding to the dispatch instructions (including test activations).

6.1.1 Dispatch Data Submission

6.1.1.1 Approach in Current Market/DRA

DRMPs with a DR Capacity Obligation are eligible for an availability payment associated with their Demand Response Capacity by submitting and maintaining energy bids in the day-ahead through to real-time markets during the availability window. This window is the range of business days and hours during a seasonal commitment period that a Demand Response Resource is expected to be available to provide demand response. The summer availability window is business days from 12:00 to 21:00 EST (hour ending 13 to 21) and the winter availability window will is business days from 16:00 to 21:00 EST (hour ending 17 to 21).

These energy bids must be greater than the bid price threshold of $100/MWh and less than the Maximum Market Clearing Price (MMCP $2000/MWh). The bid price threshold serves to identify times at which bids reflect consumption patterns to follow incentives in the Industrial Conservation Initiative (ICI) and ensure the resource is not dispatched for DR during this time. DRMPs that do not comply with this requirement may be subject to the non-performance charges described in Section 6.2.3.

6.1.1.2 Approach in the Phase I

Decision

Phase I-Eligible Generators that were successful in the TCA will be required to offer at least equal to their capacity obligation in the day-ahead and pre-dispatch time frames of the energy market during the availability window (12:00-21:00 EST for summer and 16:00-21:00 EST for winter). As generation resources do not participate in the ICI, Phase I-Eligible Generators will not be required to respect any minimum price threshold in their offers for the energy market participation. DR resources (physical and virtual loads) will continue to submit bids as per the DRA.

The IESO will work with stakeholders to develop a methodology to reflect the interaction between efficient energy market participation and capacity obligations for facility characteristics.

6.1.2 Resource Dispatch

6.1.2.1 Approach in Current Market/DRA

In the IESO-administered market, Dispatchable Load resources deliver energy by following the IESO's five-minute dispatch instructions.

Hourly Demand Response (HDR) resources receive a "standby report" in advance of a potential activation between 15:00 EST day ahead until 07:00 EST on the dispatch day, if they were scheduled to curtail for the hours of availability. If a standby report is issued HDR resources will continue to submit bids for that day consistent with their capacity obligation. HDR resources will be notified that they will be dispatched by receiving an Activation Notice approximately 2.5 hours before the start of the first dispatch hour to which it relates. HDR resources may be activated once per day for one up to four consecutive hours starting May 1, 2019.

6.1.2.2 Approach in Phase I

Decision

Phase I-Eligible Generators will be committed, scheduled, and dispatched on a five-minute interval using the existing day-ahead and real-time scheduling process.

The Day Ahead Commitment Process requires generators to submit offers day-ahead if they wish to participate in the next day's real-time market. As discussed in 5.1.1, generation CMP will be required to submit offers day-ahead and may receive a commitment schedule day-ahead. When a generation CMP receives a day-ahead commitment, it will represent an appropriate signal in advance of a dispatch to ensure that they are online and able to deliver their capacity.

6.1.3 Outage Management/Non-Performance Events

6.1.3.1 Approach in Current Market/DRA

IESO energy market participants are required to identify when their resources are unable to provide capacity through submission of outages and/or non-performance events. There are separate requirements for the Dispatchable Loads and Hourly Demand Response resources.

If Dispatchable Loads are unable to meet a capacity obligation due to outage or other reasons, they are currently required to submit an outage as per the existing outage management process set out in the Market Manual 7.3. They are also required to update their bids to reflect their consumption capability, meaning that those on outage are required to remove their bids completely. HDR resources with DR Capacity Obligation s are currently required to submit an email informing the IESO of a non-performance event (NPE) for a reduction in capacity of 5 MW or greater. Submissions indicate the anticipated DR capacity reduction and the period over which the DR capacity is reduced. Bids are also required to be updated by the HDR resource to reflect the change in capacity of the resource.

6.1.3.2 Approach in Phase I

Decision

CMPs will be required to update their bids or offers, as applicable, to reflect their actual capacity capability regardless of the nature of the outage (planned or forced). For outage submission, physical resources will continue to submit outage requests as per the existing outage management process set out in the Market Manual 7.3: Outage Management. Similar to DR resources, Phase I-Eligible Generators may request for an adjustment to non-performance charges using the notice of disagreement (NOD) process.

Virtual resources that were required to submit an email informing the IESO of an NPE will no longer be required to email the IESO. Instead, they must retain records of NPEs, that shall be provided, upon request, to the IESO. As such, the virtual CMP will need retain NPE details (event description, resource name, trade date, hours of reduced capacity, registered maximum and reduced capacity, capacity during NPE, and action taken to manage energy bids) for a period of 1 year from the end of the end of the winter Obligation Period (even if they only received a summer obligation).

Phase I-Eligible Generators on planned or forced outage must, in addition to submitting outage requests, update offers in the energy market to reflect their unavailability to provide capacity at times of system need during the availability window. This treatment is consistent with the DR resources. Since bids and offers are used to determine availability, CMPs with reduced capacity may receive availability charge for failing to provide the difference between cleared capacity obligation and available reduced capacity in the energy market. In principle, there should be no change to the current energy market participation framework for the Phase I-Eligible Generators with a TCA capacity obligation. The IESO is reviewing the current requirements to determine if any settlement adjustments are necessary to accommodate generator participation in an auction that had previously only contemplated load-side.

Non-performance charge exceptions may, upon IESO review, apply under the following scenarios:

1. Phase I-Eligible Generator is unable to submit energy offers for some or all of the Capacity Obligation due to an outage of a third party market participant (e.g. transmission outage)
2. Phase I-Eligible Generator is unable to provide capacity due to a force majeure event. For a force majeure event, the generator must notify the IESO prior to dispatch, if

possible, so that offers can be withdrawn for the resource and the resource will not be scheduled.

Supporting documentation and evidence must be provided along with the NOD submission before the NOD deadline (published in the Market Calendar).

6.1.4 Scheduling of Test Activations

6.1.4.1 Approach in Current Market/DRA

Test activations for DRMP allow the IESO to verify that the registered capacity of the resource is deliverable. Up to two tests may be scheduled during each seasonal commitment period, and tests are scheduled to occur during the availability window of the dispatch day. In principle, DR resources are expected to demonstrate a reduction in energy withdrawal at point of connection with the IESO-controlled grid in real-time[9] equal to the registered capacity of the resource.

Test activations are scheduled by the IESO one day in advance of the test by issuing an advisory notice and stand-by notification to all the DRMPs being tested. Failure of a resource to perform successful test activation may result in one or more of the following:

- Non-performance charges, as specified in Section 6.2.3;
- A subsequent test activation; and/or
- A compliance investigation to be performed by Markets Assessment and Compliance Division.

At IESO's discretion, a test activation may not be required for DR resources that have consistently and successfully delivered on their capacity obligation during the test activations.

HDR resources providing capacity will be required to demonstrate a reduction in energy withdrawal that is at least equal to the capacity obligation of the resource for 4 hours during test activation.

6.1.4.2 Approach in Phase I

Decision

Phase I-Eligible Generators with Capacity Obligations will be required to demonstrate an injection of energy at the point of connection with the IESO-controlled grid that is at least equal to the Capacity Obligation of the resource during the availability window.

[9] HDRs are measured against a baseline when evaluating their performance.

Consistent with the approach in DRA, DR resources (physical and virtual) with Capacity Obligations will be required to demonstrate a reduction in energy withdrawal at the point of connection with the IESO-controlled grid tested during the availability window.

All CMP resources may be test activated up to two times per Obligation Period.

6.2 Settlements

Market participants are settled using the physical markets settlement process, for both payments and non-performance charges. Non-performance charges resulting from a failure to satisfy capacity obligations are intended to incentivize compliance, ensure integrity of the electricity market, and to avoid the IESO paying for the capacity that has not been provided. Payment and charges described in this section are assessed and calculated for each resource registered by the market participant to fulfill the capacity obligation.

6.2.1 Measurement data submission

6.2.1.1 Approach in Current Market/DRA

Measurement data submission is required to support settlement of HDR resources. HDR resources that are not revenue metered by the IESO are required to submit measurement data at the resource level. All registered contributor measurement data is summed up to the HDR resource. Measurement data submission includes five-minute interval data for monthly and historical data, and it is due on the 6th business day before the end of the following month (i.e. for the month of May, the measurement data is due on the 6th business day before the end of June). Failure to submit measurement data results in an administration charge, discussed in Section 6.2.3.4. Measurement data submissions are not required for resources that are revenue metered by the IESO.

6.2.1.2 Approach in Phase I

Decision

There will be no changes to the measurement data submission process for HDR resources that are not metered by the IESO. This process is not applicable to the Phase I-Eligible Generators.

6.2.2 Availability Payment

6.2.2.1 Approach in Current Market/DRA

DRMP signal availability to the IESO by submitting energy bids to provide capacity. Resources are paid a full Availability Payment for each month they have a capacity obligation.

The participant is paid an Availability Payment on a monthly basis. Each payment is paid based on the DR Capacity Obligation , availability rate, Hours of Availability and number of business days within a month, regardless of the resource type. Resource availability payment for the month is calculated as:

$$Availability\ Payment\ = \sum_{h=1}^{n} DR\ Capacity \times Availability\ Rate$$

Where:

"h" represents an hour within the Hours of Availability for the month;

"n" is equal to the number of Hours of Availability for the month times the number of business days in the month;

"DR Capacity" is the DR Capacity Obligation secured through a DRA; and

"Availability Rate" is the Hourly Auction Clearing Price ($/MWh)

6.2.2.1.1 Approach in Phase I

Decision

There will be no material changes to the Availability Payment calculation except to rename terms - the calculation will be applied consistently across all the resource types including Phase I-Eligible Generators.

The Availability Payment equation for each obligation will be adjusted as follows:

$$Availability\ Payment\ = \sum_{h=1}^{n} TCA\ Capacity \times Availability\ Rate$$

Where:

"h" represents an hour within the Hours of Availability for the month;

"n" is equal to the number of Hours of Availability for the month times the number of business days in the month;

"TCA Capacity" is the TCA Capacity Obligation secured through a TCA Auction; and

"Availability Rate" is the Hourly Auction Clearing Price ($/MWh)

6.2.3 Non-Performance Charges

6.2.3.1 Availability Charge

6.2.3.1.1 Approach in Current Market/DRA

The Availability Charge applies to DRMP's that fail to make their capacity available in the energy market both during day-ahead and real time. The charge is calculated for the obligation to ensure negative amount as follows:

$$Availability\ Charge\ = \sum_{h=1}^{n} -1 \times (Max(0, DRCO_d - DR\ Bid\ Qty_h)) \times Hourly\ DRACP \times NPF_h$$

Where:

"d" represents a business day in the month;

"h" represents an hour within the availability window for day "d";

"n" represents the number of availability window for day "d";

"DRCO" is the DR Capacity Obligation effective for day "d";

"DR Bid Qty" is the total quantity of DR provided from all resources for hour "h";

"Hourly DRACP" is the hourly DRA clearing price ($/MWh); and

"NPF" is the non-performance factor (refer to table below for values).

Table 3 | Non-Performance Factor by Month

Month	Non-Performance Factor (NPF)
January	2.0
February	2.0
March	1.5
April	1.0
May	1.0
June	1.5
July	2.0
August	2.0
September	1.5
October	1.0
November	1.0
December	1.5

Note: The higher NPFs correlate to the peak months of the Obligation Period.

6.2.3.1.2 Approach in Phase I

Decision

The Availability Charge will be applied consistently across all the resource types including Phase I-Eligible Generators by measuring availability on an hourly basis. The charge calculation will not be changed, except to rename terms.

NPF will be changed to 2.0 (from 1.5) for the month of September. NPFs for the remaining months remain unchanged.

Historically, the NPF for each month was determined using historical system demand. Consistent with this approach, the IESO revisited the historical system demand and identified that, since 2015, system peak demand is experienced during the September month. The IESO reviewed the winter months and no changes are necessary.

The Availability Charge for the obligation will change to:

$$Availability\ Charge\ = \sum_{h=1}^{n} -1 \times (TCA\ Capacity -\ TCA\ Bid\ Qty_h) \times Availability\ Rate \times PF_h$$

Where:

"h" represents an hour within the Hours of Availability for the month;

"n" is equal to the number of Hours of Availability for the month times the number of business days in the month;

"TCA Capacity" is the TCA Capacity Obligation secured through an Auction;

"TCA Bid Qty" is the Quantity from the price-quantity pair of the DR Energy Bid for hour "h" for loads or the Quantity from the price-quantity pair of the energy offer for hour "h" for generators;

"Availability Rate" is the Hourly Auction Clearing Price ($/MWh); and

"PF" is the Non-Performance Penalty Factor with value (as per Table 3 | Non-Performance Factor by Month but with September value at 2) for the hour "h".

6.2.3.2 Dispatch Charge

6.2.3.2.1 Approach in Current Market/DRA

The Dispatch Charge, applicable only to Commercial and Industrial (C&I) HDR resources, is applied on failure to comply with in-market dispatch or test activation instruction. A fifteen percent (15%) deadband of the dispatch instruction is used in measuring compliance. The dispatch charge applies to the DR dispatch hour when a C&I HDR resource fails to meet their dispatch instruction within the specified deadband for any 5-minute interval within the DR dispatch hour. Dispatchable load resources are dealt with by present market compliance processes for failure to comply with dispatch instruction.

The charge for the hour is calculated for the obligation when following inequality is true:

$$Baseline_i - Actual\ Consumption_i < 85\% \times (Total\ Bid\ Qty_i - Schedule_i)$$

Where:

"i" is an interval within the DR dispatch hour within the DR activation event;

"Baseline" is the calculated C&I HDR baseline for the interval (Market Manual 5 Part 5.5, Section 1.6.25.3.1);

"Actual Consumption" is the measurement data for the interval. "Schedule" is the constrained schedule quantity for hour "h";

"Total Bid Qty" is the maximum quantity of the DR energy bid converted to an interval equivalent. "Availability Rate" is the Hourly Auction Clearing Price ($/MWh); and

"Schedule" is the real-time constrained schedule quantity amount for the interval.

The charge is applied for each resource as:

$$Dispatch\ Charge = -1 \times DRSQty_h \times DRACP_h \times DRNPF_h$$

Where:

"h" is the hour in which HDR resource failed to follow its dispatch;

"$DRSQty_h$" is the demand response scheduled quantity;

"$DRACP_h$" is the Hourly Demand Response Demand Response Auction Clearing Price;

"$DRNPF_h$" is the non-performance factor

6.2.3.2.2 Approach in Phase I

Decision

There will be no changes to the Dispatch Charge calculation. Similar to the Dispatchable Loads, no charges will be developed for failure of the Phase I-Eligible Generators to comply with dispatch instructions. Dispatch compliance will continue to be governed by the Market Rules and interpretation bulletins.

Both Phase I-Eligible Generators and Dispatchable Loads are physical resources and should be subjected to a consistent treatment for dispatch violation. HDR resources will continue to be subjected to dispatch charge for dispatch violation as per the rationale provided in Appendix A – Settlements Summary.

6.2.3.3 Capacity Charge

6.2.3.3.1 Approach in Current Market/DRA

The capacity charge applies to all resource types, and is applied when DR resources fail to provide capacity during in-market or test activations. Non-performance of delivering capacity in the energy market results in a Capacity Charge equal to one month's Availability Payment. The capacity charge is capped at one month of the availability payment for the same month in which the capacity delivery or test activation failure occurred.

Dispatchable Load Resources

Dispatchable Load with a capacity obligation are subject to a capacity charge when they fail to provide capacity during test activations only. Failure of these resources (given a deadband applied to Dispatchable Load) during energy market participation constitutes a compliance issue and this non-compliance will be dealt with appropriately by the existing energy market processes.

HDR Resources

A 20% deadband of the dispatch instruction is used in measuring compliance. An HDR resource is deemed to have failed to deliver capacity for the obligation if the following condition is true for the DR activation event:

$$\text{Avg}\ (\text{Baseline}_\text{i} - \ \text{Actual Consumption}_\text{i}) < 80\% \ \times \text{Avg}\ (\text{Total Bid Qty}_\text{i} - \ \text{Schedule}_\text{i})$$

Where:

"i" represents an interval within the DR activation event

"Baseline" is the calculated baseline based on historical consumption for interval "i" (as described in Section 7.2.1)

"Actual Consumption" is the measurement data for interval "i"

"Total Bid Qty" is the maximum (interval equivalent) quantity of the bid into the market from the price-quantity pairs

"Schedule" is the real-time constrained schedule quantity for interval "i"

"Baseline – Actual Consumption" represents the DR provided

"Total Bid Qty – Schedule" represents the DR expected.

The resulting charge is capped at one month of availability payment per obligation using the following equation:

$$\text{Capacity Charge} = \text{-1 x (Availability Payment for the calendar month)}$$

6.2.3.3.2 Approach in Phase I

Decision

There will be no changes to the Capacity Charge calculation and it will be consistently applied to all the resource types including the Phase I-Eligible Generator. Similar to the Dispatchable Loads, this charge will be applied on failure to provide capacity during the test activation.

Both Phase I-Eligible Generators and Dispatchable Loads are physical resources and should be subjected to a consistent treatment for failing to provide capacity. Virtual load resources will continue to be subjected to capacity charge on failure to provide capacity as per the rationale provided in Appendix A – Settlements Summary.

6.2.3.4 Administration Charge

6.2.3.4.1 Approach in Current Market/DRA

The Administration Charge is applied to virtual HDR resources that fail to meet measurement data submission obligations which are required to facilitate their participation in the market. In the event that the data is not submitted by the deadlines as stipulated in the Contributor Management Timelines (published in advance of the start of the seasonal commitment period), the following administration charge per obligation is capped at one month of the Availability Payment is applied:

Administration Charge = -1 x (Availability Payment for the calendar month)

6.2.3.4.2 Approach in Phase I

Decision

There will be no changes to the Administration Charge calculation. This charge is not applicable to the Phase I-Eligible Generators.

6.3 Cost Recovery

6.3.1 Approach in Current Market/DRA

The costs to be recovered include payments net of any non-performance charges and buy-out charges per month. The cost recovery for the settlement of the DR Capacity Obligations are allocated to consumers in the form of a monthly uplift charge that uses the same allocation methodology used for the global adjustment. The IESO will recover costs using the following two uplift charges:

- 1350 "Capacity Based Recovery Amount for Class A Loads"
- 1351 "Capacity Based Recovery Amount for Class B Loads"

Class A load consumers are charged based on peak demand factors (calculated using their consumption at times of historical system peaks) while Class B load consumers are charged based on their monthly consumption. The monthly consumption is the same month in which the settlements occur.

6.3.2 Approach in Phase I

Decision

There will be no change to the cost recovery methodology.

6.4 Anticipated Document and Tool Impacts

Impacted Market Rules

Market Rule	Description of Change
• N/A	• No change required

Impacted Market Manuals

Market Manual	Description of Change
• Market Manual 5, Part 5.5: Physical Markets Settlement Statements	• Update charge terms and/or equation in line with changes contemplated for availability payment, availability charge, non-performance factors, and capacity charge. • Reserve applicability of existing charge terms to *demand response resources* for current *demand response auction commitment period.*
• IESO Charge Types and Equation	
• Market Manual 5, Part 5.5: Physical Markets Settlement Statements Section 1.6.26.1	• Include reference to *transitional capacity auction.* • Update timeline from one month to two months for measurement data submissions.
• Market Manual 12.0 Section 6 Post-Auction Requirements and Section 7 Settlements	• Update description of charges to include dispatchable generation resources. • Update Energy Market Participation section to include requirements for dispatchable generation. • Replace demand response with capacity. • Update timelines for measurement data submissions.

Other Impacts

Other Impact (IT Tool, Reporting, etc.)	Description of Change
• Training Guide	• Update settlements equations.

7. List of Acronyms

C&I	Commercial and Industrial
CAP	Capacity Auction Participant
CMP	Capacity Market Participant
DACP	Day-Ahead Commitment Process
DAOS	Day-Ahead Optimization System
DR	Demand Response
DRA	Demand Response Auction
DRAP	Demand Response Auction Participant
DRMP	Demand Response Market Participant
DSO	Dispatch Scheduling and Optimization
HDR	Hourly Demand Response
ICA	Incremental Capacity Auction
ICI	Industrial Conservation Initiative
IESO	Independent Electricity System Operator
LDC	Local Distribution Company
MMCP	Maximum Market Clearing Price
MMP	Metered Market Participant
MRP	Market Renewal Program
MSP	Metered Service Provider
MW	Megawatts
NERC	North American Electric Reliability Corporation
NOD	Notice of Disagreement
NPCC	Northeast Power Coordinating Council
NPE	Non Performance Event
OEFC	Ontario Electricity Financial Corporation
RMP	Registered Market Participant
SIA	System Impact Assessment
TCA	Transitional Capacity Auction

8. Glossary

Term	Definition
Auction Period	The length of time beginning when the IESO opens the window to receive auction offers to the time when the IESO posts auction results.
Capacity Auction Participant (CAP)	A person who is a market participant that is authorized to participate in a Transitional Capacity Auction.
Capacity Market Participant (CMP)	A person who is a Market Participant that is either a Demand Response Resource or a Phase I-Eligible Generator, and that has a Capacity Obligation.
Capacity Obligation	The amount of capacity that a Capacity Market Participant is obligated to provide during the applicable availability window and Obligation Period, following successful clearing in a Transitional Capacity Auction.
Commitment Period	Has the meaning set out in 2.2.2
Demand Response Auction Clearing Price	The price at which the Demand Response Auction clears for a commitment period and will be quoted in $/MW-day.
Demand Response Auction Deposit	The deposit required to be made by a Demand Response Auction Participant in accordance with section 18 of Chapter 7, as a condition of participating in a Demand Response Auction.
Demand Response Auction Offer	An offer(s), submitted by a Demand Response Auction Participant, in the form of a price-quantity pair(s) to provide Demand Response Capacity in a Demand Response Auction.
Demand Response Auction Participant (DRAP)	A person who is a market participant that is authorized to participate only in a Demand Response Auction.
Demand Response Auction Reference Price	The estimated costs necessary to support the sufficient return on investment for a new, representative Demand Response Resource, net of expected ancillary services revenues and avoided energy costs.
Demand Response Capacity	The expected quantity of load reduction a demand resource can provide during a specified availability window and commitment period for a Demand Response Auction, and excludes energy transacted through the energy market.
Demand Response Capacity Obligation / DR Capacity Obligation	The amount of Demand Response Capacity that a Demand Response Market Participant is obligated to provide during the applicable availability window during a commitment period following a Demand Response Auction.
Demand Response Market Participant (DRMP)	A market participant that participates only in the capacity based demand response program, the demand response pilot program, or is a person with a DR Capacity Obligation.
Demand Response Prudential Support	The collateral provided by a market participant with a DR Capacity Obligation.

Demand Response Resource	A Market Participant that is either a Dispatchable Load or an Hourly Demand Response resource and that satisfies the registration and authorization requirements for the Transitional Capacity Auction or the Demand Response Auction, respectively.
Demand Response Target Capacity	The amount of Demand Response Capacity which the IESO seeks to clear through the Demand Response Auction.
Demand Response Transferee	A Demand Response Auction Participant who is willing to accept all or a portion of a DR Capacity Obligation from a Demand Response Transferor.
Demand Response Transferor	A Demand Response Auction Participant who intends to transfer all or a portion of its DR Capacity Obligation to a Demand Response Transferee.
Demand Response Zonal Constraints	The minimum or maximum amount of Demand Response Capacity that the Demand Response Auction seeks to clear for a specific electrical zone as detailed by the IESO in each pre-auction report.
Dispatchable Generator	A facility registered with the IESO as a generator with respect to which the IESO can direct real-time operation to cause a specified amount of electric energy or ancillary service to be provided to or taken off the electricity system.
Dispatchable Load	A Load Facility which is subject to dispatch by the IESO and whose level is selected or set based on the price of energy in the real-time market, and excludes Hourly Demand Response resources.
Forward Period	The period of time following an auction, to the first day participants are obligated to make their capacity available.
Hourly Demand Response (HDR)	The resource type described in section 19 of Chapter 7, that is used by the IESO as a delivery type, on an hourly basis, for a DR Capacity Obligation.
Load Facility	A facility that draws electrical energy from the integrated power system.
Market Manual	A published document that is entitled as such and that describes procedures, standards and other requirements to be followed, met or performed by market participants, the IESO and other persons in fulfilling their respective obligations under the Market Rules.
Market Rules	Rules made under section 32 of the Electricity Act, 1998.
Noncommitted	Resources that are not –in whole or in part - rate-regulated, contracted to the IESO, contracted to the OEFC, or obligated as a resource backed capacity export to another jurisdiction during the entire duration of a given Commitment Period.
Obligation Period	Has the meaning set out in 2.2.2
Phase I	The first phase of the TCA, as further described in this design document.
Phase I-Eligible Generator	An existing generator that is both Noncommitted and a Dispatchable Generator.
Target Capacity	The amount of capacity the IESO will seek to clear in a Transitional Capacity Auction.

Appendix A – Settlements Summary

Charge Code	Settlement Charge	Applicability	Rationale	Participating TCA Resources		
				Dispatchable Loads	Dispatchable Generation	Hourly DR
1314	Availability Payment	When there is a DR Capacity Obligation	Payment to capacity resources for making themselves available in the energy market.	Applicable	Applicable	Applicable
1315	Availability Charge	When Availability Requirements are not met	Non-performance charge - Failure to provide DR Energy Bids / Offer in every hour of the Availability Window. This charge is meant to incentivize availability of the capacity resources.	Applicable	Applicable	Applicable
1316	Administration Charge	When measurement data are not submitted by the deadline	Non-performance charge - Only applicable to virtual resources. HDR resources must submit measurement data for IESO to assess performance during activation (in-market or test). This charge is meant to incentivize timely data submission from HDR resources.	Not required as the resource does not need to provide measurements	Not required as the resource does not need to provide measurements	Only applies to resources that are not revenue-metered by the IESO)
1317	Dispatch Charge	When dispatch instructions were not followed	Non-performance charge – Only applicable to Virtual – C&I resource. Ensure smooth response is provided by the resource throughout the intervals and hours of activation. 15% Deadband is meant to provide equivalent treatment as the dispatch compliance deadband applicable to Dispatchable Loads and other grid connected resources.	N/A; Non-compliance with dispatch is dealt with existing market processes.	N/A; Non-compliance with dispatch is dealt with existing market processes.	Applicable
1318	Capacity Charge	When failing to deliver capacity in the energy market including a failed test activation	Non-performance charge – Applied to capacity market participants as a front-line deterrent for non-performance of capacity delivery and ensure capacity is provided on an average basis during the entire activation period (few intervals or all 4 hours). 20% deadband was	Only applicable if failed test activation	Only applicable if failed test activation	Only applicable if failure during in-market or test activation

Charge Code	Settlement Charge	Applicability	Rationale	Participating TCA Resources		
				Dispatchable Loads	Dispatchable Generation	Hourly DR
			inherited from the original DR3 design and was intended as interim measure until development of a more enduring capacity qualification and performance regime.			

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MARKET MANUAL

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Market Manual 12: Demand Response Auction

Part 12.0: Demand Response Auction

Issue 6.0

This procedure provides guidance to *market participants* on the operation of the *demand response auction* process

3. Demand Response Auction Overview

Demand response is the changing of electricity consumption patterns by end-use *consumers* in response to *market prices*. The *IESO* will use the *demand response auction* to acquire *demand response capacity* from *market participants* that are able to provide this capacity through the *energy market* in exchange for an availability payment.

The *demand response auction* will be conducted on an annual basis to procure *demand response capacity* for the upcoming summer and winter periods, also known as *commitment periods* (Ch. 7, S. 18.5.1 of the *market rules*). The breakdown of seasonal *commitment periods* is further explained in Section 3.3 of this manual.

3.1 Demand Response Auction Process

Figure 3-1 below shows the *demand response auction* process overview:

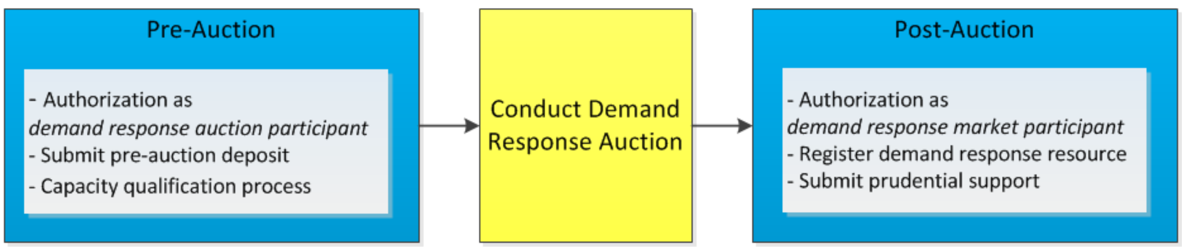

Figure 3-1: Demand Response Auction Process

Market participants who wish to participate in the *demand response auction* are required to be authorized as *demand response auction participants* and complete the capacity qualification process in order to submit their *demand response auction offers* into the *demand response auction*. Upon validating all submitted offers, the *IESO* will process the offers, determine the clearing price and quantity for each of Ontario's ten electrical zones, prepare and *publish* the post-auction reports. All *demand response auction participants* that successfully obtain a *demand response capacity obligation* through the *demand response auction* are required to register as *demand response market participant,* provide *prudential support* as determined by the *IESO*, and register their resources as demand response resources.

3.2 Demand Response Auction Timelines

Ontario's *demand response auction* will follow the following timelines:

- The *IESO* will *publish* a pre-auction report no less than two months prior to the start of the offer submission window for the *demand response auction.*

- *Market participants* intending to participate in the *demand response auction* must complete their authorization as *demand response auction participants* at least 40 *business days* in advance of the *demand response auction*.

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Menu

Sector Participants > IESO News > IESO Announces Results of Demand Response Auction

News and Updates

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IESO Announces Results of Demand Response Auction

December 13, 2018

The results of the Independent Electricity System Operator's (IESO) fourth demand response (DR) auction shows continued growth in consumer participation and significant decreases in cost.

The auction is an annual competitive process through which participating residential, commercial and industrial consumers are selected to be available to reduce their electricity consumption as needed. Successful DR providers compete in the electricity market along with generators to help maintain the reliability of the province's electricity system.

This year, 38 organizations were registered as auction participants, the highest number since the auction began in 2015. The successful proponents included four new participants who represent a mix of commercial and industrial consumers.

The average annual clearing price for availability payments of $52,810/MW represents a 30% decrease from last year, and a 42% decrease since the first auction in 2015. The auction cleared 818 megawatts (MW) for the 2019 summer commitment period and 854 MW for the 2019/2020 winter commitment period.

Moving in to its fourth year, the auction has been established as a valuable and reliable tool for the IESO to secure capacity on the system. Decreasing prices year-over-year demonstrates the ongoing maturity of the demand response market as more consumers participate and competition increases. Lower capacity prices benefit all Ontario consumers, while auction participants benefit by offsetting their energy costs and improving their competitiveness.

As the electricity system moves towards competitive electricity auctions under IESO's Market Renewal project, the participation of consumers providing demand response will increase competition leading to overall lower prices for Ontario consumers.

The full list of this year's successful participants is as follows:

Participant	Summer Capacity Cleared [MW]	Winter Capacity Cleared [MW]
CPOWER ENERGY MANAGEMENT CORPORATION	11.6	14.1
DIRECT ENERGY MARKETING LIMITED	11	14
ENERNOC LTD.	216.3	203.4
GC PROJECT LP	20.1	19.1
GERDAU AMERISTEEL CORPORATION	72	72
GERDAU AMERISTEEL CORPORATION -CAMBRIDGE	2.4	2.4
IVACO ROLLING MILLS 2004 L.P.	25	25

Participant	Summer Capacity Cleared [MW]	Winter Capacity Cleared [MW]
NRG CURTAILMENT SOLUTIONS CANADA, INC.	143.5	143.5
NRSTOR C&I L.P.	2.4	21.8
PEAK POWER INC.		1
RESOLUTE FP CANADA INC.	28	28
RODAN ENERGY SOLUTIONS INC	201.7	203.1
TEMBEC ENTERPRISES INC.	40	40
VOLTUS ENERGY CANADA LTD	44.4	66.8
Total	**818.4**	**854.2**

Additional information about the auction is available on Demand Response Auction webpage.

More information regarding technical difficulties experienced this year and a quick refresher on the treatment of zonal limits in the auction mechanism can be found here.

The next DR auction will be held in December 2019, for delivery of DR capacity for summer 2020 and winter 2020/2021. Through the Demand Response Working Group, the IESO will continue to evolve demand response as it shifts to more competitive ways to secure capacity.

More information about Market Renewal can be found at Electricity Market of Tomorrow webpage.

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134 FERC ¶ 61,187

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 35

[Docket No. RM10-17-000; Order No. 745]

Demand Response Compensation in Organized Wholesale Energy Markets

(Issued March 15, 2011)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule.

SUMMARY: In this Final Rule, the Federal Energy Regulatory Commission (Commission) amends its regulations under the Federal Power Act to ensure that when a demand response resource participating in an organized wholesale energy market administered by a Regional Transmission Organization (RTO) or Independent System Operator (ISO) has the capability to balance supply and demand as an alternative to a generation resource and when dispatch of that demand response resource is cost-effective as determined by the net benefits test described in this rule, that demand response resource must be compensated for the service it provides to the energy market at the market price for energy, referred to as the locational marginal price (LMP). This approach for compensating demand response resources helps to ensure the competitiveness of organized wholesale energy markets and remove barriers to the participation of demand response resources, thus ensuring just and reasonable wholesale rates.

EFFECTIVE DATE: This Final Rule will become effective on **[**INSERT DATE 30 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER**]**. Dates for compliance and other required filings are provided in the Final Rule.

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SUPPLEMENTARY INFORMATION:

134 FERC ¶ 61,187
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

ORDER NO. 745

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Marc Spitzer, Philip D. Moeller,
John R. Norris, and Cheryl A. LaFleur.

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

FINAL RULE

ORDER NO. 745

(Issued March 15, 2011)

I. Introduction

1. This Final Rule addresses compensation for demand response in Regional Transmission Organization (RTO) and Independent System Operator (ISO) organized wholesale energy markets, i.e., the day-ahead and real-time energy markets. As the Commission has previously recognized, a market functions effectively only when both supply and demand can meaningfully participate. The Commission, in the Notice of Proposed Rulemaking (NOPR) issued in this proceeding on March 18, 2010, proposed a remedy to concerns that current compensation levels inhibited meaningful demand-side participation.[1] After nearly 3,800 pages of comments, a subsequent technical conference, and the opportunity for additional comment, we now take final action.

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[1] Demand Response Compensation in Organized Wholesale Energy Markets, Notice of Proposed Rulemaking, 75 FR 15362 (Mar. 29, 2010), FERC Stats. & Regs. ¶ 32,656 (2010) (NOPR).

2. We conclude that when a demand response[2] resource[3] participating in an organized wholesale energy market[4] administered by an RTO or ISO has the capability to balance supply and demand as an alternative to a generation resource and when dispatch of that demand response resource is cost-effective as determined by the net benefits test described herein, that demand response resource must be compensated for the service it provides to the energy market at the market price for energy, referred to as the locational marginal price (LMP).[5] The Commission finds that this approach to compensation for

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[2] Demand response means a reduction in the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy. 18 CFR 35.28(b)(4) (2010).

[3] Demand response resource means a resource capable of providing demand response. 18 CFR 35.28(b)(5).

[4]The requirements of this final rule apply only to a demand response resource participating in a day-ahead or real-time energy market administered by an RTO or ISO. Thus, this Final Rule does not apply to compensation for demand response under programs that RTOs and ISOs administer for reliability or emergency conditions, such as, for instance, Midwest ISO's Emergency Demand Response, NYISO's Emergency Demand Response Program, and PJM's Emergency Load Response Program. This Final Rule also does not apply to compensation in ancillary services markets, which the Commission has addressed elsewhere. See, e.g., Wholesale Competition in Regions with Organized Electric Markets, Order No. 719, 73 FR 64100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281 (2008) (Order No. 719).

[5] LMP refers to the price calculated by the ISO or RTO at particular locations or electrical nodes or zones within the ISO or RTO footprint and is used as the market price to compensate generators. There are variations in the way that RTOs and ISOs calculate LMP; however, each method establishes the marginal value of resources in that market. Nothing in this Final Rule is intended to change RTO and ISO methods for calculating LMP.

demand response resources is necessary to ensure that rates are just and reasonable in the organized wholesale energy markets. Consistent with this finding, this Final Rule adds section 35.28(g)(1)(v) to the Commission's regulations to establish a specific compensation approach for demand response resources participating in the organized wholesale energy markets administered by RTOs and ISOs. The Commission is not requiring the use of this compensation approach when demand response resources do not satisfy the capability and cost-effectiveness conditions noted above.[6]

3. This cost-effectiveness condition, as determined by the net benefits test described herein, recognizes that, depending on the change in LMP relative to the size of the energy market, dispatching demand response resources may result in an increased cost per unit ($/MWh) to the remaining wholesale load associated with the decreased amount of load paying the bill. This is the case because customers are billed for energy based on the units, MWh, of electricity consumed. We refer to this potential result as the billing unit effect of dispatching demand response. By contrast, dispatching generation resources does not produce this billing unit effect because it does not result in a decrease of load. To address this billing unit effect, the Commission in this Final Rule requires the use of the net benefits test described herein to ensure that the overall benefit of the reduced

[6] The Commission's findings in this Final Rule do not preclude the Commission from determining that other approaches to compensation would be acceptable when these conditions are not met.

LMP that results from dispatching demand response resources exceeds the cost of dispatching and paying LMP to those resources. When the net benefits test described herein is satisfied and the demand response resource clears in the RTO's or ISO's economic dispatch, the demand response resource is a cost-effective alternative to generation resources for balancing supply and demand.

4. To implement the net benefits test described herein, we direct each RTO and ISO to develop a mechanism as an approximation to determine a price level at which the dispatch of demand response resources will be cost-effective. The RTO or ISO should determine, based on historical data as a starting point and updated for changes in relevant supply conditions such as changes in fuel prices and generator unit availability, the monthly threshold price corresponding to the point along the supply stack beyond which the overall benefit from the reduced LMP resulting from dispatching demand response resources exceeds the cost of dispatching and paying LMP to those resources. This price level is to be updated monthly, by each ISO or RTO, as the historic data and relevant supply conditions change.[7]

[7] In its compliance filing an RTO or ISO may attempt to show, in whole or in part, how its proposed or existing practices are consistent with or superior to the requirements of this Final Rule.

5. This Final Rule also sets forth a method for allocating the costs of demand response payments among all customers who benefit from the lower LMP resulting from the demand response.

6. The tariff changes needed to implement the compensation approach required in this Final Rule, including the net benefits test, measurement and verification explanation and proposed changes, and the cost allocation mechanism must be made on or before July 22, 2011. All tariff changes directed herein should be submitted as compliance filings pursuant to this Final Rule, not pursuant to section 205 of the Federal Power Act (FPA).[8] Accordingly, each RTO's or ISO's compliance filing to this Final Rule will become effective prospectively from the date of the Commission order addressing that filing, and not within 60 days of submission.

7. In addition, we believe that integrating a determination of the cost-effectiveness of demand response resources into the dispatch of the ISOs and RTOs may be more precise than the monthly price threshold and, therefore, provide the greatest opportunity for load to benefit from participation of demand response in the organized wholesale energy market administered by an RTO or ISO. However, we acknowledge the position of several of the RTOs and ISOs that modification of their dispatch algorithms to incorporate the costs related to demand response may be difficult in the near term. In

[8] 16 U.S.C. 824d (2006).

light of those concerns, we require each RTO and ISO to undertake a study examining the requirements for and impacts of implementing a dynamic approach which incorporates the billing unit effect in the dispatch algorithm to determine when paying demand response resources the LMP results in net benefits to customers in both the day-ahead and real-time energy markets. The Commission directs each RTO and ISO to file the results of this study with the Commission on or before September 21, 2012.[9]

II. Background

8. Effective wholesale competition protects customers by, among other things, providing more supply options, encouraging new entry and innovation, and spurring deployment of new technologies.[10] Improving the competitiveness of organized wholesale energy markets is therefore integral to the Commission fulfilling its statutory mandate under the FPA to ensure supplies of electric energy at just, reasonable, and not unduly discriminatory or preferential rates.[11]

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[9] We note that this report is for informational purposes only and will neither be noticed nor require Commission action.

[10] See, e.g., Wholesale Competition in Regions with Organized Electric Markets, Order No. 719, 73 FR 64100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281, at P 1 (2008) (Order No. 719); see also Regional Transmission Organizations, Order No. 2000, FERC Stats. & Regs. ¶ 31,089, at P 1 (1999), order on reh'g, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000), aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington v. FERC, 272 F.3d 607, 348 U.S. App. D.C. 205 (D.C. Cir. 2001).

[11] 16 U.S.C. 824d (2006); Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 1.

9. As the Commission recognized in Order No. 719, active participation by customers in the form of demand response in organized wholesale energy markets helps to increase competition in those markets.[12] Demand response, whereby customers reduce electricity consumption from normal usage levels in response to price signals, can generally occur in two ways: (1) customers reduce demand by responding to retail rates that are based on wholesale prices (sometimes called "price-responsive demand"); and (2) customers provide demand response that acts as a resource in organized wholesale energy markets to balance supply and demand. While a number of states and utilities are pursuing retail-level price-responsive demand initiatives based on dynamic and time-differentiated retail prices and utility investments in demand response enabling technologies, these are state efforts, and, thus, are not the subject of this proceeding. Our focus here is on customers or aggregators of retail customers providing, through bids or self-schedules, demand response that acts as a resource in organized wholesale energy markets.

10. As the Commission stated in Order No. 719,[13] and emphasized in the NOPR,[14] there are several ways in which demand response in organized wholesale energy markets

[12] See Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 48.

[13] Wholesale Competition in Regions with Organized Electric Markets, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292, at P 48 (2009).

[14] NOPR, FERC Stats. & Regs. ¶ 32,656 at P 4.

can help improve the functioning and competitiveness of those markets. First, when bid directly into the wholesale market, demand response can facilitate RTOs and ISOs in balancing supply and demand, and thereby, help produce just and reasonable energy prices.[15] This is because customers who choose to respond will signal to the RTO or ISO and energy market their willingness to reduce demand on the grid which may result in reduced dispatch of higher-priced resources to satisfy load.[16] Second, demand response can mitigate generator market power.[17] This is because the more demand response that sees and responds to higher market prices, the greater the competition, and the more downward pressure it places on generator bidding strategies by increasing the risk to a supplier that it will not be dispatched if it bids a price that is too high.[18] Third, demand

[15] For example, a study conducted by PJM, which simulated the effect of demand response on prices, demonstrated that a modest three percent load reduction in the 100 highest peak hours corresponds to a price decline of six to 12 percent. ISO-RTO Council Report, Harnessing the Power of Demand How RTOs and ISOs Are Integrating Demand Response into Wholesale Electricity Markets, found at http://www.isorto.org/atf/cf/%7B5B4E85C6-7EAC-40A0-8DC3-003829518EBD%7D/IRC_DR_Report_101607.pdf.

[16] Id. ("Demand response tends to flatten an area's load profile, which in turn may reduce the need to construct and use more costly resources during periods of high demand; the overall effect is to lower the average cost of producing energy.").

[17] See Comments of NYISO's Independent Market Monitor filed in Docket No. ER09-1142-000, May 15, 2009 (Demand response "contributes to reliability in the short-term, resource adequacy in the long-term, reduces price volatility and other market costs, and mitigates supplier market power.").

[18] Id.

response has the potential to support system reliability and address resource adequacy[19] and resource management challenges surrounding the unexpected loss of generation. This is because demand response resources can provide quick balancing of the electricity grid.[20]

11. Congress has recognized the importance of demand response by enacting national policy requiring its facilitation.[21] Consistent with that policy, the Commission has undertaken several reforms to support competitive wholesale energy markets by removing barriers to participation of demand response resources. For example, in Order No. 890, the Commission modified the pro forma Open Access Transmission Tariff to

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[19] See ISO-RTO Council Report, Harnessing the Power of Demand How RTOs and ISOs Are Integrating Demand Response into Wholesale Electricity Markets at 4, found at http://www.isorto.org/atf/cf/%7B5B4E85C6-7EAC-40A0-8DC3-003829518EBD%7D/IRC_DR_Report_101607.pdf ("Demand response contributes to maintaining system reliability. Lower electric load when supply is especially tight reduces the likelihood of load shedding. Improvements in reliability mean that many circumstances that otherwise result in forced outages and rolling blackouts are averted, resulting in substantial financial savings . . . .").

[20] For instance, in ERCOT, on February 26, 2008, through a combination of a sudden loss of thermal generation, drop in power supplied by wind generators, and a quicker-than-expected ramping up of demand, ERCOT found itself short of reserves. The system operator called on all demand response resources, and 1200 MW of Load acting as Resource (LaaRs) responded quickly, bringing ERCOT back into balance. OAK RIDGE NAT'L LAB., NAT'L RENEWABLE ENERGY LAB., TECH. REP. NREL/TP-500-43373, ERCOT EVENT ON FEB. 26, 2008: LESSONS LEARNED (JUL. 2008).

[21] See Energy Policy Act of 2005, Pub. L. No. 109-58, § 1252(f), 119 Stat. 594, 965 (2005) ("It is the policy of the United States that . . . unnecessary barriers to demand response participation in energy, capacity, and ancillary service markets shall be eliminated.").

allow non-generation resources, including demand response resources, to be used in the provision of certain ancillary services where appropriate on a comparable basis to service provided by generation resources.[22] Order No. 890-A further required transmission providers to develop transmission planning processes that treat all resources, including demand response, on a comparable basis.[23]

12. In Order No. 719, the Commission required RTOs and ISOs to, among other things, accept bids from demand response resources in their markets for certain ancillary services on a basis comparable to other resources.[24] The Commission also required each RTO and ISO "to reform or demonstrate the adequacy of its existing market rules to ensure that the market price for energy reflects the value of energy during an operating reserve shortage,"[25] for purposes of encouraging existing generation and demand resources to continue to be relied upon during an operating reserve shortage, and encouraging entry of new generation and demand resources.[26]

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[22] Preventing Undue Discrimination and Preference in Transmission Service, Order No. 890, FERC Stats. & Regs. ¶ 31,241, at P 887-88 (2007), order on reh'g, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), order on reh'g and clarification, Order No. 890-B, 123 FERC ¶ 61,299 (2008), order on reh'g, Order No. 890-C, 126 FERC ¶ 61,228 (2009), order on clarification, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[23] Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 216.

[24] Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 47-49.

[25] Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 194.

[26] Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 247.

13. Additionally, in recent years several RTOs and ISOs have instituted various types of demand response programs. While some of these programs are administered for reliability and emergency conditions, other programs allow wholesale customers, qualifying large retail customers, and aggregators of retail customers to participate directly in the day-ahead and real-time energy markets, certain ancillary service markets and capacity markets.[27]

14. To date, the Commission has allowed each RTO and ISO to develop its own compensation methodologies for demand response resources participating in its day-ahead and real-time energy markets. As a result, the levels of compensation for demand response vary significantly among RTOs and ISOs.[28] For example, PJM Interconnection, L.L.C. (PJM) pays the LMP minus the generation and transmission portions of the retail

[27] Other demand response programs allow demand response to be used as a capacity resource and as a resource during system emergencies or permit the use of demand response for synchronized reserves and regulation service. See, e.g., PJM Interconnection, L.L.C., 117 FERC ¶ 61,331 (2006); Devon Power LLC, 115 FERC ¶ 61,340, order on reh'g, 117 FERC ¶ 61,133 (2006), appeal pending sub nom. Maine Pub. Utils. Comm'n v. FERC, No. 06-1403 (D.C. Cir. 2007); New York Indep. Sys. Operator, Inc., 95 FERC ¶ 61,136 (2001); NSTAR Services Co. v. New England Power Pool, 95 FERC ¶ 61,250 (2001); New England Power Pool and ISO New England, Inc., 100 FERC ¶ 61,287, order on reh'g, 101 FERC ¶ 61,344 (2002), order on reh'g, 103 FERC ¶ 61,304, order on reh'g, 105 FERC ¶ 61,211 (2003); PJM Interconnection, L.L.C., 99 FERC ¶ 61,227 (2002); California Independent System Operator Corp., 132 FERC ¶ 61,045 (2010).

[28] See New England, Inc., Docket No. ER09-1051-000; ISO New England, Inc., Docket No. ER08-830-000; Midwest Indep. Transmission Sys. Operator, Inc., Docket No. ER09-1049-000.

rate.[29] ISO New England Inc. (ISO-NE) and New York Independent System Operator, Inc. (NYISO) pay LMP when prices exceed a threshold level, with the levels differing between the RTOs.[30] The Midwest Independent Transmission System Operator, Inc.'s (Midwest ISO) demand response programs[31] pay LMP for demand response resources in the day-ahead and real-time energy markets.[32] The California Independent System Operator Corporation (CAISO) pays LMP at pricing nodes, or sub-load aggregation points (Sub-LAP) in its Proxy Demand Resource program that allows qualifying

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[29] See sections 3.3A.4 and 3.3A.5 (Market Settlements in the Real-Time and Day-Ahead Energy Markets) of the Appendix to Attachment K of the PJM Tariff.

[30] For example, under ISO-NE's Real-Time Price Response Program, the minimum bid is \$100/MWh and a demand response resource is paid the higher of LMP or \$100/MWh. For the Day-Ahead Load Response Program, the minimum offer level is calculated on a monthly basis and is the Forward Reserve Fuel Index (\$/MMBtu) multiplied by an effective heat rate of 11.37 MMBtu/MWh. The maximum offer level is \$1,000/MWh. See sections III.E.2.1 and III.E.3.2 of Appendix E of the ISO New England Transmission, Markets and Services Tariff. NYISO implements a day-ahead demand response program by which resources bid into the market at a minimum of \$75/MWh and can get paid the LMP. See section 4.2.2.9 ("Day-Ahead Bids from Demand Reduction Providers to Supply Energy from Demand Reductions") of NYISO's Market Services Tariff.

[31] Midwest ISO FERC Electric Tariff characterizes Demand Response Resources (DRR) as either DRR-Type I or DRR-Type II. DRR-Type I are capable of supplying a specific quantity of energy or contingency reserve through physical load interruption. DRR-Type II are capable of supplying energy and/or operating reserves over a dispatchable range. See sections 39.2.5A and 40.2.5 of the Tariff.

[32] See Charges and Payments for Purchases and Sales for Demand Response Resources. Midwest ISO FERC Electric Tariff, section 39.3.2C.

resources to provide day-ahead and real-time energy.[33] CAISO also provides for demand response resources to participate in its Participating Load program, which enables certain resources to provide curtailable demand in the CAISO market. CAISO pays nodal real-time LMP for its Participating Load program. The Southwest Power Pool, Inc. (SPP) has filed revisions to its tariff to facilitate demand response in the Energy Imbalance Service Market.[34]

III. Procedural History

15. As noted above, the Commission issued the NOPR in this proceeding on March 18, 2010.[35] The NOPR proposed to require RTOs and ISOs to pay the LMP in all hours for demand reductions made in response to price signals. The Commission sought

[33] See section 11.2.1.1 IFM Payments for Supply of Energy, CAISO FERC Electric Tariff. CAISO notes that for a Proxy Demand Resource that is made up of aggregated loads, the Resource is paid the weighted average of the LMPs of each pricing node where the underlying aggregate loads reside. See CAISO, 132 FERC ¶ 61,045, at P 26 n.14 (2010).

[34] The Commission has directed SPP to report on ways it can incorporate demand response into its imbalance market. Southwest Power Pool, Inc., 128 FERC ¶ 61,085 (2009). As of September 1, 2010, SPP has submitted seven informational status reports regarding its efforts to address issues related to demand response resources. In orders addressing SPP's compliance with Order No. 719, the Commission also directed SPP to make another compliance filing addressing demand response participation in its organized markets. Southwest Power Pool, Inc., 129 FERC ¶ 61,163, at P 51 (2009). On May 19, 2010, SPP submitted revisions to its Open Access Transmission Tariff in Docket Nos. ER09-1050-004 and ER09-748-002 to comply with the Commission's requirements established in Order Nos. 719 and 719-A. These filings are pending before the Commission.

[35] NOPR, FERC Stats. & Regs. ¶ 32,656.

comments on the compensation proposal and, in particular, on the comparability of generation and demand response resources; alternative approaches to compensating demand response in organized wholesale energy markets; whether payment of LMP should apply in all hours, and, if not, any criteria that should be used for establishing hours when LMP should apply; and whether to allow for regional variations concerning approaches to demand response compensation.[36]

16. After receiving the first round of comments, the Commission issued a Supplemental Notice of Proposed Rulemaking and Notice of Technical Conference (Supplemental NOPR) in this proceeding on August 2, 2010.[37] The Supplemental NOPR sought additional comment on: whether the Commission should adopt a net benefits test for determining when to compensate demand response providers, and, if so, what, if any, requirements should apply to the methods for determining net benefits; and what, if any, requirements should apply to how the costs of demand response are allocated. The Commission further directed Staff to hold a technical conference focused on these two issues, which occurred on September 13, 2010.[38]

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[36] See Appendix for a list of commenters.

[37] Supplemental Notice of Proposed Rulemaking and Notice of Technical Conference, 75 FR 47499 (Aug. 6, 2010), 132 FERC ¶ 61,094 (2010) (Supplemental NOPR).

[38] See Notice of Technical Conference (Aug. 27, 2010).

IV. Discussion

17. Based upon the record in this proceeding, the Commission herein requires greater uniformity in compensating demand response resources participating in organized wholesale energy markets. This Final Rule also addresses the allocation of costs resulting from the commitment of demand response, directing that such costs be allocated among those customers who benefit from the lower LMP resulting from the demand response.

A. Compensation Level

1. NOPR Proposal

18. The NOPR proposed to require RTOs and ISOs to pay the LMP in all hours for demand reductions made in response to price signals. The NOPR sought to provide comparable compensation to generation and demand response providers, based on the premise that both resources provide a comparable service to RTOs and ISOs for purposes of balancing supply and demand and maintaining a reliable electricity grid.[39] Also as stated in the NOPR, the proposed compensation level was designed to allow more demand response resources to cover their investment costs in demand response-related technology (such as advanced metering) and thereby facilitate their ability to participate in organized wholesale energy markets.[40] The Commission sought comments on the

[39] NOPR, FERC Stats. & Regs. ¶ 32,656 at P 15.

[40] Id. at P 16.

compensation proposal and, in particular, on the comparability of generation and demand response resources; alternative approaches to compensating demand response in organized wholesale energy markets; whether payment of LMP should apply in all hours, and, if not, any criteria that should be used for establishing hours when LMP should apply; and whether to allow for regional variations concerning approaches to demand response compensation.

19. In the Supplemental NOPR, the Commission sought additional comments and directed staff to hold a technical conference regarding various net benefits tests. In particular, the Commission sought comment on: whether the Commission should adopt a net benefits test applicable in all or only some hours and what the criteria of any such test would be; how to define net benefits; what costs demand response providers and load serving entities incur and whether they should be included in a net benefits test; whether any net benefits methodology adopted should be the same for all RTOs and ISOs; proposed methodologies for implementing a net benefits test and the advantages and limitations of any proposed methodologies.[41] The September 13, 2010 Technical Conference included an eleven-member panel discussion of net benefits tests representing

[41] Supplemental NOPR, 132 FERC ¶ 61,094 at P 8-9.

a wide range of interests and viewpoints.[42] The Commission subsequently received additional written comments addressing these issues.

2. Comments

a) Capability of Demand Response and Generation Resources to Balance Energy Markets

20. Various commenters address the comparability of demand response and generation resources for purposes of compensation in the organized wholesale energy markets. To begin, numerous commenters address the physical or functional comparability of demand response and generation, agreeing that an increment of generation is comparable to a decrement of load for purposes of balancing supply and demand in the day-ahead and real-time energy markets.[43] Equating generation and demand response resources, Dr. Alfred E. Kahn states:

> [Demand response] is in all essential respects economically equivalent to supply response . . . [so] economic efficiency requires . . . that it should be rewarded with the same LMP that clears the market. Since [demand response] is actually—and not merely metaphorically—equivalent to supply response, economic efficiency requires that it be regarded and rewarded, equivalently, as a resource proffered to system operators, and be treated equivalently to generation in competitive power markets. That is,

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[42] See Sept. 13, 2010 Tr.

[43] DR Supporters Aug. 30, 2010 Comments (Kahn Affidavit at 2); Verso May 13, 2010 Comments at 3-4; Occidental May 13, 2010 Comments at 11; Viridity June 18, 2010 Comments at 5.

> all resources—energy saved equivalently to energy supplied— . . . should receive the same market-clearing LMP in remuneration.[44]

Indeed, some commenters believe that, from a physical standpoint, demand response can provide superior services to generation, such as providing a quick response in meeting system requirements and service without having to construct major new facilities.[45] Occidental asserts that the fungibility of demand response and generation output creates greater operational flexibility that, in turn, offers RTOs and ISOs multiple options to solve system issues both in energy and ancillary service markets, and that the fungible nature of demand response and generation supports comparable compensation for each as proposed in the NOPR.[46]

21. Viridity states that attempts to distinguish the physical characteristics of generation and demand response ignore bid-based security-constrained economic dispatch as the foundation for LMP and are based on the assumption that the value of load management on the grid is limited to periods when the system is stressed, i.e., traditional "super peak shaving." Viridity states that, while these arguments might have been valid 15 years ago, today competitive markets can offer proactively-managed load control and comparable and non-discriminatory treatment of load-based energy resources.

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[44] DR Supporters August 30, 2010 Reply Comments (Kahn Affidavit at 2 (footnote omitted)).

[45] Verso May 13, 2010 Comments at 3-4; Alcoa May 13, 2010 Comments at 9.

[46] Occidental May 13, 2010 Comments at 11.

Therefore, Viridity asserts that all resources should be paid LMP if the grid operator accepts their bid to achieve grid balance.[47]

22. At the same time, other commenters argue that generation and demand response are not physically equivalent, pointing out that demand response reduces consumption, whereas generators serve consumption.[48] They argue that a MW reduction in demand does not turn on the lights.[49] EPSA adds that a load reduction does not provide electrons to any other load and, instead, allows the marginal electron to serve a different customer.[50] Some commenters assert that a power system can function solely and reliably on generating plants and without any reliance on demand response, while the system cannot rely exclusively on demand response because demand response by itself cannot keep the lights on. Ultimately, some commenters point out, megawatts produced by generators need to be placed on the system in order for power to flow.[51] Battelle additionally argues that a reduction in consumption is not exactly the same as an increase

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[47] Viridity June 18, 2010 Comments at 5.

[48] ISO-NE May 13, 2010 Comments at 3.

[49] See, e.g., APPA May 13, 2010 Comments at 12; Capital Power May 13, 2010 Comments at 2.

[50] EPSA May 13, 2010 Comments at 72.

[51] See, e.g., PSEG May 13, 2010 Comments at 8.

in production, because elastic demand often comes with attendant future consequences, such as rebound, by virtue of substitution in time.[52]

23. Some commenters who argue that the physical characteristics of demand response are not comparable to generation frame their arguments in terms of the ability of the system operator to call on demand response and generation resources to provide balancing energy. They argue that generation resources provide superior service to demand response providers, positing that demand response is not intended for long periods of balancing needs,[53] and that, moreover, contracts with demand response providers limit the number of hours and times a customer may be called upon to curtail. For example, ODEC asserts that the degree of physical comparability depends on the extent to which demand response resources can be dispatched similar to a generator.[54] Calpine adds that traditional generators provide system support features that demand response cannot, such as ancillary services including governor response or reactive power voltage support, which are necessary for reliable operation of the electric system.[55]

24. Numerous commenters also address the comparability of demand response and generation in economic terms. For example, EEI states that, in finance terms, the demand

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[52] Battelle May 13, 2010 Comments at 3.

[53] AEP May 13, 2010 Comments at 7-8.

[54] ODEC May 13, 2010 Comments at 12.

[55] Calpine May 13, 2010 Comments at 4-5.

response product is, unlike generation, essentially an unexercised call option on spot market energy, and the value of that option is well-established in finance theory as the value of the resource (LMP) minus the "strike price," which EEI contends in this case is the retail tariff rate.[56] EEI and like-minded commenters support, therefore, alternative compensation for demand response to equal LMP minus the generation (or G) component of the retail rate.[57] They posit that payment of LMP without an offset for some portion of the retail rate does not send the proper economic signal to providers of demand response, because it fails to take into account the retail rate savings associated with demand response, and thereby overcompensates the demand response provider. As described by Dr. William W. Hogan on behalf of EPSA, this is sometimes called a double-payment for demand reductions, because demand response providers would "receive" both the cost

[56] EEI May 13, 2010 Comments at 4-5. See also Robert L. Borlick May 13, 2010 Comments at 4. Mr. Borlick argues that the correct price is LMP minus the Marginal Foregone Retail Rate (MFRR), describing the economically efficient price that should be paid to a demand response provider as "its offer price minus the price in its retail tariff at which it would have purchased the curtailed energy." Mr. Borlick asserts that this amount accurately represents the forgone opportunity costs that result when a demand response provider reduces its load. Id.

[57] See May 13, 2010 Comments of: APPPA; AEP; The Brattle Group; Calpine; ConEd; Consumers Energy; CPG; Detroit Edison; Direct Energy; Dominion; Duke Energy; Edison Mission; EEI; EPSA; Exelon; FTC; GDF; NYISO on behalf of the ISO RTO Council; ICC; IPPNY; Indicated New York TOs; IPA; ISO-NE; Midwest TDUs; Mirant; Midwest ISO TOs; NEPGA; NYISO; ODEC; OMS; PJM; PJM IMM; P3; Potomac Economics; PG&E; Ohio Commission; Robert L. Borlick; Roy Shanker; and RRI Energy.

savings from not consuming an increment of electricity at a particular price, plus an LMP payment for not consuming that same increment of electricity.[58] Viewing LMP as a double-payment, these commenters argue that paying LMP will result in more demand response than is economically efficient.[59] For example, Dr. Hogan states that paying LMP might motivate a company to shut down even though the benefits of consuming electricity outweigh the cost at LMP.[60] Indeed, P3 argues that compensation in excess of LMP-G is unjust and unreasonable, because such a payment level imposes costs on customers that are not commensurate with benefits received.[61]

25. ISO-NE argues that paying full LMP to demand response providers without taking into account the bill savings produced by demand response provides a significant financial incentive to dispatch demand response with marginal costs exceeding LMPs. By dispatching higher-cost demand response, ISO-NE asserts, lower-cost generation

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[58] See Attachment to Answer of EPSA, Providing Incentives for Efficient Demand Response, Dr. William W. Hogan, Oct. 29, 2009, submitted in Docket No. EL09-68-000.

[59] EPSA May 13, 2010 Comments at 23. See also May 13, 2010 Comments of APPA at 13; FTC at 9; Midwest TDUs at 14; Mirant at 2; New York Commission at 5; PJM at 6; PSEG at 5; and Potomac Economics at 6-8.

[60] Attachment to Answer of EPSA, Providing Incentives for Efficient Demand Response, Dr. William W. Hogan, Oct. 29, 2009, submitted in Docket No. EL09-68-000. In Dr. Hogan's view, supply should produce when the price of electricity exceeds its cost of production and demand should decline to consume when the costs in terms of convenience of delaying use are less than the price of electricity.

[61] P3 June 14, 2010 Comments at 2, 7-8.

resources are displaced.[62] At the same time, ISO-NE argues, generation is not dispatched and paid for only when the generation reduces LMP—generation is dispatched and paid for when it is cost-effective.[63]

26. Dr. Hogan further disputes arguments equating a MW of energy supplied to a MW of energy saved on economic grounds. Dr. Hogan draws a distinction between reselling something that one has purchased, and selling something that one would have purchased without actually purchasing it. Dr. Hogan argues that from the perspective of economic efficiency and welfare maximization, the aggregate effect of demand response is a wash producing no economic net benefit. Dr. Hogan asserts that Commission policy citing the benefits of price reduction in support of demand response compensation would amount to no less than an application of regulatory authority to enforce a buyers' cartel. He states that the Commission has been vigilant and aggressive in preventing buyers and sellers from engaging in market manipulation to influence prices, and it would be fundamentally inconsistent for the Commission to design demand response compensation policies that coordinate and enforce such price manipulation.

27. Dr. Hogan argues that the ideal and economically efficient solution regarding demand response compensation is to implement retail real-time pricing at the LMP,

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[62] ISO-NE May 13, 2010 Comments at 3-4.

[63] Id. at 28.

thereby eliminating the need for demand response programs. Realizing that this is unattainable at the present time, Dr. Hogan goes on to propose a next-best solution, which he believes is to pay demand response compensation in the amount of LMP-G, or some amount that simulates explicit contract demand response (such as "buy-the-baseline" approach discussed below). These options, he argues, more than paying LMP, better support notions of comparability between demand response resources and generation.[64]

28. The New York Commission, however, argues that requiring payment of LMP-G would result in an administrative burden of tracking retail rates for the multiple utilities, ESCOs and power authorities and create undue confusion for retail customers and administrative difficulties for state commissions and ISOs and RTOs.[65]

29. Consistent with Dr. Hogan's arguments, some commenters assert that demand response providers should actually own or pay for electricity prior to, what commenters characterize as, an effective reselling of the electricity back to the market in the form of demand response. For example, these commenters suggest that the demand response provider purchase the power in the day-ahead market and resell it in the real-time

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[64] Hogan Affidavit, ISO RTO Council May 13, 2010 Comments at 5.

[65] New York Commission May 13, 2010 Comments at 8.

markets.[66] EPSA argues that there must be some purchase requirement or representative offset to allow a demand response provider to "sell" a commodity that it owns to the ISO or RTO.[67] EPSA argues that such a requirement would send an efficient price signal, reduce incentives for gaming the system, and help address difficulties with measurement and verification of a demand reduction. EPSA highlights an ISO-NE IMM recommendation that, if the Commission permits LMP payment, it should also adopt a "buy-the-baseline" approach requiring demand response resources to purchase an expected amount of energy consumption in the day-ahead energy market and subsequently sell any demand reduction from that level in the real-time market.[68]

30. Viridity, on the other hand, argues that forcing customers to buy and then resell electricity will lead to too little demand response and that adopting a "buy-the-baseline" approach would constitute an inappropriate exercise of Commission authority to effectively force parties into contracts. Viridity and DR Supporters state that any characterization of demand response as a purchase and then resale of energy is erroneous[69] and based on the flawed assumption that demand response resources are

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[66] See, e.g., ISO-NE IMM May 13, 2010 Comments at 4-5; Midwest ISO TOs May 13, 2010 Comments at 14; PJM May 13, 2010 Comments at 5; and Duke Energy May 13, 2010 Comments at 2.

[67] EPSA June 30, 2010 Comments at 3.

[68] EPSA June 30, 2010 Comments at 23.

[69] Viridity Energy June 18, 2010 Comments at 25.

reselling energy. They state that the description of demand response as a reselling of energy has been correctly rejected by the Commission in EnergyConnect, where the Commission stated that it was establishing a policy of treating demand response as a service rather than a purchase and sale of electric energy.[70]

31. DR Supporters further argues that, despite claims to the contrary, paying full LMP to demand response providers does not constitute a subsidy for demand response any more than the remunerations of generators for the power that they sell. As Dr. Kahn states:

> Does this plan involve double compensation, as [Dr.] Hogan asserts, at the expense of power generators—of successful bidders promising to induce efficient demand curtailment and of consumers induced to practice it? Certainly not: the decrease in the revenue of the generators is (and consequent savings by consumers are) matched by the savings in their (marginal) costs of generating that power; the successful bidders for the opportunity to induce that consumer response are compensated for the costs of those efforts by the pool, whose (marginal) costs they save by assisting consumers to reduce their purchases.[71]

32. Viridity further disputes Dr. Hogan's argument that payment of LMP for demand response will distort an otherwise optimal market. Viridity posits that such arguments ignore dislocations in the wholesale power markets, the existence of market power that must be mitigated, imperfect information available to customers, barriers to entry and

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[70] DR Supporters Aug. 30, 2010 Reply Comments at 10 (citing EnergyConnect, Inc., 130 FERC ¶ 61,031 at P 30-31 (2010)).

[71] DR Supporters Aug. 30, 2010 Reply Comments, Kahn Affidavit at 10.

uneconomic resources dispatched to fulfill must-run requirements.[72] Viridity further states that Dr. Hogan's arguments fail to acknowledge the limits of the Commission's jurisdiction and widespread dislocations and distortions in virtually all economic aspects of relevant energy markets (including fuels, facilities, pricing, environmental attributes, information and participation) and fail to account for any market benefits of demand response.[73] Finally, Viridity argues that Dr. Hogan's arguments fail to reflect the many complex interactions between price, equipment operational requirements, and customer processes, which point to a complex demand response decision.[74]

33. In addition to physical and economic comparability, some commenters contrast the environmental effects of generation and demand response resources. EDF notes that current market prices fail to internalize environmental externalities – including toxic air pollution, greenhouse gas pollution, and land and water use impacts – and other social costs. EDF asserts that the social impact of these environmental externalities is especially acute at peak times, positing that generation sources used for marginal supply at such times ("peaker plants") are among the oldest, dirtiest, and most inefficient in the

[72] Viridity June 18, 2010 Comments at 13 ("Importantly, Dr. Hogan (and others) in opposing the proposed rulemaking fails to acknowledge the limits of the Commission's jurisdiction, and wide spread dislocations and distortions in virtually all economic aspects of relevant energy markets (including fuels, facilities, pricing, environmental attributes, information and participation)." (Affidavit of John C. Tysseling, Ph.D.)).

[73] Viridity Reply Comments at 13.

[74] Viridity Reply Comments at 14.

fleet.[75] The American Clean Skies Foundation contends that fossil-fuel generators are typically mispriced because wholesale prices radically understate the full environmental and health costs associated with such generators.[76] Indeed, some commenters, such as Alcoa, argue that because demand response does not result in the external costs associated with generation (e.g., greenhouse gas emissions), instead resulting in less greenhouse gas emissions than generation, it should be compensated at more than LMP.[77]

34. Taking the opposite view concerning environmental externalities, EPSA states that paying LMP for demand response will merely encourage load to switch to off-grid power (or behind-the-meter generation), while still being compensated, and that such behind-the-meter generation produces more greenhouse gases and other air emissions than electricity from the regional energy market.[78]

35. Some commenters discuss comparability of generation and demand response in terms of the market rules that apply to each resource, arguing that both resources should be comparably compensated only if the same rules for participation apply to both resources, and both resources are held to the same standards for dispatchability.[79] They

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[75] EDF Oct. 13, 2010 Comments at 2.

[76] American Clean Skies Foundation May 13, 2010 Comments at 4.

[77] Alcoa May 13, 2010 Comments at 9.

[78] EPSA May 13, 2010 Comments at 60.

[79] ODEC May 13, 2010 Comments at 12; Westar May 13, 2010 Comments at 5-6.

also argue that similar penalty structures should apply to demand response resources as apply to generation, and that demand response participation must be subject to market monitoring.[80] Calpine adds that to the extent demand response resources are used and treated on par with generators for purposes of compensation, they should be subject to the same performance testing, penalties, and other similar requirements as generators.[81]

36. Some commenters address the comparability of demand response providers and generators in terms of maintaining system reliability. PIO argues that reductions in consumption provide additional reliability.[82] According to the NEMA, North American Electric Reliability Corporation (NERC) standards suggest that, from a reliability perspective, load reductions are equivalent or even superior to generator increases for balancing purposes. For example, while specific to the Western Interconnection, BAL-002-WECC-1 lists interruptible load as comparable to generation deployable within 10 minutes.[83] EPSA maintains that demand response resources are not full substitutes based on the nature of their participation and the rules applicable to each resource in the energy

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[80] Id.

[81] Calpine May 13, 2010 Comments at 5.

[82] PIO May 13, 2010 Comments at 8.

[83] NEMA May 13, 2010 Comments at 2.

markets, pointing out, for example, that, unlike generators, demand response providers are not subject to regional and NERC mandatory reliability standards.[84]

37. On the other hand, PSEG argues that a MW of demand response does not make the same contribution towards system reliability as a MW of generation, because demand response committed as a capacity resource is only required to perform for a limited number of times over the peak period. PSEG refers to PJM's capacity market, for example, in which demand response only has to perform 10 times during the entire summer peak period, and then only for six hours per response. In contrast, PSEG argues, generators are available for dispatch, 24 hours a day, 365 days per year, except for a small percentage of time for forced and planned outages. PSEG further asserts that additional reliability standards - applicable to generating facilities, but not to demand response - increase the relative reliability value of generating resources to the system.[85]

b) <u>Appropriateness of a Net Benefits Test</u>

38. Some commenters assert that demand response providers should be paid LMP only when the benefits of demand response compensation outweigh the energy market costs to consumers of paying demand response resources, i.e., when cost-effective, as

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[84] EPSA May 13, 2010 Comments at 7.

[85] PSEG May 13, 2010 Comments at 8.

determined by some type of net benefits or cost-effectiveness test.[86] They maintain that paying LMP for demand response in all hours, including off-peak hours, might not result in net benefits to customers, because the payments might be substantially more than the savings created by reducing the clearing price at that time.[87] According to these commenters, net benefits are most likely to be positive and greatest when the supply curve is steepest, which typically occurs in highest-cost, peak hours.[88] They argue that experience to date has shown positive benefits from demand response as a peak system resource, and that, during peak periods, the positive economics of demand response are generally very clear and a cost-benefit analysis may not be needed.[89] Furthermore, some commenters suggest that limiting the hours in which demand response resources are paid

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[86] See generally May 13, 2010 Comments of NYSCPB; NECA; Capital Power; NECPUC; Maryland Commission; New York Commission; NSTAR; National Grid; NE Public Systems.

[87] Capital Power May 13, 2010 Comments at 5; P3 May 13, 2010 Comments at 5.

[88] NECPUC May 13, 2010 Comments at 13; see also Sept. 13, 2010 Tr. 13:6-19 (Mr. Keene); Maryland Commission May 13, 2010 Comments at 4-5.

[89] See, e.g., ACEEE Oct. 13, 2010 Comments 3-4. See also National Grid May 13, 2010 Comments at 4-5; NSTAR Electric Company (NSTAR) May 14, 2010 Comments at 3; Maryland Commission May 13, 2010 Comments, submitting Analysis of Load Payments and Expenditures under Different Demand Response Compensation Schemes at 10-11 (discussing PJM analysis showing that paying demand response providers LMP for all hours after compensating LSEs for lost revenues would not benefit customers in general but that positive economic benefits results when demand response providers receive LMP during at least the top 100 hours (the highest priced energy hours)).

LMP could help establish better baselines for measuring whether a demand response provider has, in fact, responded.[90]

39. Some commenters who oppose paying LMP in all hours for demand response also suggest various approaches, including net benefits tests, for determining when LMP should apply. The stated purpose of any of these tests would be to determine the point at which the incremental payment for demand response equals the incremental benefit of the reduction in load; payment of LMP would apply only up to that point.[91]

40. Opposition to use of a net benefits test comes from several directions. Numerous commenters, primarily industrial consumers and some consumer advocates, argue that a net benefits test will reduce competition,[92] have a "chilling effect" on the development of demand response,[93] and be costly and complex to implement.[94] Some commenters

[90] See, e.g., CDWR May 13, 2010 Comments at 11; National Grid May 13, 2010 Comments at 8; ISO-NE May 13, 2010 Comments at 34; ACEEE Oct. 13, 2010 Comments 4. But see ISO-NE May 13, 2010 Comments at 32-33 (contending that 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).

[91] NECAA May 13, 2010 Comments at 11; NYSCPB May 13, 2010 Comments at 5; National Grid May 13, 2010 Comments at 4-5.

[92] Viridity Oct. 13, 2010 Comments at 14.

[93] NAPP Oct. 13, 2010 Comments at 2.

[94] Viridity Oct. 13, 2010 Comments at 14; NAPP Oct. 13, 2010 Comments at 3; AMP Oct. 13, 2010 Comments at 4; CAISO Oct. 13, 2010 Comments at 5 and 16.

further state that no net benefits test is needed because the merit-order bid stack and market clearing function in a wholesale market, by definition, assures that the benefits to the system of demand response exceed the costs, and that the resource that clears is the lowest cost resource; otherwise, demand response would not dispatch ahead of competing alternatives.[95]

41. Another set of commenters argues that a net benefits test is unnecessary and inappropriate for different reasons.[96] These commenters assert that a net benefits test would be very costly and difficult to implement, that RTOs and ISOs cannot implement a net benefits test,[97] and that such a test is unnecessary with the economically efficient compensation level for demand response resources.[98] According to Andy Ott of PJM, "[t]he implicit assumption in developing a benefits test for purposes of compensation would be that you could actually determine individual customers, whether they benefitted

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[95] EDF Oct. 13, 2010 Comments at 2; Viridity Oct. 13, 2010 Comments at 10; ELCON Oct. 13, 2010 Comments at 3.

[96] See, e.g., Oct. 13, 2010 Comments of: Midwest TDUs at 4-5; NEPGA at 8, NJBPU at 2-3; NAPP at 2-3; P3; SPP at 3-4; SDG&E, SoCal Edison, and PG&E at 4-6; Viridity Energy at 2; ELCON at 2; AMP at 2; CDWR at 1, 4-5; CAISO at 4, 15; Detroit Edison at 2; Smart Grid Coalition at 2; Duke Energy at 2; EDF at 2; FTC at 1; EPSA at 4; Indicated New York TOs at 3; Midwest ISO at 9; Steel Manufacturers Ass'n at 3.

[97] P3 Oct. 13, 2010 Comments at 5.

[98] Sept. 13, 2010 Tr. 155:21-24 (Mr. Robinson); Sept. 13, 2010 Tr. 141-42 (Mr. Centolella); Dr. Hogan Sept. 13, 2010 Comments at 5; Sept. 13, 2010 Tr. 60 (Dr. Shanker); Sept. 13, 2010 Tr. 27 (Mr. Newton); SDG&E May 13, 2010 Comments at 4.

or not. That type of analysis would be very costly to implement."[99] Midwest ISO TOs further assert that it would be difficult to prescribe by regulation the hours in which demand response provides net benefits because system conditions and load patterns change across seasons and over time.[100] NEPGA argues that compensating demand response resources at LMP whenever a reduction in consumption suppresses energy prices enough to provide net benefits to load is neither just and reasonable, nor in the public interest.[101] NEPGA states that the Commission recognized in Amaranth Advisors[102] that, if prices are suppressed below competitive, market levels, society as a whole is worse off. According to NEPGA, the goal is to get the right price—the economically efficient price produced by competitive markets.

42. NYISO posits that a rule mandating payment of LMP-G avoids the need to develop a net benefits test. NYISO further states, however, that if the Commission decides to move forward with LMP for demand response, it should craft a net benefits test that minimizes any opportunities for distorting market prices or exploiting market inefficiencies. Citing support for Dr. Hogan's arguments, NYISO states that "a net benefits test should ensure that the demand response program does not have negative net

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[99] Sept. 13, 2010 Tr. 19 (Mr. Ott).

[100] Midwest ISO TOs May 13, 2010 Comments at 16.

[101] NEPGA June 21, 2010 Comments at 1-2.

[102] 120 FERC ¶ 61,085 (2007).

benefits compared to no program at all. The criterion to apply would focus on the bid-cost savings of generation and load, with the load bids adjusted for the effects of avoidance of the retail rate."[103]

c) Standardization or Regional Variations in Compensation

43. With regard to potential regional variations for compensation mechanisms across RTO and ISO markets, many commenters, mostly those in support of the NOPR's proposed compensation level, endorse standardization.[104] Some parties, primarily industrial customers and some customer advocates, argue that, regardless of location, both demand response providers and generators provide a comparable service in terms of balancing supply and demand, as discussed above, and therefore should be comparably compensated at the LMP.[105] They argue that fair, non-discriminatory markets must adapt and eliminate barriers to entry to the use and incorporation of traditional and non-

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[103] NYISO Oct. 13, 2010 Comments at 3-4.

[104] See May 13, 2010 Comments of: ArcelorMittal; Alcoa; ACENY; ACC; AFPA; CDWR; Mayor Bloomberg; Consert; CDRI; CPower; DR Supporters; Derstine's; Durgin; Electricity Committee; ELCON; Electrodynamics; ECS; EnerNOC; ICUB; IECA; IECPA; Irving Forest; Joint Consumers; Limington; Madison Paper; Massachusetts AG; NEMA; National Energy; National League of Cities; NJBPU; NAPP; Occidental; Okemo; Partners; Pennsylvania Department of Environment; Pennsylvania Commission; Rep. Chris Ross; Precision; PRLC; Raritan ; SDEG, SoCal; PG&E; Schneider; Governor O'Malley; Steel Manufacturers Ass'n; Verso; Viridity; Virginia Committee; Wal-Mart; Waterville.

[105] See, e.g., Steel Manufacturers Ass'n May 13, 2010 Comments at 12; NEMA May 13, 2010 Comments at 5.

traditional resources—where non-traditional resources include actively-managed demand—in the dispatch and management of the electric system.[106] They further posit that the lack of a unified policy itself represents a regulatory barrier to demand response,[107] and that a consistent set of rules reduces the costs and complexities of demand response participation and facilitates training and transfer of personnel across regions.[108] To that end, many commenters argue that adopting a unified approach to demand response compensation at the LMP, as opposed to allowing regional variation including payment of something less than LMP, is necessary to overcome the barriers to entry of demand response providers.[109] Reciting the many benefits of demand reductions in energy use, these commenters support a compensation level that will provide a catalyst for private sector engagement in improved energy management practices. Viridity argues that the near absence of demand response participating in energy markets is powerful empirical proof that current, varying levels of compensation are inadequate—especially

[106] Steel Manufacturers Ass'n May 13, 2010 Comments at 12.

[107] PIO May 13, 2010 Comments at 9; DR Supporters Aug. 30, 2010 Comments at 6-7.

[108] See, e.g., Alcoa May 13, 2010 Comments at 13.

[109] NECPUC May 13, 2010 Comments at 4; NYISO May 13, 2010 Comments at 16.

in markets that start with a market-based level of compensation and then reduce it by the generation portion of a customer's retail rate (LMP – G).[110]

44. Other commenters caution against standardizing the compensation level for demand response, pointing to regional differences in market structure, state regulatory environment, and resource mix.[111]

3. Commission Determination

45. The Commission acknowledges the diverging opinions of commenters regarding the appropriate level of compensation for demand response resources. As discussed above, commenters are split on this issue, with some in favor of paying the LMP for demand reductions in the day-ahead and real-time energy markets in all hours, others arguing that paying the LMP for demand reductions under any conditions will result in over-compensation or distortions in incentives to reduce consumption, and still others arguing that paying the LMP for demand reductions is only appropriate when it is reasonably certain to be cost-effective.

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[110] Viridity Energy May 13, 2010 Comments at 4.

[111] See, e.g., May 13, 2010 Comments of: ConEd at 3-4; Consumers Energy at 2; California Commission at 9; CMEEC at 2-3, 14-15; Detroit Edison at 3-5; Dominion at 8; Duke Energy at 4; EPSA at 6; Hess at 4; Indicated New York TOs at 3; Maryland Commission at 5; Midwest TDUs at 2, 6; Midwest ISO TOs at 16; National Grid at 5-6; 11-12; New York Commission at 4, 11; NCPA at 3; NYISO at 2-3; ODEC at 27; PJM at 5-6; SPP at 1.

46. In the face of these diverging opinions, the Commission observes that, as the courts have recognized, "'issues of rate design are fairly technical and, insofar as they are not technical, involve policy judgments that lie at the core of the regulatory mission.'"[112] We also observe that, in making such judgments, the Commission is not limited to textbook economic analysis of the markets subject to our jurisdiction, but also may account for the practical realities of how those markets operate.[113]

47. As discussed further below, the Commission agrees with commenters who support payment of LMP under conditions when it is cost-effective to do so, as determined by the net benefits test described herein.[114] We have previously accepted a variety of ISO and RTO proposals for compensation for demand response resources participating in

[112] Elec. Consumers Res. Council v. FERC, 407 F.3d 1232, 1236 (D.C. Cir. 2005) (quoting Pub. Util. Comm'n of the State of Cal. v. FERC, 254 F.3d 250, 254 (D.C. Cir. 2001)); see also Town of Norwood v. FERC, 962 F.2d 20, 22 (D.C. Cir. 1992).

[113] See Elizabethtown Gas Co. v. FERC, 10 F.3d 866, 872 (D.C. Cir. 1993) ("It is the FERC's established policy to consider equitable factors in designing rates, and to allow for phasing in of changes where appropriate. . . . It is hardly arbitrary or capricious so to temper the dictates of theory by reference to their consequences in practice."); Vermont Dep't of Pub. Serv. v. FERC, 817 F.2d 127, 135 (D.C. Cir. 1987) ("Indeed, 'the congressional grant of authority to the agency indicates that the agency's interpretation typically will be enhanced by technical knowledge.'" (quoting Nat'l Fuel Gas Supply Corp. v. FERC, 811 F.2d 1563, 1570 (D.C. Cir. 1987))); Columbia Gas Transmission Corp. v. FERC, 750 F.2d 105, 112 (D.C. Cir. 1984) ("the Commission is vested with wide discretion to balance competing equities against the backdrop of the public interest").

[114] See generally May 13, 2010 Comments of NYSCPB; NECA; Capital Power; NECPUC; Maryland Commission; New York Commission; NSTAR; National Grid; NE Public Systems.

organized wholesale energy markets. We find, based on the record here that, when a demand response resource has the capability to balance supply and demand as an alternative to a generation resource, and when dispatching and paying LMP to that demand response resource is shown to be cost-effective as determined by the net benefits test described herein, payment by an RTO or ISO of compensation other than the LMP is unjust and unreasonable. When these conditions are met, we find that payment of LMP to these resources will result in just and reasonable rates for ratepayers.[115] As stated in the NOPR, we believe paying demand response resources the LMP will compensate those resources in a manner that reflects the marginal value of the resource to each RTO and ISO.[116]

48. The Commission emphasizes that these findings reflect a recognition that it is appropriate to require compensation at the LMP for the service provided by demand response resources participating in the organized wholesale energy markets only when two conditions are met:

- The first condition is that the demand response resource has the capability to provide the service , i.e., the demand response resource must be able to displace a

[115] The Commission's findings in this Final Rule do not preclude the Commission from determining that other approaches to compensation would be acceptable when these conditions are not met.

[116] NOPR at P 12.

generation resource in a manner that serves the RTO or ISO in balancing supply and demand.

- The second condition is that the payment of LMP for the provision of the service by the demand response resource must be cost-effective, as determined by the net benefits test described herein.

49. With respect to the first, capability-related condition, we note that a power system must be operated so that there is real-time balance of generation and load, supply and demand. An RTO or ISO dispatches just the amount of generation needed to match expected load at any given moment in time. The system can also be balanced through the reduction of demand.[117] Both can have the same effect of balancing supply and demand at the margin either by increasing supply or by decreasing demand.

50. With respect to the second cost-effectiveness condition, the record leads us to alter the proposal set forth in the NOPR in this proceeding. As various commenters explain, dispatching demand response resources may result in an increased cost per unit to load

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[117] Andrew L. Ott Sept. 13, 2010 Statement at 1.

> Economic and Capacity-based demand response clearly provides benefits to regional grid operation and the wholesale market operation. . . . These demand resources provide benefits by providing valuable alternatives to PJM in maintaining operational reliability and in promoting efficient market operations.

Id. at 1; see also CDRI May 13, 2010 Comments at 10; CDWR May 13, 2010 Comments at 5; NJPBU May 13, 2010 Comments at 2.

associated with the decreased amount of load paying the bill, depending on the change in LMP relative to the size of the energy market. As stated above, this is the billing unit effect of dispatching demand response resources.[118] However, when reductions in LMP from implementing demand response results in a reduction in the total amount consumers pay for resources that is greater than the money spent acquiring those demand response resources at LMP, such a payment is a cost-effective purchase from the customers' standpoint.[119] In comparison, when wholesale energy market customers pay a reduced price attributable to demand response that does not reduce total costs to customers more than the costs of paying LMP to the demand response dispatched, customers suffer a net loss. Implementation of the net benefits test described herein will allow each RTO or ISO to distinguish between these situations.

51. This billing unit effect and the net benefits test through which it is addressed herein, warrant more detailed discussion. In the organized wholesale energy markets, the economic dispatch organizes offers from lowest to highest bid in order to balance supply

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[118] As stated above, dispatching generation resources does not produce this billing unit effect because it does not result in a decrease of load.

[119] As a simple example, assume a market of 100 MW, with a current LMP of \$50/MWh without demand response, and an LMP of \$40/MWh if 5 MW of demand response were dispatched. Total payments to generators and load would be \$4,000 with demand response compared to the previous \$5,000. Even though, the reduced LMP is now being paid by less load, only 95 MW compared to 100 MW, the price paid by each remaining customer would decrease from \$50/MWh to \$42.11/MWh (\$4,000/95). Therefore, the payment of LMP to demand resources is cost-effective.

and demand, taking into account other parameters such as requirements for a generator to operate at a minimum level of output or minimum amount of time, reserve requirements and so forth. With dispatch of a demand response resource, the load also goes down, that is, the level of remaining load falls. However, the “supply” of resources deployed—which includes both generation and demand response—does not fall. The total costs to the system for these resources must then be allocated among the reduced quantity of remaining load.

52. In the absence of the net benefits test described herein, the RTO’s or ISO’s economic dispatch ordinarily would select demand response when it is the incremental resource with the lowest bid. However, if the next unit of generation is not sufficiently more expensive than the demand response resource, the decrease in LMP multiplied by the remaining load would not be greater than the costs of dispatching the demand response resource. In this situation, dispatching the demand response resource would result in a higher price to remaining customers than the dispatch of the next unit of generation in the bid stack. While the demand response resource appears cost competitive in the dispatch order, selection of the demand response resource increases the total cost per unit to remaining load, and it would not be cost-effective to dispatch the demand response resource.

53. For this reason, the billing unit effect associated with dispatch of a demand response resource in an energy market must be taken into account in the economic comparison of the energy bids of generation resources and demand response resources. Therefore, rather than requiring compensation at LMP in all hours, the Commission requires the use of the net benefits test described herein to ensure that the overall benefit of the reduced LMP that results from dispatching demand response resources exceeds the cost of dispatching those resources. When the above-noted conditions of capability and of cost-effectiveness are met, it follows that demand response resources that clear in the day-ahead and real-time energy markets should receive the LMP for services provided, as do generation resources. LMP represents the marginal value of an increase in supply or a reduction in consumption at each node within an ISO or RTO, i.e., LMP reflects the marginal value of the last unit of resources necessary to balance supply and demand. Indeed, LMP has been the primary mechanism for compensating generation resources clearing in the organized wholesale energy markets since their formation.[120]

54. The Commission finds that demand response resources that clear in the day-ahead and real-time energy markets should receive the same market-clearing LMP as compensation in the organized wholesale energy markets when those resources meet the conditions established here as a cost-effective alternative to the next highest-bid

[120] See DR Supporters Aug. 30, 2010 Reply Comments (Kahn Affidavit at 2 (footnote omitted)).

generation resources for purposes of balancing the energy market. We discuss below the comments filed on these issues.

55. Some commenters dispute that the foregone consumption of energy by demand response resources performs the service of balancing supply and demand in the energy market as would energy supplied by generators in the day-ahead and real-time energy markets, arguing that it is inappropriate to pay electric consumers to not consume.[121] The Commission disagrees. Generation and load must be balanced by the RTOs and ISOs when clearing the day-ahead and real-time energy markets, and such balancing can be accomplished by changes in either supply or demand. The Commission finds that in the organized wholesale energy markets demand response can balance supply and demand as can generation.

56. Commenters that oppose this finding do not adequately recognize a distinctive and perhaps unique characteristic of the electric industry. The electric industry requires instantaneous balancing of supply and demand at all times to maintain reliability. It is in this context that the Commission finds that demand response can balance supply and demand as can generation when dispatched, in the organized wholesale energy markets.

[121] See, e.g., ISO-NE May 13, 2010 Comments at 3; APPA May 13, 2010 Comments at 12; Capital Power May 13, 2010 Comments at 2; EPSA May 13, 2010 Comments at 72.

57. Due to a variety of factors, demand responsiveness to price changes is relatively inelastic in the electric industry and does not play as significant a role in setting the wholesale energy market price as in other industries. The Commission has recognized that barriers remain to demand response participation in organized wholesale energy markets. For example, in Order No. 719, the Commission stated:

> [D]espite previous Commission and RTO and ISO efforts to facilitate demand response, regulatory and technological barriers to demand response participation persist, thereby limiting the benefits that would otherwise result. A market functions effectively only when both supply and demand can meaningfully participate, and barriers to demand response limit the meaningful participation of demand in electricity markets.[122]

Barriers to demand response participation at the wholesale level identified by commenters include the lack of a direct connection between wholesale and retail prices,[123] lack of dynamic retail prices (retail prices that vary with changes in marginal wholesale costs), the lack of real-time information sharing, and the lack of market incentives to invest in enabling technologies that would allow electric customers and

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[122] Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 83 (citing Federal Energy Regulatory Commission Staff, A National Assessment of Demand Response Potential (June 2009), found at http://www.ferc.gov/legal/staff-refports/06-09-demand-response.pdf; Barriers to Demand Side Response in PJM (2009)). In compliance filings submitted by RTOs and ISOs and their market monitors pursuant to Order No. 719, as well as in responsive pleadings, parties have mentioned additional barriers, such as the inability of demand response resources to set LMP, minimum size requirements, and others.

[123] See, e.g., Monitoring Analytics May 13, 2010 Comments at 4-6.

aggregators of retail customers to see and respond to changes in marginal costs of providing electric service as those costs change. For example, Dr. Kahn states:

> These circumstances—specifically, the fact that pass-through of the LMP is costly and (perhaps) politically infeasible, the possibly prohibitive cost of the metering necessary to charge each ultimate user, moment-by-moment, the often dramatic changes in true marginal costs for each—can justify direct payment at full LMP to distributors and ultimate customers who promise to guarantee their immediate response to such increases in true marginal costs of supplying them.[124]

Furthermore, EnerNOC states:

> On a more fundamental level, the inadequate compensation mechanisms in place today in wholesale energy markets fail to induce sufficient investment in demand response resource infrastructure and expertise that could lead to adequate levels of demand response procurement. Without sufficient investment in the development of demand response, demand response resources simply cannot be procured because they do not yet exist as resources. Such investment will not occur so long as compensation undervalues demand response resources.[125]

58. The Commission concludes that paying LMP can address the identified barriers to potential demand response providers.

59. Removing barriers to demand response will lead to increased levels of investment in and thereby participation of demand response resources (and help limit potential

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[124] DR Supporters Sept. 16, 2009 Comments filed in Docket No. EL-09-68-000 (Kahn Affidavit at 6). See also id. at 4 (Customers offering to reduce consumption should be induced "to behave as they would if market mechanisms alone were capable of rewarding them directly for efficient economizing.").

[125] EnerNOC May 13, 2010 Comments at 4; see also Alcoa May 13, 2010 Comments at 4; Viridity May 13, 2010 Comments at 5-6.

generator market power), moving prices closer to the levels that would result if all demand could respond to the marginal cost of energy. To that end, the Commission emphasizes that removing barriers to demand response participation is not the same as giving preferential treatment to demand response providers; rather, it facilitates greater competition, with the markets themselves determining the appropriate mix of resources, which may include both generation and demand response, needed by the RTO and ISO to balance supply and demand based on relative bids in the energy markets. In other words, while the level of compensation provided to each resource affects its willingness and ability to participate in the energy market, ultimately the markets themselves will determine the level of generation and demand response resources needed for purposes of balancing the electricity grid.[126]

60. Another issue raised by a number of commenters, largely representing generators, is whether a lower payment based on LMP-G is the economically-efficient price that sends the proper price signal to a potential demand response provider. These commenters argue that, by not consuming energy, demand response providers already effectively receive “G,” the retail rate that they do not need to pay. They therefore contend that demand response providers will be overcompensated unless “G” is deducted from

[126] Generation and demand response resources have the potential to earn other revenues through bilateral arrangements, capacity markets where they exist, and ancillary services.

payments made by the RTO or ISO for service in the wholesale energy market, resulting in a payment of LMP-G. These commenters suggest that payment of LMP-G will result in a price signal to demand response providers equivalent to the LMP (i.e., (LMP - G) + G). Similarly, some commenters argue that paying demand response resources the LMP will lead to a wholesale electricity price that is not economically efficient.[127]

61. The Commission disagrees with commenters who contend that demand response resources should be paid LMP-G in all hours. First, as discussed above, demand response resources participating in the organized wholesale energy markets can be cost-effective, as determined by the net benefits test described herein, for balancing supply and demand and, in those circumstances, it follows that the demand response resource should also receive compensation at LMP. Second, such comments largely rely on arguments about economic efficiency, analogizing to incentives for individual generators to bid their marginal cost. These arguments fail to acknowledge the market imperfections caused by the existing barriers to demand response, also discussed above. In Order No. 719, the Commission found that allowing demand response to bid into organized wholesale energy markets "expands the amount of resources available to the market, increases competition, helps reduce prices to consumers and enhances reliability."[128]

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[127] See NEPGA June 21, 2010 Comments at 1-2.

[128] Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 154.

Furthermore, Dr. Kahn argues that paying demand response LMP sets “up an arrangement that treats proffered reductions in demand on a competitive par with positive supplies; but the one is no more a [case of overcompensation] than the other: the one delivers electric power to users at marginal costs—the other—reductions in cost—both at competitively-determined levels.”[129]

62. Several other considerations also support this Commission conclusion. In the absence of market power concerns, the Commission does not inquire into the costs or benefits of production for the individual resources participating as supply resources in the organized wholesale electricity markets and will not here, as requested by some commenters, single out demand response resources for adjustments to compensation. The Commission has long held that payment of LMP to supply resources clearing in the day-ahead and real-time energy markets encourages “more efficient supply and demand decisions in both the short run and long run,”[130] notwithstanding the particular costs of production of individual resources. Commenters have not justified why it would be appropriate for the Commission to continue to apply this approach to generation resources yet depart from this approach for demand response resources.

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[129] DR Supporters Aug. 30, 2010 Reply Comments (Kahn Affidavit at 9-10).

[130] See New England Power Pool, 101 FERC ¶ 61,344, at P 35 (2002).

63. In addition, we agree with the New York Commission that given the differences in retail rate structures across RTO footprints and even within individual states, requiring ISOs and RTOs to incorporate such disparate retail rates into wholesale payments to wholesale demand response providers would, even though perhaps feasible, create practical difficulties for a number of parties, including state commissions and ISOs and RTOs. Moreover, incorporating such rates could result in customer uncertainty as to the prevailing wholesale rate.

64. Some arguments advocating paying LMP-G rather than LMP are based on an assumption that demand response resources need to purchase the energy in day-ahead markets or by other means and then "resell" the energy to the market in the form of demand response. However, as the Commission previously stated in EnergyConnect, the Commission does not view demand response as a resale of energy back into the energy market.[131] Instead, as the Commission also explained in EnergyConnect and in Order No. 719-A, the Commission asserts jurisdiction with respect to demand response in organized wholesale energy markets because of the effect of demand response and related RTO and ISO market rules on Commission-jurisdictional rates.[132]

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[131] See EnergyConnect, 130 FERC ¶ 61,031 at P 32.

[132] Id.; see also Order No. 719-A, FERC Stats. & Regs. ¶ 31,292, at P 47.

65. With regard to the “buyers’ cartel” argument, the Commission disagrees that market rules establishing circumstances in which particular resources can participate and receive the LMP represents cooperative price setting. RTOs and ISOs evaluate the bids from generation and demand response resources to establish the order of dispatch which secures the most economical supplies needed, consistent with the reliability constraints imposed on the system. Imposing a cost-effectiveness condition does not convert this unit commitment process by the RTO or ISO into collusion among bidders, whether generation or demand response. Furthermore, the market rules administering such a program would be approved by this Commission and demand response resources would be subject to Commission-approved rules, just like any other participants in the organized wholesale energy markets. In addition, arguments that the subject of this proceeding is equivalent to the types of market manipulation investigated in Amaranth and ETP are groundless and without merit. In Amaranth, the trader was accused of engaging in a fraudulent scheme with scienter in connection with a jurisdictional transaction. Here, there is no such allegation, merely speculation that the Commission is somehow facilitating coordination of demand- side bidders in order to lower prices.

66. Some commenters argue that demand response providers and generators should both be compensated at the market clearing price only if both are subject to the same market participation rules, penalty structures, testing requirements, and market monitoring provisions. The ISOs and RTOs already consider how to ensure

comparability between demand response and generation in terms of market rules.[133] The Commission agrees that as a general matter demand response providers and generators should be subject to comparable rules that reflect the characteristics of the resource, and expect ISOs and RTOs to continue their evaluation of their existing rules in light of this Final Rule and make appropriate filings with the Commission.

67. Some commenters argue that the Commission should not impose a single pricing rule due to differences in market structure, state regulatory environment, and resource mix among the ISOs and RTOs. While such differences may exist, the commenters have not shown why such differences warrant a different compensation level among the ISOs and RTOs. As discussed above, regardless of the resource mix or the state regulatory environment, demand response, which satisfies the net benefits test described herein and can balance the system, is a cost-effective alternative to generation in the organized wholesale energy markets, and payment of LMP represents the marginal value of a decrease in demand.

[133] See PJM Interconnection, L.L.C., 129 FERC ¶ 61,081 (2009).

B. Implementation of a Net Benefits Test

1. Comments

68. In response to questions that the Commission posed in the Supplemental NOPR, some commenters advocate a net benefits trigger based on a particular price threshold.[134] The NYISO currently has a static bid threshold of $75/MWh in its day-ahead demand response program.[135]

69. However, other commenters assert that using a static threshold based on historical data misses the changes that occur within electricity markets across seasons and years, and that it is erroneous to assume that all demand response occurring above a certain threshold price (for instance, at the very highest loads or highest priced hours) will result in lower costs to wholesale customers and that demand response is not cost-effective at

[134] For example, National Grid states that the threshold could be triggered by a particular price on the supply offer curve at which the additional cost of paying LMP to demand response resources is most likely to be outweighed by LMP reductions in the wholesale energy market as a result of the demand reductions produced by these resources. National Grid May 13, 2010 Comments at 6. Those in favor of a price threshold include National Grid (but allow the ISO or RTO to identify threshold based on analysis); NE Public Systems; NECPUC; ISO-NE (minimum offer price based on fixed heat rate, times a fuel price index); New York Commission (supports ISO-NE's heat rate indexed price threshold).

[135] NYISO implements a day-ahead demand response program by which resources bid into the market at a minimum of $75/MWh and can get paid the LMP. See section 4.2.2.9 ("Day-Ahead Bids from Demand Reduction Providers to Supply Energy from Demand Reductions") of NYISO's Market Services Tariff.

prices below the static threshold price.[136] They argue that a static threshold offer price cannot easily adjust with changing energy market prices which may result in inefficient dispatch of demand resources, excluding demand response participation in hours when demand response can provide beneficial savings and including demand response participation in hours when there are no beneficial savings.[137] The New York Commission supports a dynamic, rather than a static bid threshold, arguing that, while a static bid threshold helps prevent demand response providers from gaming the system by seeking compensation for reducing electricity consumption for reasons other than market prices, it can also limit participation in a demand response program because prices might not exceed the threshold on a consistent basis.[138]

70. In a similar vein, some commenters suggest utilizing a dynamic bid threshold for determining when LMP payment would apply.[139] For example, NECPUC favors use of a dynamic mechanism such as a price threshold based on a preset heat rate of marginal

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[136] Sept. 13, 2010 Tr. 52-53 (Mr. Peterson); Massachusetts AG Oct. 13, 2010 Comments at 23.

[137] Massachusetts AG Oct. 13, 2010 Comments (attachment, Demand Response Potential in ISO New England's Day-Ahead Energy Market, Synapse Energy Economics, Inc. Oct. 11, 2010 at 9). See generally, NECPUC May 13, 2010 Comments at 18.

[138] Id.

[139] National Grid May 13, 2010 Comments at 6; New York Commission May 13, 2010 Comments at 10; Viridity May 13, 2010 Comments at 24. See generally NECPUC, New York Commission; ISO-NE; NSTAR; ACEEE; and NYSCPB Oct. 13, 2010 Comments.

generation and fuel price, like that currently used in New England's Day-Ahead Load Response Program (DALRP),[140] for the ISO-NE control area.[141] National Grid suggests a trigger, determined by each ISO or RTO, using a particular price on the supply offer curve at which the additional cost of paying LMP to demand resources is most likely to be outweighed by LMP reductions in the wholesale energy market as a result of the demand reductions.[142]

71. Still other commenters urge compensating demand response during an ISO- or RTO-defined period of critical high-cost hours in which it is cost-effective to pay LMP. These commenters argue that the effect of demand response on the market clearing price is greatest during a limited number of hours during the year.[143] Therefore, identifying the hours in which to pay LMP to demand response resources could be used as a cost-effective net benefits test with potential savings for ratepayers. According to PJM,

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[140] The DALRP establishes a minimum offer price by approximating the variable cost component, in the form of a fuel cost, of a hypothetical peaking unit sufficiently high enough in the supply stack to ensure net benefits. On a monthly basis, this minimum offer price is reset to reflect the product of an appropriate fuel price index and a proxy heat rate. See NECPUC Oct. 13, 2010 Comments at 15.

[141] NECPUC Oct. 13, 2010 Comments at 14-16; NECPUC May 13, 2010 Comments at 17.

[142] Id. at 5-6.

[143] Maryland Commission May 13, 2010 Comments at 4-5; see generally NSTAR, ACEEE and NYSCPB Oct. 13, 2010 Comments.

further analysis is needed to ascertain the critical high-cost hours in which it will be cost-effective to pay full LMP for demand response.[144]

72. The Consumer Demand Response Initiative (CDRI) proposes a mechanism for determining what demand response resources are cost-effective in any hour.[145] This dispatch algorithm tests whether the money necessary to compensate demand response is less than the cost savings due to the decreased market-clearing price resulting from implementing demand response. In a sense, it is a dynamic cost/benefit analysis built into the dispatch algorithm. This cost/benefit analysis accounts for the billing unit effect. The billing unit effect occurs when demand response resources are dispatched to balance the system; the associated reduction in load results in fewer MWh of realized load (demand) paying for the sum of generator and demand response resource MWh, so load pays an effective rate which is greater than the LMP set to procure resources. Some commenters assert that if the Commission finds that a net benefits test is needed, it should

[144] Maryland Commission May 13, 2010 Comments at 4 n.9.

[145] The approach submitted by CDRI was developed for implementation in the ISO-NE day-ahead energy market. The discussion here is generalized to be applicable to any energy market that uses security-constrained economic dispatch to select the least-cost resources and establish a market-clearing price.

require organized wholesale energy market operators to implement a proposal similar to that submitted by CDRI.[146]

73. Under the proposal submitted by CDRI, the demand response bids are part of the supply stack to which a security-constrained economic dispatch process is applied. All demand response bids that result in a lower price to customers, including consideration of the reduced number of billing units, are selected while those bids that raise the price, as compared to selecting the next generation bid in the supply stack, are not. This dispatch algorithm, as proposed, would be used by the ISO or RTO to determine a revised LMP that would be charged to load. The revised LMP creates a surplus (or over-collection) of revenue for the ISO or RTO that is then distributed to the LSEs through a settlement algorithm with the goal of holding LSEs harmless.[147]

74. During the September 2010 Technical Conference, Dr. Ethier of ISO-NE stated that a dynamic net benefits test done on an hourly basis that examines the effect of the demand response resource on LMPs, similar to that proposed by CDRI, would become

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[146] PIO July 27, 2010 Comments at 6; Massachusetts AG Oct. 13, 2010 Comments at 11; Viridity Oct. 13, 2010 Comments at 2. See CDRI May 13, 2010 Comments for a full description of the algorithms.

[147] CDRI May 13, 2010 Comments Attachment B at 18. CDRI states that the dispatch and settlement algorithms "could be employed to evaluate dispatch and assure customer benefits, without being employed to perform allocations and settlements." CDRI Oct. 13, 2010 Comments at 4.

very complicated to implement and require essentially an iterative process.[148] Dr. Ethier states that the ISO would have to run the dispatch model to formulate a base LMP with no demand response and then re-run it with demand response in the market; however those two iterations alone do not "cover the whole waterfront" in terms of the possible iterations required. According to Dr. Ethier, the ISO could dispatch too much demand response the first time, or if the ISO first rejected dispatching demand response, it may need to go back and dispatch smaller amounts of demand response to determine what would happen to the LMPs. Dr. Ethier stated that it is unclear where the ISO would stop the iteration of testing the impact on LMPs of dispatching demand response.[149] Andy Ott of PJM also stated during the technical conference that implementing a net benefits test would entail an iterative process that would be costly and difficult, if the RTO could even do it.[150]

75. Other commenters do not support the use of a net benefits test, but state that if one is adopted it should be based on general principles that RTOs and ISOs must apply to their systems in determining when LMP payments will apply.[151] A few commenters

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[148] Sept. 13, 2010 Tr. 80-81 (Dr. Ethier).

[149] Id.

[150] Sept. 13, 2010 Tr. 82:16-21 (Mr. Ott).

[151] See generally AEP, Midwest ISO, Occidental, NYISO, Constellation Oct. 13, 2010 Comments.

articulated specific criteria to be used in a net benefits test.[152] AEP believes that the objective of an incentive payment for demand response resources on the basis of broad market benefits can be achieved through a review of the costs and benefits of individual providers. Constellation states that any net benefits test should be based on the difference between the value consumers receive from energy and the cost of energy production.[153]

76. ISO-NE argues that a net benefits test should be based on economic efficiency, the sum of producer and consumer surplus, which suggests that demand response incentives ought to be provided to encourage demand reductions when the cost of energy production exceeds the value of consumption, and to encourage usage when the cost of energy production is less than the value of consumption. ISO-NE further states that a net benefits test that focuses solely on consumer savings ignores the value lost by consumers when energy consumption levels are reduced in response to incentive payments. ISO-NE posits that any variant of a LMP payment should be limited to a very small number of

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[152] See, e.g., Midwest ISO October 13, 2010 Comments at 9-14 and Table 1 (setting forth comprehensive list of benefits and costs of demand response by type of market participants); Occidental October 13, 2010 Comments at 4-5 (any net benefits test must take into consideration offsetting variables, such as higher LMPs in the subsequent periods where demand rebound increases market price, and capacity market price effects); AEP October 13, 2010 Comments at 3-4 (AEP does not recommend the use of a societal benefits component (i.e., health, environment, or employment efforts)).

[153] Constellation October 13, 2010 Comments at 3-4.

high-priced hours to minimize the economic distortions and avoid significant administrative complexities.[154]

77. A few commenters state that policies affecting energy prices will also impact capacity prices because generation owners with fixed costs must raise capacity price offers to remain financially viable at lower energy prices.[155] ISO-NE and Pepco argue, therefore, that the Commission should adopt a net benefits test that considers the impact of demand response compensation on both energy and capacity markets.[156] According to ISO-NE, when considering capacity market impacts under full-LMP compensation, long-term increases in capacity prices in response to suppressed LMPs offset consumer savings and leaves consumers worse off over time.[157] Robert Weishaar of the DR Supporters argues that properly compensating demand response should flatten the load profile and decrease the forecast of load projections, which would reduce capacity clearing prices.[158] Donald Sipe of CDRI adds that to the extent that scarcity revenues are

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[154] ISO-NE Oct. 13, 2010 Comments at 4-5 and 21.

[155] See, e.g., Sept. 13, 2010 Tr. 94:13-22 (Dr. Shanker); Sept. 13, 2010 Tr. 98:4-24 (Mr. Peterson); Sept. 13, 2010 Tr. 99:2-7 (Mr. Sunderhauf); ISO-NE Oct. 13, 2010 Comments at 5.

[156] Sept. 13, 2010 Tr. 99:1-24 (Mr. Sunderhauf); ISO-NE Oct. 13, 2010 Comments at 5.

[157] ISO-NE Oct. 13, 2010 Comments at 6.

[158] Sept. 13, 2010 Tr. 103-104 (Mr. Weishaar).

not sufficient, capacity markets are designed to ensure that a generator's capital costs are recovered; in a forward market that looks ahead as load adjusts, one can see whether a resource is performing or not. For purposes of long-run reliability, he argues, as long as compensation is in the amount that is necessary to induce new investment and reflects market value, the argument that demand response in the bid stack will push out generators is only true if generators are higher priced than the consumer resources that are brought by demand response.[159]

2. <u>Commission Determination</u>

78. For the reasons discussed previously, the Commission is requiring each RTO and ISO to implement the net benefits test described herein to determine whether a demand response resource is cost-effective. More specifically, the Commission is adopting two distinct requirements with respect to the net benefits test. While we find that the integration of the billing unit effect into the RTO/ISO dispatch processes has the potential to more precisely identify when demand response resources are cost-effective, we also recognize and understand the position of several of the RTOs and ISOs that modification of their dispatch algorithms may be difficult in the near term. Given these technical difficulties, we will require to RTOs and ISO to perform (1) the net benefits test described below to determine on a monthly basis under which conditions it is cost-

[159] Sept. 13, 2010 Tr. 106:16-24 (Mr. Sipe).

effective to pay full LMP to demand resources;[160] and (2) a study of the feasibility of developing a mechanism for determining the cost-effective dispatch of demand resources.

79. First we direct each RTO and ISO to undertake an analysis on a monthly basis, based on historical data and the RTO's or ISO's previous year's supply curve, to identify a price threshold to estimate where customer net benefits, as defined herein, would occur. The RTO or ISO should determine the threshold price corresponding to the point along the supply stack for each month beyond which the benefit to load from the reduced LMP resulting from dispatching demand response resources exceeds the increased cost to load associated with the billing unit effect, and update the calculation monthly. The ISOs and RTOs are to determine monthly threshold prices based on historical data. The threshold prices would be updated monthly as new data becomes available and posted on the RTO web site. For example, the RTO should conduct an analysis of supply curves for January through December 2010 to be used as a starting point to establish threshold prices for 2011. Those numbers would be updated monthly during 2011 for significant changes in resource availability and fuel prices, with the process repeated monthly to reflect that

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[160] There will be inherent differences in the supply curves determined by each RTO and ISO under the net benefits test required herein due to decisions the RTOs and ISOs must make based on supply data for their regions, the mathematical methods each RTO and ISO chooses to use for smoothing the supply curves, the certainty of changes in supply due to outages in each region, local generation heat rates, and the choice of relevant fuel price indices.

month's data from the previous year.[161] The supply curve analysis should be updated monthly, by the 15th day of the preceeding month in advance of the effective date, to allow demand response providers as well as other market participants to plan, while still reflecting current supply conditions.[162]

80. Based on historical evidence and analysis submitted in this proceeding, the threshold point along the supply stack for each month will fall in the area where the supply curve becomes inelastic, rather than the extreme steep portion at the peak or in the flat portion of the supply curve.[163] In other words, LMP will be paid to demand response resources during periods when the nature of the supply curve is such that small decreases

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[161] The ISOs and RTOs are to select a representative supply curve for the study month, smooth the supply curve using numerical methods, and find the price/quantity pair above which a one megawatt reduction in quantity that is paid LMP would result in a larger percentage decrease in price than the corresponding percentage decrease in quantity (billing units). Beyond that point, a reduction in quantity everywhere along an upward sloping supply curve would be cost-effective.

[162] Thus, the test is to determine where: (Delta LMP x MWh consumed) > (LMP_{NEW} x DR); where LMP_{NEW} is the market clearing price after demand response (DR) is dispatched and Delta LMP is the price before DR is dispatched minus the market clearing price after DR is dispatched.

[163] Supply elasticity is defined as the percentage change in quantity supplied divided by the percentage change in price. When the elasticity is less than or equal to one, supply is considered inelastic. So, for example, in the inelastic portion of the supply curve, a reduction in quantity supplied by one percent will result in more than a one percent decrease in price. Using the terms related to demand response compensation, the billing unit effect (percentage change in quantity supplied) will be more than offset by lower LMP (percentage change in price), thus resulting in lower prices for wholesale load.

in generation being called to serve load will result in price decreases sufficient to offset the billing unit effect. The Massachusetts AG noted that the actual supply stack has locally flat and steep sections at all bid prices. We recognize that the threshold price approach we adopt here may result in instances both when demand response is not paid the LMP but would be cost-effective and when demand response is paid the LMP but is not cost-effective. We accept this result given the apparent computational difficulty of adopting a dynamic approach that incorporates the billing unit effect in the dispatch algorithms at this time.[164]

81. We direct each RTO and ISO to file its analysis as supporting documentation to the accompanying tariff revisions with the Commission on or before July 22, 2011, along with proposed tariff revisions necessary to comply with this Final Rule. The filing should include the data, analytical methods and the actual supply curves used to determine the monthly threshold prices for the last 12 months to show how the RTO or ISO would calculate the curves.[165] The Commission-approved net benefits test methodology must be posted on the RTO or ISO's website, with supporting documentation. The RTO or ISO must also post the price threshold levels that would have been in effect in the previous 12 months. In addition, when the net benefits test

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[164] See supra note 114.

[165] See supra P 6.

becomes effective, the supply curve analysis for the historic month that corresponds to the effective month should be updated for current fuel prices, unit availabilities, and any other significant changes to historic supply curve and posted on the RTO website (for example, the supply curve analysis for the March price threshold would be posted in mid-February). Finally, the supply curve analyses for all months should be updated and posted on the RTO website if a significant change to the composition or slope of the historic monthly curves occurs, such as extended outages or retirements not previously reflected.

82. Some commenters argue that that there would be no need for a net benefits test if demand response resources were paid LMP-G, while others argue that use of a net benefits test otherwise undermines our decision to compensate demand response resources at the LMP. As stated above, the Commission finds that when a demand response resource participating in an organized wholesale energy market is capable of balancing supply and demand in the energy market and is cost-effective, as determined by the net benefits test described herein, that demand response resource should receive the same compensation, the LMP, as a generation resource when dispatched. We see no reason to reduce that compensation simply to avoid the use of the net benefits test that will ensure benefits to load.

83. Nearly every participant in the net benefits panel at the September 13, 2010 Technical Conference agreed that it would be counterproductive to defer to the RTO or

ISO stakeholder process to determine when demand response provides net benefits without explicit guidance from the Commission.[166] We believe that this result, and the guidance provided in this Final Rule will provide for timely improvements to RTO and ISO market pricing for demand response resources participating in organized wholesale energy markets.

84. In addition to requiring each RTO and ISO to construct the net benefits test described herein, the Commission also imposes a second requirement for each RTO and ISO to undertake a study, examining the requirements for and impacts of implementing a dynamic approach to determine when paying demand response resources LMP results in net benefits to customers. We believe that integration of the billing unit effect into RTO and ISO dispatch algorithms holds promise for more accurately integrating demand resources on a dynamic basis into the dispatch of the RTOs and ISOs. In theory, this could help ensure that the cost-effective level of demand response resources is dispatched or scheduled into the organized wholesale energy markets. Given the potential of software enhancements to determine the amount of cost-effective demand response resources purchased in the day-ahead and real- time energy markets, we believe that it

[166] "[G]etting this decision resolved is an impediment to all the other stuff we want to do with price response to demand, and DR generally in our market . . . so until we get through this, we're not going to make much progress . . . the implication of that is if you send something back that leaves a lot of room for debate, it's going to be a while on all those other things." Testimony of Robert Ethier, Vice President, Market Design, ISO-NE, Sept. 13, 2010 Tr. at 136.

would be useful for the Commission to know more about the feasibility of and requirements for implementing improvements to the existing dispatch algorithms. Therefore, we will require each RTO and ISO to undertake a study, either individually or collectively, examining the requirements for, costs of, and impacts of implementing a dynamic net benefits approach to the dispatch of demand resources that takes into account the billing unit effect in the economic dispatch in both the day-ahead and real-time energy markets, and to file the results of their study with the Commission on or before September 21, 2012.

85. ISO-NE and Pepco suggest that the net benefits test also consider the impact of demand response compensation on both energy and capacity markets. However, this Final Rule is focused only on organized wholesale energy markets, not capacity markets.[167] Given the differences in capacity markets among the ISOs and RTOs, the record in this proceeding provides neither a reasonable basis for including capacity market effects in net benefits calculations in the energy markets, nor have ISO-NE and Pepco provided a methodology for taking such effects into account. Indeed, in some

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[167] Additionally, the arguments presented for focusing on the effect of demand response compensation in wholesale energy markets on capacity markets were not convincing – that decreases in energy market revenues by generators will be recouped in the form of increased capacity prices. First, they fail to consider how the increased participation by demand resources could actually increase potential suppliers in the capacity markets by reducing barriers to demand resources, which would tend to drive capacity prices down. Second, they did not examine the way in which capacity markets already may take into account energy revenues.

cases, the capacity markets already reflect energy and ancillary service revenue in determining capacity prices.

C. Measurement and Verification

1. NOPR Proposal

86. In the NOPR, the Commission explained that demand response curtailment is a reduction in actual load as compared to the demand response provider's expected level of electricity consumption.[168] The NOPR did not address measurement and verification of demand response.

87. Each RTO and ISO with a demand response program has procedures for the measurement and verification of demand response. These procedures include techniques to establish a customer baseline for each demand response participant. This customer baseline then becomes the basis for measuring the quantity of demand response delivered to the wholesale market. Customer baselines are often based on historic load information, such as an average of five of the last ten comparable days' hourly load profile. Techniques vary among RTOs and ISOs and most have several techniques that may be allowed, depending on the demand response provider's characteristics.[169]

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[168] Demand Response Compensation in Organized Wholesale Energy Markets, FERC Stats. & Regs. ¶ 32,656, at P 1 (2010).

[169] See, e.g., ISO/RTO Council, North American Wholesale Electricity Demand Response 2010 Comparison, under the tab for "Performance Evaluation Methods"

(continued…)

2. Comments

88. Commenters assert that the integrity of a demand response program is heavily dependent on measurement and verification.[170] Some commenters raise the issue that paying LMP in all hours presents a significant challenge to the accurate measurement and verification of demand response.[171] ISO-NE argues that when a market participant schedules demand reductions for many consecutive days, baselines may become stale—no longer reflecting a customer's "normal" electricity usage.[172] ISO-NE goes on to argue that "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" to avoid the potential for manipulation.[173] In the context of the Commission's proposal to pay demand response the LMP in all hours, ISO-NE goes on to advocate requiring

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(http://www.isorto.org/atf/cf/%7B5b4e85c6-7eac-40a0-8dc3-003829518ebd%7D/IRC%20DR%20M&V%20STANDARDS%20IMPLEMENTATION%20COMPARISON%20(20100524).XLS).

[170] Illinois CUB May 14, 2010 Comments at 16-17; Joint Consumers May 13, 2010 Comments at 12; P3 May 12, 2010 Comments at 38; Westar May 13, 2010 Comments at 3.

[171] See, e.g., ISO-NE May 13, 2010 Comments at 32.

[172] Id.

[173] ISO-NE May 13, 2010 Comments at 34. ISO-NE identifies several practices that, in its view, might be deployed by a demand responder to receive payment when it has not, in fact, responded to price. ISO-NE states that observations of such behavior in the Fall of 2007 led it to limit the hours demand response offers could clear the market. Citing ISO New England Inc., Docket No. ER08-538-000 (February 5, 2008 filing). ISO-NE May 13, 2010 Comments at 32-34.

demand response to establish baselines by purchasing energy in the day-ahead market as a way to overcome its concerns with statistical baseline methods.[174] ISO-NE IMM makes similar arguments and recommendations.[175] Westar also appears to support this approach.[176]

89. Similarly, CPower notes that with some baseline methods, paying LMP in all hours could reward demand responders for any shift in demand from the baseline, not just shifting load from high LMP hours to low LMP hours, or could simply shift load from day-to-day in different hours to affect the calculation of actual curtailment, which it labels "checkerboarding." However, CPower believes that the capability of consumption management to shed or shift load for many hours is well into the future, and perhaps not a current concern. CPower also believes that baseline standards along with market monitoring will develop to meet these concerns.[177]

90. ISO-NE IMM asserts that "[if] the Commission adopts any proposal that permits the use of an administrative baseline it should explicitly state that any demand reductions offered into Commission-jurisdictional markets that are not genuine, even if they are the

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[174] Id.

[175] ISO-NE IMM May 13, 2010 Comments at 9-13 and Attachment A.

[176] Westar May 13, 2010 Comments at 3.

[177] CPower May 13, 2010 Comments at 4-5.

result of 'normal' activity . . . may be violations of the Commission's anti-manipulation rules and subject to penalties thereunder."[178]

91. Noting the ongoing efforts by the industry and the North American Energy Standards Board (NAESB) on measurement and verification, EnerNOC takes the view that resolution of customer baseline issues should not delay the issuance of this Final Rule.[179]

92. Finally, some commenters assert that measurement and verification methods should not be standardized, but left to the RTOs and ISOs to reflect the unique features of their individual energy, ancillary services, and capacity markets.[180]

3. Commission Determination

93. The Commission agrees with commenters who assert that measurement and verification are critical to the integrity and success of demand response programs. Without a determination of a demand response provider's expected use of power, the ISOs and RTOs cannot determine whether that provider has in fact reduced its energy

[178] ISO-NE IMM May 13, 2010 Comments at 14 (footnotes omitted) (ISO-NE MMU also notes that "[i]n assessing whether demand reductions are genuine, allowance should be made for non-performance analogous to a generator's forced outage.").

[179] EnerNOC, Inc. May 13, 2010 Comments at 4.

[180] ECS May 13, 2010 Comments at 3; Indicated New York TOs May 13, 2010 Comments at 2-3; Midwest ISO May 13, 2010 Comments at 17, 21; National Grid May 13, 2010 Comments at 11-12; NSTAR May 14, 2010 Comments at 9; PPL May 13, 2010 Comments at 4.

usage when paid to do so. Towards that end, all the RTOs and ISOs already have measurement and verification protocols for their demand response programs.[181] In addition, we have adopted Phase I standards for measurement and verification published by the North American Energy Standards Board, [182] and have recognized the potential benefits of the continuing NAESB effort to craft Phase II standards with more substantive and consistent wholesale standards for measurement and verification.[183]

94. A number of commenters maintain that compensating demand response resources at the LMP during all hours could make determining baselines for demand response providers exceedingly difficult. However, the impact of our adopting the net benefits test described herein is that the LMP will not be paid to demand response resources in all hours. Accordingly, implementation of this Final Rule would not appear to prevent the determination of appropriate baselines. Nonetheless, we direct ISOs and RTOs to review their current requirements in light of the changes in this Final Rule and develop appropriate revisions and modifications, if necessary, to ensure that their baselines remain accurate and that they can verify that demand response resources have performed. Specifically, we direct each RTO and ISO to include as part of the compliance filing

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[181] See, e.g., PJM Interconnection, L.L.C., 123 FERC ¶ 61,257 (2008).

[182] Standards for Business Practices and Communication Protocols for Public Utilities, Final Rule, 131 FERC ¶ 61,022 (2010).

[183] Id., at P 32-34.

required herein, an explanation of how its measurement and verification protocols will continue to ensure that appropriate baselines are set, and that demand response will continue to be adequately measured and verified as necessary to ensure the performance of each demand response resource. If necessary, each RTO and ISO should propose any changes needed to ensure that measurement and verification of demand response will adequately capture the performance (or non-performance) of each participating demand response market participant to be consistent with the requirements of this Final Rule.

95. Finally, we agree with ISO-NE IMM that demand reductions that are not genuine may be violations of the Commission's anti-manipulation rules.[184] Allegations of such behavior will continue to be investigated, and when appropriate, sanctions will be brought to bear.

D. Cost Allocation

1. NOPR Proposal

96. In response to the NOPR and September 13, 2010 Technical Conference, many commenters argue that, in order to determine the justness and reasonableness of the proposed compensation level, the corresponding cost allocation must be considered.[185]

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[184] 18 CFR 1.c (2010).

[185] ISO-NE May 13, 2010 Comments at at 39-40; see also May 13, 2010 Comments of: AEP at 6-10; CAISO at 6; ConEd at 2; Hess at 3; ICC at 12; PJM at 8; Potomac Economics at 3; Massachusetts AG at 11; Midwest ISO TOs at 5-6; Midwest TDUs at 13; EEI at 5; NECPUC at 12, 22; NECA at 11; RRI at 6; SDG&G at 3-4.

More specifically, these commenters raise concerns regarding how the costs associated with payment of LMP for demand response will be allocated, or assigned, within an ISO or RTO. Several commenters assert that the issues of cost allocation and net benefits are inherently linked, so that the Commission must address both issues together.[186]

2. Comments

97. Comments reveal five specific methods for cost allocation: (1) assignment of costs to the load serving entity (LSE) associated with the demand response provider, (2) assignment of costs broadly to all purchasing customers, (3) bifurcated assignment of costs with some directly assigned to a LSE and others assigned broadly, (4) directly assign the cost for demand response compensation to the retail customers that bid the demand response into the wholesale market, and (5) the settlement method proposed by CDRI, which incorporates the cost of demand response into the dispatch algorithm. Some commenters argue not for a specific method, but for each regional entity to select and employ a method of its own,[187] and a few other commenters assert that the Commission need not address cost allocation in this proceeding.[188]

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[186] As further addressed below, several commenters assert that the costs of demand response compensation should be borne by only those market participants determined to have benefitted from the subject load reduction, as determined by some type of net benefits test. See, e.g., May 13, 2010 Comments of: ISO-NE at 5-6; NECPUC at 22; PJM at 12-14; P3 at 37-38.

[187] EPSA May 12, 2010 Comments at 67; Midwest TDUs May 13, 2010 Comments at 1; ODEC May 14, 2010 Comments at 5; Potomac Economics May 14, 2010 (continued…)

98. Some commenters argue that costs should be assigned to the LSE associated with the demand response provider because it is this entity that receives the full benefit of demand response.[189] Others argue that costs should be assigned broadly to all purchasing customers because of the concept of cost causation.[190] Cost causation dictates that the costs of demand response should be allocated directly to those entities that benefit from the demand response service provided.[191] Another method presented involves a bifurcated assignment of costs, with some directly assigned to a LSE and others assigned broadly.[192] The fourth method suggested is to directly assign the costs of demand

Comments at 9-10; RRI May 13, 2010 Comments at 4; SoCal Edison May 13, 2010 Comments at 4 (advocating that the local regulatory authority is the proper entity to regulate cost allocation); Viridity May 13, 2010 Comments at 24; EnerNOC Sept. 13, 2010 Comments at 1; Midwest TDUs Sept. 13, 2010 Comments at 2.

[188] Massachusetts AG May 13, 2010 Comments at 9-10.

[189] PJM May 13, 2010 Comments at 15; Midwest ISO May 13, 2010 Comments at 6; CAISO May 13, 2010 Comments at 6; Detroit Edison May 13, 2010 Comments at 3-4; EEI May 13, 2010 Comments at 5; NUSCO May 13, 2010 Comments at 2; National Grid Sept. 13, 2010 Comments at 2-3; Midwest ISO Oct. 13, 2010 Comments at 4.

[190] NECPUC May 13, 2010 Comments at 22; DC OPC May 13, 2010 Comments at 4; PCA Sept. 10, 2010 Comments at 4; Steel Manufactures Ass'n Sept. 13, 2010 Comments at 5; Ohio Commission Sept. 13, 2010 Comments at 4; Wal-Mart Sept. 14, 2010 Comments at 3.

[191] PJM May 13, 2010 Comments at 9; NECPUC May 13, 2010 Comments at 22; PCA Sept. 10, 2010 Comments at 4.

[192] PJM May 13, 2010 Comments at 12; ISO-NE May 13, 2010 Comments at 5.

response to the retail customer that bid the demand response into the wholesale market.[193] Lastly, the settlement algorithm proposed by CDRI adjusts upward the day-ahead price paid by the customers that participate in the day-ahead energy market to account for these costs.[194]

3. Commission Determination

99. When a demand response provider curtails, the RTO experiences a reduction in load with a corresponding reduction in billing units through which the RTO derives revenue. When the two conditions discussed above are met, however, the RTO must pay LMP to both generators and demand response providers for the resources that clear the energy market. The difference between the amount owed by the RTO to resources, including demand response providers, and the revenue it derives from load results in a negative balance that must be addressed through cost allocation. Therefore, a method is needed to ensure that RTOs and ISOs recover the costs of obtaining demand response.

100. Since the dispatch of demand response resources affects the LMP charged, and will result in a lower LMP, the customers benefitting from that lower LMP depends upon transmission constraints, and the price separation such constraints cause within the RTO.

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[193] DC OPC May 13, 2010 Comments at 4. It concedes that this could be a complex undertaking and would result in billing a retail customer for energy that did not consume. Id.

[194] CDRI, Integration of Demand Response Into Day Ahead Markets (Attachment B), May 13, 2010 Comments at 16.

In some hours in which transmission constraints do not exist, RTOs establish a single LMP for their entire system (a single pricing area) in which case the demand response would result in a benefit to all customers on the system. When transmission constraints are present, however, LMPs often vary by zone, or other geographic areas. Allocating the costs associated with demand response compensation proportionally to all entities that purchase from the relevant energy market in the area(s) where the demand response resource reduces the market price for energy at the time when the demand response resource is committed or dispatched will reasonably allocate the costs of demand response to those who benefit from the lower prices produced by dispatching demand response.[195]

101. We reject the various other methods of cost allocation suggested by commenters. Assignment of all costs to the LSE associated with the demand response provider, as suggested by some commenters, would not include others who benefit from the demand response. Bifurcated assignment of costs to the LSE and to others appears to represent an arbitrary division of cost responsibility without regard to the degree to which each receives benefits.

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[195] This approach is consistent with long-standing judicially-endorsed cost allocation principles. See, e.g., Midwest ISO Transmission Owners v. FERC, 373 F.3d 1361, 1368, 1370-71 (D.C. Cir. 2004); see also Illinois Commerce Comm'n v. FERC, 576 F.3d 470, 476 (7th Cir. 2009).

102. We therefore find just and reasonable the requirement that each RTO and ISO allocate the costs associated with demand response compensation proportionally to all entities that purchase from the relevant energy market in the area(s) where the demand response reduces the market price for energy at the time when the demand response resource is committed or dispatched. Accordingly, each RTO and ISO is required to make a compliance filing on or before July 21, 2011 that either demonstrates that its current cost allocation methodology appropriately allocates costs to those that benefit from the demand reduction or proposes revised tariff provisions that conform to this requirement.

E. Commission Jurisdiction

1. Comments

103. Some commenters, including several state commissions and LSEs, express concern about whether and how standardizing demand response compensation in the wholesale market will affect treatment of demand response at the retail level. They assert that the issue of demand response compensation is fundamentally intertwined with retail rates, ratepayer issues, and state jurisdictional concerns.[196] Some commenters note general concerns about the need for federal and state level coordination. They assert that

[196] See, e.g., CAISO May 13, 2010 Comments at 12; PJM May 13, 2010 Comments at 8 (appropriate and efficient demand response compensation may require coordination between the Commission, retail regulatory authorities, competitive retail suppliers, and other RTOs).

many states have taken significant steps to install advanced meters and implement programs to encourage efficient use of energy and that the success of state-level efforts should be a factor in deciding whether and how to implement demand response programs in the wholesale market.[197] According to these commenters, a Commission-mandated compensation level could have the unintended consequence of retarding the expansion of price-responsive demand at the retail level.[198]

104. Other commenters flatly question the Commission's jurisdiction to set the compensation for demand response in wholesale energy markets. They argue that it is within the purview of retail regulatory authorities to take into account local policies and concerns, and the types of demand response being offered, when determining the appropriate compensation level.[199] Indeed, the California Commission seeks clarification

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[197] See ISO-NE IMM May 13, 2010 Comments at 6.

[198] Illinois Commission May 13, 2010 Comments at 8; PJM May 13, 2010 Comments at 23; EEI May 13, 2010 Comments at 4; Capital Power May 13, 2010 Comments at 5; ODEC May 13, 2010 Comments at 60; Steel Producers May 13, 2010 Comments at 2.

[199] See Illinois Commission May 13, 2010 Comments at 13; CAISO May 13, 2010 Comments at 12-13; PJM IMM May 13, 2010 Comments at 5 ("The assertion that demand side participants should be paid full LMP, regardless of their retail tariff rate, because the current approach of paying LMP minus G represents an intervention into retail rate design, cannot be correct. The entire demand side program exists only because of the disconnect between wholesale and retail rates. The assertion that the program design should not account for the details of retail rate design leads to the conclusion that there should be no demand side program at all."); NECPUC May 13, 2010 Comments at 25 ("As energy market customers benefit most from both a well-functioning wholesale

(continued…)

that this Commission does not seek to regulate retail customer rates or seeks LSE oversight authority traditionally exercised by states. The California Commission asserts that this Commission's actions concerning CAISO's Proxy Demand Resource tariff filing[200] illustrates that demand response settlement mechanisms are within the authority of the California Commission.[201]

105. Other commenters foresee retail regulatory authorities effectively taking an end-run around any Commission-mandated compensation level by adjusting retail rate design

market and robust participation in retail programs, a balance between these two segments is essential. Compensation that increases demand response resource participation in the wholesale market should not be so generous, from the perspective of the customer, that it makes participation in retail programs pale in comparison."); SDG&E, SoCal Edison, and PG&E May 13, 2010 Comments at 4 ("[M]andating that ISOs take on settlement responsibility or precluding any retail settlement between retail customers, LSEs or DRPs would intrude on retail jurisdictional authority and contravenes the premise of separation outlined in Order 719."); Consumers Energy May 13, 2010 Comments at 3; Detroit Edison May 13, 2010 Comments at 4.

[200] See California Independent System Operator Corp., 132 FERC ¶ 61,045 (2010).

[201] California Commission May 13, 2010 Comments at 9-10. 1. See also SDG&E, SCE, PG&E May 13, 2010 Comments at 2 ("[T]he Commission should clarify that its order does not preclude LRAs from administering retail revenue settlements between retail customers, Load Serving Entities (LSEs) and Demand Response Providers (DRPs) associated with DR participation in wholesale markets.").

or prohibiting jurisdictional end-use customers from participating in wholesale market opportunities available to demand response resources.[202] The Illinois Commission argues:

> [W]hen load serving entities are vertically integrated with generation regulated under state authority . . . any non-zero payment to a demand response resource reduces the revenues to generators under the state regulatory authority. The result is a leakage of money to an entity outside of the state's regulatory authority. Therefore, retail rates to all customers may need to be increased in order to recover the costs to generators that would have otherwise been recovered through the purchase of electricity, but instead went to the payment of a demand response resource. Therefore, compensating demand response resources may increase the likelihood that state commissions will prohibit the participation of demand response resources in the jurisdictions.[203]

106. Similarly, PJM states that the prohibition devised by retail regulatory authorities with jurisdiction over smaller distributors that deliver 4 million MWh or fewer per annum

[202] See PJM May 13, 2010 Comments at 24; PJM May 13, 2010 Comments at 18 (It is reasonable to assume that each retail regulatory authority in PJM will re-examine the impact of load reduction based on wholesale compensation equal to the LMP, including cost allocation, on the LSEs subject to its jurisdiction, and potentially re-align retail market rules affecting economic load response participation.); Delaware Commission and NECPUC May 13, 2010 Comment at 25; OMS May 13, 2010 Comments at 7 (state commissions and LSEs have significant concerns that the potential costs for non-participating customers may exceed the benefits that ARCs can provide to their states and to participating customers, so state commissions will have a significant disincentive to support the participation of ARCs in RTO energy markets and in their states if LMP compensation is adopted).

[203] Illinois Commission May 13, 2010 Comments at 15.

may entail the revocation of previously provided permission to participate in some or all of the wholesale market opportunities for demand resources.[204]

107. Some commenters further posit that, even where retail regulatory authorities do not prohibit or limit demand response participation, they may make adjustments to the retail rate, which affect the ultimate compensation that the retail customer will be paid for its demand reductions.[205] For example, the OMS asserts,

> If the Commission were to adopt the proposed rule, state commissions and LSEs could correct this distorted price signal by revising retail tariffs for customers that do business with [aggregators of retail customers] in order to charge the retail rate to participating customers for energy which was not consumed or metered as a result of load reductions.[206]

108. Another set of commenters, especially generators, assert that due to the disconnect between wholesale and retail issues related to demand response, Commission-mandated payments for demand response will fail to address true barriers to demand response, which exist, they assert, at the retail level. These commenters argue that the Commission's actions in this proceeding ignore the fact that the primary barrier to demand response is the disconnect between retail and wholesale prices and, according to these commenters, the remedy resides at the retail -- not wholesale -- level where there is

[204] PJM May 13, 2010 Comments at 20-21.

[205] CAISO May 13, 2010 Comments at 4.

[206] OMS May 13, 2010 Comments at 3. See also EEI May 13, 2010 Comments at 4.

a lack of dynamic pricing.[207] For example, some commenters recognize that the lack of retail real-time pricing is a barrier to demand response participation but further assert that whatever changes the Commission makes to wholesale demand response (where there is real-time pricing) will not address that fundamental problem.[208]

109. On the other hand, some commenters, such as commercial customers, wholly reject challenges to the Commission's authority to set the compensation level for demand response occurring in organized wholesale energy markets.[209] They assert that the FPA gives the Commission broad authority to correct market flaws, including compensation for demand response.[210]

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[207] Calpine May 13, 2010 Comments at 3.

[208] See EPSA May 13, 2010 Comments at 7 ("The NOPR incorrectly attempts to resolve retail market barriers to DR participation (i.e., lack of dynamic pricing) through a wholesale pricing fix."); RRI Energy May 13, 2010 Comments at 5 ("The NOPR is essentially trying to use an inefficient wholesale solution to remedy a retail problem. The NOPR does not attempt to address (nor should it attempt to address) the various retail rate structures that demand response providers in various regions of the country face."); The Brattle Group May 13, 2010 Comments at 8 ("[T]he appropriate avoidable retail generation rate is best done through agreements between the LSE and the curtailment service provider under the oversight of the relevant retail regulating authority. This approach . . . avoids requiring the RTO to sort through potentially complicated retail rate structures."); Steel Manufacturers Ass'n May 13, 2010 Comments at 9 ("[T]here is no rational basis for the Commission, or RTOs, to adopting varying demand response participation or compensation rules based on the retail pricing method of otherwise qualified participating loads.").

[209] DR Supporters Aug. 30, 2010 Reply Comments at 4.

[210] Id.

110. Some commenters further argue that any disconnect between wholesale and retail issues relevant to demand response should not negate the Commission's efforts in this proceeding. They argue that dynamic retail pricing, retail shopping opportunities and the potential for retail energy efficiency measures are no substitute for adequate wholesale demand response compensation and the deployment of demand response measures akin to a generator.[211]

111. Moreover, some commenters assert that, while the Commission has authority to establish the compensation level for demand response in the wholesale market, the Commission cannot require subtraction of retail rate components from the LMP rate, reasoning that retail rates reflect a myriad of local concerns beyond the Commission's jurisdiction. These commenters assert that LMP reflects the wholesale value of the demand response service provided and that proponents of the LMP-G formulation (subtracting a portion of the retail rate) seek to draw the Commission into a review of retail rate matters beyond its purview.[212] Additionally, these commenters point to the difficulty of isolating the generation component of the retail rate from other components, such as transmission, distribution, and overhead. They argue that different retail rate contracts reflect different costs of generation, depending on local circumstances existing

[211] Wal-Mart May 13, 2010 Comments at 11.

[212] Viridity June 18, 2010 Comments at 13.

at the time the contract was executed, and that retail rate structures reflect a wide range of competing considerations, such as cost causation, the impact of rate design on employment, and the state of the local economy, all of which are appropriately left to state commissions. These commenters posit that, instead of tailoring the wholesale rate, i.e., LMP, to retail rate conditions, it is better to get the wholesale rate right in the first instance and then allow retail rate structures adjust as needed to wholesale market conditions.[213] According to Dr. Kahn, accounting for the retail rate in this Final Rule would "ignore the proper scope of the Commission's regulatory responsibilities, the fact that the great majority of retail rate designs are economically inefficient and that it is retail rates that should not be permitted to undermine efficient wholesale rates rather than the reverse."[214]

2. <u>Commission Determination</u>

112. We begin by rejecting challenges to the Commission's authority to set the compensation level for demand response in organized wholesale energy markets. Section 205 of the FPA tasks the Commission with ensuring that all rates and charges for or "in connection with" the transmission or sale for resale of electric energy in interstate commerce, and all rules and regulations "affecting or pertaining to" such rates or charges

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[213] Viridity June 18, 2010 Comments at 14.

[214] DR Supporters Aug. 30, 2010 Comments (Kahn Affidavit at 4).

are just and reasonable.[215] The Commission has previously explained that it has jurisdiction over demand response in organized wholesale energy markets, because it directly affects wholesale rates.[216]

113. For this reason, the Commission has jurisdiction to regulate the market rules under which an ISO or RTO accepts a demand response bid into a wholesale market.[217] Furthermore, as discussed above, the Commission's actions in this proceeding are consistent with Congressional policy requiring federal level facilitation of demand response, because this Final Rule is designed to remove barriers to demand response participation in the organized wholesale energy markets.

114. Nevertheless, we recognize that jurisdiction over demand response is a complex matter that lies at the confluence of state and federal jurisdiction. By issuing this Final Rule, the Commission is not requiring actions that would violate state laws or regulations. The Commission also is not regulating retail rates or usurping or impeding state regulatory efforts concerning demand response.

115. We acknowledge that many barriers to demand response participation exist and that our ability to address such barriers is limited to the confines of our statutory authority. At the same time, the FPA requires the Commission to ensure that the rates

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[215] 16 U.S.C. 824d (2006).

[216] Order No. 719-A, FERC Stats. & Regs. ¶ 31,292 at P 47.

[217] Order No. 719-A, FERC Stats. & Regs. ¶ 31,292 at P 52.

charged for energy in wholesale energy markets are just, reasonable, and not unduly discriminatory or preferential. The Commission has the authority, indeed the responsibility, to assure that wholesale rates are just and reasonable. Therefore, we disagree with commenters who would have the Commission refrain from acting on demand response compensation in the organized wholesale energy markets because of the potential actions that state retail regulatory authorities may or may not take. As we note above, this Final Rule is not intended to usurp state authority or impede states from taking any actions within their authority. Rather, the Commission is taking action here to fulfill its statutory mandate to ensure just, reasonable, and not unduly discriminatory or preferential wholesale rates.

V. Information Collection Statement

116. The Office of Management and Budget (OMB) requires that OMB approve certain information collection and data retention requirements imposed by agency rules.[218] Therefore, the Commission is submitting the proposed modifications to its information collections to OMB for review and approval in accordance with section 3507(d) of the Paperwork Reduction Act of 1995.[219]

117. OMB's regulations require approval of certain information collection requirements imposed by agency rules. Upon approval of a collection(s) of information,

[218] 5 CFR § 1320.11(b) (2010).

[219] 44 U.S.C. § 3507(d) (2006).

OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of a rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

118. The Commission is submitting these reporting requirements to OMB for its review and approval under section 3507(d) of the Paperwork Reduction Act. Comments are solicited on the Commission's need for this information, whether the information will have practical utility, the accuracy of provided burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected, and any suggested methods for minimizing the respondent's burden, including the use of automated information techniques.

Burden Estimate and Information Collection Costs: The estimated Public Reporting burden and cost for the requirements contained in the final rule follow.

FERC-516 Data Collection	**Number of Respondents (a)**	**No. of Responses Per Respondent Per Year (b)**	**Hours Per Response (c)**	**Total Annual Hours (d) [a*b*c]**
Compliance filing, including tariff provisions and analysis (one-time filing, due 7/22/2011)	6 (RTOs and ISOs)	1 (one-time filing)	300	1,800 (one-time filing)
Study on	6 (RTOs and	1(one-time	2,000	12,000 (one-

dynamic net benefits approach (one-time filing, due 9/21/2012)	ISOs)	filing)		time filing)
Monthly update to price threshold and web posting (due monthly, starting after the compliance filing due 7/22/2011)	6 (RTOs and ISOs)	12	50	3,600

In Year 1, the following requirements are imposed[220]: (1) compliance filing due on or before July 22, 2011, and (2) monthly updates (for months 5-12, and starting after the compliance filing). The total corresponding burden hours are estimated to be: 1,800 hrs. + (8 filings * 6 respondents * 50 hrs./filing), for a total of 4,200 hours. The corresponding total cost is estimated to be: 4,200 hours * $220/hour, for a total of $924,000.

In Year 2, (a) the monthly update to the price threshold, and (b) the study on dynamic net benefits approach (due on or before September 21, 2012) are imposed. The corresponding total burden is estimated to be 3,600 + 12,000 hours, for a total of 15,600

[220] The one-time study is due on or before September 21, 2012. For the purpose of the burden and cost estimates, we are including all of the burden and cost related to the study in Year 2, although filers may perform part of the work in Year 1.

hours. The corresponding total cost estimate is: 15,600 hours * $220/hour, for a total of $3,432,000.

In Year 3, the monthly update to the price threshold is imposed. The corresponding total burden and cost are estimated to be 3,600 hours and $792,000 (3,600 hours * $220/hour).

Title: FERC-516, "Electric Rate Schedules and Tariff Filings"

Action: Proposed Collections.

OMB Control No: 1902-0096.

Respondents: Business or other for profit, and/or not for profit institutions.

Frequency of Responses: One-time filings for (a) the compliance filing, due on or before July 22, 2011, and (b) the study on dynamic net benefits approach, due on or before September 21, 2012. In addition, monthly updates to the price threshold and web posting will be required starting after the compliance filing.

Necessity of the Information: The information from FERC-516 enables the Commission to exercise its statutory obligation under sections 205 and 206 of the FPA. FPA section 205 specifies that all rates and charges, and related contracts and service conditions for wholesale sales and transmission of energy in interstate commerce be filed with the Commission and must be "just and reasonable." In addition, FPA section 206 requires the Commission, upon complaint or its own motion, to modify existing rates or services that are found to be unjust, unreasonable, unduly discriminatory or preferential.

119. In Order No. 719, the Commission emphasized the importance of demand response as a vehicle for improving the competitiveness of organized wholesale electricity markets and ensuring supplies of energy at just, reasonable and not unduly discriminatory or preferential rates. This Final Rule addresses the need for organized wholesale energy markets to provide compensation to demand response resources on a comparable basis to supply-side resources when demand response resources are comparable to supply-side resources, so that both supply and demand can meaningfully participate. This final rule establishes a specific compensation approach for demand response resources participating in organized wholesale energy markets, administered by RTOs and ISOs. Each Commission-approved RTO and ISO that has a tariff provision providing for participation of demand response resources in its organized wholesale energy market must: (a) pay demand response resources the market price (full LMP) for energy (when found to be cost-effective as determined by the net benefits test described herein), (b) submit a one-time compliance filing, (c) perform monthly updates to the Price Threshold, and (d) submit a one-time Study on Dynamic Net Benefits Approach.

120. Interested persons may obtain information on the reporting requirements by contacting: Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 [Attention: Ellen Brown, Information Clearance Officer, Office of the Executive Director, e-mail: DataClearance@ferc.gov, phone: (202) 502-8663, fax: (202) 273-0873]. Comments on the requirements of the final rule may also be sent to the

Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission]. For security reasons, comments to OMB should be submitted by e-mail to: oira_submission@omb.eop.gov. Comments submitted to OMB should include Docket Number RM10-17 and OMB Control Number 1902-0096.

VI. Environmental Analysis

121. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[221] The Commission concludes that neither an Environmental Assessment nor an Environmental Impact Statement is required for this Final Rule under section 380.4(a)(15) of the Commission's regulations, which provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to the filing of schedules containing all rates and charges for the transmission or sale subject to the Commission's jurisdiction, plus the classification, practices, contracts, and regulations that affect rates, charges, classifications, and services.[222]

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[221] Regulations Implementing the National Environmental Policy Act, Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs., Regulations Preambles 1986-1990 ¶ 30,783 (1987).

[222] 18 CFR § 380.4(a)(15) (2010).

VII. Regulatory Flexibility Act

122. The Regulatory Flexibility Act of 1980 (RFA)[223] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. The RFA mandates consideration of regulatory alternatives that accomplish the stated objectives of a rule and that minimize any significant economic impact on a substantial number of small entities. The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[224] The SBA has established a size standard for electric utilities, stating that a firm is small if, including its affiliates, it is primarily engaged in the transmission, generation and/or distribution of electric energy for sale and its total electric output for the preceding twelve months did not exceed four million megawatt hours.[225] ISOs and RTOs, not small entities, are impacted directly by this rule.

123. California Independent System Operator Corp. (CAISO) is a non-profit organization with over 54,000 megawatts of capacity and over 25,000 circuit miles of power lines.

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[223] 5 U.S.C. § 601-612 (2006).

[224] 13 CFR § 121.101 (2010).

[225] 13 CFR § 121.201, Sector 22, Utilities.

124. New York Independent System Operator, Inc. (NYISO) is a non-profit organization that oversees wholesale electricity markets, dispatches over 500 generators, and manages a nearly 11,000-mile network of high-voltage lines.

125. PJM Interconnection, L.L.C. (PJM) is comprised of more than 600 members including power generators, transmission owners, electricity distributors, power marketers, and large industrial customers, serving 13 states and the District of Columbia.

126. Southwest Power Pool, Inc. (SPP) is comprised of 61 members serving over 6.2 million households in nine states and has almost 50,000 miles of transmission lines.

127. Midwest Independent Transmission System Operator, Inc. (Midwest ISO) is a non-profit organization with over 145,000 megawatts of installed generation. Midwest ISO has over 57,000 miles of transmission lines and serves 13 states and one Canadian province.

128. ISO New England, Inc. (ISO-NE) is a regional transmission organization serving six states in New England. The system is comprised of more than 8,000 miles of high-voltage transmission lines and over 350 generators.

129. The Commission believes this rule will not have a significant economic impact on a substantial number of small entities, and therefore no regulatory flexibility analysis is required.

VIII. Document Availability

130. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington DC 20426.

131. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

132. User assistance is available for eLibrary and the Commission's website during normal business hours from FERC Online Support at 202-502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

IX. Effective Date and Congressional Notification

133. This Final Rule will become effective on [INSERT DATE 30 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]. The Commission has

determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs, Office of Management and Budget, that this rule is not a "major rule" as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

By the Commission. Commissioner Moeller dissenting with a separate statement attached.

(S E A L)

Kimberly D. Bose,
Secretary.

In consideration of the foregoing, the Commission proposes to amend Part 35, Chapter I, Title 18, Code of Federal Regulations, as follows.

PART 35—FILING OF RATE SCHEDULES AND TARIFFS

1. The authority citation for Part 35 continues to read as follows:

Authority: 16 U.S.C. 791a-825r, 2601-2645; 31 U.S.C. 9701; 42 U.S.C. 7101-7352.

2. Amend § 35.28 as follows:

Add a new paragraph (g)(1)(v).

§ 35.28 Non-discriminatory open access transmission tariff.

* * * * *

(v) Demand response compensation in energy markets. Each Commission-approved independent system operator or regional transmission organization that has a tariff provision permitting demand response resources to participate as a resource in the energy market by reducing consumption of electric energy from their expected levels in response to price signals must:

(A) pay to those demand response resources the market price for energy for these reductions when these demand response resources have the capability to balance supply and demand and when payment of the market price for energy to these resources is cost-effective as determined by a net benefits test accepted by the Commission;

(B) allocate the costs associated with demand response compensation proportionally to all entities that purchase from the relevant energy market in the area(s) where the demand response reduces the market price for energy at the time when the demand response resource is committed or dispatched.

Note: The following appendix will not be published in the Code of Federal Regulations.

APPENDIX

List of Commenters

Alcan Primary Products Corp. (Alcan)
Alcoa Inc. (Alcoa)
Alliance for Clean Energy New York, Inc. (ACENY)
Alliance to Save Energy (Alliance)
American Chemistry Council (ACC)
American Clean Skies Foundation
American Council for an Energy-Efficient Economy (ACEEE)
American Electric Power Service Corporation (AEP)
American Forest & Paper Association (AFPA)
American Municipal Power, Inc. (AMP)
American Public Power Association (APPA)
American Wind Energy Association (AWEA)
ArcelorMittal USA Inc. (ArcelorMittal)
Battelle Pacific Northwest Laboratories (Battelle)
Boston College Law School Administrative Law Class (BC Law)
California Department of Water Resources State Water Project (CDWR)
California Independent System Operator Corporation (CAISO)
California Public Utilities Commission (California Commission)
Calpine Corp. (Calpine)
Capital Power Corporation (Capital Power)
Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California (Six Cities)
Citizens for Pennsylvania's Future (PennFuture)
Coalition of Midwest Transmission Customers (CMTC)
Connecticut Municipal Electric Energy Cooperative (CMEEC)
Consert Inc. (Consert)
Conservation Law Foundation (CLF)
Consolidated Edison Solutions, Inc. (ConEd)
Constellation Energy Commodities Group, Inc. (Constellation)
Consumer Demand Response Initiative (CDRI)
Consumer Power Advocates (CPA)
Consumers Energy Company (Consumers Energy)
CPG Advisors, Inc. (CPG)
CPower, Inc. (CPower)
Crane & Co., Inc. (Crane)
Delaware Public Service Commission (Delaware Commission)

Demand Response and Smart Grid Coalition (Smart Grid Coalition)
Demand Response Supporters (DR Supporters)
Derstine's Inc. (Derstine's)
Detroit Edison Company (Detroit Edison)
Direct Energy Services, LLC (Direct Energy)
Dominion Resources Services, Inc. (Dominion)
Dr. Alfred E. Kahn (Dr. Kahn)
Dr. Charles J. Cicchetti (Dr. Cicchetti)
Dr. Roy J. Shanker (Dr. Shanker)
Dr. William W. Hogan (Dr. Hogan)
Duke Energy Corporation (Duke Energy)
Durgin and Crowell Lumber Co., Inc. (Durgin)
Edison Electric Institute (EEI)
Edison Mission Energy (Edison Mission)
Electric Power Supply Association (EPSA)
Electricity Committee
Electricity Consumers Resource Council (ELCON)
Electrodynamics, Inc. (Electrodynamics)
Energy Curtailment Specialists, Inc. (ECS)
EnergyConnect (EnergyConnect)
Energy Future Coalition (EFC)
EnerNOC, Inc. (EnerNOC)
Environmental Defense Fund (EDF)
Exelon Corporation (Exelon)
Federal Trade Commission (FTC)
FirstEnergy Service Company (FirstEnergy)
GDF SUEZ Energy North America, Inc. (GDF)
Hess Corporation (Hess)
Illinois Citizens Utility Board (Illinois CUB)
Illinois Commerce Commission (ICC)
Independent Power Producers of New York, Inc. (IPPNY)
Indicated New York Transmission Owners (Indicated New York TOs)
Industrial Energy Consumers of America (IECA)
Industrial Energy Consumers of Pennsylvania (IECPA)
Intergrys Energy Services, Inc. (Intergrys)
International Power America, Inc. (IPA)
Irving Forest Products, Inc. (Irving Forest)
ISO New England Inc. (ISO-NE)
ISO-NE Internal Market Monitor (ISO-NE IMM)
Jiminy Peak Mountain Resort, LLC

Joint Consumer Advocates (Joint Consumers)
Limington Lumber (Limington)
Madison Paper Industries (Madison Paper)
Maryland Governor Martin O'Malley (Governor O'Malley)
Maryland Public Service Commission (Maryland Commission)
Massachusetts Attorney General (Massachusetts AG)
Midwest Independent Transmission System Operator, Inc. (Midwest ISO)
Midwest ISO Transmission Owners (Midwest ISO TOs)
Midwest TDUs
Mirant Corporation (Mirant)
Monitoring Analytics, LLC (PJM IMM)
National Electrical Manufactures Association (NEMA)
National Energy Marketers Association (NEM)
National Grid USA (National Grid)
National League of Cities (NLC)
Natural Gas Supply Association (NGSA)
New England Conference of Public Utilities Commissioners (NECPUC)
New England Consumer Advocates (NECA)
New England Power Generators Association Inc. (NEPGA)
New England Power Pool Participants Committee (NEPOOL)
New England Public Systems (NE Public Systems)
New Jersey Board of Public Utilities (NJBPU)
New York Independent System Operator, Inc. (NYISO)
New York Mayor Michael R. Bloomberg (Mayor Bloomberg)
New York State Consumer Protection Board (NYSCPB)
New York State Public Service Commission (New York Commission)
North America Power Partners LLC (NAPP)
Northeast Utilities Services Company (NUSCO)
Northern California Power Agency (NCPA)
NSTAR Electric Company (NSTAR)
Occidental Chemical Corp. (Occidental)
Office of the People's Counsel for the District of Columbia (DC OPC)
Okemo Mountain Resort (Okemo)
Old Dominion Electric Cooperative (ODEC)
Organization of Midwest ISO States (OMS)
Partners HealthCare (Partners)
Pennsylvania Department of Environmental Protection (PA Department of Environment)
Pennsylvania Office of Consumer Advocate (PCA)
Pennsylvania Public Utility Commission (Pennsylvania Commission)
Pennsylvania State Representative Chris Ross (Rep. Ross)

Pepco Holdings, Inc. (PHI)
PJM Interconnection, L.L.C. (PJM)
PJM Power Providers Group (P3)
Potomac Economics, Ltd. (Potomac Economics)
PPL Parties (PPL)
Praxair, Inc. (Praxair)
Precision Lumber, Inc. (Precision)
Price Responsive Load Coalition (PRLC)
PSEG Companies (PSEG)
Public Interest Organizations (PIO)
Public Utilities Commission of Ohio (Ohio Commission)
Raritan Valley Community College (Raritan)
Robert J. Borlick (Mr. Borlick)
RRI Energy, Inc. (RRI)
San Diego Gas & Electric Company (SDG&E)
Schneider Electric USA, Inc. (Schneider)
Southern California Edison Company (SoCal Edison)
Southwest Power Pool, Inc. (SPP)
Steel Manufacturers Association (Steel Manufacturers Ass'n)
Steel Producers (SP)
Tendrill Networks, Inc. (Tendrill)
The Brattle Group
The E Cubed Company, L.L.C. (E3)
University of California, San Diego (UCSD)
Utility Economic Engineers (UEE)
Verso Paper Corp. (Verso)
Virginia Committee for Fair Utility Rates (Virginia Committee)
Viridity Energy, Inc. (Viridity)
Wal-Mart Stores, Inc. (Wal-Mart)
Waterville Valley Ski Resort Inc. (Waterville)
Westar Energy, Inc. (Westar)
Wisconsin Industrial Energy Group (WIEG)

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

(Issued March 15, 2011)

MOELLER, Commissioner, *dissenting*:

While the merits of various methods for compensating demand response were discussed at length in the course of this rulemaking, nowhere did I review any comment or hear any testimony that questioned the benefit of having demand response resources participate in the organized wholesale energy markets. On this point, there is no debate. The fact is that demand response plays a very important role in these markets by providing significant economic, reliability, and other market-related benefits.

However, in a misguided attempt to encourage greater demand response participation in the organized energy markets, today's Rule imposes a standardized and preferential compensation scheme that conflicts both with the Commission's efforts to promote competitive markets and with its statutory mandate to ensure supplies of electric energy at just, reasonable, and not unduly discriminatory or preferential rates.[1] For these reasons, I cannot support this Rule.

Standardizing Demand Response Compensation

As an initial matter, RTOs and ISOs currently offer different types of demand response products that vary from region to region and in terms of capability and services offered in the day-ahead and real-time energy markets. Moreover, the RTOs and ISOs to date have been working with their market participants in a stakeholder process to design demand response compensation rules that are tailored to suit the needs of their individual energy markets. However, this will all change once the Rule takes effect and this existing framework is replaced with the requirement that every organized wholesale energy market pay demand resources the market price for energy (LMP) when its demand reductions are, in theory, found to be cost-effective.

[1] 16 U.S.C. § 824d (2006).

As I recognized in my initial statement in this proceeding, organized markets such as the PJM Interconnection have already demonstrated the ability to develop demand response compensation rules. Accordingly, I would have preferred to allow these markets to continue to develop their own rules. Different demand response products will have different values that reflect their varying capabilities and to require a standard payment fails to reflect these meaningful differences.[2]

However, without ever determining that the existing region-by-region approach to compensation is unjust and unreasonable, the Rule implies that the current approach is no longer adequate to ensure that rates remain just and reasonable. In turn, the Rule finds that "greater uniformity in compensating demand response resources" is required and as justification for its action, references the existence of various barriers that limit the participation of demand response in the energy markets.[3] The majority ultimately concludes that these barriers can be removed by better equipping demand response providers with the financial resources to invest in enabling technologies.[4] This is to say that the majority believes that paying demand resources more money will help overcome these barriers and encourage more participation. The Rule, however, never clearly explains how the existence of barriers, in turn, justifies a payment of full LMP to demand resources.

The Rule (like the NOPR) does not sufficiently discuss the need for standardizing compensation across the organized markets or elaborate on how standardization will remove genuine barriers that prevent meaningful participation by demand resources in the energy markets.[5] While the Energy Policy Act of 2005 states that the policy of the

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[2] California Commission May 13, 2010 Comments at 6, "[P]romulgating a uniform national rule at this time may inadvertently impede the implementation of optimal demand response compensation for an individual ISO or RTO which address the needs of that particular region." The California Commission "is concerned that mandatory 'one size fits all' pricing may stifle national and regional efforts to collect valuable data and experience regarding the effects of different demand response program designs on consumer participation and conflict with Congressional objectives."

[3] Rule at P 17, 57-59.

[4] Rule at P 57-59.

[5] Significant barriers do exist which prevent demand response from reaching its full potential. Specifically, 24 barriers were identified in our National Assessment of Demand Response Potential, FERC Staff Report, (June 2009) at 65-67.

U.S. Government is to remove unnecessary barriers to demand response, the statute never authorized the Commission to stimulate increased demand response participation by requiring its compensation to include incentives or preferential treatment.[6] Although, the majority is quick to claim "that removing barriers to demand response participation is not the same as giving preferential treatment to demand response providers…", this is exactly what is occurring in this Rule.[7] As discussed below, the majority's determination is troubling as the Rule both affords preferential treatment to demand response resources and unduly discriminates against them in other respects.

Demand Response Resources are Comparable . . . Sometimes

At the outset, the concept of "comparability" is at the core of this rulemaking, *i.e.*, whether demand response resources are capable of providing a service comparable to generation resources and if so, whether these resources should receive comparable compensation for a comparable service. On this point, I believe they should.[8] This is not to say that a megawatt produced is the same as a megawatt not consumed; they are not perfect equivalents. The characteristics of a megawatt and a "negawatt" are different, both in terms of physics and in economic impact.

Assuming, however, that a demand resource can provide a balancing service that is identical to that of a generation resource, it would make sense that a demand resource providing a comparable service would receive comparable compensation. But this may not occur under the Rule. The majority explains that if a demand resource is capable of providing a service comparable to a generation resource, it will only be eligible to receive comparable compensation, by definition, if it can also be determined that the resource will result in a price-lowering effect to the market by passing a net benefits test.[9]

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[6] See Energy Policy Act of 2005, Pub. L. No. 109-58, § 1252(f), 119 Stat. 594, 965 (2005).

[7] Rule at P 59.

[8] As explained below, I believe that comparable compensation is represented by the value realized by the demand resource for providing a comparable service, regardless of whether the source of that value is a payment from the market or a savings by the resource.

[9] Rule at P 47-50.

In no other circumstance is a resource required to show that its participation will depress the market price in order to receive comparable compensation for a comparable service.[10] Such a definition unduly discriminates against demand resources and as such, this requirement is unjust, unreasonable, and unduly discriminatory.

Overcompensating Demand Resources and the Net Benefits Test

At first glance, the Rule's requirement that RTOs and ISOs pay demand response resources the LMP only when it is deemed cost-effective appears to make sense. There is near-universal agreement that the LMP reflects the value of the marginal unit, and as such, it sends the proper price signal to keep supply and demand in relative balance. Accordingly, the Rule explains that if the demand resource is capable of providing a comparable service and is also cost-effective (*i.e.*, using a net benefits test to ensure that the overall benefit of the reduced LMP that results from dispatching demand recourses exceeds the cost of dispatching those resources), then this resource should be paid the same as a generation resource. However, the decision to pay demand resources the full LMP under such circumstances actually results in overcompensation that is economically inefficient, preferential to demand resources, and unduly discriminatory towards other market resources.

An example may help to illustrate a major flaw with this Rule. Assume that both a generation resource and a demand resource bid into the energy market and both bids are accepted and paid the LMP ($100). Then consider the fact that the demand resource will save an amount that it would have otherwise paid by not purchasing generation at the retail rate ("G"), which is $25. While the Rule requires that RTOs and ISOs pay the demand resource the LMP (which is the identical amount the generation resource receives), the Rule effectively ignores the fact that the demand resource will actually receive a total compensation of LMP+G ($125) as a result of its decision not to consume.[11] Meanwhile, the generation resource will only receive the LMP ($100)

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[10] Testimony of Audrey Zibelman, President and CEO of Viridity Energy, Inc., Sept. 13, 2010 Tr. at 119, "[T]he fact that we're debating this [net benefits test] is somewhat absurd. We have not required any other resource to demonstrate a benefit in order to enter this market."

[11] The proper economic measure of value realized by the demand resource is one where the RTO or ISO makes a reduction from the LMP to account for the retail rate, but then recognizes that the savings associated with the avoided retail generation cost should be added back into the equation, *i.e.*, (LMP-G)+G.

payment as a result of its decision to produce. While the Rule's intent is to ensure that a demand resource receives "the same compensation, the LMP, as a generation resource", this is not the actual result.[12] In this example, what will happen is that the Rule will require that the demand response resource be overcompensated by $25.[13]

The Rule effectively finds that demand resources being compensated at the *value* of full LMP is not enough, so instead requires that demand resource be *paid* the full LMP plus be allowed to retain the savings associated with its avoided retail generation cost. Professor William W. Hogan refers to this outcome as a "double-payment" because demand resources would "receive" both the cost savings from not consuming electricity at a particular price, plus an LMP payment for not consuming that same increment of electricity.[14] Not only is this result not comparable (by valuing a negawatt more than a megawatt) and economically inefficient (by distorting the price signal), but this preferential compensation will harm the efficiency of the competitive wholesale energy markets.

The use of a net benefits test further reduces competitive efficiency and only complicates the issue. As the Rule explains, the net benefits test involves the determination of a threshold price point that is plotted along a historical supply curve in an attempt to accurately calculate whether the cost of procuring additional demand response is outweighed by the value it brings to the market in the form of a lower LMP.[15]

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[12] Rule at P 82. If it were the result, the generation resource would be paid the LMP, $100, and the demand resource would be paid $75 and realize an additional $25 in retail rate savings. Accordingly, both resources realize equivalent compensation valued at $100.

[13] Ohio Commission May 13, 2010 Comments at 6, "[T]he Commission's proposal that RTOs pay demand response resources the full LMP takes the incentives for wholesale demand response resources a step too far. It would provide an incentive to the supplier of a demand response resource that exceeds the payments available to an equivalent supply resource. The Commission should instead focus on removing the existing barriers in the wholesale markets…."

[14] See Attachment to Answer of EPSA, Providing Incentives for Efficient Demand Response, Dr. William W. Hogan, October 29, 2009 (Docket No. EL09-68).

[15] Testimony of Robert Weishaar, Jr., Attorney for Demand Response Supporters, Sept. 13, 2010 Tr. at 46-47, "Administratively constructing an LMP-based break point for compensating Demand Response participation would ignore many other qualitative and

(continued…)

However, this test, which attempts to justify the LMP payment by promising a “win-win” outcome, is nothing more than a fig leaf that provides little protection against the long-term potential for unintended market damage. As recognized by ISO-NE, generation is not dispatched and paid for only when such generation reduces LMP, instead generation is dispatched and paid for only when it is cost-effective.[16] Likewise, logic would require that demand resources be treated similar to generation resources and be similarly cost-effective.

During a technical conference convened to discuss the specific question on the necessity of a net benefits test, the Commission heard testimony from a panel of experts. A clear majority of the witnesses (representing a spectrum of interests that included demand response advocates, economists, generators, and the RTOs and ISOs) argued against the use of a complicated and admittedly imprecise[17] net benefits test.[18] Chief among their concerns was that a net benefits test is unnecessary since the market clearing function in a wholesale market, by definition, serves to guarantee that the resource that clears the market is the lowest-cost resource.[19] Other experts commented that the net benefits test would be complicated, costly to implement, and of little value.[20] Notably, Dr. Alfred E. Kahn, the majority’s oft-quoted expert in defense of the full LMP payment, did not opine on the merit of subjecting the LMP payment to a net benefits test.

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quantitative benefits of Demand Response. Focusing only on the LMP impacts of Demand Response is problematic."

[16] ISO-NE May 13, 2010 Comments at 3-4.

[17] Rule at P 80. Recognizing that “the threshold price approach we adopt here may result in instances both when demand response is not paid the LMP but would be cost-effective and when demand response is paid the LMP but is not cost-effective.”

[18] Testimony of Donald Sipe, Attorney for Consumer Demand Response Initiative, Sept. 13, 2010 Tr. at 43, "[T]here is probably not a need for a Net Benefits Test. But if one is adopted, it should not be an artificial threshold that can be wrong both ways. It should not be a mechanism that treats DR differently than generation.”

[19] Viridity Energy, Inc., Oct. 13, 2010 Comments at 10. See also ELCON Oct. 13, 2010 Comments at 3; and Environmental Defense Fund Comments at 2.

[20] Testimony of Andy Ott, Sr. Vice President, PJM Interconnection, Sept. 13, 2010 Tr. at 19, "[Y]ou have to use caution to actually take a benefits test and apply that to compensation, because you may have unintended consequences."

Further, as explained by Dr. Roy J. Shanker, if the Commission adopted the payment of LMP minus the retail rate ("G"), then there is no need for a net benefits test since the customer is paid the difference between the LMP and what they would have paid under their retail rate, which is their net benefit. [21] He testified that the "Net Benefits criteria is troubling in and of itself, as it explicitly incorporates consideration of portfolio effects caused by the reduced demand on all load payments, versus the economic decision-making of individual market participants pursuing their own legitimate business purpose."[22]

I similarly agree that this test is unnecessary and will only distort price signals by attracting more demand response than is economically efficient.[23] The use of a net benefits test also is troubling in that the Commission's decision can be viewed as somehow equating the concept of a just and reasonable rate with a lower price.[24] However, I recognize that to defend its compensation scheme, the majority needed some proposal that could arguably demonstrate that the cost of paying full LMP to demand resources would be outweighed by the "benefit" of a lower market price.[25] The net benefits test serves this unenviable role.

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[21] Testimony of Roy J. Shanker, Ph.D, PJM Power Providers Group, Sept. 13, 2010 Tr. at 60, "If the Commission adopts the appropriate non-discriminatory pricing for Demand Response, and payment of LMP minus the retail rate in the context of customer that face a fixed retail rate, then there is no need for a Net Benefits test."

[22] Id., Tr. at 61.

[23] EPSA May 13, 2010 Comments at 23. See also May 13, 2010 Comments of APPA at 13; FTC at 9; Midwest TDUs at 14; Mirant at 2; New York Commission at 5; PJM at 6; PSEG at 5; and Potomac Economics at 6-8.

[24] Courts have stated that to be "just and reasonable," rates must fall within a "zone of reasonableness" where they are neither "less than compensatory" to producers nor "excessive" to consumers. Farmers Union Central Exchange v. FERC, 734 F.2d 1486 (D.C. Cir. 1984), cert denied, 469 U.S. 1034 (1984). See also EPSA May 13, 2010 Comments at 19; and ISO-NE at 26-28.

[25] Testimony of Ohio Commissioner Paul Centolella, Sept. 13, 2010 Tr. at 141, "The Net Benefits test reflects a recognition that paying full LMP may over-compensate Demand Response and increase cost to customers."

Relationship to State Retail Regulation

The Rule recognizes that the demand resource will retain the retail rate ("G") as part of the provider's total compensation, but declines to account for this savings citing "practical difficulties" for state commissions, RTOs and ISOs.[26] While the authority over retail rates is properly within the jurisdiction of the state commissions, under the LMP-G equation, the RTO/ISO merely subtracts the retail rate; it does not interfere with the retail rate in any way.[27] Although the Rule refers to the New York Commission's position that subtracting the retail rate would be an "administrative burden" or create "undue confusion"[28], other state commissions disagree and contend that the retail rate can be deducted without any concern about impacting the states' retail jurisdiction.[29]

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[26] Rule at P 63. The RTOs and ISOs uniformly state that compensation which ignores the retail rate will yield uneconomic outcomes and overcompensate the demand resource. Moreover, none of the RTOs or ISOs claimed it would be difficult to subtract the retail rate from the LMP payment. See May 13, 2010 Comments of CAISO at 5-6; ISO-NE at 17-26; Midwest ISO at 6-11; NYISO at 12-16; and PJM at 5-16.

[27] Testimony of Joel Newton, New England Power Generators Ass'n, Sept. 13, 2010 Tr. at 75; "The Commission is getting into a real close area with retail ratemaking as we go through this entire process. For the Commission then to say 'ignore the LSE payment' which is the realm of state commissions, it's almost as you're just hoping that the state commissions will go out and fix it. The state commissions can do that…[b]ut the proper thing to do now is to get the price right at the outset." See also Testimony of Ohio Commissioner Paul Centolella, Sept. 13, 2010 Tr. at 197; "[FERC is] putting the state in the position where if we were to try to get back to an efficient level of incentives, we would be having to in effect issue a charge for energy that was not consumed. We would be doing what would be perceived as a take-back by that customer. And that would put us in a very difficult position."

[28] Rule at P 28. Significantly, the New York Commission "acknowledges the overstated price signal inherent in an LMP-based formula for DR compensation…." "Although we understand that *an LMP demand response compensation formula may result in uneconomic demand response decisions in the markets (i.e., a price signal that exceeds marginal cost)*, it also creates an incentive to participate in DR programs…." New York Commission May 13, 2010 Comments at 5-6 (emphasis added).

[29] Illinois Commission May 13, 2010 Comments at 13, "[I]f tariffs are well designed, controversy over the jurisdictional issue can be avoided. Requiring an ex ante approval of the retail rate to be subtracted from the LMP at the time demand response resources are utilized …accomplishes this design." See also Indiana Commission

(continued…)

Moreover, the Rule does not conclude that LMP-G would interfere with the retail jurisdiction of the states, but goes as far as to acknowledge the subtraction of G is "perhaps feasible."[30] The fact is that this calculation is quite feasible. Markets such as the PJM Interconnection currently subtract the retail rate portion from the LMP payment and there is no evidence that accounting for the retail rate by making the necessary reduction is either burdensome or interferes with the retail jurisdiction of state commissions.[31]

The Unintended Consequences of Paying Too Much

Today's determination, unencumbered by "textbook economic analysis of the markets subject to our jurisdiction" will undoubtedly have effects, both in the short-term and the long-term.[32] The intended consequence of providing additional compensation to demand resources is that demand response participation will increase in the energy markets. In turn, this additional demand response participation will have the effect of lowering the market price. However, it is at this point where the unintended effects will begin to appear.

With a reduced LMP, the price signal sent to customers will be that the cost of power is cheaper so they may decide to use more power even though the real cost of producing that power is now higher. Such a result turns the concept of scarcity pricing on its head and results in an economically inefficient outcome. Conversely, customers who are demand response providers now stand to receive more than the market price as an incentive to curtail their consumption and will begin to make inefficient decisions about using power.[33] Such inefficiencies will result in customers experiencing a short-

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September 16, 2009 Comments at 3 (Docket No. EL09-68), "LMP-G is an accepted indicator of cost-effectiveness. Therefore, to provide incentive compensation at a level that is above the LMP raises the specter of unjust and unreasonable rates."

[30] Rule at P 63.

[31] See Sections 3.3A.4 and 3.3A.5 (Market Settlements in the Real-Time and Day-Ahead Energy Markets) of the Appendix to Attachment K of the PJM Tariff.

[32] Rule at P 46.

[33] Federal Trade Commission May 13, 2010 Comments at 6, "If customers have to pay the retail price for power they use but pay nothing for power they resell, then they will have incentives to resell power in situations in which it would be more beneficial for

(continued…)

term benefit by way of a lower LMP, but will also impose long-term costs on the energy markets.[34]

The long-term costs of allowing demand resources to receive preferential compensation will manifest themselves in various ways. As noted in my initial statement in this proceeding, the lack of dynamic prices at the retail level is the primary barrier to demand response participation. This Rule does not remedy this barrier and customers who pay fixed retail rates will not benefit from lower wholesale market prices. Meanwhile, at the wholesale level, the corrosive effect of overcompensating demand resources over time will come at the expense of other resources, particularly generation resources that will have less to invest in maintaining existing facilities and financing new facilities.[35]

The Commission's recent progress in promoting competitive wholesale energy markets has the potential to be undone as a result of this well-meaning, but misguided Rule. I believe in the proven value of market solutions and therefore agree with the majority's statement that "while the level of compensation provided to each resource affects its willingness and ability to participate in the market, ultimately the markets themselves will determine the level of generation and demand response resources needed

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society for them to consume it." See also EPSA May 13, 2010 Comments at 23; APPA at 13; FTC at 9; Midwest TDUs at 14; Mirant at 2; New York Commission at 5; PJM at 6; PSEG at 5; and Potomac Economics at 6-8.

[34] PJM's Independent Market Monitor (a/k/a Monitoring Analytics, LLC) Oct. 16, 2009 Comments at 7-8 (Docket No. EL09-68), "Demand side resources are not generation. In a well functioning market, demand-side resources avoid paying the market price of energy when they choose not to consume. This allows customers to make efficient decisions about using power. It also follows that a customer receiving more than the market price as an incentive to curtail will make inefficient decisions about using power, and that this inefficiency imposes a cost rather than providing a benefit to society."

[35] NYISO May 13, 2010 Comments at 15, "[P]aying demand response an LMP-based payment because it is thought that demand response participation will reduce LMPs for all customers is not a sufficient rationale for justifying an 'additional payment' for a favored technology. Demand response is not the only resource able to provide such benefits. However, [other] technologies may be kept out of the market by demand response that would be uneconomic at LMP-G but participates when subsidized at LMP."

for purposes of balancing the electricity grid."[36] That's precisely how markets should work. Price signals will attract resources and new investment when prices are high, and perhaps not so much when prices are low.[37] If the playing field is level, resources can compete to the best of their abilities and efficient, cost-effective market outcomes will result.

As noted earlier, I would have preferred that we allow the regional markets to continue to develop their own compensation proposals. However, I also recognize that returning to a pre-NOPR era would be difficult now that the Commission has signaled a new policy of standardized compensation. Accordingly, if I were to now support any standardization of demand response compensation, it would be the LMP-G approach, which in my opinion, is the only economically efficient outcome for the markets.

Ultimately, the Rule, by requiring demand resources to artificially suppress the market price in order to receive incomparable compensation, will negatively impact the long-term competitiveness of the organized wholesale energy markets.[38] As such, lacking sufficient rationale, I cannot support this Rule as it violates the Commission's statutory mandate to ensure supplies of electric energy at just, reasonable, and not unduly discriminatory or preferential rates.

Philip D. Moeller
Commissioner

[36] Rule at P 59.

[37] PJM Interconnection's experience with paying LMP-G for demand response in its energy market provides an example of how market fundamentals properly influence demand resource participation. PJM's Independent Market Monitor recently reported that "[p]articipation levels through calendar year 2009 and through the first three months of 2010 were generally lower compared to prior years due to a number of factors, including lower price levels, lower load levels, and improved measurement and verification, but *have showed strong growth through the summer period as price levels and load levels have increased*. Citing Monitoring Analytics, LLC, 2010 State of the Market Report for PJM at 30 (March 10, 2011) (emphasis added).

[38] Federal Power Act § 205(a), 16 U.S.C. § 824d (2006), "[A]ll rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful."

Transitional Capacity Auction

Phase I Design Document

JUNE 5, 2019

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Powering Tomorrow.

Summary

Every minute of every day, the Independent Electricity System Operator (IESO) manages the reliability of the province's electricity grid and administers Ontario's electricity markets so that businesses, communities and consumers have the power they count on to meet their needs – and at the lowest cost.

Creating a stable and efficient marketplace that produces value for consumers involves encouraging competition and innovation among suppliers – and is the catalyst behind initiatives to resolve longstanding market design issues. In 2016 the IESO established a Market Renewal Program (MRP) to introduce fundamental reforms to markets that have remained relatively unchanged since they were introduced in 2002. The rationale for delivering a more efficient, stable marketplace was clear: open electricity markets create transparent price signals, enabling generators and other resources to respond to system conditions. More competition enables efficiencies by opening up opportunities for new ways of doing things, which, in turn, drive down costs and support broader public-policy goals aimed at improving affordability and supporting economic growth.

Emerging capacity needs

In the fall of 2018, the IESO released a forecast showing that Ontario is emerging from a capacity surplus to a period of system need. In particular, it is expected that there will be a signifiant increase in the need for capacity from 2022 to 2023, arising as a result of expiring long-term generation contracts, and nuclear units being refurbished or retired.

In order to ensure that we are able to reliably meet the expected capacity requirement, the IESO is developing an auction mechanism for acquiring capacity in advance of MRP's Incremental Capacity Auction (ICA), the first auction of which will deliver capacity in 2025.

Ensuring adequate capacity requires having sufficient resources available to produce electricity or reduce consumption when needed. This is essential to operating a reliable electricity system.

In Ontario's electricity system, consumers pay for both the actual production of electricity (energy), as well as the capability to generate electricity when needed (capacity). The IESO's MRP will result in energy and capacity being supplied to consumers more efficiently by incorporating enhancements to the existing energy markets and by introducing auctions for securing capacity. The Transitional Capacity Auction (TCA) is a first step toward this more efficient system.

Introducing a Transitional Capacity Auction

The IESO is moving away from long-term fixed-technology contracts toward solutions that emphasize flexibility and put the needs of the system first. This is why the IESO is addressing future capacity needs through predictable, competitive auctions. Auctions help the IESO deliver reliability to customers, in a cost effective manner, by enabling direct competition between resources while allowing the IESO to transparently adjust to changing supply-demand dynamics.

The Transitional Capacity Auction will evolve the existing Demand Response Auction (DRA) to enable competition between additional resource types, starting in December 2019. Introducing the TCA now creates an opportunity to phase-in some of the design features contemplated for the more comprehensive ICA, allowing both the IESO and participants to learn and adjust before the expected period of significant system need. At the same time, the increased competition fostered by the TCA is expected to reduce costs, further benefiting ratepayers in the nearer term.

The DRA has been working well. With each auction, there has been increased participation, new entrants, and decreasing prices – all key elements expected from a competitive auction. But we cannot rely on the DRA to meet expected capacity needs. Building on the proven DRA platform as a transition to the future ICA is the best way for the IESO to help provide a reliable future at a reasonable cost.

How the Transitional Capacity Auction will be implemented

The TCA will transition the DRA to the ICA's broader capacity auction at a measured pace, fostering confidence that the sector is ready to meet capacity needs in the early-2020s. The DRA has proven successful in driving down capacity costs and increasing competition. Enhancing our approach to capacity auctions this year by opening participation to other resources is another step toward a more competitive electricity marketplace; it moves us down the path of efficiency, competition, and transparency – the key principles of our market renewal efforts – as quickly as possible.

TCA Phase I (auction to be held in late 2019) – Will be limited to evolving the existing DRA by adding Noncommitted, Dispatchable Generators as eligible participants alongside Demand Response participants.

TCA Phase II (auctions to be held starting in 2020) – Will focus on enabling more resources such as Imports, Self-Schedulers, and Uprates, and incorporating some ICA design features. The TCA Phase II design will be detailed in a separate design document.

Enabling resources to participate

Providing capacity to meet resource adequacy means that the capacity has to be delivered into the energy market and the IESO recognizes that not all resource types are currently enabled to effectively participate in the current energy market. Through the Market Development Advisory Group, the Demand Response Working Group, and other related efforts, gaps and opportunities will be examined for enabling and enhancing existing, new and emerging resources to deliver services to the IESO.

As more resources are enabled in the TCA, updates will be made to the Market Rules, Manuals, and Tool(s) to incorporate resource specific requirements

Eligibility and participation criteria

Table 1 | Eligibility and Participation Criteria

Resources eligible to participate in Phase I	Resources ineligible to participate in Phase I
• **Demand Response Resources** Response resource that satisfies the registration and authorization requirements for the Transitional Capacity Auction or the Demand Response Auction, respectively • **Phase I-Eligible Generator** An existing generator that is both Noncommitted and a Dispatchable Generator.	• **Capacity from resources contracted wholly or in part for energy or capacity (this includes both the contracted capacity or the merchant component of a resource)** This capacity will be considered in Phase II to allow sufficient time for consideration of implications to electricity supply contracts[1]. • **Rate regulated facilities** • **Energy efficiency** • **Resources not permitted in Ontario (e.g. coal-fired generation)** • **Imports** This capacity will be considered in Phase II to allow sufficient time to develop protocols with neighbouring jurisdictions for both system and resource backed imports. Furthermore, for resource-backed imports, time must be taken to design a deliverability assessment. • **Self-scheduling resources** This capacity will be considered in Phase II to allow sufficient time to develop the appropriate design and associated settlement tools. Consideration will be given to develop appropriate measurement of capacity in the absence of offers.

[1] Further information is available at: http://www.ieso.ca/en/Market-Renewal/Background/MRP-implications-to-electricity-supply-contracts

Key Transitional Capacity Auction Periods

The key Auction Periods closely resemble the periods used in the DRA.

Figure 1 | Transitional Capacity Auction Periods for Phase I

Pre-Auction Period

Approximately three months before the auction takes place, the IESO will publish a report stating how much capacity will be targeted through the auction, along with key milestones, auction parameters and zonal constraints. Longer-term outlooks indicating future needs will be shown in an update on Ontario's future capacity needs in the third quarter of 2019.

The IESO will set the target capacity to ensure reliability needs are met at the lowest cost over the longer term. This means the target capacity will be set to reflect the immediate capacity needs, but also set to incent participation from a wider-range of providers to encourage competition. Chapter 3 explains more details of the pre-Auction Period.

Auction Period

The Auction Period is the length of time beginning when the IESO begins accepting auction offers to the time when the IESO posts auction results. Chapter 4 details how the auction is cleared using auction offers.

Forward period

The forward period is the time between an auction and the first day participants are obligated to deliver on their Capacity Obligation – which will be five months for the summer Obligation Period and eleven months for the winter Obligation Period for Phase I of the TCA. Chapter 5 provides details of what participants are obligated to do during the forward period.

Commitment period

Participants that clear the auction will receive payments during the commitment period based on their total cleared capacity and the applicable auction clearing price. The amount of capacity that clears in the auction becomes the participant's TCA Capacity Obligation; participant must satisfy an obligation to make its capacity available by participating in the day-ahead commitment process in the energy market, as described in Chapter 6. The TCA, like the former DRA, will continue to use, two seasonal Obligation Periods in each auction year:

- Summer – May 1 to October 31
- Winter – November 1 to April 30

These periods account for seasonal demand characteristics and supply capability over different seasons. Seasonal commitment periods encourage participation by providing demand response resources with the flexibility to offer into the auction in a manner most consistent with their capabilities.

Stakeholder engagement

In TCA Phase I, the IESO is looking for stakeholder feedback on auction elements that inhibit or prohibit an eligible resource's ability to participate and provide capacity in the auction and subsequent commitment periods. In TCA Phase II, the IESO will seek stakeholder feedback on subsequent design improvements to further enable broader participation for future auctions while also incorporating additional features such as qualifying capacity.

Conclusion

The transition from the DRA to the TCA is a phased approach to a much more competitive marketplace and a natural next step in moving to the more comprehensive ICA for Ontario. Taking a balanced approach that minimizes disruption to the existing market, while enabling greater participation where it is cost effective to do so, ensures that reliability needs over the long term will be met at the lowest cost.

This design document is a stepping-off point for stakeholder engagement on the detailed decisions that will need to be addressed before Phase I implementation. Phase II implementation will be presented in separate design documents.

Incremental Capacity Auction High-Level Design

Executive Summary

Independent Electricity System Operator

MARCH 2019

Posted for Stakeholder Comment

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Powering Tomorrow.

Executive Summary

Every minute of every day, the Independent Electricity System Operator (IESO) manages the reliability of the province's electricity grid and administers Ontario's electricity markets so that businesses, communities and consumers have the power they count on to meet their needs – and at the lowest cost.

Creating a stable and efficient marketplace that produces value for consumers involves encouraging competition and innovation among suppliers – and is the catalyst behind initiatives to resolve long-standing market design issues. In 2016 the IESO established a Market Renewal Program (MRP) to introduce fundamental reforms to markets that have remained relatively unchanged since they were introduced in 2002. The rationale for delivering a more efficient, stable marketplace was clear: open electricity markets create transparent price signals, enabling generators and other resources to respond to system conditions. More competition enables efficiencies by opening up opportunities for new ways of doing things, which, in turn, drive down costs and support broader public-policy goals aimed at improving affordability and supporting economic growth.

Promoting Competition: Introducing the Incremental Capacity Auction

As we prepare for a potential need for new electricity supply in the coming years, significant changes are underway that will see new resources acquired at the lowest cost to Ontario consumers through an Incremental Capacity Auction (ICA) as part of the MRP. A core element of the MRP, this made-in-Ontario solution will enable resources to compete to meet adequacy needs, while helping the IESO adjust to changing supply-demand dynamics.

A recent, long-term forecast released by the IESO showed that Ontario is emerging from a capacity surplus. A need for additional resources is appearing at a time when long-term contracts with generation facilities begin to expire, and nuclear units are being refurbished or retired.

The ICA will help us prepare for this future by allowing more resource types to compete to provide future capacity, enabling the IESO to flexibly meet the province's adequacy needs. This will provide generators whose contracts have expired or are expiring over the next few years with the opportunity to continue to participate in the electricity market, while achieving cost efficiencies that will translate into more affordable outcomes for Ontario consumers. When implemented, the ICA is expected to contribute the largest portion of the anticipated $3.4 billion savings the MRP is expected to deliver over a 10-year timeframe.

How It Works

Through an auction process, participants (such as electricity generating facilities, demand response providers and imports) receive compensation for capacity, or in other words for being available to provide power in the future during specific hours. The ICA in Ontario is being designed so a base auction will be held every year to secure resources for a delivery date three and a half years out.

Ensuring adequate capacity – in other words, having sufficient resources available to produce electricity or reduce consumption when needed – is essential to operating a reliable electricity system.

In an electricity system, consumers pay for both the actual production of electricity (energy), as well as the capability to generate electricity when needed (capacity). The IESO's MRP will result in energy and capacity being supplied to consumers more efficiently by incorporating enhancements to the existing energy markets and by introducing auctions for securing capacity.

In recent years, Ontario has used long-term contracting as a means of securing capacity. While this approach was responsible for the development of new generation infrastructure, the lack of flexibility in adjusting the amount of capacity secured or how facilities operate in the energy market led to excess costs for consumers over the longer term.

Long-term contracts also mean that suppliers are insulated from the risks associated with changing supply-demand dynamics, while the system, and ultimately consumers, pay a significant price for any change in conditions that results in contracted resources being underused (e.g., when demand for electricity is lower than anticipated). With the introduction of a capacity auction, investment risks can be more appropriately shared between consumers and suppliers.

Once the ICA is implemented, electricity producers can be paid for both the electricity they actually produce (through the energy market) and the capacity they provide (through the ICA). Capacity auctions also increase the system's ability to adjust to changing supply and demand dynamics. In other jurisdictions, including the U.S. and Europe, capacity auctions have also proven to be successful in enabling non-traditional, low-cost capacity resources, such as demand response, imports and generator uprates to compete against new and existing sources of capacity.

In Ontario, demand response auctions, where participating demand-side resources, such as residential, commercial and industrial consumers, are selected to be available to reduce their electricity consumption as needed, have been held since 2015 with great success. The result has been reduced auction prices, increased competition and the participation of new resources.

As part of the transition toward implementing the ICA, the IESO will build on the success of the current demand response auction by allowing other existing resource types to compete. This will provide an opportunity for generators whose contracts are expiring over the next few years, as well as imports and other resources, to participate alongside demand response in the auction and help meet emerging resource adequacy needs.

This staged approach to implementing the ICA will help Ontario transition to a more competitive marketplace by allowing both the IESO and market participants to continue to learn and improve processes as resource adequacy needs increase.

Fundamentals of the Incremental Capacity Auction

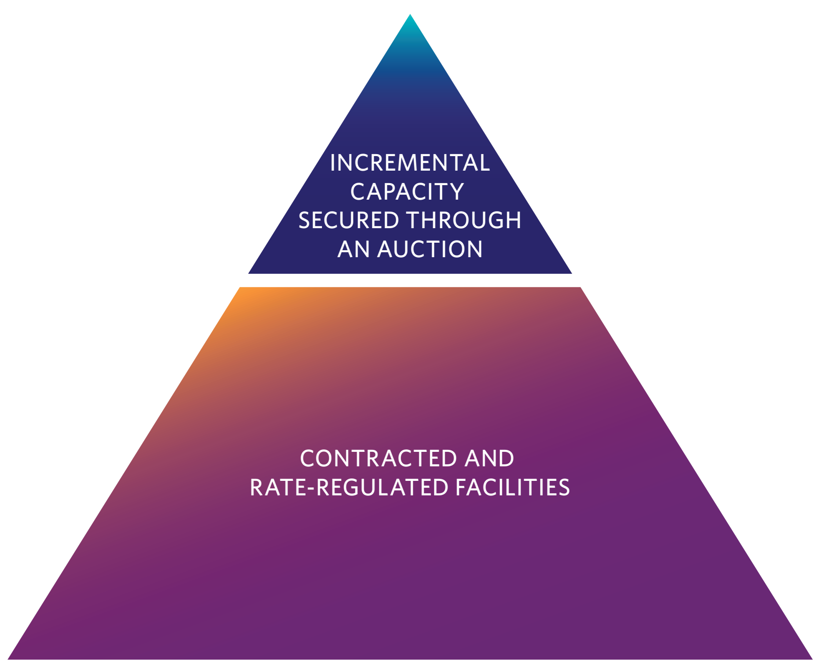
The goal for the ICA is to secure capacity to meet Ontario's future resource adequacy needs transparently and at the lowest cost in the long run.

Under the ICA, potential suppliers of capacity will have the opportunity to secure a portion of their future revenues on an annual basis up to three and a half years in advance of when they will be required to be online to produce energy or reduce consumption. The annual nature of the auction will therefore provide generators with a line of sight into the revenue they can earn for up to four years into the future, as well as certainty that there will be opportunities to continue to earn capacity revenue on an ongoing basis. This certainty, along with the opportunity to earn revenue in the energy and ancillary services markets, will allow resources to determine what type of investment decisions they want to make.

One of the advantages of the ICA is that all eligible sources of capacity – new and existing, on both the supply and demand sides – compete with each other, regardless of resource type. Prior to each auction, resources will go through a qualification process to determine the contribution each can provide. From the perspective of meeting adequacy needs, there is no functional difference between a megawatt of power from an electricity generating facility and a megawatt of reduced consumption from demand response.

In addition to driving competitive behaviour, the ICA will enable the IESO to adjust the amount of capacity secured each year, supporting its ability to respond to changing adequacy needs and to minimize the potential for a capacity surplus and the associated unnecessary costs for ratepayers.

Unlike other jurisdictions that secure most of their capacity through an auction, the Ontario version will be "incremental," meaning that it will only secure capacity beyond that already under contract or rate regulation. While the development of certain resources such as nuclear or large hydro may be more feasible with longer-term commitments, a wide variety of resources are expected to compete in the ICA, enhancing the system's ability to cost effectively adjust to changing supply and demand requirements.



*For **suppliers**, capacity auctions provide the price stability and revenue certainty to incentivize them to make sufficient capacity available*

*For **consumers**, capacity auctions help to ensure that the required resources are available to meet energy needs at lowest cost*

Benefits of the Made-in-Ontario Incremental Capacity Auction

Under the model proposed by the IESO, the ICA is expected to:

- Unlock capacity from existing assets including, on the demand side, reducing the need to build more costly capacity sources such as new generation facilities.
- Deliver the most economically efficient outcomes while providing the flexibility to reassess and refine capacity requirements annually.
- Support innovation by encouraging competition across resource types.
- Attract non-traditional, low-cost resources that historically have not had the opportunity to compete to meet resource adequacy needs in Ontario.

Key Design Elements

Each auction will seek to secure a predetermined quantity of capacity (known as the target capacity), which reflects the total forecasted need during a future year (the commitment period) less the expected contributions of contracted and rate-regulated resources.

The process to determine a resource's useful capacity will be closely aligned with both the overall resource adequacy forecasting methodology and with the way performance obligations are assessed. Taken together, this process helps establish the capacity that will be secured through the ICA.

Eligibility and Participation Criteria

Participation in the ICA will be open to:	Participation in the ICA will not be open to:
• All generation technology types that are not otherwise ineligible under Ontario laws and regulations • Demand response resources located in Ontario • Contracted resources with capacity in excess of that which is contracted • Resource-specific or system-backed capacity imports[1] • Resources that meet a minimum one megawatt size requirement on an installed capacity (ICAP) basis • Aggregated resources (subject to requirements defined in the Market Rules) • Energy storage	• Resource types not permitted by Ontario laws and regulations, whether Ontario-based or as a resource-backed import • Capacity that is the subject of a contract with the IESO or the Ontario Electricity Financial Corporation (OEFC) • Ontario-based rate-regulated facilities • Energy efficiency in the initial years • Demand response not located in Ontario • New resources proposed to be located in jurisdictions other than Ontario • Portfolio-backed imports • Resources that will not be energy market participants by the start of the commitment period

[1] More information on capacity imports, including the definitions of the different types, can be found in Section 4.6 of the main document.

Prospective participants will be required to submit information regarding resource eligibility and to provide an auction deposit to help ensure only entities with a high probability of being able to meet obligations by the commitment period are able to participate. Once a resource is deemed eligible to participate, the IESO will conduct a capacity qualification process to determine the maximum quantity of capacity that may be offered into the auction. This process will involve both a:

- **Resource assessment** to determine the average amount of capacity that a resource can be expected to provide during periods of system need in each of the summer and winter seasons. This assessment will be tailored to the type of resource being reviewed and will consider the effects of forced outages on resource availability and output.
- **Deliverability assessment** to determine the extent to which energy supplied during periods of system need can be transported by the transmission system from the resource to where it is needed by consumers on the Ontario grid.

The quantity of capacity determined during the resource assessment will be adjusted based on the deliverability assessment to arrive at the resource's qualified capacity for each six-month season. During the commitment period, resources cleared through the auction will have performance obligations, including a requirement to offer/bid into the day-ahead and real-time energy markets during certain hours up to the resource's real-time capability. These hours will be consistent with the hours over which the amount of capacity the resource was qualified to offer were established.

Capacity Zones

Capacity zones will be defined and included in the pre-auction report to reflect major transmission limitations of the Ontario system and will be used in auction clearing so resource adequacy needs are efficiently met. Where certain zonal transmission constraints are binding, zonal prices will be established to send price signals for the value of capacity in specific parts of the province. These prices may be higher or lower than the system-wide price.

Clearing the Auction

Clearing the auction is what happens when committed capacity is determined and prices are established. Similar to the existing energy market, the ICA will select the resources that clear the auction based on the intersection of a demand curve and a supply curve. The demand curve is a representation of the range of incremental capacity the IESO, on behalf of consumers, is willing to buy at various price levels. One of the key points that defines the demand curve is the target capacity and net cost of new entry (CONE). Net CONE represents the estimated average annual capacity payment that a new reference resource would need to receive over its expected lifecycle to be financially viable.

The supply curve will be created based on submitted auction offers stacked from least expensive to most expensive. The auction will co-optimize both seasons over the year and will then select the set of resources that clear the auction based on the intersection of the supply and demand curves (subject to any relevant constraints such as transmission limitations), which establishes clearing prices.

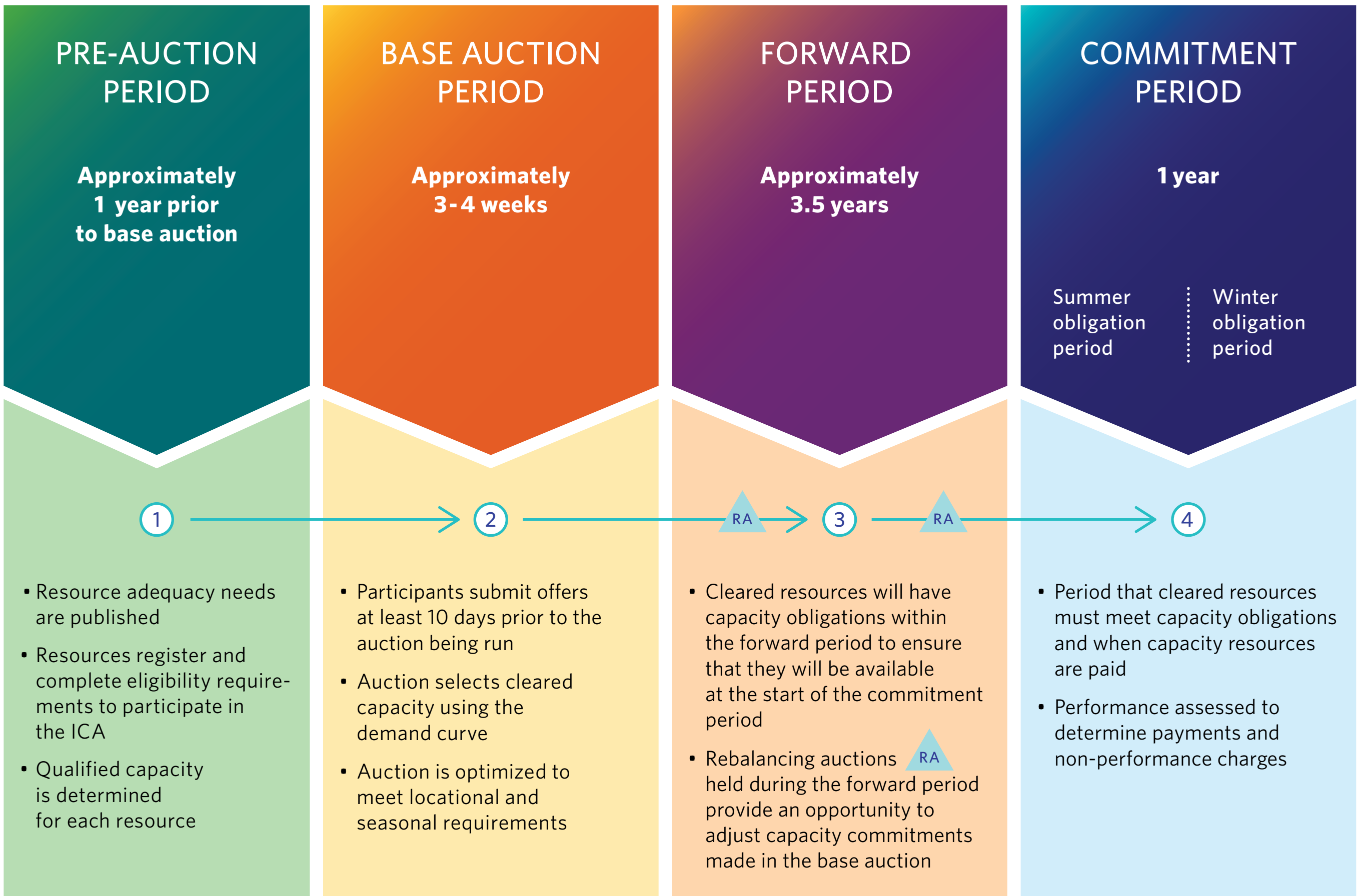
Market Power Mitigation

To ensure the integrity of auction outcomes, the IESO will take measures to mitigate the exercise of market power that might adversely affect the auction clearing price. Market power can be exercised by participants that physically or economically withhold a portion of their capacity from the auction. To mitigate against the risk of increased clearing prices caused by physical withholding, most existing resources, including those that have come off a contract, will be required to offer their capacity into the ICA, subject to outcomes for those who enter into a delisting process. With respect to economic withholding, a pivotal supplier test will determine whether a resource is required to meet the target capacity. Participants that fail the pivotal supplier test will be required to submit offers into the ICA at or below an established offer cap.

Key Incremental Capacity Auction Periods

The ICA will have four major periods – the pre-auction, base auction, forward and commitment – each of which involves different IESO and participant activities.

FIGURE ES-1: OVERVIEW OF ICA PERIODS



The ICA will be a ***forward auction*** *that will select a product to be delivered years in the future*

In the one-year pre-auction period, the IESO will publish system needs, and resources will complete the eligibility requirements and capacity qualification processes to be ready for the base auction. Once a base auction occurs, the forward period of approximately three and a half years begins. During this period, new build resources will have to ensure they are ready to deliver on their obligations by the start of the commitment period, which runs from May 1 to April 30 annually. As a result, participants may need to begin their resource development activities prior to the auction date to ensure their project is completed in time.

The auction will arrive at a system-wide price for capacity that will be paid to all resources that clear the auction (i.e., those selected by the auction's optimization engine as part of the lowest-cost solution to satisfy forecasted demand).

Another feature of the made-in-Ontario auction is recognition of the seasonal nature of the province's demand profile and the variation in some resources' ability to support resource adequacy needs. The auction will commit resources in both a summer (May 1 to October 31) and a winter (November 1 to April 30) timeframe, each of which will have a separate clearing price and a specific qualified capacity value. Having separate winter and summer seasons will allow for the closest match between a committed resource's capabilities and the system's resource adequacy requirements throughout the year, while promoting competition among all resource types.

Pre-Auction Period

To support auction participation, the IESO will publish a pre-auction report approximately one year prior to each base auction. This report will contain:

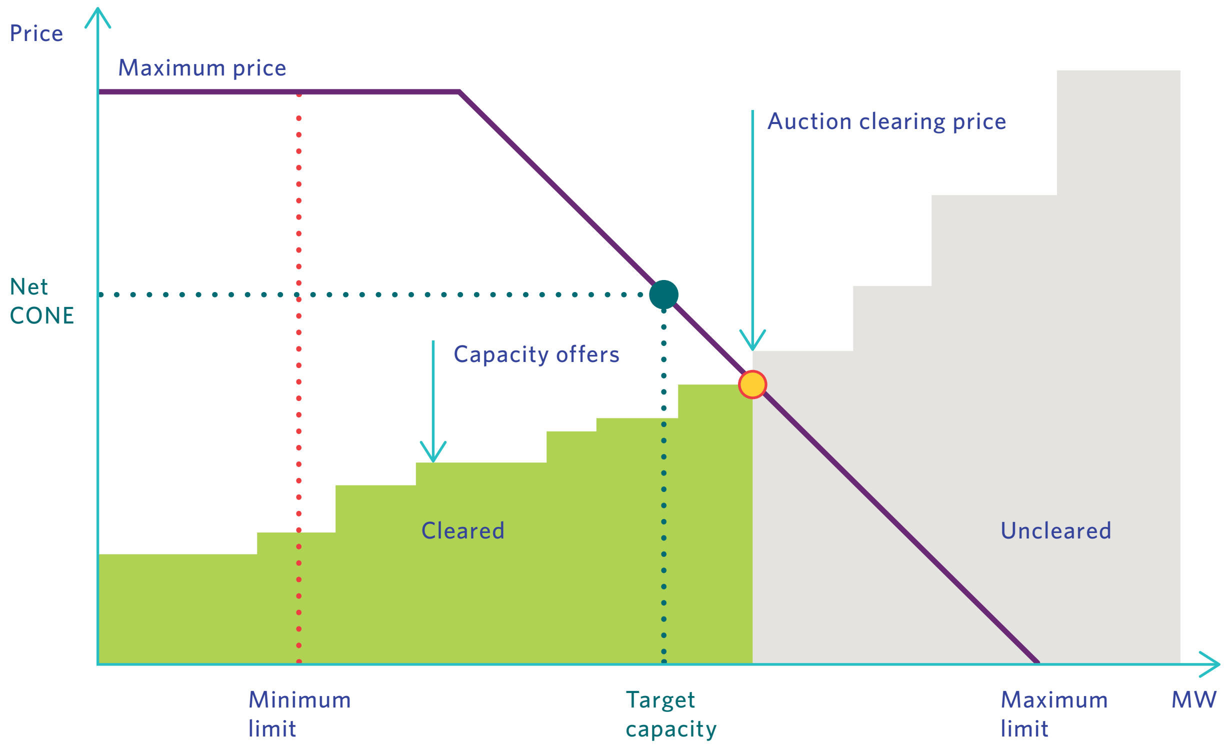
- **Demand curve parameters** set in advance of the auction, including:
  - Preliminary target capacity for the upcoming auction[2]
  - Minimum and maximum capacity limits
  - Net CONE
  - Shape of the demand curve
  - Maximum auction clearing price (MACP)
- **Capacity zones** to reflect the effects of the province's internal transmission constraints, which can mean that capacity may either need to be located within a zone to support adequacy or that capacity exported from a zone may be restricted.
- **Anticipated capacity needs** for at least five years beyond the commitment period to help participants identify potential opportunities for their resources in future auctions.
- **Pre-auction deliverability** that describes transmission constraints that might impact resource deliverability and auction clearing.
- **Market power mitigation parameters** that establish technology-specific default offer caps that will apply to participants identified as having market power.

Base Auction

There will be one base auction and two rebalancing auctions per commitment period. Base auctions will occur during the winter months. All auctions will be conducted using sealed bids and will be cleared in a single round. To offer into the auction, participants will be required to provide an auction deposit that is proportional to the amount of capacity they are offering into the auction and which will be higher for new build resources than for existing resources. Participants will be allowed to submit offers with multiple price-quantity pairs (laminations) and specify for each subsequent lamination whether the offered quantity must be cleared in full or if it can be cleared partially. Resources will be allowed to submit offers for the summer obligation period only, the winter obligation period only, or for the entire annual commitment period.

[2] The final target capacity value will be confirmed shortly before each base auction.

FIGURE ES-2: BASIC ICA CLEARING



New resources that are successful in the auction will be required to submit security in respect of their development obligations during the forward period, which will be exchanged for performance security before the start of the commitment period. Existing resources that are successful in the auction will only be required to provide performance security.

Eligible new resources can clear with a commitment for more than one year (called a multi-year commitment) providing certainty that they will earn a set price for more than a single commitment period.

A public, post-auction report will include auction clearing prices for each season at the system-wide and zonal levels, cleared capacity, a qualitative discussion and analysis of the auction results. Successful participants will also receive a private report letting them know the amount of their capacity that cleared the auction for each obligation period and the auction clearing price that will apply.

Forward Period

The time period between the base auction and the start of the commitment period is called the forward period. Existing resources will have minimal forward period obligations. New build resources will have additional obligations, including the requirement to complete:

- Project milestones and project progress reports
- Energy market participant authorization
- Facility registration in the energy market
- Meter registration
- Completion security requirements

During the forward period, the amount of required completion security will be reduced as certain project milestones are completed. If it is determined that a new build resource will be unable to come into service in time to fulfill its capacity obligations, the IESO may require the participant to shed their obligation in a rebalancing auction.

Two rebalancing auctions will be held during the forward period. These will allow the IESO to adjust the quantity of capacity committed if the resource adequacy forecast changes (e.g., due to a changed demand forecast) resulting in a change to the target capacity for the commitment period. Rebalancing auctions will also allow participants to increase or decrease their capacity obligation and new participants to obtain an obligation, for a given commitment period.

Commitment Period

Participants that clear the auction will receive payments during the commitment period based on their total cleared capacity and the applicable auction clearing price. The amount of capacity that clears in the auction becomes the participant's ICA committed capacity. A participant must satisfy an obligation to make its capacity "available" by participating in the energy markets. Those resources that are more available than expected may be eligible to receive additional incentive payments, while resources that are available less than required will face non-performance charges.

A generator's payments for availability will be based on the average of offers submitted during prescribed hours, with exceptions for when resources are on an approved planned outage. Given that the ICA exists to ensure that sufficient capacity is available when needed to meet system peaks, resources that clear the auction must offer into the IESO day-ahead and real-time energy markets with their available capacity. Demand response resources will have equivalent obligations but may have a different assessment method.

During the commitment period, the IESO may initiate a capacity check test to ensure that a resource is capable of performing at a level consistent with the amount of capacity it cleared in the auction. There will be charges for failing to pass a capacity check test.

Conclusion

Through the MRP, Ontario's electricity markets are being redesigned to deliver a reliable system at the lowest cost for consumers. At its core, the MRP focuses on improving how electricity is priced, scheduled and dispatched, and enhances the system's ability to respond to unexpected, short-term changes in supply and demand.

A fundamental element of this redesign is the made-in-Ontario incremental capacity auction, which supports the broader MRP goal of providing incentives for resource owners to align their behaviours and decisions with system needs – an outcome that will lead to the most efficient system in both the short-and long-term.

This high-level design, which outlines the key design decisions associated with implementation of the ICA, is an important step toward ensuring Ontario's resource adequacy needs are met in a more competitive, innovative and cost-effective manner.

The introduction of annual auctions with short duration commitments that vary seasonally will help to deliver more efficient outcomes. At the same time, the financial certainty offered by a recurring auction alongside a robust energy market that properly values the electricity services Ontario needs will provide the right level of private sector investment within Ontario.

At the outset of the MRP, the IESO understood that success in creating a market that better meets the needs of suppliers and consumers would require the broad support of stakeholders who were prepared to invest time and effort in developing solutions that will work for the sector and the IESO. This document is the culmination of months of extensive consultation with stakeholders. It provides both a comprehensive summary of the decisions that have been made and serves as a stepping-off point for engagement on the detailed decisions that will need to be made to implement the ICA.

The IESO is looking forward to working with Ontario's electricity partners to bring this vision into reality.

To see the full ICA high-level design document, visit www.ieso.ca/Sector-Participants/Market-Renewal/Incremental-Capacity-Auction-High-Level-Design.

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MARCH 2019

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Fundamentals of the Incremental Capacity Auction

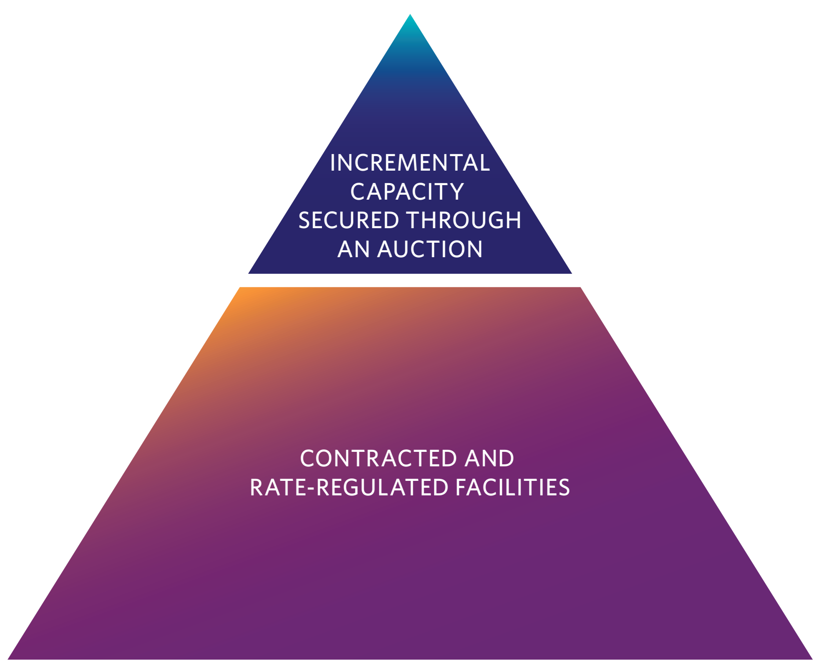
The goal for the ICA is to secure capacity to meet Ontario's future resource adequacy needs transparently and at the lowest cost in the long run.

Under the ICA, potential suppliers of capacity will have the opportunity to secure a portion of their future revenues on an annual basis up to three and a half years in advance of when they will be required to be online to produce energy or reduce consumption. The annual nature of the auction will therefore provide generators with a line of sight into the revenue they can earn for up to four years into the future, as well as certainty that there will be opportunities to continue to earn capacity revenue on an ongoing basis. This certainty, along with the opportunity to earn revenue in the energy and ancillary services markets, will allow resources to determine what type of investment decisions they want to make.

One of the advantages of the ICA is that all eligible sources of capacity – new and existing, on both the supply and demand sides – compete with each other, regardless of resource type. Prior to each auction, resources will go through a qualification process to determine the contribution each can provide. From the perspective of meeting adequacy needs, there is no functional difference between a megawatt of power from an electricity generating facility and a megawatt of reduced consumption from demand response.

In addition to driving competitive behaviour, the ICA will enable the IESO to adjust the amount of capacity secured each year, supporting its ability to respond to changing adequacy needs and to minimize the potential for a capacity surplus and the associated unnecessary costs for ratepayers.

Unlike other jurisdictions that secure most of their capacity through an auction, the Ontario version will be "incremental," meaning that it will only secure capacity beyond that already under contract or rate regulation. While the development of certain resources such as nuclear or large hydro may be more feasible with longer-term commitments, a wide variety of resources are expected to compete in the ICA, enhancing the system's ability to cost effectively adjust to changing supply and demand requirements.



Transitional Capacity Auction

Phase I Design Document

JUNE 5, 2019

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Introducing a Transitional Capacity Auction

The IESO is moving away from long-term fixed-technology contracts toward solutions that emphasize flexibility and put the needs of the system first. This is why the IESO is addressing future capacity needs through predictable, competitive auctions. Auctions help the IESO deliver reliability to customers, in a cost effective manner, by enabling direct competition between resources while allowing the IESO to transparently adjust to changing supply-demand dynamics.

The Transitional Capacity Auction will evolve the existing Demand Response Auction (DRA) to enable competition between additional resource types, starting in December 2019. Introducing the TCA now creates an opportunity to phase-in some of the design features contemplated for the more comprehensive ICA, allowing both the IESO and participants to learn and adjust before the expected period of significant system need. At the same time, the increased competition fostered by the TCA is expected to reduce costs, further benefiting ratepayers in the nearer term.

The DRA has been working well. With each auction, there has been increased participation, new entrants, and decreasing prices – all key elements expected from a competitive auction. But we cannot rely on the DRA to meet expected capacity needs. Building on the proven DRA platform as a transition to the future ICA is the best way for the IESO to help provide a reliable future at a reasonable cost.

How the Transitional Capacity Auction will be implemented

The TCA will transition the DRA to the ICA's broader capacity auction at a measured pace, fostering confidence that the sector is ready to meet capacity needs in the early-2020s. The DRA has proven successful in driving down capacity costs and increasing competition. Enhancing our approach to capacity auctions this year by opening participation to other resources is another step toward a more competitive electricity marketplace; it moves us down the path of efficiency, competition, and transparency – the key principles of our market renewal efforts – as quickly as possible.

TCA Phase I (auction to be held in late 2019) – Will be limited to evolving the existing DRA by adding Noncommitted, Dispatchable Generators as eligible participants alongside Demand Response participants.

TCA Phase II (auctions to be held starting in 2020) – Will focus on enabling more resources such as Imports, Self-Schedulers, and Uprates, and incorporating some ICA design features. The TCA Phase II design will be detailed in a separate design document.

Demand Response Working Group Meeting Materials

Demand Response Working Group

June 19, 2019

Implications for ICA and TCA Participation

- In the Demand Response Auction, HDR participants could reflect the expected cost of out-of-market activations in DR Auction offer prices
  - Since the DR Auction was for DR only, all HDR resources were impacted equally
- In the context of the proposed capacity auctions, where HDR will be competing against other resource types, how these costs are recovered will potentially impact market efficiency

Demand Response Working Group Meeting Materials

Demand Response Working Group

June 19, 2019

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Energy Payments for Economic Activation of DR Resources

Objective:

- Determine whether there is a net benefit to electricity ratepayers if DR resources are compensated with energy payments for economic activations before end of 2020

Next Step:

- Obtain input from stakeholders, including DRWG and the Market Development Advisory Group, on approach to conducting the analysis required to make this determination

Demand Response Working Group Meeting Materials

Demand Response Working Group

June 19, 2019

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Cost Recovery for Out-of-Market Activation of Hourly DR Resources - Proposal

Demand Response Working Group

June 19, 2019

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Purpose

- Discuss a proposal to provide HDR resources cost recovery for out-of-market activations (i.e. testing or emergency activations) consistent with treatment of other resource types

HDR Activations

- There are two ways an HDR resource can be activated

In-Market

- Based on market economics
- HDR energy bids intended to reflect the maximum they are willing to consume at given price
- HDR will be “activated” when the price for electricity is greater than their willingness to consume

Out of Market

- HDR resources can be activated outside of market economics to respond to a:
    1. Capacity test, or
    2. Emergency Control Action
- HDR will be activated even if the electricity price is lower than their bid price

- Observed bid prices and stakeholder feedback indicate that activation costs (explicit and opportunity) can be significant for HDR resources

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Out Of Market Costs

- When other resource types (dispatchable load, generator, import) are dispatched out-of-market they are eligible for some form of "make-whole-payment"
  - A make-whole payment may apply when a participant faces a shortfall between their resource bid/offer price and the revenue earned through market clearing prices
  - The payment restores the participant to the financial situation they would have been in as implied by their bids/offers
- HDR resources do not receive a make-whole payment for out of market activations
- These costs may be reflected in their capacity offers potentially increasing the cost of the capacity

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Implications for ICA and TCA Participation

- In the Demand Response Auction, HDR participants could reflect the expected cost of out-of-market activations in DR Auction offer prices
  - Since the DR Auction was for DR only, all HDR resources were impacted equally
- In the context of the proposed capacity auctions, where HDR will be competing against other resource types, how these costs are recovered will potentially impact market efficiency

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Proposal

- IESO's initial assessment concludes that providing HDR resources cost recovery for out-of-market activations is:
  - appropriate as testing or emergency activations can occur at a price below bid price of an HDR
  - consistent with energy market and existing design treatment of other resources (including dispatchable load)

Potential Design Considerations/Issues

IESO requests feedback from stakeholders on potential design considerations, including:

- Most appropriate method for determining compensation; for example:
  - Using energy bids as representative costs
  - Historical precedents, such as CBDR activation payments
  - Identify costs on individual or type of resource basis
- Undue administrative burden of potential options
- Operational impacts on market participants, for example measurement data requirements
- Other considerations that should be assessed

Next Steps/Timelines

- Stakeholders to provide feedback on concept and design considerations by July 5
- Work with stakeholders on design details of this concept and initiate market rule amendment process during Q3, 2019
- Timeline
  - Implement changes for May 2020 TCA obligation period to enable DR participants to incorporate change to offers in December TCA

Energy Payments for Economic Activation of DR Resources - Proposal

Demand Response Working Group

June 19, 2019

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Purpose

- Obtain input from stakeholders on approach to conducting the analysis required to determine whether there is a net benefit to electricity ratepayers if DR resources are compensated with energy payments for economic activations

Questions

- What is the appropriate analysis to complete?
  - Is a net benefit to ratepayers test appropriate?
- Who is best to complete the analysis?
  - IESO? Consultant?
- Who else should be consulted?
  - Market Development Advisory Group? OEB?
- When is a decision required by?

Next Steps

- IESO would like to receive proposals from stakeholders on how best to proceed by July 19

Recap

Action Items	Timeline
• Revised DRWG 2019 Work Plan - General Feedback from Stakeholders	July 5, 2019
• Cost Recovery for Out-of-Market Activation of HDR Resources – Stakeholder feedback to IESO concept and input to questions	July 5, 2019
• Energy Payments for Economic Activation of DR Resources Research Plan – Stakeholder feedback to IESO	July 19, 2019
• Testing of Hourly DR Resources • Stakeholder feedback • IESO response to stakeholder proposals	 July 5, 2019 September DRWG meeting
• Transfer of DR Auction Obligations	June 25, 2019 Technical Panel

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Recap - continued

Action Items	Timeline
• Contributor Management, Measurement Data Submission and DR Audit	
• IESO to provide recommendations on Contributor Management process	September DRWG meeting
• IESO to provide recommendations on Measurement Data Submission	September DRWG meeting
• IESO to provide response to DR participant comments from April DRWG	September DRWG Meeting
• Update Market Manual 12.0	By end of 2019
• Separating Virtual and Physical HDR Resources • IESO to discuss with stakeholders	Before September DRWG meeting

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QUESTIONS & COMMENTS

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134 FERC ¶ 61,187
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 35

[Docket No. RM10-17-000; Order No. 745]

Demand Response Compensation in Organized Wholesale Energy Markets

(Issued March 15, 2011)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule.

SUMMARY: In this Final Rule, the Federal Energy Regulatory Commission (Commission) amends its regulations under the Federal Power Act to ensure that when a demand response resource participating in an organized wholesale energy market administered by a Regional Transmission Organization (RTO) or Independent System Operator (ISO) has the capability to balance supply and demand as an alternative to a generation resource and when dispatch of that demand response resource is cost-effective as determined by the net benefits test described in this rule, that demand response resource must be compensated for the service it provides to the energy market at the market price for energy, referred to as the locational marginal price (LMP). This approach for compensating demand response resources helps to ensure the competitiveness of organized wholesale energy markets and remove barriers to the participation of demand response resources, thus ensuring just and reasonable wholesale rates.

57. Due to a variety of factors, demand responsiveness to price changes is relatively inelastic in the electric industry and does not play as significant a role in setting the wholesale energy market price as in other industries. The Commission has recognized that barriers remain to demand response participation in organized wholesale energy markets. For example, in Order No. 719, the Commission stated:

> [D]espite previous Commission and RTO and ISO efforts to facilitate demand response, regulatory and technological barriers to demand response participation persist, thereby limiting the benefits that would otherwise result. A market functions effectively only when both supply and demand can meaningfully participate, and barriers to demand response limit the meaningful participation of demand in electricity markets.[122]

Barriers to demand response participation at the wholesale level identified by commenters include the lack of a direct connection between wholesale and retail prices,[123] lack of dynamic retail prices (retail prices that vary with changes in marginal wholesale costs), the lack of real-time information sharing, and the lack of market incentives to invest in enabling technologies that would allow electric customers and

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[122] Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 83 (citing Federal Energy Regulatory Commission Staff, A National Assessment of Demand Response Potential (June 2009), found at http://www.ferc.gov/legal/staff-refports/06-09-demand-response.pdf; Barriers to Demand Side Response in PJM (2009)). In compliance filings submitted by RTOs and ISOs and their market monitors pursuant to Order No. 719, as well as in responsive pleadings, parties have mentioned additional barriers, such as the inability of demand response resources to set LMP, minimum size requirements, and others.

[123] See, e.g., Monitoring Analytics May 13, 2010 Comments at 4-6.

aggregators of retail customers to see and respond to changes in marginal costs of providing electric service as those costs change. For example, Dr. Kahn states:

> These circumstances—specifically, the fact that pass-through of the LMP is costly and (perhaps) politically infeasible, the possibly prohibitive cost of the metering necessary to charge each ultimate user, moment-by-moment, the often dramatic changes in true marginal costs for each—can justify direct payment at full LMP to distributors and ultimate customers who promise to guarantee their immediate response to such increases in true marginal costs of supplying them.[124]

Furthermore, EnerNOC states:

> On a more fundamental level, the inadequate compensation mechanisms in place today in wholesale energy markets fail to induce sufficient investment in demand response resource infrastructure and expertise that could lead to adequate levels of demand response procurement. Without sufficient investment in the development of demand response, demand response resources simply cannot be procured because they do not yet exist as resources. Such investment will not occur so long as compensation undervalues demand response resources.[125]

58. The Commission concludes that paying LMP can address the identified barriers to potential demand response providers.

59. Removing barriers to demand response will lead to increased levels of investment in and thereby participation of demand response resources (and help limit potential

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[124] DR Supporters Sept. 16, 2009 Comments filed in Docket No. EL-09-68-000 (Kahn Affidavit at 6). See also id. at 4 (Customers offering to reduce consumption should be induced "to behave as they would if market mechanisms alone were capable of rewarding them directly for efficient economizing.").

[125] EnerNOC May 13, 2010 Comments at 4; see also Alcoa May 13, 2010 Comments at 4; Viridity May 13, 2010 Comments at 5-6.

generator market power), moving prices closer to the levels that would result if all demand could respond to the marginal cost of energy. To that end, the Commission emphasizes that removing barriers to demand response participation is not the same as giving preferential treatment to demand response providers; rather, it facilitates greater competition, with the markets themselves determining the appropriate mix of resources, which may include both generation and demand response, needed by the RTO and ISO to balance supply and demand based on relative bids in the energy markets. In other words, while the level of compensation provided to each resource affects its willingness and ability to participate in the energy market, ultimately the markets themselves will determine the level of generation and demand response resources needed for purposes of balancing the electricity grid.[126]

60. Another issue raised by a number of commenters, largely representing generators, is whether a lower payment based on LMP-G is the economically-efficient price that sends the proper price signal to a potential demand response provider. These commenters argue that, by not consuming energy, demand response providers already effectively receive "G," the retail rate that they do not need to pay. They therefore contend that demand response providers will be overcompensated unless "G" is deducted from

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[126] Generation and demand response resources have the potential to earn other revenues through bilateral arrangements, capacity markets where they exist, and ancillary services.

payments made by the RTO or ISO for service in the wholesale energy market, resulting in a payment of LMP-G. These commenters suggest that payment of LMP-G will result in a price signal to demand response providers equivalent to the LMP (i.e., (LMP - G) + G). Similarly, some commenters argue that paying demand response resources the LMP will lead to a wholesale electricity price that is not economically efficient.[127]

61. The Commission disagrees with commenters who contend that demand response resources should be paid LMP-G in all hours. First, as discussed above, demand response resources participating in the organized wholesale energy markets can be cost-effective, as determined by the net benefits test described herein, for balancing supply and demand and, in those circumstances, it follows that the demand response resource should also receive compensation at LMP. Second, such comments largely rely on arguments about economic efficiency, analogizing to incentives for individual generators to bid their marginal cost. These arguments fail to acknowledge the market imperfections caused by the existing barriers to demand response, also discussed above. In Order No. 719, the Commission found that allowing demand response to bid into organized wholesale energy markets "expands the amount of resources available to the market, increases competition, helps reduce prices to consumers and enhances reliability."[128]

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[127] See NEPGA June 21, 2010 Comments at 1-2.

[128] Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 154.

Furthermore, Dr. Kahn argues that paying demand response LMP sets "up an arrangement that treats proffered reductions in demand on a competitive par with positive supplies; but the one is no more a [case of overcompensation] than the other: the one delivers electric power to users at marginal costs—the other—reductions in cost—both at competitively-determined levels."[129]

62. Several other considerations also support this Commission conclusion. In the absence of market power concerns, the Commission does not inquire into the costs or benefits of production for the individual resources participating as supply resources in the organized wholesale electricity markets and will not here, as requested by some commenters, single out demand response resources for adjustments to compensation. The Commission has long held that payment of LMP to supply resources clearing in the day-ahead and real-time energy markets encourages "more efficient supply and demand decisions in both the short run and long run,"[130] notwithstanding the particular costs of production of individual resources. Commenters have not justified why it would be appropriate for the Commission to continue to apply this approach to generation resources yet depart from this approach for demand response resources.

[129] DR Supporters Aug. 30, 2010 Reply Comments (Kahn Affidavit at 9-10).

[130] See New England Power Pool, 101 FERC ¶ 61,344, at P 35 (2002).

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[129] DR Supporters Aug. 30, 2010 Reply Comments (Kahn Affidavit at 9-10).

[130] <u>See</u> <u>New England Power Pool</u>, 101 FERC ¶ 61,344, at P 35 (2002).

would be useful for the Commission to know more about the feasibility of and requirements for implementing improvements to the existing dispatch algorithms. Therefore, we will require each RTO and ISO to undertake a study, either individually or collectively, examining the requirements for, costs of, and impacts of implementing a dynamic net benefits approach to the dispatch of demand resources that takes into account the billing unit effect in the economic dispatch in both the day-ahead and real-time energy markets, and to file the results of their study with the Commission on or before September 21, 2012.

85. ISO-NE and Pepco suggest that the net benefits test also consider the impact of demand response compensation on both energy and capacity markets. However, this Final Rule is focused only on organized wholesale energy markets, not capacity markets.[167] Given the differences in capacity markets among the ISOs and RTOs, the record in this proceeding provides neither a reasonable basis for including capacity market effects in net benefits calculations in the energy markets, nor have ISO-NE and Pepco provided a methodology for taking such effects into account. Indeed, in some

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[167] Additionally, the arguments presented for focusing on the effect of demand response compensation in wholesale energy markets on capacity markets were not convincing – that decreases in energy market revenues by generators will be recouped in the form of increased capacity prices. First, they fail to consider how the increased participation by demand resources could actually increase potential suppliers in the capacity markets by reducing barriers to demand resources, which would tend to drive capacity prices down. Second, they did not examine the way in which capacity markets already may take into account energy revenues.