YORK UNIVERSITÉ UNIVERSITY

FACULTY OF ENVIRONMENTAL STUDIES

HEALTH, NURSING
& ENVIRONMENTAL
STUDIES BLDG.
4700 KEELE ST.
TORONTO ON
CANADA M3J 1P3
T 416 736 5252
F 416 736 5679
fes.yorku.ca

Submission to the IESO Incremental Capacity Auction Engagement Process

By

Adlar Gross, MES.
Research Assistant

And

Mark S. Winfield, Ph.D.
Professor

Sustainable Energy Initiative

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Introduction

The Faculty of Environmental Studies Sustainable Energy Initiative[1] has several active research projects related to low-carbon sustainable energy transitions in the electricity sector. These include SSHRC funded research partnership development projects on Smart Grids[2] and Community Energy Planning[3]; leadership of the policy and regulation project within NSERC Network on Energy Storage Technologies (NEST);[4] and research on policy frameworks for energy efficiency and conservation as a tool for low-carbon sustainable energy transitions. Prof. Winfield has published extensively on electricity, energy and climate change related issues in Ontario.

The IESO capacity market (CM) proposal has been presented as the IESO's primary proposed mechanism for meeting new electricity supply requirements in the future. It is also expected to be the IESO's primary location for the commercialization of innovative activities within the Ontario electricity system. In that context it has significant implications for the future of energy efficiency (EE); demand response (DR), distributed energy resources (DERs); energy storage and renewable energy (RE) sources in Ontario.

IESO Market Renewal Objectives and Drivers

The IESO Market Renewal is being driven by a number of challenges with the status quo model. These are:

- Uncertainty for developers
- Resource specific procurements do not maximize competition or foster innovation
- Lack of flexibility to respond to evolving needs through lock-in of specific resource types
- Price of capacity co-mingled with other value drivers
- Contractual incentives are not always aligned with system needs

Key drivers for a CM in Ontario are similar to what has driven CMs in other jurisdictions. Chief among these is the missing money problem, which previously had been addressed in Ontario through the use of long-term procurement contracts. A switch to CMs in Ontario also hopes to achieve flexibility in meeting capacity requirements, transparent price signals, the ability for all resource types to participate, and shift of investment risk away from ratepayers to the supplier.

The primary drivers of benefit from market renewal are expected to be:

- Fuel, emissions, and O&M cost savings
- Reduced curtailments/spilling of non-emitting resouces
- Increased export revenues and reduced import costs
- Investment cost savings

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[1] https://sei.info.yorku.ca/

[2] https://uwaterloo.ca/sustainable-energy-policy/projects/unlocking-potential-smart-grids

[3] https://www.cekap.ca/

[4] https://www.ryerson.ca/nestnet/

- Reduced gaming opportunities, administrative complexity and unwarranted transfer payments
- Supporting competition and innovation
- Alignment with provincial policy golas

The expected benefit to customers compared to a continuation of long-term contracting scenario is in the range of $120-$200 million/year as a result of surplus capacity exports and reduced contracting, and $290-610 million in later years based on the IESO's 2016 Planning Outlooks[5]. However, it should be noted that these benefits are based on the assumption that the CM will procure the exact amount of supply needed. This is not realistic based on results from other jurisdictions (see **Figure 2** below). Furthermore, it should be noted that while a CM is a mechanism for procuring the lowest-cost capacity, benefits are not necessarily a result of the CM but are a result of procuring low-cost capacity which could also be procured through a different mechanism.

A CM could lead to reduced need for contractual support of new investment and lower contract prices due to a clearer view of post contract revenue. More efficient resource entry, exit and upgrade signals is expected to be provided by the CM so that customers will no longer have to pay for unneeded excess capacity due to lower prices during periods of excess capacity, which encourages suppliers to mothball, export or retire unneeded and higher cost resources.

Capacity auctions also only procure the amount of capacity predicted for a single year, reducing the risks of oversupply associated with long-term supply and demand forecasting. Use of one-year commitment periods reduces risk that customers will be locked into high price contracts for many years. Stable capacity payments also reduce uncertainty, making investment more attractive.

Efficiency and cost effectiveness goals may also be met through the provision of correct price signals: the supplier specifies prices and the auction clears the most cost-competitive resources. Flexibility to adapt to rapid energy sector changes may also be provided through short commitment periods and the long-term certainty of market mechanisms as auctions allow demand forecasts to update regularly, allowing procurement of the correct amount as forecasts change and procurement of the most cost effective resources, while considering what is necessary to support particular resource types.

Experience from other jurisdiction have shown that low cost non-traditional resources are procured first such as DR and uprates to existing assets with new merchant generation only procured when price signals are high enough to attract that investment. A CM also aims to level the playing field for different technologies.

The CM design is based on five fundamental assumptions (**Figure 1**). First, rather than a centralized CM as in other regions, the CM will be an incremental capacity auction (ICA)

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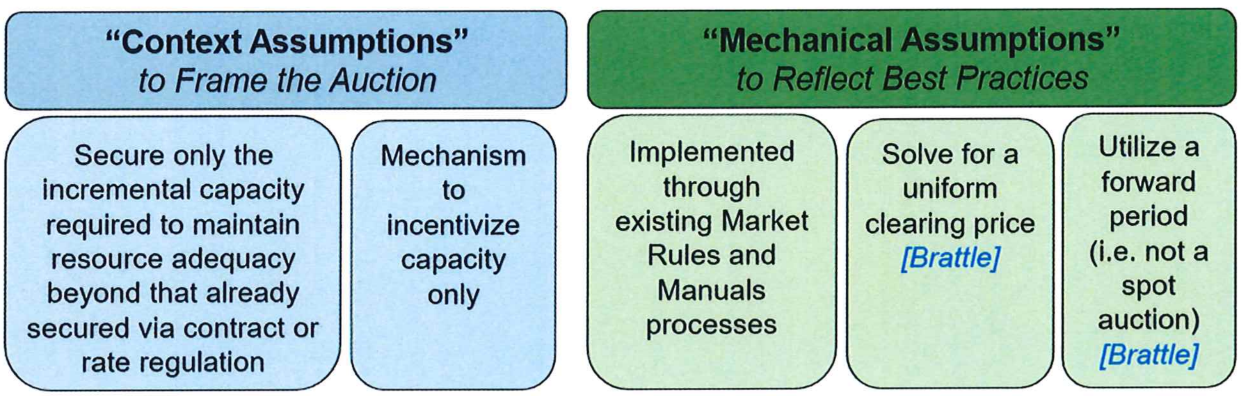
[5] The Brattle Group. (2017). Benefits Case Assessment of the Market Renewal Project.

meaning it will seek to procure capacity that is incremental to what is already under contract and rate regulation. Incremental capacity will come from merchant capacity which are resources that are not under contract and resources that have the ability to generate capacity in excess of what has been contracted. Incremental need in MW for each commitment period and zone will therefore be established through the forecasted peak demand plus the reserve margin less the MW contribution from contracted and regulated facilities.

Second, the CM will seek only to achieve resource adequacy, as any approach that would focus on maintaining more than resource adequacy would reduce the expected benefits of the auction by not sending clear price signals for the value of capacity and would require some degree of centralized and administrative decision-making that would reduce the ability of the private sector to find innovative solutions to meet system needs. The approach is to have clear and distinct price signals for each product and services needed to meet system needs. Resources that maximize revenue from other markets while minimizing their cost of supply are therefore expected to be the most competitive in the auction.

Figure 1. IESO capacity market design assumption



The next three mechanical assumptions are based on international best practices. Implementation through existing market rules and manuals is expected to maximize benefits of the market design by increasing stakeholder confidence in the mechanism and reducing uncertainty that the opportunity to earn capacity payments will not be available over the useful life of the resource. A uniform clearing price has been shown to achieve the most efficient results in the short and long run by incentivizing suppliers to offer at the lowest acceptable price to maximize their likelihood of clearing the market. This approach also minimizes costs as the market will clear the low-cost mix of resources and recognizes equal value of the same product purely by their ability to deliver MW of capacity. A forward period was chosen as opposed to a spot market as spot markets can limit competition between new and existing resources and increase price volatility and resource shortages as there is little recourse to correct for shortages through rebalancing auctions for example. The exact length of the forward period has yet to be determined.

Implications for the IESO Incremental Capacity Auction

Despite the apparent success of CMs in meeting resource adequacy goals, overcoming the missing money problem and shifting risk away from ratepayers in recent years, significant debate has emerged around the efficiency and effectiveness of CMs and whether or not they are the appropriate mechanism to facilitate the clean energy transition with markets constantly under review and rules being changed to adapt to the shifting landscape[6].

In a survey of US electricity sector experts on CMs the main concerns raised by respondents in order of frequency, were:

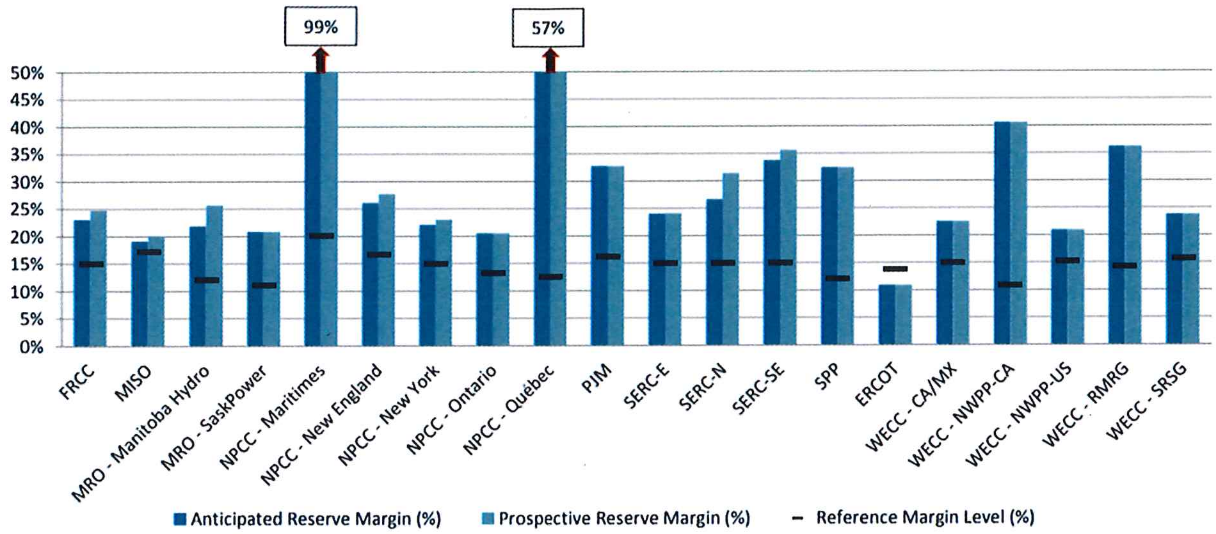
- The differing designs and timing of neighbouring capacity markets,
- Continuous administrative rule changes that increase regulatory risk for investors
- Exercise of market power, including bidding above marginal cost and then double dipping by selling capacity credits, and then exporting power from the same generator to a neighbouring market
- Uncertainty around the availability of generation capacity that has been committed under actual scarcity conditions[8].

CMs can also be susceptible to manipulation by generators and loads due to their preset procurements, which leads to the need for regulations on offers and performance, bid mitigation, and other complications**Error! Bookmark not defined.**. For example, in 2018 the PJM independent market monitor found that energy markets have been workably competitive, while CMs have failed the three pivotal supplier tests (TPS), finding that structural market power is endemic to the CM[7].

In terms of meeting reliability goals, CMs have been successful with implementing regions meeting their reserve margin targets. However, many argue that they have done so in an economically inefficient way, which has resulted in excess generation capacity at the cost of consumers[8]. Indeed, most regions end up procuring substantially larger reserve margins than required[9] (**Figure 2**).

Figure 2. Comparison of anticipated and prospective reserve margins to a reference level*

[6] Heidorn, R. (September, 2018). 'Almost nobody is happy' with capacity markets at conference. *RTO Insider.*
[7] Independent Market Monitor for PJM. (2019). State of the market report for PJM. Section 5: Capacity Market
[8] Bhagwat, P. C., de Vries, L. J., and Hobbs, B. F. (2016). Expert survey on capacity markets in the US: Lessons for the EU. *Utilities Policy, 38.* 11-17.
[9] NERC. (2018). Summer reliability assessment.



*Anticipated reserve margin is existing certain capacity plus capacity under construction. Prospective reserve margin is generating units that are expected to be available. The reference margin is the required reserve margin for that area.

Some have also recognized the natural hedge conferred by CMs to natural gas (NG) generators. Since the inception of liberalized electricity markets in the late 1990s the majority of merchant investment for new generation capacity has been in NG generation and has been the dominate form of capacity procured in CMs. Improvements in the efficiency of combined cycle plants as well as low NG prices as a result of the shale revolution have contributed to this[10]. However, NG has a natural hedge in electricity markets. The price in electricity markets have been historically set by the short-run marginal cost of generation. Since NG is characterized by low capital costs and high operating costs, NG is often the price maker. Electricity market prices are therefore effectively tied to NG fuel prices as the marginal cost of generation for a NG plant depends on the efficiency of the plant and the fuel price. As price makers, NG plants therefore enjoy a natural hedge in electricity markets as fuel prices are passed through to consumers making them less exposed to market risks[11]. This can make investment in renewable energy technologies less attractive[12].

Mays et al. (2019), argue that this hedge only confers an advantage when combined with CMs. In energy-only markets NG peaker plants with high operating costs rely on scarcity events to recover their fixed and operating costs. A CM removes risk related to the frequency of scarcity events, while only partially derisking variable and baseload generation. Therefore, the

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[10] Mays, J., Morton, D. P., and O'Neill, R. P. (2019). Asymmetric risk and fuel neutrality in capacity markets. USAEE Working Paper No. 19-385

[11] Gross, R., Blyth, W. and Heptonstall. (2010). Risks, revenues and investment in electricity generation: Why policy needs to look beyond costs. *Energy Economics, 32*(4). 796-804.

[12] Guo, X., Beskos, A., and Siddiqui. (2016). The natural hedge of a gas-fired power plant. *Computational Management Science, 13*(1). 63-86.

introduction of a CM has a stronger impact on the risk profile of technologies with higher operating costs.

Capacity Markets in the Clean Energy Transition

CMs at their core have always been about ensuring grid reliability by meeting resource adequacy goals at the lowest cost through technology neutral competition. However, as the market share of alternative resources increases, including DERs and variable renewable generation (VRE) new challenges for measuring their reliability benefits are arising, creating legitimate differences in opinion and tensions between local regulatory authorities and regional transmission operators[13]. Key elements that have been debated and periodically revised include:

- Should qualifying capacity be limited to resources that can be made available on demand, or evaluated based upon a probabilistic expectation of performance?
- How location specific should capacity procurement be?
- What performance characteristics should be required?
- What are the performance obligations of participating capacity?
- Should those obligations be applied uniformly or adapted to specific resources such as energy-limited storage, and variable energy resources?

There is also no clear convergence on how VREs should be treated in CM's as is evidenced by the variety of methods for how non-performance penalties are defined, how these penalties should be applied to VREs and how qualifying capacity should be determined[14]. For example, see **Table 1** for variations across U.S CMs in calculating qualifying capacity of VRE.

Table 1. Qualifying capacity of VRE in across U.S. Capacity Markets

ISO	Wind	Solar
PJM	14.7–17.6%	38%–60%
ISO-NE	9–18% (summer)	27–33% (summer)
MISO	15.6%	50%
NYISO	10% (summer)	26–46% (summer)
	30% (winter)	0–2% (winter)
	38% (offshore, both seasons)	

Whether or not a market is truly technology neutral is ultimately determined by the market rules, and in practice market rules have favoured certain types of resources. The primary examples of this in U.S. CMs are market rules that do not adequately account for the

[13] Bushnell, J. Flagg, M., and Mansur, E. (2017). Capacity markets at a crossroads. Energy Institute at Haas.
[14] Byers C., Levin, T., and Botterud, A. (2018). Capacity market design and renewable energy: Performance incentives, qualifying capacity, and demand curves. *Electricity Journal, 31.* 65-74.

operational characteristics of different technologies which have acted as barriers to participation of alternative energy sources such as DR, EE, VRE and energy storage.

Barriers to Alternative Energy Resources in the ICA High-Level Design

While we commend the IESO for opening eligibility to a wide range of resources by allowing aggregation, and accounting for seasonal differences in performance by establishing separate winter and summer auctions with respective demand curves, a number of concerns remain as to how market rules may confer advantages to certain resources.

A key concern is the uncertainties involved with valuing the capacity of VRE years in advance of their actual production which can also negatively impact the revenues they receive from the CM. Due to the methodology for calculating unforced capacity (UCAP) VRE will receive less capacity revenues from the CM and will therefore rely more on energy market revenues for cost recovery. This puts more pressure on energy markets to be designed to accurately reflect demand and supply and not be distorted by capacity payments. Non-performance penalties contemplated in the High-Level Design also present more risk for VRE that other resources do not have. This needs to be balanced with the natural hedge that NG generators have in CMs and energy markets as described above.

Current barriers to further DER integration were identified by the recent Non-Emitting Resource Sub-Committee (NERSC) report to the Market Renewal Group. In order to overcome revenue streams gaps NERSC identified the need to unbundle ancillary services and for the creation of new ancillary services such as flexibility and ramping products in order to respond to the growth of VRE and DER. The lack of demand-side bilateral contract counterparties was also identified as a barrier, citing the ability of LSEs in the US to contract with customers to meet system needs. In terms of CM participation key market barriers included the 1 MW minimum size threshold, costs related to metering and communication, and barriers to energy storage that prevent them from delivering their full value to the grid, such as the many regulatory and load-related charges that energy storage is subject to as both a generator and a load.

It may be difficult for aggregators to reach the 1 MW minimum capability requirement as eligibility is limited to those DERs that are connected to a single transmission node. This concern has been raised in regard to participation in NYISO's ancillary markets as part of their DER integration proposal[15]. In recognition that individual resource capability is not necessarily a marker of value, NYISO has lowered this threshold to 100 kW for their energy and CMs. Another challenge of DERs in CMs is the decline in capacity value as net peak shifts.

Allowing DR resources participating in the Transitional Capacity Auction to participate in and receive payments from the energy market in the same way other eligible generation resources

[15] NYISO. (2017). Distributed energy resource 2017 market design concept proposal

do is also imperative to ensuring fair competition with the other resources. Other eligible generators should be subject to the same performance penalties as DR.

A lack of a mechanism for behind-the-meter generation to participate other than through DR products will also restricts the ability of these resources to provide their full value that they are capable of to the system and ratepayers. It should also be noted here

The High-level design contemplates a minimum duration threshold of between 2 to 4 hours. Where this number ends up will heavily impact the business case for energy storage as requiring that storage resources are able to deliver for a four-hour period will significantly increase costs in order to reach the required capacity. In addition, if a state of charge capable of delivering for four hours is required at all times, then this may prevent the storage resource from being able to provide other grid services. In terms of the 3.5 year forward period, some DR resources will have difficulties in securing individual customers so far in advance, however new builds, particularly hydroelectric resources will have difficulty with a short forward period, preferring longer forward periods to have enough time for construction[16].

There is also an ongoing debate as to what the appropriate reference technology should be to determine the net cost of new energy (net CONE), which serves as the basis of the demand curve and is one factor in determining the market clearing price which occurs at the intersection of the demand curve and the supply curve. Gas-fired simple-cycle CT is often used as the reference technology. Concerns over this are that a reference technology based on the lowest capital cost of capacity might lead to overpayment of other technologies with lower net CONE and the approach may favour selection of one technology when a larger technology mix would be desirable.

In order for market rules to capture the operational characteristics of different resources. This may mean setting different participation rules for different resources. This approach has drawn criticism particularly in regard to DR in PJM markets, where concerns were raised that DR resources were not being treated in a manner comparable to generation resources suggesting that DR should be subject to a must-offer requirement in the energy market as well as an offer cap. However, FERC ruled that functional and operation differences between DR and generation are justification to accommodate unique operational characteristics of DR[17].

While the details of the market rules will be a large determining factor on whether or not DERs will be able to participate, and compete on an even footing with other resources, the ability of DERs to provide their full value will require proper grid upgrades to allow the needed visibility and bidirectional flow associated with DERs. For energy storage, a key problem that needs to be overcome is that the IESO system sees a storage resource as two separate entities, a load and a generator with no storage capacity and no relationship to each other. The result is a risk of

[16] Charles River Associates. (2017). A case study in market design and considerations for Alberta.
[17] The Brattle Group. (2017). Review of PJM's Independent Market Monitor's Criticism of Demand Response Participation in PJM's Capacity and Energy Markets.

conflicting dispatch instruction between the two facility components and an inability to optimize storage capacity through the Dispatch Scheduling and Optimization (DSO) algorithm[18].

As lessons are learned from the current fleet of dispatchable storage facilities in Ontario key questions around market design include:

- Can market participants adequately manage state of charge on their own? Is this the most efficient solution?
- Is the mandatory window for bid/offer changes too
- restrictive?
- Can storage facilities feasibly offer reliable operating reserve without state of charge monitoring in the DSO algorithm?
- Will conflicting dispatch between generator and load segments become a significant problem?

It is clear that how these questions are answered will significantly affect the business case for energy storage. If market participants are not allowed to manage their own state of charge through for example requirements that a minimum state of charge be required at all times for participation in a particular market then the ability to value stack will be diminished. Questions also remain as to if performance penalties in CMs will be enough of an incentive to avoid a situation where there is insufficient state of charge to meet a performance obligation.

In order for market rules to capture the operational characteristics of different resources, this may mean setting different participation rules for different resources. At the same time, resources competing for delivery of the same product should be subject to the same penalties and compensation methods. Accounting for different operational characteristics in an approach that has drawn criticism particularly in regard to DR in PJM markets, where concerns were raised that DR resources were not being treated in a manner comparable to generation resources suggesting that DR should be subject to a must-offer requirement in the energy market as well as an offer cap. However, FERC ruled that functional and operation differences between DR and generation are justification to accommodate unique operational characteristics of DR[19].

Alternative Market Designs

Due to the existing bilateral contracts with nuclear and RE suppliers forming the majority of generation, who will not be allowed to participate in the CM, the ICA is intended to procure additional capacity beyond what is met by these resources. However, a number of NG generation units will soon be reaching the end of their contracts enabling them to participate in the auction (**Figure 3**). **While the CM claims to be technology neutral, it is clear from the context of the electricity sector that existing NG generators that have already recovered their**

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[18] Energy Storage Advisory Group. (2018). Ontario energy storage context.

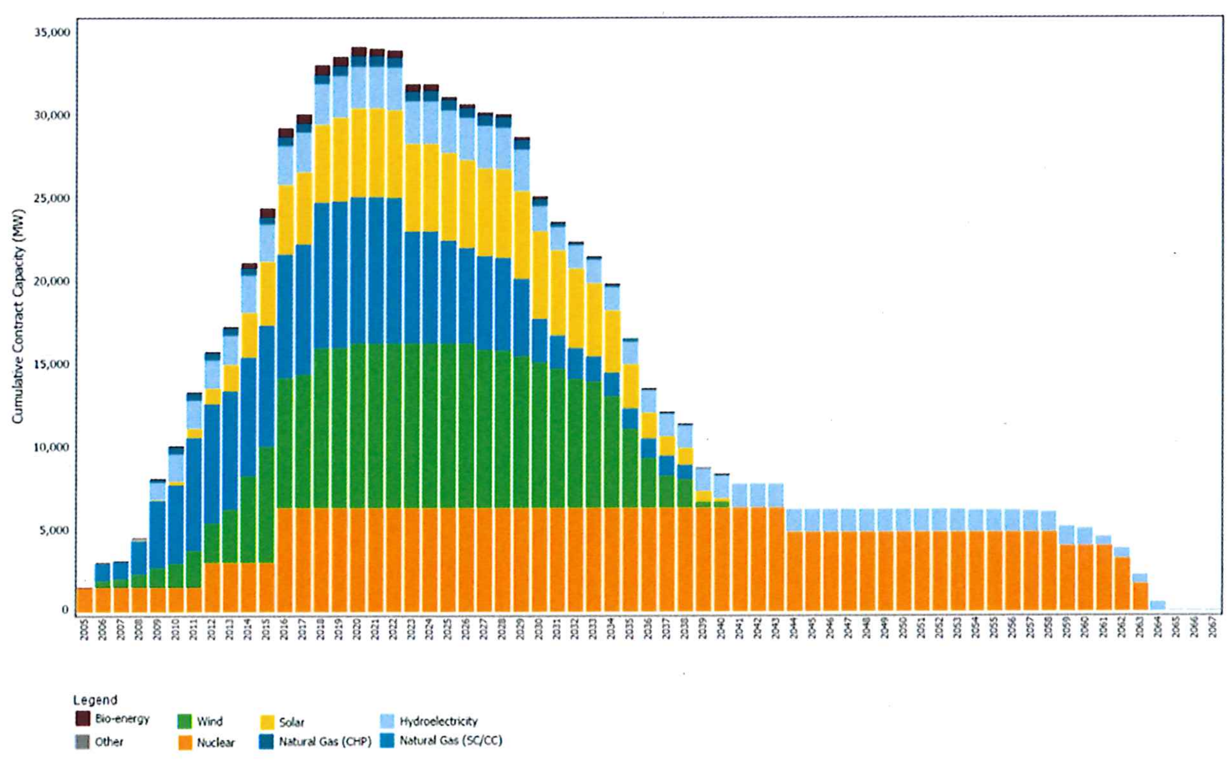
[19] The Brattle Group. (2017). Review of PJM's Independent Market Monitor's Criticism of Demand Response Participation in PJM's Capacity and Energy Markets.

fixed costs will be able to make the lowest bid into the auction. This effectively makes the CM a method for determining which existing NG generators are the most cost-effective and should be allowed to operate and which ones should retire.

These problems are reinforced by the lack of any weighting of environmental attributes in the proposed CM design. This approach will again tend to favour NG generation over other alternatives, particularly RE and storage. The lack of weighting of environmental attributes could also encourage the use of fossil-fueled (e.g. diesel) resources for DR. The limitation on participation of EE resources other than for DR, prior to 2024 is also a serious concern.

Market designs are stable and long-lasting constructs. Rather than commit to a design that will likely have to be changed in the near future due to the rise of DERs, the IESO should consider alternative market designs that will allow proper integration of DERs and address the flexibility needs of increasing shares of VRE. At the very least alternative CM market designs should be considered that value the quality of the service provided such as flexibility rather than just procuring the lowest cost firm capacity resources.

Figure 3. Expected lifetime of IESO contracts[20]



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[20] IESO. (2017). A progress report on contracted electricity supply

Flexibility

What can be agreed on is that markets need to provide resource adequacy and reliability as the share of VRE and behind-the-meter and front-of-the-meter DERs continue to increase, and as costs continue to fall rapidly. This adds a new dimension to the conventional resource adequacy question: flexibility. Flexibility solves the emerging system quality problem of ensuring that the right mix of resources are in place to ensure supply can be balanced with demand. This is in the context of increasing variability in net demand forecasts.

Traditionally, ancillary markets have been used to ensure flexibility options are available to the system. However, short-term markets such as these may not suffice when integrating higher shares of VRE. CMs in terms of how they have been traditionally designed do not address this either as they only value firm capacity, therefore devaluing other resource attributes, and favouring low cost, and therefore likely less flexible capacity[21].

As the IESO's High-Level ICA design largely reflects conventional design based on the experience of CMs in the US it is doubtful that it will be able to address these needs. Although, the IESO does expect that system flexibility will be an area for future market evolution as the share of DERs in the system continues to rise and recognizes the need to adapt future market designs to integrate DERs into the system and allow them to participate in wholesale markets[22]. However, it should be noted that the IESO does not expect a large level of load defection from DERs in the near-term due to the current lack of out of market subsidies and out of market payments. The IESO should carefully consider this assumption as the costs of DER continue to rapidly fall. This will have major implications for demand forecasts and properly setting demand curves in the capacity auctions and will increase risks of procuring over-supply. DERs can be deployed quickly which could significantly alter demand during the 3.5 year forward period.

The ability to value flexibility is gaining increased attention in electricity markets, although few have yet developed concrete mechanisms to do so. CAISO and MISO seem to be the first in developing products to ensure up and down ramping capabilities. The CAISO Flexible Ramping Product allows sufficient ramping capability to be procured through economic bids in the 15- and 5-minute markets. Two products, the Flexible Ramp Up and Flexible Ramp Down provide additional capability to account for uncertainty due to demand and renewable forecasting errors as well as real-time interchange schedules[23]. MISO is developing a product that issues

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[21] Hogan, M. (2012). What lies beyond capacity markets? Delivering least-cost reliability under the new resource paradigm.

[22] IESO. (2019). Participation in Ontario's future electricity markets. A Non-Emitting Resource Subcommittee report to the Market Renewal Working Group.

[23] CAISO. (2019). Flexible Ramping Product. Retrieved from: http://www.caiso.com/informed/Pages/StakeholderProcesses/CompletedClosedStakeholderInitiatives/FlexibleRampingProduct.aspx

payments to resources cleared for ramp capability regardless of real-time dispatch instructions[24].

These approaches are short-term mechanisms that work alongside the energy and ancillary markets. However, to ensure flexible resources are available over the long-term, price signals may be needed similar to the basis that CMs were developed on. In order to do this Hogan proposes mechanisms to integrate net demand forecasts into investor's revenue models[25]. A separate capability market that would seek to balance greater resource flexibility at least cost, taking into account the costs of curtailing VRE generation or committing back-up generation would be ideal. However, as few markets have the time or capacity to do this Hogan proposes an enhanced services market and an apportioned forward capacity mechanism.

The enhanced services market would utilize a long-term services market to procure resource capabilities derived from the net demand forecast with value being set by periodic forward auctions. Capabilities to be procured would likely be already existing functions such as ten-minute spinning and non-spinning reserves, and operating reserves. This would most likely operate in the absence of a CM, although it conceivably could operate alongside one if the CM was strictly to address resource adequacy. The benefit of this approach is to unbundle the long-term procurement of system services from processes to procure firm production capacity.

The apportioned forward capacity mechanism would apportion the existing CM into tranches based on the target mix of resource capabilities derived from the net demand forecast. This takes existing resource adequacy mechanism and breaks the quantity of firm resources required into tranches based on specific resource attributes. Resources would then bid into the highest-value tranche they could qualify for and tranches would clear starting with the most flexible one. The original PJM CM design in fact contemplated a design similar to this but was dropped in the final design in response to stakeholder concerns around complexity and market liquidity. The tranches specified in this design were dispatchable, flexible cycling, supplemental reserves, and tranche that included all other products. The market then cleared in stages based on the desired amounts in each category. One of the advantages of this approach is system operators can differentiate the value of capacity payment streams based on operation capabilities rather than on criteria that have no tangible reliability rationale such as new versus existing resources or strategic reserves versus other firm capacity.

Enabling DER

No matter the CM design, a sustained buildout of DER will be constrained until the needed upgrades to grid communication, controls and metering to allow bi-directional flow and sufficient visibility are addressed. As the role of LDCs as enablers of DER continues to grow and

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[24] MISO. (2019). Ramp capability product development. Retrieved from: https://www.misoenergy.org/stakeholder-engagement/issue-tracking/ramp-capability-product-development/

[25] Hogan, M. (2012). What lies beyond capacity markets? Delivering least-cost reliability under the new resource paradigm.

address the challenges through enabling platforms such as Hydro Ottawa's GREAT DR Protocol and the Alectra's Power.House a bottom-up model resembling load-serving entitiesin the US could be an attractive model. Such an approach was outlined in a discussion paper prepared for the Ontario Energy Association in 2018 and has the potential to provide significant benefits through increased efficiencies in planning and resource procurement[26]. The proposed model would give LDCs the responsibility to secure resources from third-party providers as well as the ability to meet their own supply needs through owning and operating their own assets. Any additional capacity needed could then be procured through an IESO procurement process.

Work in the NYISO to integrate DERs into the energy, capacity and ancillary markets also provides a promising way forward[27]. The proposal sets a broader definition of DERs, distinguishing between different types of DER: dispatchable, non-dispatchable and front of the meter. Also key to the proposal is developing more granular pricing in conjunction with distribution utilities which would offer more locational pricing points on the transmission system. Currently, prices are calculated and published on a zonal basis every five minutes which does not provide the necessary level of granular pricing needed to determine the most cost-effective locations within a zone to invest. The new approach publishes intra-zonal prices that identify where on the grid DERs would be most beneficial. The NYISO also recognizes that as more behind-the-meter solar is added this could lead to more dynamic load particularly in concentrated communities like New York City, which will require sufficient resources to be available to respond to unexpected load increases. To address this the NYISO is developing additional reserve requirements for New York City that will provide location-specific market signals consistent with any reliability need[28].

In addition to allowing participation of EE in the ICA, the IESO should also consider allowing behind-the-meter solar another avenue to participate as passive DR as is done in the ISO-New England market.

Conclusions

The IESO has presented a detailed concept for the operation of an incremental capacity market in Ontario. However, we are concerned that the current proposal would tend to favour conventional fossil-fuel resources, particularly NG, while its implications for newer and

[26] Power Advisory LLC. (2018). Policy Case: Recommendations for an Ontario Load-Serving Entity Model. Retrieved from: https://energyontario.ca/wp-content/uploads/2018/09/OEA-LSE-Report-September-2018-Final.pdf
[27] NYISO. (2017) Distributed energy resources market design concept proposal. Retrieved from: https://www.nyiso.com/documents/20142/1404696/Distributed%20Energy%20Resources%202017%20Market%20Design%20Concept%20Proposal.pdf
[28] NYISO. (2019). State of the grid. Retrieved from: https://www.nyiso.com/documents/20142/2223020/2019-Power-Trends-Report.pdf/0e8d65ee-820c-a718-452c-6c59b2d4818b

potentially more sustainable technological options, including EE, RE, DERs and storage are at best unclear.

Ontario's situation is unusual in that it will have a large (~10,000MW capacity) fleet of relatively underutilized NG resources coming off contract over the next decade. The nature of the original contracts for these resources has been such that their capital costs will be retired. The combination of the high operational flexibility of these resources, along with their low operating costs due to low natural gas prices, and the absence of any weighting of the environmental attributes of resources in the IESO's design, means that they are likely to be able to participate in the proposed capacity market at very low cost, and are likely to dominate that market as a result. This will run risks of significant increases in GHG emissions associated with Ontario's electricity sector, while leaving little room for innovation and the adoption of new, and potentially more sustainable, energy technologies.

IESO needs to consider the implications of these risks, and the experiences of other jurisdictions with the development of capacity markets, in the design of its capacity market initiative. Conservation may also need to be given to the role of other mechanisms in optimizing the contributions of EE, storage, DERs and RE in Ontario's energy system.