
Near-Term Reliability Auctions in the NEM

Lessons from International Jurisdictions

PREPARED FOR



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Executive Summary

The Australian National Electricity Market (NEM) has experienced a series of events in the past year, including a blackout and involuntary load shedding in South Australia, the retirement of the Hazelwood power station, and the failure of the Tasmania–Victoria interconnector. These events had a variety of causes, but they highlight the potential vulnerability of reliability and system security in the future as variable renewable electricity (VRE) resources further displace traditional capacity that historically provided dispatchability and other grid services.

The Commonwealth requested that AEMO evaluate the need for dispatchable resources in the NEM and how various options for obtaining these resources could impact wholesale prices. As one part of its response to the government’s request for advice, AEMO asked The Brattle Group to review the experience of other jurisdictions around the world that have used a range of different approaches to securing supply commitments to improve reliability and security. We present a series of case studies of other markets’ experiences that may provide useful lessons for the NEM. For each case study, we describe the problem(s) faced by the market, the chosen solution, and highlight key insights applicable to the NEM’s current situation. The case studies we have chosen include measures implemented in energy-only markets like the NEM and from a variety of other market and regulatory contexts.

Energy-only markets by definition do not place obligations on market participants to procure or invest in a certain amount of capacity. Rather, energy (and ancillary services) prices drive investment. In some jurisdictions, additional measures have been implemented to provide greater certainty that reliability goals will be met. In Belgium, the system operator procures strategic reserves on a 1-year forward basis to support reliability. These strategic reserves are held outside the market and only deployed when there is a supply shortfall and load shedding would otherwise be necessary. This preserves the price signal for investment in the energy market. Similarly, Texas supports reliability without interfering with market price signals by using a demand response program called the Emergency Response Service (ERS), which only operates if an immediate supply shortfall is forecast. Texas also issues reliability must run (RMR) contracts to prevent imminent generation retirements that would threaten reliability. To preserve the market price signal, these generators must offer at the market caprice cap. In Alberta a fast-acting demand response program was created to secure higher levels of imports on its interconnector with , without interfering with market price signals. The Load Shed Service for Imports (LSSi) program stabilizes frequency following a loss of generation contingency by disconnecting LSSi providers’ load.

In some markets, long term contracts are used to varying degrees to procure energy and capacity to meet policy goals with greater certainty. In Ontario, long-term contracts have been used to acquire the majority of its supply. These contracts have been effective in maintaining reliability and achieving policy goals, but have undermined the potential for market-based investment leading to high realized costs of electricity. The Province is now attempting to return to a more market-based investment model to address rising costs.

Capacity mechanisms explicitly pay resources for being *available* to generate, in addition to paying them for the actual energy generated. However, in recent years a number of system operators with capacity mechanisms have realized that the capacity paid for may not always be able to deliver the services they need. In New York, the system operator is evaluating the option of imposing additional requirements on some resources participating in the capacity mechanism, such as having backup fuel. To strengthen incentives for performance, they have also introduced increasingly strong administrative scarcity pricing in the energy market during shortage conditions. In New England, strong performance incentives have been introduced by imposing large penalties on under-performing resources and granting large bonuses to over-performing resources. In Ireland, “reliability options” have been introduced that combine an availability payment to generators and a partial hedge on energy prices for customers. Generators will compete to sell these reliability options in a centralized exchange.

I. Introduction

As one part of responding to a recent request from the Commonwealth for advice on the need for dispatchable resources in the National Electricity Market (NEM), the Australian Energy Market Operator (AEMO) asked The Brattle Group to review the experience of other jurisdictions around the world that have used a range of different approaches to securing supply commitments to improve reliability and security.

We present a series of case studies of other markets' experiences that may provide useful lessons for the NEM. For each case study, we describe the problem(s) faced by the market, the chosen solution, and highlight key insights applicable to the NEM's current situation. The case studies we have chosen include measures implemented in energy-only markets like the NEM and from a variety of other market and regulatory contexts.

II. Energy-Only Markets Augmented by Reliability and Security Products

Energy-only markets by definition do not place obligations on market participants to procure or invest in a certain amount of capacity. Rather, energy (and ancillary services) prices drive investment. The investment signal becomes stronger when capacity is needed for reliability, since prices rise as supplies become scarce. We refer to "scarcity prices" as prices substantially above short-run marginal cost. Scarcity prices may be set by what the market will bear or at the price cap when supplies are inadequate (as in the NEM) or with other administrative pricing mechanisms (as in Texas and other markets).

There is no guarantee that scarcity prices will be sufficient to always meet policymakers' goals, however, for two reasons: (1) scarcity prices may not be aligned with the policymakers' reliability objective, reflecting the objective's implied value of lost load; or (2) the market may be slow to respond to rising energy and ancillary service prices, particularly surrounding large discontinuous and uncertain events such as major plant retirements. Thus energy-only markets may find that they have less supply than needed to achieve certainty over reliability goals.

To help address this problem, system operators in Belgium and Texas have the ability to hold capacity resources in reserve, to be made available only during events of severe system stress. (Texas has also dramatically increased its administrative scarcity pricing provisions during shortage conditions.) The reserves are intended to boost the reliability of the system without undermining investment signals in the energy market. Alberta uses a uniquely structured demand response program to secure its interconnection with British Columbia. While Alberta's program addresses a system security need rather than a reliability need, we present it here because the mechanism is relevant to the Australian context.

A. BELGIAN STRATEGIC RESERVES

In the winter of 2014, the Belgian system operator (Elia) anticipated a supply shortfall due to a combination of planned nuclear retirements, announced retirements of gas plants, and a lack of investment in new supply. It implemented a Strategic Reserve in its energy-only market to avoid the capacity shortfall and maintain reliability. The construct is similar in many ways to AEMO's Reliability and Reserve Trader (RERT) program. The system operator procures a block of capacity that can be called upon in case of a supply shortfall, with the supply dispatched only during supply shortfalls.¹

In order to improve reliability, reserve capacity must be incremental to the capacity that is anyway available in the market. Elia has attempted to achieve this by limiting participation in the strategic reserve procurement to demand response and existing generators that have announced plans to mothball or retire. Generators that have announced retirement or mothballing are required to offer into the procurement mechanism, and qualifying demand resources are also eligible to offer.² However, there is some concern that marginal generators may have an incentive to announce retirement in order to enter the reserve.

The primary goal of a strategic reserve is to boost reliability without undermining investment signals in the energy market. Belgium's strategic reserve achieves this by limiting activation to severe reliability events when the market would otherwise require load shedding and by keeping prices at the cap during activation. The system operator activates the reserve only when there is insufficient supply to meet demand in the day-ahead market, or if it anticipates a shortfall within the operating day.³ During reserve activation, energy prices rise to the market price cap.

Belgium's strategic reserves can be activated either during the day ahead process, or during real time. Belgium's non-mandatory day ahead market is conducted by EPEX Spot, a third party exchange. If the day ahead market fails to clear, the strategic reserves are deployed at the day-ahead market price cap of €3,000/MWh. Additionally, if the system operator determines that a real time shortage would have existed but for the activation of the reserve, the real time price is set at the balancing market price cap of €4,500/MWh.

¹ The RERT program differs from Belgian strategic reserves in terms of the time frame for procurement and the conditions for deployment. Starting in summer 2017/18, RERT resources can be procured up to ten weeks in advance of anticipated need, compared to the Belgian annual procurement cycle that begins a year prior to delivery. Belgian strategic reserves can be deployed only if an energy shortfall is anticipated, whereas RERT can be deployed for an operating reserve shortfall. During RERT deployment, energy prices are set by conducting a "but-for" pricing run without the deployed supply, but Belgium sets energy prices at the price cap throughout deployment.

² Demand resources can offer two types of service. "Drop-to" requires demand to reduce consumption down to a pre-specified level when called upon. "Drop-by" requires demand to reduce consumption by a pre-specified number of megawatts.

³ Resources in the Reserve have up to 6.5 hours to respond after they have been activated.

Belgium's tendering for strategic reserve capacity takes place on an annual schedule. One year ahead of the winter reliability period, the system operator performs a study to determine the shortfall relative to the supply needed to meet Belgian reliability requirements. In addition to determining the quantity of reserves required, it also determines whether supply should be procured on 1, 2, or 3-year contracts, depending on the expected duration of the shortfall.⁴ After approval from the Minister of Energy of the quantity and duration of contracts to be procured, the system operator conducts a pay-as-bid tendering process for the shortfall.⁵ The tendering process concludes two months prior to the start of the winter reliability period.

Figure 1 shows the quantity of resources procured for each of the three years the strategic reserve has been active. In the reserve's first year, the anticipated shortfall was just over 800 MW. By the next year, the procurement target had increased substantially to over 1,500 MW, in part due to 1,650 MW of announced retirements.⁶ The European Commission expressed concern that some of these retirements may have been motivated by an attempt to secure payments in the strategic reserve.⁷ In 2016/17, the procurement target dropped substantially after nuclear capacity avoided anticipated retirement.

Existing peaking generators that would otherwise be retired or mothballed are a natural resource for strategic reserves because of their combination of low fixed costs and high marginal costs. Demand response also lends itself to strategic reserves with its low fixed costs and tendency not to curtail until prices rise above a relatively high "strike price." By contrast, resources with high fixed costs and low marginal costs are better suited to operate many hours of the year in the energy market. Such resources would face substantial losses if they were kept in the reserve and their supply withheld from the market. Since demand response and existing peaking generators would operate infrequently in the energy market, there is little value to be lost from holding them in reserve.⁸

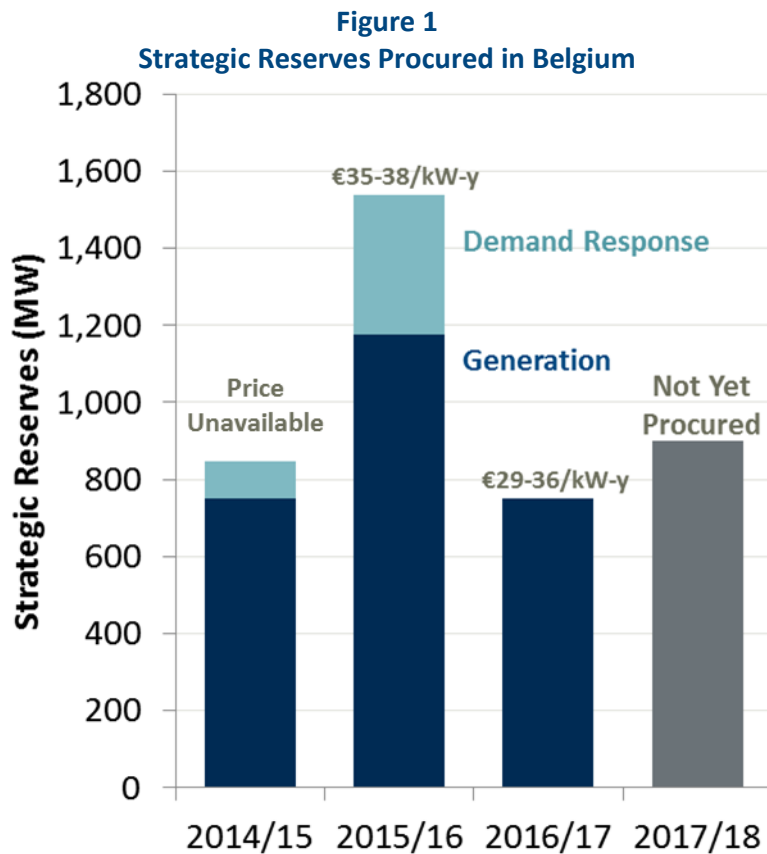
⁴ Strategic reserves may be procured with delivery periods of up to three years if the system operator anticipates a multi-year shortfall. If the shortfall is expected to vary across the delivery period, the system operator will procure no more than the minimum shortfall on a multi-year basis. The remainder will be procured on a single-year basis.

⁵ While the auction is ostensibly pay-as-bid, the national energy regulator has the authority to revise offers it determines to be "manifestly unreasonable." Market participants have expressed concern about the non-transparency of this scheme. See p. 123 of European Commission (2016).

⁶ See Elia (2015).

⁷ See p. 135 of European commission (2016).

⁸ Allowing supply in the reserve to offer into the energy markets is not a recommended solution to this problem due to the risk of suppressing energy prices.



Source: B. De Wachter, Elia. "Strategic Reserves in Belgium," European Capacity Mechanisms Forum, February 2017. Posted at: <http://www.elia.be/en/suppliers/purchasing-categories/energy-purchases/Strategic-Reserve-Volumes-Prices>

B. TEXAS EMERGENCY RESPONSE SERVICE AND RELIABILITY-MUST-RUN

The Electric Reliability Council of Texas (ERCOT) is the system operator for the energy-only wholesale market covering much of Texas. A load-shedding event in the spring of 2006 prompted ERCOT to create the Emergency Interruptible Load Service (EILS) product, later renamed Emergency Response Service (ERS).⁹ Participating load resources commit to be available for curtailment during times of supply scarcity, via direct signal from ERCOT. In exchange, ERS resources receive an availability payment, not unlike capacity payments received by load resources participating in capacity mechanisms elsewhere.

ERS resources can offer with a notification period of either 10-minutes or 30-minutes and are then required to respond to a signal from the system operator within that time period. ERCOT deploys these resources when an immediate reserve shortfall occurs, using an out-of-market signal. Resources with 10-minute notification times are paid the same as 30-minute resources for their availability, but are deployed only during less-frequent severe reserve

⁹ See Brown et al. (2015), p. 43.

shortfalls. All ERS resources are limited to a maximum of eight cumulative hours of deployment in an ERS contract period, which lasts four months.¹⁰

ERS resources are procured through an auction three times per year, for four-month contract terms. For each term, ERCOT procures resources across six availability periods that together cover all hours of each four-month contract term.¹¹ The different periods give load resources the flexibility to choose when to offer depending on the nature of their loads.¹² For historical reasons, ERCOT procures ERS up to a \$50 million annual expenditure limit which is divided between each availability period in a year based on anticipated need for ERS.¹³ ERCOT then develops a capacity demand curve for each availability period reflecting both the expenditure limit and an offer cap of \$80/MW/h.¹⁴ Figure 2 shows an indicative ERS demand curve for a single availability period.

ERS resources have baselines representing their expected consumption during all of the hours of the availability period. In establishing the baseline, ERCOT may account for factors including weather, day of the week, time of day, and consumption during similar days. ERCOT measures curtailment relative to this baseline when evaluating the performance of ERS resources. It also imposes an availability penalty on resources consuming *less* than their baseline throughout the availability period, except when called upon to curtail. The availability penalty discourages demand response (DR) from curtailing before being activated, even if energy prices are high. This is similar to strategic reserves, where reserves are prevented from reacting to energy prices and are activated only during times of system stress.¹⁵

¹⁰ See ERCOT (2017a) for a detailed discussion of the ERS product types and ERCOT (2017b) for a discussion of the performance requirement.

¹¹ As an example, Time Period 1 spans 6AM – 8AM on Mon-Fri except ERCOT Holidays (for a total of 255 hours over the course of four months). Other time periods cover different parts of the day at various durations (e.g., 9AM – 1PM).

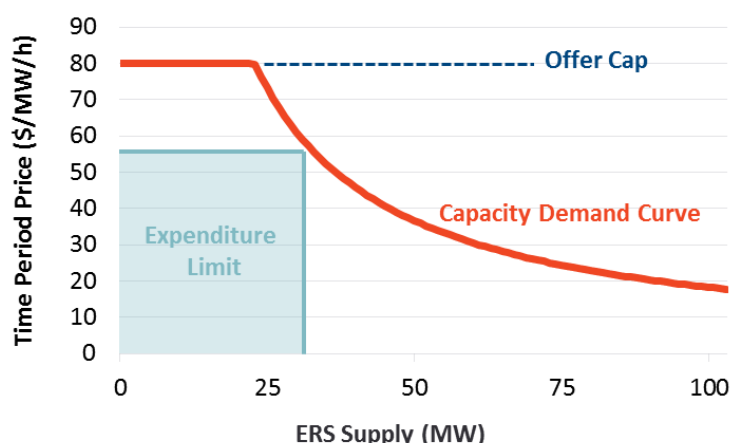
¹² See ERCOT (2015), p. 10.

¹³ The \$50 million expenditure limit is allocated amongst 18 time periods (3 four-month contract terms × 6 time periods). See ERCOT (2013), p. 5.

¹⁴ Under some circumstances, the procurement limit may be exceeded in an individual time period due to lumpy offers.

¹⁵ ERCOT activates ERS resources only when operating reserves are substantially below requirements (below 2,300 MW) and are not expected to be recovered within 30 minutes. See ERCOT (2016c).

Figure 2
Indicative Emergency Response Service Auction Demand Curve



Source and Notes:

Adapted from: ERCOT, “Emergency Response Service Procurement Methodology,” Nov. 2013. Demand curve parameters taken from Time Period 2 in 6/1/17-9/30/17 contract term; hourly expenditure limit of \$1,833 as determined by a time period expenditure limit of \$778,917 for both ERS-10 and ERS-30 resources across a total of 425 hours in Time Period 2.

ERCOT also has a generation-based mechanism to support reliability. A unit at risk of imminent retirement may be held online by ERCOT through a reliability must run (RMR) contract if the unit is needed to support transmission system reliability. Similar to ERS resources, the output of RMR-contracted units is mostly withheld from the energy market by requiring these units to offer at the cap of \$9,000/MWh into the day ahead market (the day ahead market is not mandatory for other resources).¹⁶ However, if the RMR unit is needed to relieve a binding transmission constraint, ERCOT may mitigate its offer down to a level far below the offer cap. This practice generated controversy among market participants during the recent RMR process for Greens Bayou 5.¹⁷

C. ALBERTA UNDER-FREQUENCY LOAD SHEDDING SERVICE

Alberta receives substantial imports over its interconnection with British Columbia. When this interconnection trips offline it de-synchronizes Alberta from the rest of the grid and the province becomes islanded. As a relatively small market with 9,000 MW average load, losing the 700 MW interconnector from British Columbia poses a significant security threat (although not as large of a threat as losing Heywood in South Australia). To enable fast response to such a contingency, the Alberta Energy System Operator (AESO) implemented a security service product called the Load Shed Service for Imports (LSSi) program in 2011. The LSSi program enables the AESO to stabilize frequency following a loss of generation contingency by disconnecting LSSi providers’ load.¹⁸ This mitigates the risk of a system

¹⁶ See ERCOT (2016a).

¹⁷ See p. 96 of Potomac Economics (2017).

¹⁸ A similar mechanism called the under frequency load shedding scheme is operating in Tasmania. See AEMO (2017).

blackout event when the interconnector fails, and allows Alberta to import a larger quantity of supply over the interconnector.¹⁹

To be eligible to participate in the LSSi program, a load must be greater than 1 MW, have under-frequency relays installed at each site to detect when frequency drops below 59.5 Hz, and have real-time SCADA connectivity to the system operator.²⁰ The committed load must be disconnected within 0.2 seconds when the frequency drops to 59.5 Hz.²¹ LSSi providers sign three year contracts with the AESO to participate in the program and are incentivized through a three-part payment structure: (1) *availability payments* of \$5/MWh are awarded across hours when the LSSi provider offers to disconnect their load²²; (2) *arming payments* are awarded when the AESO instructs the LSSi provider to continuously measure system frequency to enable rapid load shedding if the target frequency of 59.5 Hz is reached or a SCADA trip signal is received (payment is based on a fixed price between the AESO and each LSSi provider that is set in the competitively sealed bid Request for Proposals for Load Shed Services for Imports (the RFP) process)²³; and (3) *tripping payments* of \$1000/MWh are paid when the LSSi provider's load is tripped offline.²⁴ The AESO calculates the LSSi requirements based on expected load and the combined net schedule import for the British Columbia and Montana interconnectors.²⁵ Between April 1, 2012 and March 31, 2013 the LSSi was available in 8,551 hours of the year, and out of those hours LSSi was armed 2,059 hours, or over 24% of the time.²⁶

AESO's LSSi program allows Alberta to secure its system with higher levels of imports from neighboring British Columbia. By procuring relay-connected demand response, Alberta can avoid involuntary load shedding even if the interconnector trips when transmitting a large amount of power. AESO's relatively small size and weak interconnection with neighboring

¹⁹ Alberta's load share by customer class in 2016 was approximately 50% industrial, 25% commercial, 20% residential, and 5% farm. See AUC (2017).

²⁰ SCADA is the normal telemetry system used by the AESO.

²¹ See AESO, p.4.

²² The LSSi provider must submit their offered load no later than 23 minutes before the start of the next hour and be able to "arm" their facilities within 15 minutes when prompted by the AESO. "Arming" means enabling the functionality of the LSSi scheme such that it is continuously measuring system frequency and operates when the target frequency is reached or a SCADA Trip Signal is received." See AESO, p. 3-4.

²³ Once armed, the LSSi provider must keep their load armed for the scheduling hour (10 minutes before the hour, 60 minutes of the hour, and 10 minutes of the following hour). The actual volume of load to be tripped must remain between 95% and 150% of armed load. See AESO, p. 3-4.

²⁴ See AESO (2014a), slide 4.

²⁵ As net scheduled imports increase, the LSSi requirement increases. The 2015 RFP process sought to procure 350 – 450 MW from the LSSi program. See AESO (2015), slide 22.

²⁶ Only considers hours when enough LSSi was available to increase import schedule level. See AESO (2014b), p.10.

regions make it somewhat comparable to South Australia. A program like LSSi could potentially help South Australia enable higher import capability while securing the system against a trip of the Heywood interconnector.

III. Ontario Long-Term Contracts Approach

After a brief experiment with merchant investment in the late 1990s and early 2000s, Ontario concluded that its energy market would not deliver the supply needed to operate the system reliably while meeting policy objectives.²⁷ A long-term contracting program was initiated, which became the dominant form of investment in the Province. Other jurisdictions, such as California and some states in the midwestern and Southern U.S., also use contracts to secure some portion of their supply. The program was effective in maintaining reliability and achieving policy goals, but undermined the potential for market-based investment. Due to the high realized costs to consumers of the contract program, the Province is now attempting to return to a more market-based investment model.

The Independent Electricity System Operator (IESO) was established in 1998 to oversee the wholesale electricity market following restructuring and the break-up of Ontario Hydro, the Province's vertically integrated utility. In the years immediately following restructuring, the Province was faced with aging energy infrastructure and supply inadequacy while embarking on a program to reduce its reliance on coal.²⁸ To maintain resource adequacy and enable rapid decarbonization, Ontario initiated a program of administrative resource planning, tasking the IESO with contracting for supply and determining when and what type of resources should be developed.²⁹

Over the past two decades the IESO has signed a large number of long-term supply contracts under Ministry of Energy oversight and direction.³⁰ The Ontario Electricity Financial Corporation (OEFC) holds a small number of contracts that resulted from the restructuring of Ontario Hydro. Many of these contracts are structured as contracts for differences, where contracted resources settle with the IESO for the difference between the energy price and the contract price. Ontario Power Generation (OPG) also owns resources that are paid through regulated cost recovery at rates approved by the Ontario Energy Board (OEB).³¹

²⁷ See ECSTF (2004), pp. ii—iii.

²⁸ See Ontario Ministry of Energy (2013), p. 2.

²⁹ Supply contracting was initially conducted by the Ontario Power Authority (OPA). OPA was established in 2004 to provide long-term planning with supply contracts to the electricity sector and merged with the IESO in 2015. See Pfeifenberger, *et al.* (2017), p. 7.

³⁰ Many of these contracts were originally signed by the Ontario Power Authority (OPA), which was merged with the IESO in 2015.

³¹ See Pfeifenberger, *et al.* (2017), p. 61.

Ontario's mix of contracted and regulated supply ensured reliability and supported decarbonization over the last two decades.³² However, by the end of 2016, nearly all capacity in Ontario was under long-term supply contracts with the IESO or was regulated supply owned by OPG. Over 27,000 MW of capacity was under IESO contracts, 360 MW under OEFC contracts, and 10,300 MW were OPG regulated assets.³³ Provided that future resources begin operations and existing resources continue to operate as expected, Ontario's energy supply from contracts and regulated assets will reliably meet peak load through 2019.³⁴

There have been significant political challenges due to the government's direct involvement in electricity supply and the high cost of contracted resources. Over the past decade, the cost of out-of-market payments has increased significantly. The global adjustment, which recovers payments to contracted generators, has increased from 8% of total customer commodity costs in 2006 to 77% in 2016.³⁵ In addition to the rising costs, there is concern that the long-term contracts reduce competition and provide little incentive for emerging technologies. The government has responded by intervening to reduce consumer prices and initiating a process to introduce more competition in electricity supply.³⁶ There are currently efforts underway to implement an incremental capacity auction in Ontario as a lower cost mechanism for achieving long-term supply adequacy.³⁷ Contracted supply may prove to be a challenging factor under the new mechanism because it is not incentivized to maximize returns since they are guaranteed payments through their contracts with the IESO.

IV. Capacity mechanisms with Various Reliability Product Definitions

Capacity mechanisms explicitly pay resources for being *available* to generate, in addition to paying them for the actual MWh generated. However, in recent years a number of system operators with capacity mechanisms, including ISO-NE, have realized that the capacity paid for may not always be able to deliver the services they need. These capacity mechanisms have enhanced their reliability product definitions to better match capacity payments to delivered reliability. Other markets, including Ireland, have enhanced the basic reliability product definition to include a call option to hedge consumers' energy price exposure. The product

³² By 2015, all coal generation was retired and greenhouse gas emissions had fallen by 80% since 2005. See IESO (2016), p. 4.

³³ See Pfeifenberger, *et al.* (2017), p. 78-79.

³⁴ See IESO (2016), p. 10. The Ontario Planning Outlook considers four different demand growth profiles, all of which are met up to 2019.

³⁵ See Pfeifenberger, *et al.* (2017), p. 61. Global adjustment is the difference between wholesale energy prices and the regulated rates from OPG's nuclear and hydroelectric generators, payments for building or refurbishing infrastructure, and rates through contracted generators. See IESO (2017).

³⁶ See Ontario (2017).

³⁷ See Pfeifenberger, *et al.* (2017).

definitions used in these mechanisms may more generally inform the design of arrangements for securing supply commitments to improve reliability and security.

A. NEW YORK AVAILABILITY PAYMENTS

The New York Independent System Operator (NYISO) operates market-wide auctions for all of the capacity needed to meet New York’s reliability target. NYISO’s capacity mechanism compensates generators with an availability payment paid out in monthly or six-month strips.³⁸ Supply resources selling capacity also earn revenues by participating in the energy and ancillary services markets.

All resource types are eligible to offer into the capacity auctions based on their expected unforced capacity (UCAP) availability at system peak.³⁹ For thermal generators and batteries, UCAP is installed capacity derated by the expected outage rate and deratings of the unit in question. For intermittent supply, UCAP values are based on expected output of the unit at peak times.⁴⁰ For demand response, UCAP values are based on test and event performance conducted by the NYISO.⁴¹ By using UCAP metrics, NYISO accounts for the historic availability of resources.⁴² A condition of accepting an availability payment is that supply resources must offer into the day-ahead energy market at their marginal cost, they must limit maintenance outages to low-demand periods, and they face penalties for non-delivery.

The NYISO availability payments mechanism provides a resource-neutral means of achieving the reliability standard at a reasonable cost, but due to relatively small penalties for non-performance, does little to ensure that procured capacity performs as expected during the operating time frame.⁴³ To address this shortcoming, NYISO is evaluating the option of imposing additional requirements on some resources participating in the capacity mechanism, such as having backup fuel⁴⁴ To strengthen incentives for performance, NYISO and other US capacity mechanisms have introduced increasingly strong administrative scarcity pricing in

³⁸ NYISO’s capacity mechanism includes three auctions. (1) Capability period auctions that solves for a six month period, May-October or November-April; (2) monthly auction that is run at least 15 days prior to the start of the month; and (3) spot auctions that are run 2-4 days prior to the start of the month. See NYISO (2017a), slides 72-75.

³⁹ Other markets with high penetrations of call-limited, dispatch-limited, or intermittent resource types have instituted various qualification standards for awarding a resource-neutral capacity value across types if they provide the same reliability value.

⁴⁰ NYISO uses a “Production Factor” for this calculation which is based on historic operating data between 2pm and 6pm in the summer and 4pm-8pm in the winter (peak times). The exception to this is for intermittent resources with less than 60 days of historic operating data, in which the factor will be based on NERC class average of forced outage rate of similar resources. See NYISO (2017b), p. 4-21 to 4-27.

⁴¹ See NYISO (2017b), p. 4-60.

⁴² See NYISO (2017a), slide 32.

⁴³ See NYISO (2015), p. 2.

⁴⁴ See NYSIO (2016a).

the energy market. NYISO's "Comprehensive Shortage Pricing" mechanism raises prices as high as \$3,250/MWh during shortage conditions.^{45,46} PJM and ISO New England have similar scarcity prices in the energy market but have additionally incorporated performance incentives directly into their capacity mechanisms. We discuss the ISO New England case in Section IV.C.

B. IRELAND "RELIABILITY OPTIONS"

Ireland's Single Electricity Market currently makes administratively determined capacity payments to all generators.⁴⁷ Beginning in early 2018, however, generators will compete to sell "reliability options" in a centralized auction.⁴⁸ Generators will receive an up-front payment similar to the availability payment made to generators selling capacity in New York and other U.S. markets with capacity mechanisms. The reliability option contract also requires generators to pay the system operator the difference between the energy price and a predetermined strike price when the energy price exceeds this strike price. Since the system operator passes these savings on to consumers, the reliability options function as a partial energy price hedge for consumers.^{49,50}

Reliability options in Ireland are similar to "cap futures" traded on the Australian Securities Exchange (ASX). Both are effectively call options on energy that compensate sellers with upfront payments in exchange for contingent payments when energy prices exceed a strike price.^{51, 52} The Irish options, however, must have physical backing by a specific generating unit and are sold through a centralized auction. The Irish system operator establishes a demand curve for the quantity of reliability options needed to achieve its reliability requirement.⁵³ The demand curve values all capacity, although this value declines as more

⁴⁵ See NYISO (2014).

⁴⁶ See NYISO (2016b).

⁴⁷ See SEM (2017a).

⁴⁸ Reliability options are call options on energy. Call options are derivatives traditionally used in financial markets to hedge against upward price movements of an underlying security. The buyer of a call option has the right to buy the security from the seller at a future point in time at the predetermined strike price and are exercised when the strike price is lower than the prevailing spot price. The buyer of a call option thereby locks in a maximum price for the underlying security to be purchased in the future. In exchange, the buyer pays an upfront "premium" to the seller.

⁴⁹ If, during the contracted year, generators receive prices exceeding the strike price, a "true-up" mechanism ensures that generators reimburse consumers so that consumers only pay up to the strike price for all purchased energy.

⁵⁰ The Single Electricity Market Operator will purchase the reliability options on behalf of load serving entities.

⁵¹ See SEM (2016a), p. 3.

⁵² See ASX (2015), p. 7.

⁵³ See SEM (2016a), p. 68.

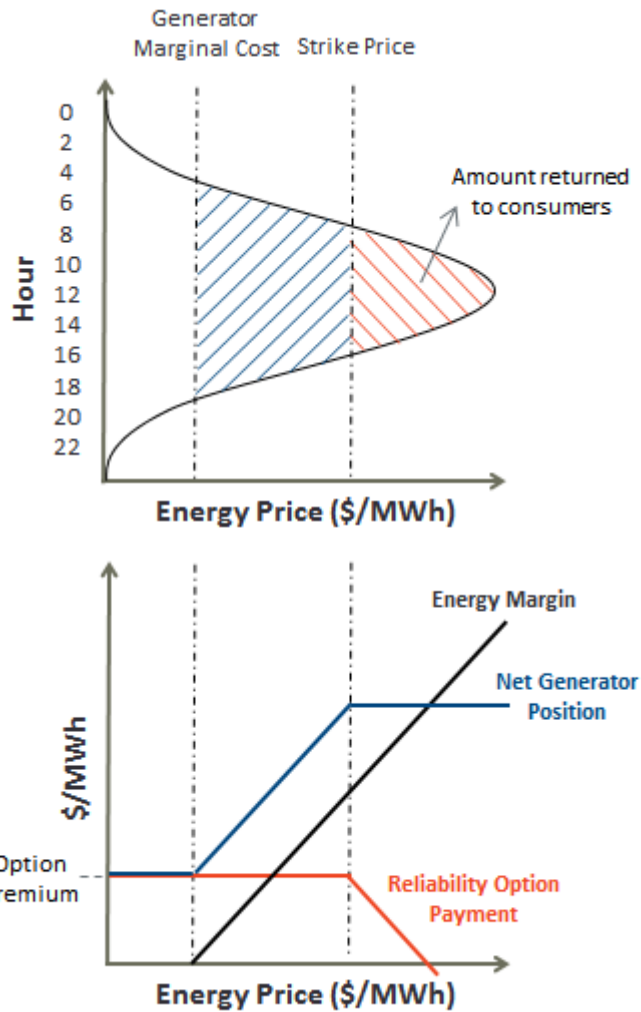
capacity is procured. The costs of procuring the options, as well as the payouts, are allocated to customers.^{54,55}

Figure 3 illustrates the operation of the Irish reliability option. The top chart shows an example energy price profile that peaks at noon. A generator who had not sold a reliability option would earn an energy margin any time the energy price exceeded its marginal cost. A generator who has sold an option must return earnings above the strike price to the consumer. This is illustrated by the red shaded area in the figure. The area shaded in blue shows the net position of a generator who has sold an option. The net position is equal to the energy margin earned by the generator, less payments returned to consumers. The bottom chart illustrates the generator's energy margin, reliability option payments, and net position as a function of the energy price. The chart shows that the net position is capped at the strike price.

⁵⁴ Other differences include (1) the contract term (three months for cap futures, one year for reliability options) and (2) the strike price (\$300 for cap futures, likely much higher for reliability options as discussed in-text).

⁵⁵ While consumers gain a hedge against high energy prices by buying reliability options through their load serving entities, the option hedge may be inefficient relative to each individual's actual hedging needs which would have been managed through traditional risk management products in the retail market.

Figure 3
Hypothetical Generator's Short Position on Reliability Option



Notes: Net generator position = energy margin + reliability option payment. The flat portion of the reliability option payment curve denotes the premium earned by the generator from selling the option. The downward-sloping portion of the curve reflects reimbursements to consumers when energy prices exceed the strike price.

In addition to providing consumers with a hedge against high energy prices, reliability options maintain the energy price signal to generators to incentivize performance. If a generator that has sold an option is unavailable when prices exceed the strike price, it must cover its position by buying energy on the spot market and selling at a potentially large loss. The risk of incurring this loss during high-priced periods incentivizes generators to maximize availability. This approach also reduces incentives for sellers to exercise market power because whatever their portfolio of resources would earn from withholding would be paid back to consumers.

Despite the above benefits, market design is made somewhat more complicated by the need to determine an appropriate strike price for the reliability options. High strike prices ensure that the reliability options will be “out of the money” most of the time and cost less to

consumers, but at very high strike prices the reliability option converges to a product very similar to the availability payments approach (such as in NYISO).⁵⁶ On the other hand, if the strike price is too low, some resources will find they have marginal operating costs in excess of the strike price. Such resources would make a loss selling at the low strike price, and high-marginal-cost resources such as demand response would correspondingly include expected losses in their offers. The Irish market operator has initially decided to base the strike price on a hypothetical low efficiency peaking unit at a minimum of €500/MWh.⁵⁷

C. NEW ENGLAND “PERFORMANCE INCENTIVES”

ISO New England (ISO-NE) changed its capacity mechanism beginning with the 2018 deliverability year to better link capacity payments and resource performance in real time.⁵⁸ Extended cold snaps and gas pipeline constraints in New England had revealed that some generators were unable to provide energy in scarcity conditions, but were receiving capacity payments nonetheless. Under the new performance incentives, generators are heavily penalized for unavailability during emergency conditions and are also rewarded for performing in excess of their obligation.⁵⁹ Performance incentives encourage generators to, for example, add dual-fuel capability to minimize non-performance at times of constrained natural gas supplies.

The performance incentives involve a two-stage settlement mechanism for capacity payments: (1) capacity resources receive availability payments at the capacity auction clearing price and (2) penalties are imposed on under-performing generators, with the collected revenues paid out as bonus payments to over-performing generators.⁶⁰ The penalty rate for under-performers began at \$2,000/MWh and will increase to \$5,445/MWh by 2024.⁶¹

⁵⁶ See Oren (2005), p. 2.

⁵⁷ See p. 90 of SEM (2016b) for discussion of the rationale for setting the strike price based on a hypothetical low efficiency peaking unit, and see p. 3 of SEM (2017b) for the minimum strike price of €500/MWh.

⁵⁸ See ISO-NE (2017a).

⁵⁹ Capacity scarcity conditions are defined as any period of five or more minutes of reserve shortages. See ISO-NE (2017b), p. 182.

⁶⁰ See Borgatti (2016), p. 8.

⁶¹ See Newell (2014), p. 45.

List of Acronyms

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AESO	Alberta Electric System Operator
ASX	Australian Securities Exchange
DR	Demand Response
EILS	Emergency Interruptible Load Service
ERCOT	Electric Reliability Council of Texas
ERS	Emergency Response Service
IESO	Independent Electricity System Operator
ISO-NE	Independent System Operator New England
LSSi	Load Shed Service for Imports
MW	Megawatt
MWh	Megawatt Hour
NEM	National Electricity Market
NYISO	New York Independent System Operator
OEB	Ontario Energy Board
OEFC	Ontario Electricity Financial Corporation
OPA	Ontario Power Authority
OPG	Ontario Power Generation
PJM	PJM Interconnection
RERT	Reliability and Emergency Reserve Trader
RFP	Request for Proposal
RMR	Reliability Must Run
UCAP	Unforced Capacity
USE	Unserved Energy
VRE	Variable Renewable Electricity

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