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Structuring the Ontario electricity market to produce economically efficient long-term price signals

prepared for the C.D. Howe Institute

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Prevailing Ontario power sector arrangements have led to economically inefficient production and consumption decisions. Power costs to Ontario consumers reflect the added expense from the failure to rely on either market price signals or long-term resource planning to inform generation investment decisions. The current period of surplus generation allows time for a thoughtful transition to a durable market framework consisting of Load Serving Entities ("LSEs") required to participate in a seven year laddered forward Resource Adequacy Market ("RAM"). Existing OPA capacity, including needs-based nuclear refurbishment projects that passed a natural gas price referent test, would be allocated to LSEs through low cost back to back contracts. Demand response ("DR") programs would be replaced by the right for load management to participate in the RAM. LSE market decisions would be technology neutral, with environmental externalities addressed through use of cap and trade mechanisms. Following un-coerced efforts to renegotiate existing contracts to reduce the Global Adjustment ("GA"), the OPA would become solely a residual contract administrator.

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Calculations produced for the purposes of this paper are purely illustrative; additional analysis would be required for any such calculations to be cited in legal or regulatory proceedings. Given the conceptual nature of this paper, discussions of individual elements are not intended to be comprehensive or exhaustive. Findings in this paper should in no way be construed as suggesting that the authors support establishment of capacity markets in all jurisdictions or under any circumstances.

1 Executive summary

An ongoing challenge for power markets worldwide is to assure sufficient continued investment to maintain reliability. While not appropriate in all circumstances, a properly designed capacity market in Ontario may enable the province to increase reliance on market signals for new investment. To be effective, a capacity market would need to be accompanied by several changes in the role and function of existing Ontario power market institutions, as well as a clear framework to isolate policymakers from implementation agencies.

The Ontario power sector today is characterized by oversupply, a mismatch of generator capabilities and needs, rising prices to final consumers, a lack of transparency in price formation, and volatile and contradictory policies. Consequently, private sector actors are unable to justify investment without some form of government-backed contract. While various governments have announced laudable goals, failure to rely on either sound planning or market principles has meant that generation capacity has not been procured at a long-run least cost. Worthy objectives do not justify abandonment of market discipline; in fact, properly designed markets are essential elements in assuring that society is able to perform the constrained optimization required to maximize production of policy-compliant goods relative to limits imposed by society's willingness to pay.

Current surplus supply conditions provide a window for thoughtful policy review. To reorient the Ontario power sector towards appropriate consideration of long-run least cost investment, structures need to be established which allow for transparent and effective price signals. Doing so first requires creating appropriate buffers between implementation entities and policymakers, such that ministerial directives can no longer be used to interfere with the day to day operation of key power sector institutions. Next, it requires replacement of the Ontario Power Authority's ("OPA") principal buyer role with newly-created load serving entities ("LSEs"), diversifying participants on the buy side of the market. Finally, a Resource Adequacy Market ("RAM") should be created to provide a graduated seven year forward capacity market.

The combination of energy and RAM prices, along with emissions reduction credit ("ERC") prices from a cap and trade scheme, would serve as the primary pricing signals for new investment going forward, including new renewables investment and non-traditional resource types, like demand response. The province's history of intervention in the power markets means that energy-only markets (markets in which compensation to generators in spot markets is based solely on volumetric payments when the plant actually runs) would likely be greeted with skepticism by investors, even if structural barriers to ministerial intervention are created. The market would be technology and ownership neutral, and would enable the phase-out of a range of "out of market" nuclear, renewables, and energy efficiency incentives. Provided ERC markets are appropriately structured, future investments in zero emission sources and demand response would not disappear, but would be market driven.

This paper is structured as follows: first, we provide background on the current wholesale electricity market structure in Ontario. Next, we explore the steps necessary to create a durable investment climate for the power sector in the province. We then examine how these steps are related to other major policy issues, such as nuclear refurbishment and climate change. Finally, we identify what needs to be done over the near-term to put the Ontario power sector on a sound, long-term footing.

Figure 1. Summary of recommendations

1. Implement changes at relevant power market institutions to assure board members are independent of government, serve staggered defined terms, and are subject to removal based only on a limited number of conditions. These institutions need dedicated funding streams protected from legislative whims. (Page 14)
2. Work to eliminate the Global Adjustment ("GA"). (Page 15)
3. Re-orient the Ontario power sector away from use of Ontario Power Authority ("OPA") as a principal buyer. (Page 17)
4. Enshrine the independence of the key market institutions and clarify their mandates. (Page 18)
5. Cease efforts to merge OPA and Independent Electricity System Operator ("IESO"). (Page 18)
6. OPA should be directed to cease further contracting (including with expiring non-utility generators or NUGs), focus on uncoerced mutually beneficial contract negotiations to reduce the GA, and ultimately become a pure contracts administrator. (Page 18)
7. IESO should design demand response programs consistent with its market operations. (Page 18)
8. Ontario Energy Board ("OEB") should cease rate-regulating Ontario Power Generation's ("OPG") prescribed assets, but periodically review OPA's budget, progress in reducing the GA, and plans for shrinking. (Page 19) OPA should develop contracts on a plant-by-plant basis for OPG-prescribed assets. (Page 30)
9. To explore the future role of nuclear, the OPA should hold a final procurement round, based on an announced maximum price consistent with a carbon-neutral CCGT and an assessment of the timing for baseload resource needs. (Page 20)
10. OPA should establish four or five new Load Serving Entities ("LSE") for sale by auction to the private sector, with initial boundaries mapping to a set of contiguous Local Distribution Company ("LDC") service territories. LDCs themselves would retain current form and functions. (Page 21)
11. To form a new Resource Adequacy Market ("RAM"), establish a laddered capacity market with purchase requirements decreasing with time. (Page 23)
12. Allocate all of OPA's capacity to the LSEs on a pro-rata basis using back-to-back contracts. LSEs should then offer customers a default alternative of spot price plus RAM pass-through. (Page 27)
13. OPA should issue periodic calls for proposals from existing contract holders to modify their contracts, with the proviso that all proposals must result in a material reduction in GA payments. (Page 31)
14. Join the Western Climate Initiative ("WCI") carbon dioxide emissions reduction credit market as a means to transition to cap and trade mechanisms. (Page 32)
15. Encourage demand response aggregators and allow them to participate in capacity auctions. (Page 33)

2 Problems with the status quo

The current approach to power sector investment and planning in Ontario is unsustainable. Investment decisions reflect neither market signals nor long-term, centralized, utility-style system plans. The electricity sector is being used to support a range of shifting policy objectives, including job creation, economic growth, and emissions reduction, without credible examination of whether burdening the electricity ratepayer with the cost of such initiatives is economically efficient. While Ontario has created the appropriate institutional foundation for a viable power sector, its failure to insulate such bodies from ad hoc policy changes has proven costly to consumers while undermining democratic principles of openness and public participation. No political party has a monopoly on political interference in the power sector in Ontario; over the past decade, both parties have engaged in ill-considered price freezes, sudden policy shifts, and stop-gap solutions. As a result of this uncertainty, all sizable investments in the Ontario generation sector currently require long-term, government-backed contracts.

2.1 Where Ontario is today

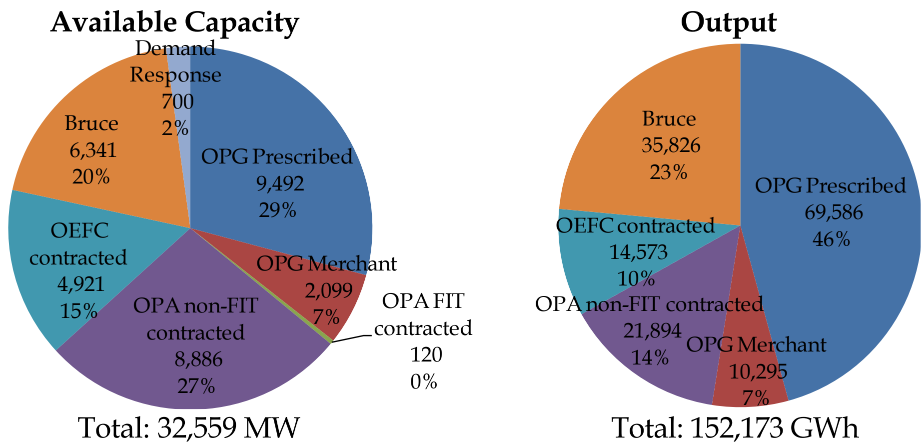
While often characterized as a "hybrid" market, the Ontario electricity market today largely consists of the contracting activities of a principal buyer, the Ontario Power Authority, whose decisions are heavily influenced by the provincial government. While the provincially-owned generator Ontario Power Generation ("OPG") remains the dominant supplier, its role has diminished as the OPA contracted with new entrants (Figure 2). Although OPA contracting decisions are nominally based on the Long-term Energy Plan ("LTEP"), the LTEP has been overridden by provisions of the Green Energy Act ("GEA") and subsequent ministerial directives. The Ontario Independent Electricity System Operator ("IESO") coordinates dispatch and transmission flows, and operates spot markets, but repeated government interventions in the power sector have made investors wary about building generation capacity without an OPA contract. The Ontario Energy Board ("OEB") regulates a portion of OPG's generation capacity, but otherwise has limited oversight of generation markets and the OPA.[1]

Despite limited or negative load growth over the past five years (2007-2011 inclusive), averaging -1.1% per year, Ontario installed capacity has grown over the same period by 1.8% per year. While a portion of this capacity increase has been justified by the decision to close all of Ontario's

[1] Under the Ontario Energy Board Act, the OEB can only review OPA's activities related to conservation targets, and payments to and from distributors, retailers, or the IESO under the Province's regulations. OPA is required to assist the OEB by facilitating stability in rates for certain types of customers, and provide information relating to medium and long-term electricity needs, adequacy, and reliability of the power systems. OEB also approves annual fees of the OPA and reviews and approves the Integrated Power System Plan ("IPSP" – predecessor to LTEP) and the procurement process of OPA. Source: Ontario Energy Board website. History of the OEB. <http://www.ontarioenergyboard.ca/OEB/Industry/About+the+OEB/Legislation/History+of+the+OEB>

coal-fired power stations, analysis suggests that continuation of current policies could result in excess supply through 2019 (Figure 3).[2]

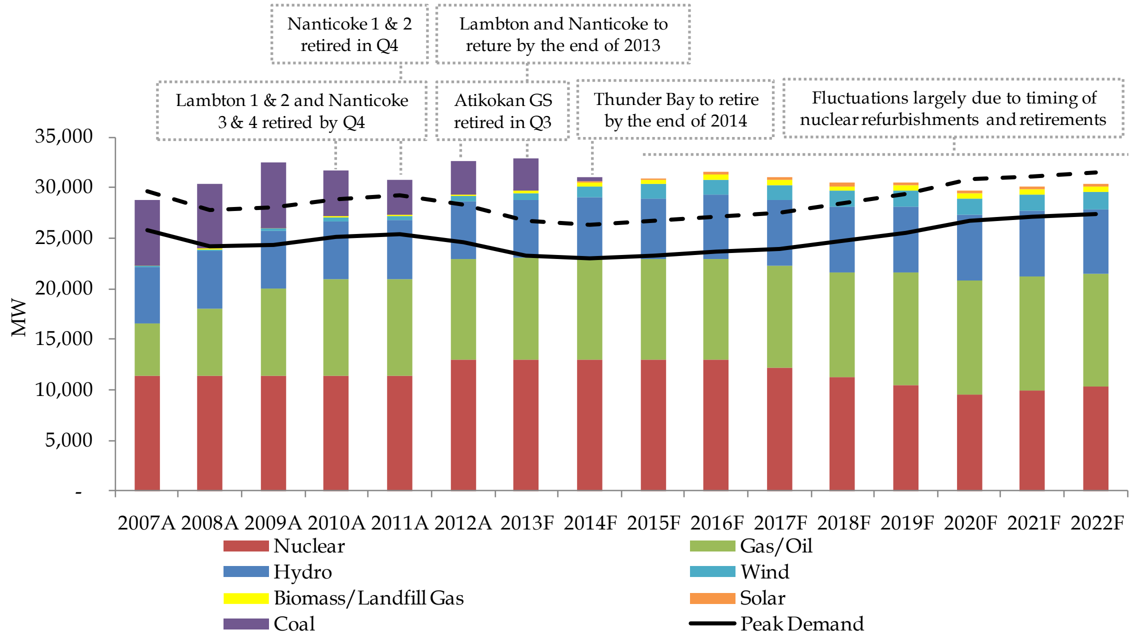
Figure 2. 2012 Ontario available capacity and output by asset type



Note: Capacity for wind is de-rated to 23.5% (average of 13.4% summer and 33.6% winter), and capacity for solar is de-rated to 20% (average of 40% summer and 0% winter), as reported by IESO in NERC NPCC 2012 Ontario Comprehensive Review of Resource Adequacy 2013-2017. Capacity for hydro-electric resources is de-rated to 72% (average of 67% and 77% range of contribution factors used by IESO in Ontario Reserve Margin Requirements 2013-2017). As of December 31, 2012, OPA reports 501 MW of in-service FIT and microFIT capacity (solar, wind and biomass) which, after applying de-rates, translates into 120 MW of available capacity.
Sources: commercial database; OPA Quarterly Progress Reports on Contracted Electricity Supply; and IESO reliability reports

Figure 3. Ontario supply-demand balance 2007 to 2022

[2] Bear in mind that the graphic shows only capacity currently under contract; it does not account for additional capacity to be added under the ongoing FIT program.



Notes: Capacity for wind, solar and hydro-electric resources treated in the same fashion as for **Figure 2**. OPA contracted supply is as of December 31, 2012. OPA reports 2,019 MW in-service wind capacity and 3,772.4 MW under construction expected to come online by the end of 2015; with de-rate factor of 23.5% this translates into 474 MW in 2012 and 886.5 MW of additional wind by the end of 2015. OPA RESOP solar contracts are added to IESO reported actual capacity. While the IESO Ontario Reserve Margin Requirements 2013-2017 report suggests average reserve margin target of 18.66%, the 15% reserve margin in the above indicative supply-demand forecast assumes interconnections make a contribution to reliability.
Sources: IESO historical data; IESO 18-month Outlook Updates and Ontario Demand Forecasts; OPA Quarterly Progress Reports on Contracted Electricity Supply; OPA Ontario Electricity Demand 2012 Annual Long-term Outlook presentation; and LEI CMI analysis

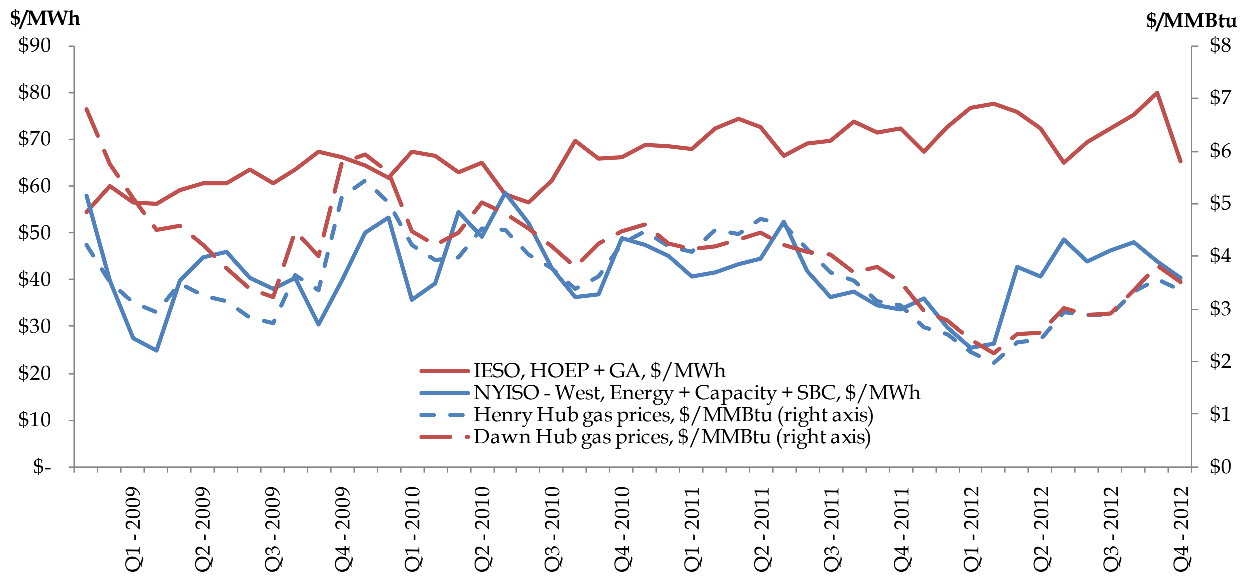
2.2 Cost impacts

Examining the impact of the status quo on costs to final consumers requires an understanding of the relationship between IESO prices and what is known as the Global Adjustment ("GA"). The GA was originally established as a so-called "Provincial Benefit," separate from the Debt Retirement Charge ("DRC"). The DRC can be considered a form of Competitive Transition Charge ("CTC") put in place at the time of market opening; at that time, it consisted mainly of payments on outstanding Ontario Hydro debt which Ontario Hydro successor companies were unable to absorb. The GA quickly became a convenient means for provincial governments to obscure the costs of market interventions. Ultimately, with the creation of the OPA, the GA came to include as well the costs of OPA contracts that could not be recovered through market revenues.[3] Changes in IESO prices and the level of the Global Adjustment are largely symmetrical; under the contracts for differences ("CfD") structure adopted in many fossil-fuel

[3] In 2011, GA was comprised of charges on contracts for generators including non-utility generators administered by the Ontario Electricity Financial Corporation ("OEFC", 20%), OPG's nuclear and baseload hydroelectric generation (25%), and OPA contracts with generators and suppliers of conservation services (54%). Source: IESO website. Global Adjustment Archive. <http://ieso.ca/imoweb/b100/ga_archive.asp> (LEI calculated shares based on total 2011 GA reported)

OPA contracts, OPA payments to generators fall or become negative (generators pay OPA) as IESO prices approach or exceed the contract price.

Figure 4. Comparison of IESO prices plus GA to Western New York energy and capacity prices and natural gas prices

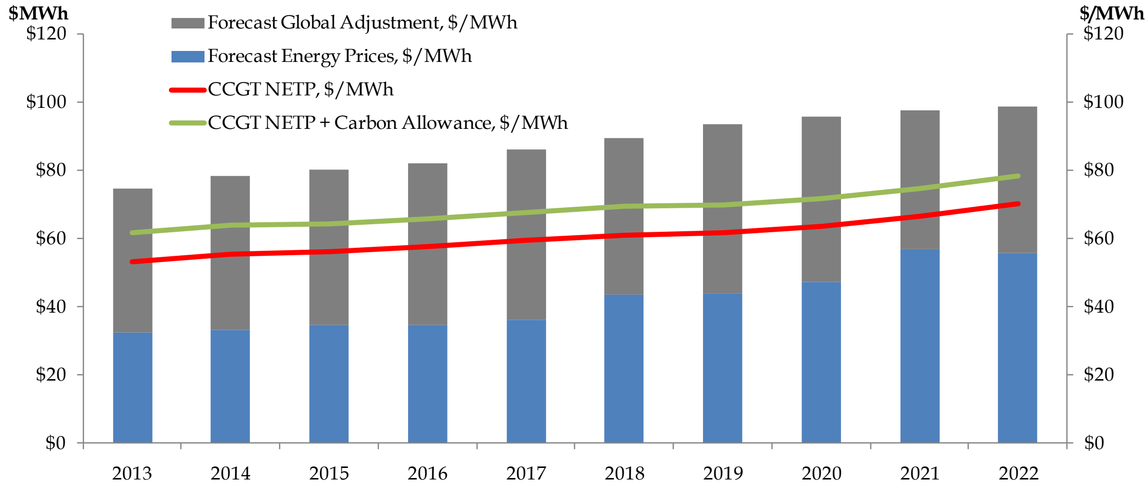


Note: Competitive transition charges (CTCs) in Western New York were eliminated in January 2012 and are excluded from the chart; all figures nominal Canadian dollars, using Bloomberg historical monthly exchange rates.
Sources: IESO; OPA; NYISO; Bloomberg; LEI analysis

It is useful to examine the sum of IESO prices and the GA from two perspectives: first, over the recent past, in comparison with adjacent markets, and second, into the future, in comparison with the all-in cost of a new, generic combined cycle gas turbine ("CCGT"). As Figure 4 above demonstrates, total energy costs to Ontario consumers have been higher than those in neighboring western New York despite falling natural gas prices, even when capacity and renewables costs (paid for under the GA in Ontario) are taken into consideration.

Even when taking into account the System Benefits Charge ("SBC") in New York (the SBC pays for various policy initiatives consistent with some aspects of the GEA), wholesale electricity costs in Western New York have been significantly lower than Ontario. Natural gas plants serve as the price setting unit in most electricity markets in North America. Western New York all-in prices are more rapidly allowing customers to benefit from declines in natural gas prices, while Ontario all-in prices are not.

Figure 5. Comparison of LEI modeled hourly Ontario electricity price ("HOEP") plus GA and natural gas CCGT Levelized Cost of Energy ("LCOE")



Note: CCGT capacity factor assumed to be 85%;[4] gas prices are NYMEX Henry Hub forwards as of mid-October 2012 escalated toward the Energy Information Administration ("EIA") *Annual Energy Outlook ("AEO") 2012* projected 2020 gas price, plus the 5-year (2007-2011) average differential between annual Henry Hub and Dawn prices; carbon allowance price assumed to be $20/ton; all figures nominal Canadian dollars and assuming exchange rate CA $1/US$.
Sources: IESO; OPA; EIA *AEO 2012*; LEI analysis

Looking forward, projections suggest that Ontario will be paying substantially more over the next decade than the cost of a baseloaded CCGT, even when carbon costs are taken into account (Figure 5). In other words, had different policies been pursued, Ontario could have had both clean electricity and lower prices by allowing natural gas to play an even more prominent role in Ontario's fuel mix.

[4] Assumed CCGT capacity factor reflects a unit added to the system when it is efficient to do so, rather than current actual capacity factors of underutilized existing plants. Current (2012) CCGT capacity factors averaged 26%, according to a commercially-available database. Underutilized gas plants further highlight the extent to which supply and demand have been mis-matched in Ontario.

Figure 6. List of ministerial directives to OPA related to procurement

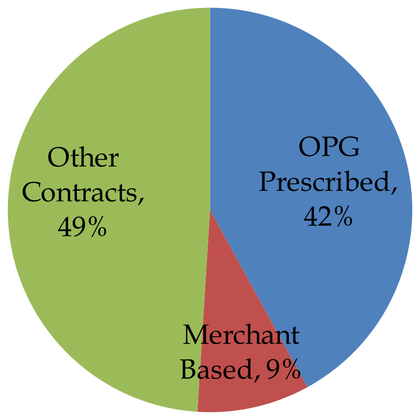
Date	Directive
March 24, 2005	Execution and delivery of CES contracts and a DR contract in accordance with the terms of the 2,500 MW RFP
June 15, 2005	"Early Movers" - Negotiate and Conclude Contracts with Certain Generation Facilities
June 15, 2005	Immediate Launch of Procurement Processes to address needs in Downtown Toronto and Western Greater Toronto Area ("GTA")
October 14, 2005	Contracts for the Refurbishment of Bruce A at the Bruce Nuclear Facility Generating Station
October 20, 2005	GTA West Supply Initiative - Goreway Station Project
November 7, 2005	RES I RFP - assume OEFC's contracts
November 16, 2005	RES II RFP - enter intro contract with nine suppliers for 1,000 MW
December 14, 2005	Early Movers - Negotiate and Conclude Contracts with Certain Generation Facilities
February 10, 2006	Toronto Reliability Supply and Conservation Initiative - with respect to 2,500 MW RFP
March 21, 2006	Standard Offer Program - enter into contracts with small renewable generators
June 14, 2007	Clean Energy and Waterpower in Northern Ontario Standard Offer
August 27, 2007	Procurement of up to 2,000 MW of Renewable Energy Suppl
December 20, 2007	Hydroelectric Energy Supply Agreements with Ontario Power Generation Inc
January 31, 2008	Procuring Approximately 350 MW of New Gas-Fired Electricity Generation for Northern York Region
February 25, 2008	Procuring Electricity From Energy From Waste ("EFW") Pilot or Demonstration Projects ("PDPs")
April 10, 2008	Procurement for Electricity From Combined Heat and Power (CHP) Renewable Co-generation Projects
August 18, 2008	Southwest Greater Toronto Area (GTA) Supply - procure CCGT facility for generating about 900 MW in Oakville
December 19, 2008	Procuring Electricity from a Commercial Durham and York Region Energy from Waste (“EFW”) Facility
December 24, 2008	Negotiating New Contracts with Early Movers Generation Facilities
January 23, 2009	Biogas Projects and Renewable Energy Standard Offer (RESOP)
May 7, 2009	Negotiating New Contracts with Hydro-Electric Generation Facilities
September 24, 2009	Develop a feed-in tariff (“FIT”) program
January 6, 2010	Negotiate and execute a New Contract with Ontario Power Generation (OPG)
April 1, 2010	Negotiate one or more Power Purchase Agreement(s) (“PPA”) with respect to the Korean Consortium projects
August 26, 2010	Atikokan Biomass Energy Supply Agreement (“ABESA”) with Ontario Power Generation
November 23, 2010	Negotiating New Contracts with Non-Utility Generators
November 23, 2010	Combined Heat and Power (“CHP”)
June 3, 2011	Bruce and West of London Transmission Areas -offer FIT contracts for up to 750 MW and 300 MW of renewable generation facilities
July 29, 2011	Korean Consortium’s Haldimand Projects - direction to the OPA to negotiate power purchase agreements (PPAs) with Samsung C&T Corporation and Korea Electric Power Corporation
August 17, 2011	Thunder Bay Generating Station Conversion to Natural Gas
August 19, 2011	Procuring Electricity from Energy from Waste (“EFW”) facilities
April 5, 2012	Continue the FIT and microFIT programs
July 11, 2012	Feed-In Tariff Program Launch
November 23, 2012	Renewable Energy Program Re-Launch
December 11,2012	Renewable Energy Program Re-Launch to Strengthen Community and Aboriginal Participation in the FIT program
December 13,2012	Southwest Greater Toronto Area (SWGTA) Supply - move TransCanada 900 MW CCGT plant to lands of Lennox GS
January 21, 2013	Hydroelectric Projects - confirming 9,000 MW of hydroelectricity contracts
June 12, 2013	Renewable Energy Program - stopping procurement of Large FIT and setting 150 MW target for Small FIT, and 50 MW for microFIT for each of the next four years

Source: OPA. “Directives to OPA from Minister of Energy.” <http://www.powerauthority.on.ca/about-us/directives-opa-minister-energy-and-infrastructure>

The Ontario power market lacks either the clarity of a disciplined integrated resource plan (“IRP”) or the benefits of competitive pressure on generators who are forced to rely on the market to attain revenue. In a fully regulated market, the utility would submit an IRP to its regulator, the IRP would be vetted in an open regulatory process, and the utility would be charged with implementing the IRP at least cost. By contrast, the most recent LTEP, last issued by the OPA in

2010,[5] has been undermined by the GEA's Feed-in Tariff ("FIT") program, which obligates the OPA to contract with qualifying projects, even if the resulting capacity is not needed currently[6] or inconsistent with the LTEP. The LTEP is further neutered when ministerial directives are issued directing that OPA contract in particular ways. Between 2005 and June 2013, the Minister of Energy issued 66 directives to OPA. Out of these, 36 directed OPA with relation to procurement of power/capacity from OPG or other generators. Figure 6 presents the list of such directives.

Figure 7. Expected breakdown of Ontario 2013 generation based on contractual position



Note: LEI expects the merchant share (proportion of plants whose revenues are determined by HOEP) to drop further over the next 3 years.
Source: Ontario Energy Board. *Regulated Price Plan – Price Report, May 1, 2013 to April 30, 2014*. April 5th, 2013. p. 21. <http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2004-0205/RPP_Price_Report_May2013_20130405.pdf>

In the meantime, the government has banished the word "market" from the Independent Electricity System Operator's ("IESO") name, and (as shown in Figure 7) 91% of energy is either under contract with the OPA or rate-regulated by OEB.[7] IESO-run markets represent residual

[5] Ontario Ministry of Energy. *Ontario's Long-Term Energy Plan*. November 23rd, 2010. <http://www.energy.gov.on.ca/docs/en/MEI_LTEP_en.pdf>

[6] FIT Program Version 2.0 (effective since August 10th, 2012) rules improved on previous arrangements by including a Procurement Targets provision establishing the maximum amount of MWs procured during an application period; OPA will procure up to 200 MW worth of contracts (the Procurement Target) during the current Small FIT application window (December 14th, 2012 – January 18th, 2013). An additional 15 MW is set aside for pilot rooftop solar projects on unconstructed buildings. Sources: OPA. FIT Rules Version 2.1. December 14th, 2012. <http://fit.powerauthority.on.ca/sites/default/files/page/FIT_Rules_Version_2.1.pdf>; OPA. "Changes resulting from November 23, 2012 and December 11, 2012 directives." <http://fit.powerauthority.on.ca/FAQs/changes-resulting-from-directives-November23-December%2011-2012>; OPA. Project Size Caps. <http://fit.powerauthority.on.ca/fit-program/application-submission-and-evaluation-process/project-size-caps>; OPA. "December 14, 2012: Small FIT Version 2 application window now open." December 14th, 2012. <http://fit.powerauthority.on.ca/newsroom/december-14-2012-fit-20-program-launched>

[7] OEB. *Regulated Price Plan – Price Report, May 1, 2013 to April 30, 2014*. April 5th, 2013. p. 21. <http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2004-0205/RPP_Price_Report_May2013 _20130405.pdf>

balancing arrangements based on short-run marginal costs, because most participants if operating recover their remaining revenue requirement for the life of their projects through OPA contracts.

Failure to properly implement either a planned or a market approach to the power sector has resulted in significant cost impacts for Ontario consumers. This failure has caused a surplus of generation capacity in Ontario. Using the average net revenue requirement of the Clean Energy Supply conventional gas-fired contracts signed by OPA ($7,900 per MW-month)[8] as a proxy for the marginal cost of new capacity, and using the projected excess available capacity presented in Figure 3, we can estimate that Ontario consumers could expect to pay an additional $42 to $370 million per year above and beyond what is required to meet a 15% reserve margin between 2013 and 2015, before considering the costs of surplus baseload generation. This estimate may be conservative, given that significantly higher capacity costs have been reported for recently constructed plants.[9]

Similarly, the Auditor General of Ontario also stated that the Feed-in-Tariff program causes higher prices and added about $4.4 billion in costs over the 20-year contract terms as compared to what would have been incurred under the Renewable Energy Standard Offer Program ("RESOP").[10]

Other costs resulting from failure to implement a planned or a market approach to the power sector include an estimated $900 million extra to move gas-fired plants out of Oakville and Mississauga, and $28 million from the premature efforts to convert the Thunder Bay Generating Station from coal to gas after spending $190 million on construction.[11] Furthermore, the Ministerial-directed project of converting the Atikokan coal-fired plant into a biomass-fired plant

[8] OEB. *Regulated Price Plan – Price Report May 1, 2013 to April 30, 2014*. April 5th, 2013. p. 17. <http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory%20Proceedings/Policy%20Initiatives%20and%20Consultations/Regulated%20Price%20Plan> and <http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2004-0205/RPP_Price_Report_May2013_20130405.pdf>

[9] The new Napanee Generating Station gas-fired plant will receive at least $15,200 per MW each month, regardless of output. Source: OPA. *Memorandum of Understanding*. September 24th, 2012. p. 9. <http://www.powerauthority.on.ca/sites/default/files/news/DOCS-%2311803315-v8-Oakville_GS_Alternative_Project_MOU.PDF>

[10] Ministry of Energy. 2011 Annual Report of the Office of the Auditor General of Ontario. Electricity Sector—Renewable Energy Initiatives. <http://www.auditor.on.ca/en/reports_en/en11/303en11.pdf>

[11] Legislative Assembly of Ontario. *Official Report of Debates (Hansard)*. March 18th, 2013. <http://www.ontla.on.ca/web/house-proceedings/house_detail.do?Date=2013-03-18&Parl=40&Sess=2&locale=en >

has a construction cost of $170 million and likely will result in a levelized cost of energy more than twice that of a combined cycle natural gas plant.[12]

2.3 Politicization of power sector investment decisions

Power sector investments are capital-intensive and long-lived. A lack of constancy in power sector policies reduces the willingness of private investors to participate. Government intervention becomes self-perpetuating, as the province replaces (directly through OPG or indirectly through OPA) private risk-taking capital. Without proper safeguards, this transfer of risk from private investors to ratepayers and/or taxpayers can result in inefficient capital allocations, as governments stray from commercial objectives and apply artificially low hurdle rates to specific projects, if indeed a hurdle rate is applied at all. The electricity sector becomes a convenient instrument for policy implementation, regardless of the corresponding economic merits or lack thereof. Given the mismatch between short-run political horizons (four to six years) and long-run least cost planning (ten to twenty years), it is critical to have the appropriate safeguards in place to prevent election-driven policy volatility.

A properly functioning power sector policy framework involves the government setting broad policy objectives, which are then implemented through independent institutions and market mechanisms. It does not involve the government issuing directives for specific actions without thoughtful analysis and transparent deliberation. We would argue that the most appropriate policy objective for the power sector is to ***meet the reliability expectations of the average customer at long-run least cost within the prevailing environmental regulations***.

Before loading any additional responsibilities onto the power sector, policymakers must perform appropriate cost-benefit analysis. For example:

- ✓ If job creation is the objective, is converting Atikokan to biomass the most cost-effective way to do this?
- ✓ If the desire is to achieve a carbon-neutral power sector, does the Green Energy Act accomplish this in the most economically efficient fashion?
- ✓ How does cancelling fully permitted, under construction power plants meet any stated policy objectives?

Failure to credibly consider these questions before acting leads to unnecessary costs, and ultimately reduces the resources available to governments to meet other pressing needs.[13]

Unless institutions are truly autonomous from government, politicians in many jurisdictions just cannot resist the temptation to circumvent electricity sector policymaking processes. In Ontario,

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[12] OPG. "Atikokan Generating Station Biomass Conversion Project." Accessed December 2012. <http://www.opg.com/power/thermal/fuelconversion/atikokanfuelconversion.asp>

[13] Given that economic efficiency has been one of the driving motivations for attempting to catalyze consolidation at the distribution level, it is striking that it is mentioned far less frequently in discussions of generation policy.

this tendency dates back to well before market opening, to rate freezes imposed on Ontario Hydro in the 1990s.[14] Autonomy from government does not mean being exempt from government oversight; it does, however, mean that qualified executives and boards are allowed to organize their activities consistent with clear mandates and free from unscheduled interventions from policymakers.

Figure 8. Comparison of board selection criteria in Ontario, New York, and Michigan

Body	Ontario Energy Board	Ontario Power Authority	Ontario Energy Financial Corporation	New York State Public Service Commission	Michigan Public Service Commission
Number of members	At least five (currently 6 full time, 4 part time)	11	At least 2 and not more than 12 directors (currently 8)	5	3
Appointed by	The Lieutenant Governor in Council. In practice, nominated by the Minster of Energy	Minister of Energy	Appointed by the Lieutenant Governor in Council and is accountable to the Minister of Finance	Governor	Governor
Confirmation required?	Subject to review by Standing Committee on Government Agencies	Subject to review by Standing Committee on Government Agencies	Subject to review by Standing Committee on Government Agencies	Confirmation by Senate	Consent of the Senate
Nomination committee?	No	Self nomination if there is vacancy	No	Yes, governor cannot reject nomination list twice	No
Limitation on political parties?	No	No	No	No more than 3 members may represent the same political party	No more than two Commissioners may represent the same political party
Explicit qualitifaction requirement?	No	No	No, the current Board is largely comprised of public servants employed by the Crown	Yes, education and training and 3 or more years of experience in fields of economics, engineering, law, accounting, etc.	None
Term	First term shall not exceed 2 years, may be reappointed for one or more terms of office, each of which does not exceed 5 years	Hold office at pleasure for initial term not exceeding two years and may be reappointed for successive terms not exceeding five years each	Hold office at pleasure for a term not exceeding 3 years and may be reappointed for successive terms not exceeding 3 years each	6 years	Staggered 6 years term

Source: New York State. PBS Public Service Law. Article 1. <http://public.leginfo.state.ny.us/LAWSSEAF.cgi?QUERYTYPE=LAWS+&QUERYDATA=$$PBS4$$@TXPBS04+&LIST=SEA105+&BROWSER=BROWSER+&TOKEN=43134504+&TARGET=VIEW> and <http://open.nysenate.gov/legislation/bill/S1984-2011>; Michigan State. Act 3 of 1939. <http://www.legislature.mi.gov/(S(hbxvge45qb45od55gevznk55))/documents/mcl/pdf/mcl-chap460.pdf>; Ontario Province. Electricity Act, 1998. <http://www.e-laws.gov.on.ca/html/statutes/english/elaws_statutes_98e15_e.htm#BK155>; Ontario Energy Board. Act 1998 <http://news.ontario.ca/mei/en/2011/03/statement-by-minister-brad-duguid-in-nominating-a-new-chair-of-the-ontario-energy-board-1.html>

There are two ways to limit the ability of governments to make ad hoc interventions in the power sector: creating buffered boards and divestiture. The first is to establish the relevant institutions in a way that ensures that board members are independent of the government. Board member

[14] Ontario Hydro rates were frozen from 1993 to 2003. Dewees, Donald. "*Electricity Restructuring and Regulation in the Provinces: Ontario and Beyond*." York University. September 2010. <http://www.economics.utoronto.ca/public/workingPapers/tecipa-205-1.pdf>

terms need to be staggered, and removal only based on a limited number of conditions such as criminal activity or mental instability. Board independence is a necessary but not sufficient precondition for institutional independence – the entities need to have dedicated funding streams which are not subject to the whims of the legislature[15,16]. In Ontario, however, the former is a greater issue than the latter. As the table on the next page shows, neighboring US states protect the independence of key institutions with defined terms of office for board members, and require that the board not be solely in the hands of one political party (Figure 8).

Establishing institutional independence improves the prospects for constancy of policy; divestiture blunts the impact of ministerial directives, because it means that policymakers can no longer directly order state owned companies to proceed with particular investments without due consideration. While divestiture may take the form of "inclusive privatization", involving pension funds, unions, and community or social organizations in the shareholding structure, the outcome is that the resulting entities focus on achieving commercial objectives within a broad policy framework applicable to all such companies.

2.4 Challenges with the Global Adjustment

Compounding issues with political meddling, the GA interferes with economically efficient decision making in several ways. It distorts pricing signals, because customers only know the amount of the GA assessment after they have made their consumption decisions. The GA in fact in some ways cancels out attempts by consumers to save money by altering their demand levels and patterns, as changes in wholesale prices due to lower demand levels are offset by the reciprocal increase in the GA to cover fixed obligations for supply. The GA makes consumer bills less comprehensible, potentially undermining consumer acceptance of power sector policies. Programs for large users serve to further mute price signals to these customer classes, and blunt the incentive for bilateral contracting. The GA comingles costs from achieving environmental objectives with those incurred as a result of reliability goals, and the lack of transparency prevents customers themselves from signaling through the market their desired levels (in excess of statutory norms) of each of these elements. Finally, this very lack of transparency can lead to a tendency among policymakers to use the GA to hide the consequences of poor decisions.

By working to eliminate the GA, Ontario can improve the fidelity of the price signal to final consumers. Among other benefits, this would reduce the yo-yo effect of suppressing wholesale prices on one hand, and thereby potentially increasing demand, and on the other spending on demand-side management ("DSM") programs whose effectiveness would be enhanced if customers were charged full and transparent costs for power.

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[15] The OEB is funded by fees, assessments and administrative penalties it collects from the regulated entities. (Memorandum of Understanding between the Minister of Energy and Infrastructure and the Chair of the Ontario Energy Board, March 11, 2010, Article 13.3)

[16] The OPA's operating budget is funded by fees on electricity consumers ($0.551/MWh) and registration fees on OPA procurements (OPA Annual Report 2012, page 10).

2.5 Why the status quo is not sustainable

The current arrangements in the Ontario power sector are not sustainable. Repeated use of ministerial directives increases uncertainty about policy direction and durability. Use of a feed-in tariff structure exacerbates imbalances in supply composition and increases costs. Requiring a provincially owned generator to pursue investments for other than purely commercial reasons creates additional cost challenges. Inefficient consumption decisions are triggered by the suppression and distortion of price signals through the GA and other means. As Ontario power costs diverge from those in neighboring states and provinces, economic activity may suffer, and eventually the province's credit rating may be at risk if rising prices and falling demand lead to stranded assets coupled with implicitly provincially-backed entities.[17] However, Ontario can address all these issues if it focuses on improving price signals, codifying autonomy for provincial electricity institutions, and deploying long-run least cost approaches to meeting stated policy objectives. Recent initiatives by the Wynne government suggest it is aware of the challenges and is seeking to address them in an economically-rational fashion.

[17] While OPG and OPA may be ostensibly arms-length from the provincial government, the spill-over effects on the province's credit of allowing either to default makes it unlikely that rating agencies would ignore their liabilities in considering the province's credit were either to face financial difficulties.

3 Creating a meaningful long-term price signal for power in Ontario

The Ontario power sector already contains the appropriate building blocks to create a stable long-term investment climate. Instead of replacing (or merging) existing institutions, policymakers should refocus them on decision-making that emphasizes long-run economic efficiency, including providing effective and transparent price signals. Attention to long-run economic efficiency allows society to achieve the optimal allocation of goods and services consistent with that society's objectives. Obscuring price signals ultimately reduces social welfare by leading to a mis-allocation of resources.

3.1 Providing appropriate price signals and reallocating risk

By increasing the number of private sector actors, initially through the privatization of the Mississagi hydro assets and subsequently through contracts issued by the OPA through various procurement rounds and the FIT, Ontario has already begun the process of creating a more dynamic and innovative power sector than existed under Ontario Hydro. However, while the number of participants has increased on the generation side, the number of potential counterparties has narrowed. Effectively, OPA has "crowded out" private long-term electricity buyers – generators have little incentive to seek alternative purchasers, and electricity buyers cannot match the credit quality and duration of OPA contracts. OPA contracts shift operational risks within the control of the developer to the developer's shareholders (if the plant fails to operate, the developer does not get paid), along with the risk of cost overruns. Ratepayers, however, bear the risk that OPA will over-contract on their behalf. Risk allocation becomes particularly awkward when OPA is directed to contract with OPG, as contacts are simply shifting risk between ratepayers and taxpayers.

Instead of articulating an overarching goal and allowing the required institutions to determine a least cost means of achieving it, policymakers become entangled in the details, lack the expertise to fully assess the implications of their decisions, and end up spending more while achieving less. Failure to allow for technology and owner-neutral processes often divorces actions from consequences. OPA should not be used as a rural development agency; if a conversion of an elderly coal plant to biomass needlessly adds costs for all consumers, more jobs may be lost due to the increases in electricity costs than were saved by keeping the generation station open. Likewise, if the objective is to decarbonize the electricity sector, allowing OPA to run technology-neutral processes in which nuclear, solar, wind, and hydro compete assures that electricity consumers do not pay more than is necessary to meet the desired goals. From an ownership perspective, failing to subject OPG to the same discipline that private developers face – the need to bid for and win contracts, and once won stay within their expected budget if they expect to profit – means that ratepayers, rather than shareholders, end up paying for cost overruns; even if OPG did bear the burden of cost overruns, taxpayers would ultimately pay the cost through reduced dividends.

If the government could be relied upon to allow OPA to implement contracting according to long-term system plans on a technology and owner-neutral life cycle least cost basis, fewer changes to the overall structure of the Ontario power sector would be necessary. However, this has not proven to be the case. By re-orienting the Ontario power sector away from use of OPA as a principal buyer, risks can be reallocated, price signals made more transparent, and investment and consumption decisions improved.[18] Diversifying procurement responsibilities will reduce risks of oversupply; shareholders of purchasers face lower profits if their companies over-contract, whereas entities like OPA face limited consequences in similar situations. In parallel, relying solely on private capital for future investment will force consideration of least cost alternatives to meet power supply needs consistent with environmental laws, while necessitating the transition of rural development and jobs growth responsibilities back to those agencies most experienced and effective at them.

3.2 Stages of market evolution

We envision six steps to transition the Ontario power market to a durable set of arrangements which result in long-run least cost to consumers. These steps are as follows:

1. ***strengthening the autonomy of power sector institutions***
2. ***addressing the role of nuclear***
3. ***creation of Load Serving Entities*** ("LSEs") required to participate in a Resource Adequacy Market ("RAM")
4. ***establishment of the RAM***
5. ***allocation of capacity*** (total plant output potential, expressed in MW) and energy (production, which occurs when capacity is called upon, expressed in MWh) from all existing OPA contracts to LSEs, with all subsequent contracting driven by LSE perceptions of need relative to their RAM responsibilities
6. provide customers with ***default supply options*** which pass through RAM and spot prices, with those wishing to hedge ability to do so using competitive offerings from LSEs.

Below, we describe of each of these steps in greater detail.

3.2.1 Getting institutional relationships right

The first step in setting a proper foundation for power market evolution is to enshrine the independence of the key market institutions and clarify their mandates. Difficult though it may be, once the long-term policy direction for the power sector has been defined, policymakers then need to put appropriate distance between themselves and the implementing institutions. While some measure of independence can be assured by insulating OEB, IESO, and OPA board members from removal for any reason other than expiration of term, mental incompetence or moral turpitude, and by providing dedicated funding mechanisms for those institutions, further

[18] Those who laud the apparent simplicity of an OPA contracting regime should consider the systematic imperative for central procurement entities to over-contract (consequences for undersupply are felt immediately, while costs of oversupply only become apparent over a long period of time, and possibly after the decision-maker is no longer in the job), and their susceptibility to political interference. Ultimately, the "simplicity" will prove costly to ratepayers unless the procurement entity and its regulator are truly arms-length from politicians and the long term procurement plans (including the associated target reserve margins) are subjected to full and proper regulatory review.

steps may be needed to prevent OPG and Hydro One from being used as instruments of social policy. In addition to allowing the government to reallocate scarce investment dollars to areas with higher social returns, and shifting risks away from taxpayers to shareholders, inclusive privatization[19] allows company management to focus on running the businesses without fear of needing to respond to unanticipated ministerial directives, adding to the companies' clarity of purpose.

Efforts to merge the OPA and IESO, currently on hold, should be abandoned permanently. Due to the difference in functions between the two agencies, savings from the combination are illusionary, and the potential for conflict of interest is rife. While areas where functions are duplicated (and there are few) should be allocated to one or the other, maintaining the two as separate entities is critical to the integrity of the Ontario power market. Mixing the functions of market and transmission operator with that of contract administration will raise the suspicions of market participants that the market and transmission system will be operated in a fashion that reduces OPA-related costs at the expense of other market participants while undermining the fidelity of the market price signal. Ultimately, this may drive participants from the market, increasing future investment costs and reducing diversity of actors.[20]

As described further below, IESO's mandate should be expanded to include the administration of a long-term capacity market. On the other hand, OPA's should narrow. OPA was originally intended as a transitional agency,[21] designed to address a looming supply shortfall by providing stability to investors while the Ontario power market was steadied. OPA successfully accomplished this. Through subsequent procurements and the FIT, OPA also catalyzed the creation of a local private sector renewable energy industry. Now that these goals have been achieved, and once nuclear refurbishment contracts have been negotiated, OPA should be directed to cease further contracting, focus on contract renegotiations to reduce the GA, and ultimately become a pure contracts administrator. The conservation programs of the OPA should be wound down consistent with a plan to enhance the market price signals for efficient demand side management, while IESO designs demand response programs consistent with its market operations. Finally, as discussed later in Section 4.1 of this paper, once OPG rate regulated assets

[19] While a degree of public float is beneficial for deepening Canadian equity markets, the shareholder arrangements for Bruce Power (a partnership among Cameco Corp., TransCanada Corp., the Power Workers' Union, the Society of Energy Professionals and indirectly the Ontario Municipal Employees Retirement System) present a model for incorporating private capital into OPG or its divisions. Source: Bruce Power website: http://www.brucepower.com/about-us/

[20] A more appropriate candidate for merger would be OPA and OEFC, given that both administer long-term contracts, though OEFC's role will gradually diminish as contracts expire.

[21] "… — OPA CEO Jan Carr suggests that the authority should be a "transitional agency" and will at some point "do itself out of a job." Reflecting this view, the OPA's 2007 business plan suggests that, "Over time, as the market develops sufficient ability to ensure timely investment in supply resources, the need for OPA procurement activities will decline." Source: Wyman, Michael. "Power Failure: Addressing the Causes of Underinvestment, Inefficiency and Governance Problems in Ontario's Electricity Sector." May 2008. <http://www.cdhowe.org/pdf/commentary_261.pdf>

are covered by contracts (signed with OPA but assigned to LSEs per the process described herein), OEB would cease to rate-regulate OPG's prescribed assets,[22] but would periodically review OPA's budget, progress in reducing the GA, and plans for shrinking as the number of contracts administered peaks and responsibilities for procurement wane.

3.2.2 Address role of nuclear

A key element for future Ontario power sector investors will be an understanding of the role of nuclear. Until the future post-refurbishment and retirement size of Ontario's nuclear fleet is known, and the extent to which future investments in nuclear will be subject to least cost principles is determined, investors will be hesitant to make market-based commitments to new generation investments. Long gestation periods and high capital intensity make it almost impossible to finance new nuclear plants without long-term contracts. The same is true of large scale life extension projects at existing nuclear facilities. Although fuel source diversity may also be of value, Ontario's power sector would have a range of sources even if nuclear were no longer available. While a fair comparison with conventionally-fuelled projects requires consideration of the benefits from zero emissions, levelized cost estimates often fail to capture decommissioning and spent fuel management costs. Comparisons of any technology to CCGTs by any analyst should be made using the net present value of life of plant gas costs, rather than today's prevailing historically low prices.[23] Nonetheless, even accounting for such factors, in a technology-neutral long-run least cost competition, most types of new nuclear projects would struggle unless natural gas prices increase significantly and carbon is heavily taxed.

The indicative cost comparisons in Figure 9 suggest that while some refurbishment projects may be competitive with new baseload gas fired plants when environmental externalities are considered, new nuclear is not likely to be cost competitive. Given that existing nuclear power stations are (after significant initial investment) a part of Ontario's physical endowment, they should not be abandoned lightly. At the same time, nuclear should not be preserved at any cost.

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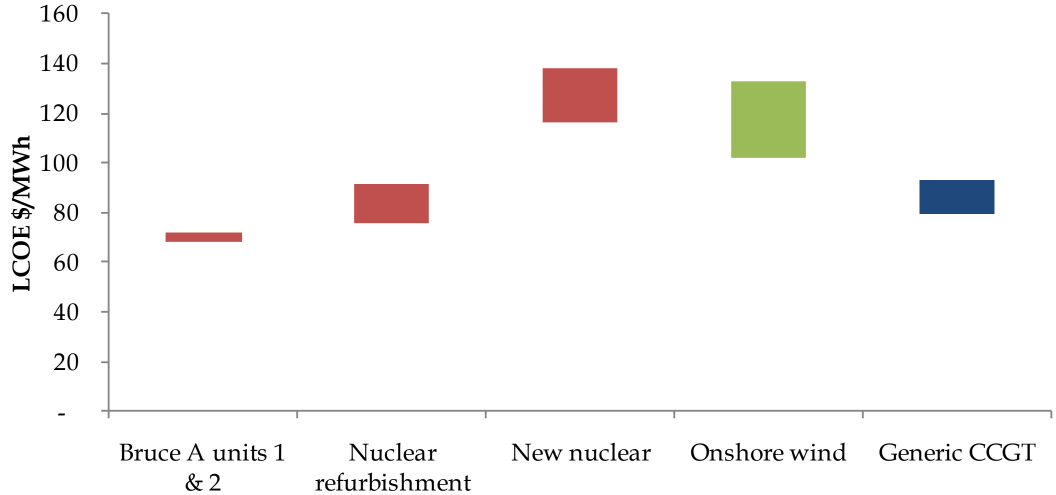
[22] Creating contracts would eliminate the need for an ongoing incentive ratemaking process for OPG, as the contracts themselves would embed the incentives that regulation would otherwise attempt to mimic. While we have elsewhere in this paper noted the difficulties involved when one government authority contracts with another, we regard shifting from OEB regulation to OPA contracts as a transitional step to making OPG fully subject to market forces.

[23] While some may argue that an advantage of new or refurbished nuclear at existing sites is the ability to make use of existing transmission infrastructure, new gas facilities at the existing nuclear sites could accomplish the same objective.

Figure 9. LCOE comparison between nuclear refurbishments, new nuclear, onshore wind and generic CCGT



Note: LCOE as of 2012. All figures nominal Canadian dollars and assuming exchange rate CA $1/US$. CCGT LCOE low estimate based on 85% capacity factor, with natural gas prices based on net present value of 20-year forecast prices, a $20/ton carbon price, and EIA *AEO 2012* capital cost assumptions. CCGT LCOE high-end estimate based on 70% capacity factor, 7.5/MMBtu gas price, a $20/ton carbon price, and costs based on Ontario-specific cost average. Refurbishment cost of Bruce based on actual announced cost and contract price with OPA. Other nuclear refurbishment costs based on average for Darlington, Gentilly, and Point Lapreau. LCOE of new nuclear based on EIA *AEO 2012* assumptions and on average costs of Olkiluoto (Finland) and Flamanville (France) European Pressurized Reactor plants currently under construction. Onshore wind LCOE based on FIT 2.0 price schedule and EIA *AEO 2012* assumptions. Weighted average cost of capital ("WACC") for all projects assumed to be 8.88%. See also Appendix A.

To properly explore the role of nuclear during the process of a transition to market based investment planning, the OPA should hold one final procurement round. However, such a procurement round should be based on an announced threshold price, and an assessment of the timing of need for baseload resources. The threshold price should be based on the levelized cost of a new CCGT, incorporating an appropriate present value of the cost for carbon and natural gas; bid documents should note that no bids above this would be accepted.[24] In the event that the procurement failed, site owners would be free to redevelop the sites as they saw fit (including conversion to gas), but would do so solely on the basis of revenues from spot markets, bilateral contracts, and the resource adequacy market described below.

3.2.3 Identifying load serving entities

A properly functioning market has an appropriate number of sellers *and buyers*. An important step in creating a more robust set of potential counterparties is to increase the number of entities with a direct responsibility for serving load. Such "load serving entities" ("LSEs") are responsible for providing customers with the commodity portion of their load, as distinct from the

[24] While we believe that over time the Ontario market needs to evolve towards technology-neutral generation investment signals, this final procurement is intended to test the value of the existing nuclear endowment against a natural gas default option. Alternatively, the final procurement round could define the product consistent with what refurbished nuclear plants would be able to supply (baseload power for 20 years commencing approximately five years from the auction date), but allow all technologies to bid.

transportation of it. An LSE can be a competitive retailer or a utility, but its defining characteristic is that it faces consequences should it fail to provide energy and capacity that an end-user has contracted for.[25] LSEs are the predominant form of organization to meet load obligations in competitive electricity markets, particularly those with mechanisms like the RAM.

Existing electricity local distribution company ("LDC") service territories in Ontario are the logical starting point for creation of LSEs. However, electricity local distribution companies in Ontario are regulated businesses of varying size and capabilities; these companies are already facing significant pressure as they seek to upgrade their physical plant and comply with Ontario's sophisticated, but increasingly complex, incentive rate system. This suggests that creation of the LSEs within the LDCs could prove to be a distraction, and may not be effective. As an alternative, four or five new LSEs could be established by OPA for sale by auction to the private sector, with initial boundaries mapping to a set of contiguous LDC service territories.[26]

The new LSEs would be responsible for procuring energy and capacity on behalf of the customers within their initial service territories. However, end customers would be able to choose third party retailers as their LSEs, and the new LSEs would be eligible to compete in the territories of the other LSEs. The LSEs would be auctioned to experienced commercial companies, accompanied by a pro rata allocation of existing OPA capacity volumes through a back-to-back capacity contract, as described further below. This pro rata allocation would be further divided proportionally among the LSEs' regulated (customers who have yet to choose a competitive supplier) and competitive customers,. The default offering for regulated customers would be divided between an energy and capacity component; the existing GA would continue to be assessed by LDCs on wires charges to assure that it remained non-bypassable.

3.2.4 Creation of a resource adequacy market

To facilitate the move from Ontario's semi-planned principal buyer-based market, Ontario should establish a long-term resource adequacy market ("RAM"). The RAM could be considered a form of capacity market. North American wholesale electricity markets have evolved in one of two ways: energy-only markets, such as Alberta and the Electric Reliability Council of Texas ("ERCOT"), or energy and capacity markets. California ISO, ISO New England, Midwest ISO, New York ISO, and PJM capacity markets are summarized in Figure 10. In an energy-only

[25] For the purposes of this paper, customers directly connected to the transmission system would also be considered to be LSEs, subject to the same rights and obligations as the LSEs created to serve residential customers. Directly connected customers, as well as existing competitive retailers, would face capacity obligations, but would be included in the pro rata allocation of OPA contracted capacity described here.

[26] LSE territories would not map directly to the outline of all existing LDCs, since some, such as HydroOne, own non-contiguous territories. Existing LDCs would be allowed to bid on LSE franchises through their unregulated subsidiaries, subject to current affiliate relations codes designed to prevent use of utility brands to create an unfair advantage in the retail market. Bidders for the LSEs would have the right to supply and obligation to serve existing regulated customers; this relationship may be valuable as a hedge for new generation businesses and for building new retail platforms. Within the confines of existing privacy laws, bidders would prior to the auction have information on customer numbers, levels of demand, and load shapes. Proceeds from the auction would be used to reduce the GA.

market, participant revenues are determined either by their participation in the spot market or by their bilateral contract position. Energy and capacity markets provide an additional revenue stream from capacity payments – a "payment for existence" which a plant receives even if it is not dispatched, provided that if it is called upon it is in fact able to run.

For energy-only markets to work properly, they must be allowed to reach peak prices which reflect a scarcity value when appropriate, so as to provide price signals to new entrants. Competitive wholesale markets with price caps, particularly when those price caps are significantly below the value of lost load ("VoLL"), the economic impact incurred as a result of an outage), may fail to provide such signals. Capacity markets were put in place in some power markets to provide an additional means of signaling when new build is required. While we find that, when allowed to work properly, energy-only markets can be the most economically efficient design for competitive wholesale electricity markets, an energy-only market in Ontario may be greeted with skepticism by investors given the province's history of suppressing price signals. One of the key motivations for implementing capacity markets in the markets where they exist has been to replace the so-called "missing money" that arises when governments and regulators seek to artificially suppress peak prices, for example through price caps.

In energy-only markets, while an ISO may monitor projected reserve margins, the size of the reserve margin is largely left to the market. By contrast, in a capacity market, LSEs are required by the market operator to procure sufficient capacity (usually denominated in $/kW over a unit of time, such as a month) to meet a target reserve margin set by an ISO. Thus, an LSE will, in addition to procuring sufficient energy to meet its customer's needs, be required to calculate each customer's peak load and procure sufficient capacity to meet that peak load plus a reserve margin. If the customer peak load is 100 MW, and the target reserve margin is 15%, the required amount of capacity the LSE must purchase is 115 MW.

Capacity markets have faced several challenges. In initial capacity market designs, capacity prices were not known more than a year in advance, meaning developers needed to forecast future capacity prices and convince their bankers to consider the associated revenue stream in determining the debt carrying capability of the asset. Some capacity markets have been redesigned to allow for three year forward capacity markets. Capacity markets also tended to be binary – during periods of surplus, capacity was worthless, while when scarcity conditions arose, the price of capacity rose to the cap, usually set at the amortized cost of a new simple cycle gas turbine, which serves as a proxy for an economic means of meeting peak load. System operators have attempted to address the binary nature of capacity markets through the creation of floor prices and complex "demand curve" approaches which adjust minimum prices based on reserve margins and bids.

Figure 10. Selected ISO capacity market designs

ISO	Capacity market design summary
CAISO	▪ Spot capacity market, serves 1 state, since 2004* ▪ No centralized capacity market currently in place; System Resource Adequacy Requirement ("RAR") and Local RAR satisfied by utilities/LSEs on annual and monthly basis through bilateral trading of a capacity product defined by California Public Utilities Commission ("CPUC") ▪ LSEs issue long-term RFPs under longer-term procurement plans subject to Utility Long-Term Procurement Planning managed by CPUC
ISO-NE	▪ Forward capacity market, serves 6 states, since 2006 ▪ Use of 3-year forwards via Forward Capacity Auction ("FCA") with annual reconfiguration auctions ▪ Local requirement for import constrained areas; with commitment period start, LSEs and generators can also participate in seasonal and monthly reconfiguration auctions ▪ ISO-NE 's December 2012 FERC compliance filing implemented a buyer-side offer floor mitigation mechanism, eliminating previous offer floor beginning in 2017/2018 ▪ Commencing with 2016/2017 proposes modeling four capacity zones: Connecticut, NEMA/Boston, Maine and Rest of POOL
MISO	▪ Voluntary capacity market, serves 11 states, since 2009 ▪ Starting in June 2013, an organized yet voluntary capacity market will be set up; nevertheless, most capacity transactions are still expected to be handled on bilateral basis ▪ Balancing Authorities ("BAs") within MISO will be divided among seven (7) Load Resources Zones ("LRZ") based on factors such as electrical boundaries and relative strength of interconnections between BAs ▪ Each LRZ will have a clearing price corresponding to its market conditions ▪ LSE are required to buy from supply resources (which participate) in order to comply with the resource adequacy requirement in their zones
NYISO	▪ Spot capacity market, serves 1 state, since 1999 ▪ Monthly Installed Capacity Spot Market Auction ▪ LSEs with unmet RA obliged to purchase capacity and offer excess capacity ▪ Locational: New York City ("NYC"), Long Island ("LI"), and Rest of State ("ROS") ▪ Local RA in LI and ROS due to transmission constraints ▪ Use of downward sloping demand curve ▪ New entrants cannot compete until they are operational
PJM	▪ Forward capacity market, serves 13 states and District of Columbia, since 2007 ▪ 3-year ahead Forward Capacity Market that relies on a downward sloping demand curve ▪ LSEs can use self-supply and bilateral contracts and residual capacity procured in competitive auction

Note: *CAISO System RAR instituted in 2004 and Local RAR in 2006
Sources: various ISOs

The RAM envisioned for Ontario would be a form of laddered capacity market, with purchase requirements decreasing for years further into the future. Capacity markets can be viewed as an administrative method of addressing a perceived market failure in which the contract length customers are willing to enter into for hedging purposes is too short to provide sufficient certainty for financing.[27] In addition to providing greater long-term price transparency, the laddered

[27] The failure of customers to enter into longer term, higher priced hedges may be linked to the fact that policymakers seem unwilling to allow those who had the opportunity to hedge, but failed to do so, to face the consequences

capacity market is intended to provide some elasticity to capacity pricing in future years. The IESO would set target internal reserve margins, and administer forward capacity markets. To provide a meaningful long-term investment signal,[28] LSEs would be required to demonstrate sufficient capacity to meet their current load plus required reserves for a period three years into the future, based on IESO projections; in addition, the LSEs would be required to contract for a declining proportion of current load plus reserves for each year four to seven years into the future. LSEs failing to meet their requirements would face a penalty equal to the monthly amortized cost of a new simple cycle gas turbine. The table in Figure 11 below shows the proportion of peak load LSEs would be required to purchase in the present associated with each of the seven forthcoming years.

While it is true that from a customer perspective, capacity payments are not "free", from a market perspective if the capacity market is properly designed the payments are substitutes for what would otherwise be higher peak prices. An effective capacity market may allow for reserve margin targets to be met with less need for super-peak pricing to signal that entry is necessary. New entrants may apply a lower cost of capital to markets with multiple durable revenue streams, reducing long run marginal costs. Furthermore, the cost of reliability itself becomes more explicit, allowing for more informed discussion of the trade-offs embodied in selecting a particular target reserve margin.

Figure 11. Indicative forward capacity purchasing requirements for LSEs

	Years from present time						
	+1	+2	+3	+4	+5	+6	+7
Capacity contracting requirement as percent of current peak load in the specified future year	115%	115%	115%	115%	115%	115%	115%
Share of requirement to be procured in present year	100%	100%	100%	90%	80%	70%	60%
Effective capacity contracting requirement in present year	115%	115%	115%	104%	92%	81%	69%

Source: LEI

Initially, and quarterly thereafter, the IESO would launch an auction for capacity for each of the years in the full seven year forward period. Existing generators, and new entrants, would sell capacity not currently under OPA contract into the auction, and LSEs would purchase their requirements through the auction. However, IESO would maintain an ongoing reconfiguration

of their actions during periods of volatile electricity prices. Price caps are one way in which policymakers decrease the cost of failing to hedge, and thus reduce the attractiveness of contracting.

[28] The seven year laddered purchase requirement is intended to provide a long-term price signal that facilitates longer term debt financing for developers, while not unduly burdening retailers. IESO will need to pay careful attention to the design of prudential requirements on LSEs and others trading in the RAM, so that credit requirements do not serve as undue barriers to entry in the retail market while protecting against the consequences of default.

market for all interim years, posting bid-ask spreads on its website. LSE compliance would be assessed quarterly against the IESO projections. LSEs would also be allowed to procure capacity through bilateral contracts, but would need to register the contract with IESO for the compliance purposes. Capacity floor prices would be imposed for years less than five years into the future in which projected supply relative to demand results in a reserve margin less than half of the IESO target, and such floor prices would increase if the projected supply-demand balance resulted in a reserve margin of less than a quarter of the IESO target within less than five years in the future. Details of such floor prices would be the subject of market design deliberations.

One of the biggest changes in capacity markets, and a contributing factor to maintaining capacity prices at moderate levels, has been the increased ability of demand response aggregators (entities which assemble commitments and capabilities to reduce load from smaller customers into blocks large enough to be dispatched) to participate. While generators have expressed concern that demand response and physical generation are not equivalent, demand response aggregators have proven to be highly flexible and have aided in maintaining reliability during tight supply situations. Demand response would be eligible to participate in capacity auctions, and would be subject to the same deliverability standards as conventional generation.

Intermittent resources would be eligible for capacity based on resource specific average seasonal capacity factors calculated based on contribution to peak load. These class-specific capacity factors would be reviewed by IESO every five years for adjustment. In addition, those intermittent resources which prove to have actual capacity factors significantly (one standard deviation) below their resource category average would be further de-rated in subsequent auctions; conversely, those resources performing significantly better than their peers would have the ability to be assigned a higher capacity credit in subsequent auctions.

Because of current ample supply in Ontario, it may be several years before the RAM would signal significant investment needs. However, the IESO should be attentive to synchronization of market rules with neighboring markets to allow export of capacity. Because capacity cannot be sold in two markets simultaneously, subject to the amount of firm transmission available, capacity prices in neighboring markets can help to provide an implicit floor for capacity prices in Ontario during years when the IESO-administered floor price related to low projected reserve margins is not in place.

3.2.5 Capacity reallocation

For LSEs to fulfill their responsibilities in the RAM, they need to have access to capacity. Because through its contracts OPA controls the large majority of capacity in the province, a means needs to be found to transfer this capacity to the LSEs. However, because a transfer of individual contracts could be administratively complex,[29] a more straightforward approach would be to

[29] To be clear, we are not suggesting assignment of existing OPA contracts, but rather that OPA resells or assigns capacity from existing contracts using new contracts – existing OPA counterparties would not be asked to transfer their contracts to the new LSEs. Capacity allocation is a one-time exercise – once completed, it would not occur again, minimizing the possibility of investor uncertainty.

allocate all of OPA's capacity to the LSEs on a pro rata basis using back-to-back contracts (or some other form of capacity assignment) with the OPA which mirror the terms of the underlying contracts OPA holds, but possibly in different quantities (i.e., one 500 MW contract could be offset by five 100 MW contracts). LSEs would pay a nominal sum, such as one dollar per year, for these contracts, which would be for the life of OPA's contracts. This means that over time, the contract capacity would taper off, after rising in early years for plants that have been contracted for[30] but are not yet online. All LSEs registered by a cut-off date would be eligible for the capacity allocation based on their demonstrated existing peak load commitments. This vesting-style approach provides substance to newly formed LSEs by clarifying available supply.[31]

Because customers have already paid for the existing capacity through the GA, and will continue to do so, it is not necessary for OPA to charge the LSEs for the capacity. Because the LSEs would be contracting for their net needs through the RAM, RAM pricing would reflect the non-energy costs of incremental capacity.

3.2.6 Continuation of default alternatives

Each LSE would be required to offer its customers a default alternative of spot price plus RAM pass-through, similar to current arrangements which are described in the text box below; TOU prices would only be set by the OEB for those customers without real-time meters. Customers would be free to switch based on LSE competitive offerings, which would likely include long-term fixed prices for energy and RAM capacity. In order to offer fixed prices on RAM capacity, LSEs would need to be active participants in the RAM. Because of the requirement to contract for RAM seven years forward, LSEs would likely offer forward terms to consumers of up to seven years; restrictions on switching after contracting but before the end of the contract term would be based on the LSE's commercial terms and conditions.

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[30] This includes contracts that have been approved and in process of being built; the moratorium would apply only to new incremental contracts.

[31] LSEs would be allowed to sell surplus allocated capacity in neighboring markets. Presumably, bidders for LSEs would incorporate this potential benefit into their LSE valuations, meaning customers would ultimately benefit since LSE auction proceeds would revert to customers through a reduction in the GA.

To assure appropriate customer attribution of the capacity transferred from OPA, LSEs would be required to allocate this capacity monthly on a pro rata basis between default and contracted capacity. The RAM price pass through for default customers would be a weighted average of the near zero cost of the OPA-related component and the market procured RAM capacity. Access to the OPA-related capacity volumes for contracted quantities would allow LSEs to craft competitive offerings while preventing creation of perverse incentives for default customers to avoid switching.

3.3 Why proposed structure is best alternative for Ontario

Continuation of centralized contracting in Ontario runs the risk that the power sector will continue to be used to meet the needs of narrow sets of politically advantageous constituencies at the cost of ratepayers as a whole. There is little evidence that the current procurement arrangements can be sufficiently depoliticized to allow for long-run least cost planning; even if they could, central planners may not be able to resist the temptation to stray from technologically neutral approaches.

By contrast, immediate transition to an energy-only market is also unfeasible. Investors will doubt that prices will be allowed to rise to levels that would make investment attractive. Although examples of shorter term capacity markets exist, shorter term forward visibility of capacity pricing is an impediment to financing.

The proposed RAM incorporates the best features of neighboring markets, facilitating potential integration, and creates a role for market-driven demand response. Customers will not pay twice for existing capacity; capacity under existing contracts will have already been allocated to LSEs,

Current retail supply arrangements in Ontario

Currently, residential and small business consumers who buy their electricity directly from their local utility (instead of from retailers) pay either a tiered or time-of-use ("TOU") rate according to the Regulated Price Plan ("RPP"), depending on whether they have smart meters installed.

RPP prices are set by the OEB and reviewed twice per year, on May 1 and November 1. To calculate RPP prices, the OEB forecasts the cost to supply electricity to RPP consumers for the next 12 months, taking into account factors such as forecast prices for coal and natural gas, supply fuel mix, contract with generators, and demand forecast.

While all Ontario electricity consumers are required to pay their share of the GA, a forecast of the GA is included in the RPP prices and therefore is not shown separately on the bill.

Effective May 1st, 2013, the peak TOU price increased from 11.8 cents/kWh (November 1st, 2012) to 12.4 cents/kWh, and the off-peak price will increase by 0.4 cents to 6.7 cent/kWh. For tiered prices, the first tier (up to 600 kWh per month for households) price will be 7.8 cents/kWh (0.4 cent increase from previous RPP). Above the tier threshold, the price will increase from 8.7 to 9.1 cents/kWh.

As of April 5th, 2013, about 83.2% of RPP-eligible consumers were on TOU billing.

Source: Ontario Energy Board website. Time-of-use (TOU) and Regulated Price Plan (RPP) FAQ. Accessed April 2013. <http://www.ontarioenergyboard.ca/OEB/Consumers/Electricity/Electricity%20Prices/Regulated%20Price%20Plan%20FAQs>

effectively making the RAM a residual capacity market. If accompanied by economy-wide efforts to price negative externalities from emissions and effluents, the arrangements will ultimately facilitate market-driven private sector investments in the Ontario power sector consistent with the province's environmental goals.

4 Related issues

Evolution of wholesale electricity markets does not occur in a vacuum. This is particularly true in Ontario, where the current fuel mix is a legacy of prior government policies, resulting in a cascade of potential nuclear retirements through the coming decade. Choices for electricity market policy are shaped by, and in turn impact, pre-existing contracts and commitments and climate change policies. Below, we discuss a range of issues, which need to be considered in parallel with stabilizing the Ontario electricity market, along with complementary policies.

4.1 Evolution of OPG

For the RAM to work properly, it needs to incorporate OPG assets, and future OPG investments need to be driven entirely by market forces. While privatization of some or all of OPG would be beneficial to place it definitively beyond the reach of ministerial directives, steps other than privatization can be taken in the meantime to improve the functioning of the Ontario wholesale power market. By developing contracts on a plant-by-plant[32] basis for the OPG prescribed assets,[33] policymakers and company management have greater flexibility in asset configurations should creation of new private gencos be contemplated. These contracts would need to be sufficiently long to maintain OPG credit quality, but thereafter, provided OPG or its successor companies lacked market power, no further contracts other than those obtained commercially in the market would be required.[34] OPG's non-prescribed assets would remain merchant, able to sell into both the energy market and the RAM or enter into bilateral contracts.

These contracts on the current prescribed assets should exclude refurbishments, which on a going forward basis would need to be financed through contracts sought in the marketplace, just as any other private sector actor will after the RAM is put in place. Once the contracts commence, OPG would no longer need to be rate regulated by OEB, lessening the regulatory burden significantly for all stakeholders. Moving the OPG assets from regulation to contracts puts all market participants on a more level playing field. Furthermore, it allows the capacity from the OPG

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[32] For hydro plants on a single river system, a bundled contract can be considered.

[33] OPG prescribed assets include all nuclear facilities (Darlington and Pickering A and B) and most of its baseload hydroelectric facilities (Sir Adam Beck 1 and 2, Pump generating station, DeCew Falls 1 and 2, and R.H. Sounders). For electricity generated by its prescribed facilities, OPG receives a regulated price determined by the OEB. Source: OPG. 2011 Annual Report. <http://www.opg.com/pdf/annual%20reports/Annual%20Report%202011.pdf>

[34] Recent announcements that OPG will be allowed to bid for large scale renewables contracts raise several potential concerns, however. While the shut-down of coal capacity has reduced OPG's overall market share, it remains dominant. Private sector players competing against OPG will question whether OPG applies a commercially-reasonable cost of capital to its projects, and whether OPG has unfair access to sites, particularly those with favorable grid access. OPG has little experience with non-hydro renewable technologies, and investors may also question OPA's ability to negotiate as aggressively with OPG as it does with private entities if key contract milestones are missed.

prescribed assets to be allocated among LSEs as part of the process described above.[35] Finally, if it proves politically challenging to sell OPG plants outright, dispatch rights associated with the contracts can be auctioned to other market participants, addressing market power concerns and deepening the electricity market.[36]

4.2 Optimization of existing contracts

Honoring existing contracts is an essential component of creating a favorable investment climate. However, this does not mean that existing contractual provisions should not be vigorously enforced, nor does it mean that negotiated mutually beneficial contract amendments should not be sought. The recent renegotiation of arrangements with Samsung provides a sensible template for treatment of existing contracts. Uncompelled contract renegotiations are a normal feature of every day commercial relationships. In the US, utility buy outs of PURPA[37]-era contracts were common. There were a variety of contractual arrangements as a result of such negotiations, including lump sum payments in return for contract terminations, lengthening contract terms but with a decrease in prices paid for near-term output, increases in dispatchability compensated by provisions to cover the costs of added strain on equipment from additional starts and stops, changes in price shapes, and a host of other permutations.

OPA could issue periodic calls for proposals from existing contract holders to modify their contracts, with the proviso that all proposals must result in a material reduction in GA payments associated with the plant. OPA should be able to utilize securitization techniques to arbitrage differences in cost of capital between it and its counterparties. Counterparties would receive a lump sum payment to exit their contract; their facilities would then become merchant plants, increasing the relevance of wholesale spot markets and releasing capacity to be contracted with third parties. OPA would issue long-term debt to make the lump sum payments, with the debt backed by future GA payments. Provided that payments on the debt are lower than the payments that OPA would otherwise have made on the terminated contracts, the GA will fall.

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[35] While this capacity could theoretically still be allocated while remaining under regulation, mechanisms would need to be devised to prevent OPG from financing upgrades under ratebase; all upgrades of the regulated assets would need to be financed on a market basis. Moving the regulated assets to a contract basis would create greater investor confidence that OPG is not being subsidized by ratepayers.

[36] A public entity like the Alberta Balancing Pool need not be created for this exercise; numerous examples of private sector contracts transferring dispatch rights, such as tolling agreements, exist without the need for an intermediary. The Balancing Pool arose partially to serve as the counterparty for unsold dispatch rights, a problem that can be avoided through appropriate auction design.

[37] The Public Utility Regulatory Policy Act ("PURPA") was passed in 1978 and required natural monopoly electric utilities to buy power from other more efficient generators at the utility's own avoided cost basis. Over time, PURPA contracts have become less lucrative as utility avoided cost have fallen. Source: US Department of Energy Office of Electricity Delivery & Energy Reliability. Public Utility Regulatory Policies Act of 1978. <http://energy.gov/oe/services/electricity-policy-coordination-and-implementation/other-regulatory-efforts/public>

4.3 Cost-effectively fulfilling environmental objectives

Production of power from fossil-fueled sources, even natural gas, produces negative externalities – costs to society which are not reflected in the price paid for the good or service. Emissions and effluents are a large portion of these negative externalities. North America has yet to develop a coherent strategy for addressing climate change. However, the propensity has been for governments to subsidize inputs rather than to price negative externalities. Consequently, a potential disconnect can arise between the amount of subsidy provided and the value of the environmental benefits of particular technologies. Use of cap and trade mechanisms is a means of avoiding such disconnects and establishing a technology-neutral approach to emissions reductions.

A practical means for Ontario to transition to use of cap and trade mechanisms would be for the province to join the Western Climate Initiative ("WCI")[38] carbon dioxide emissions reduction credit ("ERC") market, as Quebec has done.[39]

Because Ontario would then be joined with Quebec and California in an expanding continental ERC market, Ontario participants would have the benefits of a more liquid market, while the Ontario government would gain additional revenues from the sale of ERCs consistent with the provincially set cap on CO_2 emissions. Coupled with a phase-out of the FIT and renewables-specific procurements, joining WCI could ultimately be a more efficient way of achieving environmental objectives. Cost impacts on electricity consumers could be further mitigated if Ontario were to adopt a so-called "cap and dividend" approach, with the proceeds of the ERC auction applied towards reducing the GA.[40] Furthermore, Ontario could design floor and ceiling

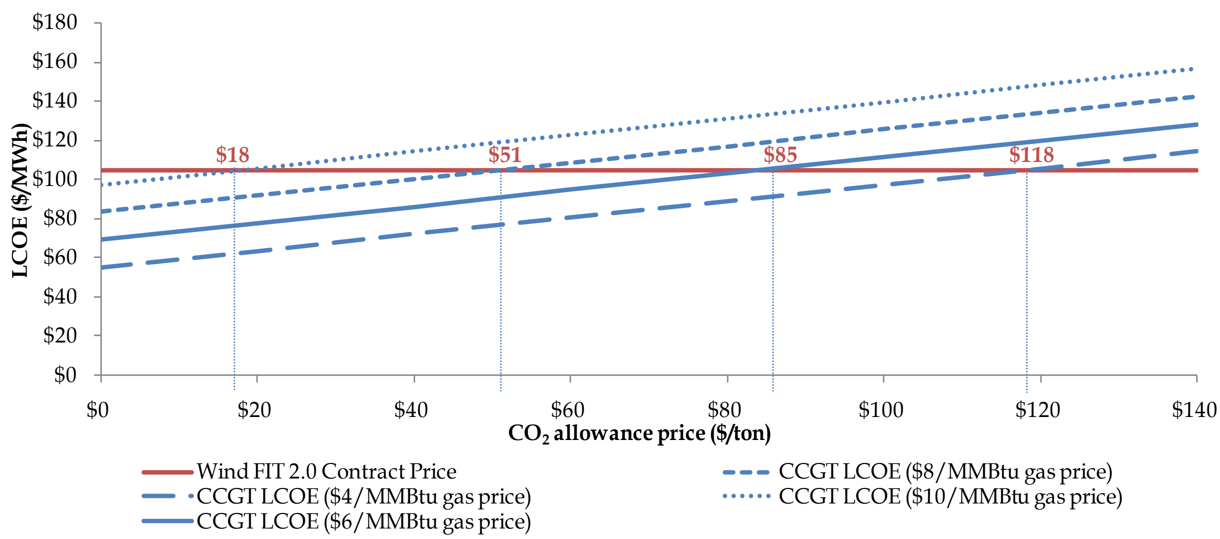
[38] The December 2009 Climate Change Action Plan set targets for reducing Ontario's greenhouse gas emissions ("GHG emissions"): 6% below 1990's levels by 2014, 15% by 2020 and 80% by 2050 and foresees working with WCI to design a cap-an-trade program. WCI is a collaboration of four Canadian jurisdictions (British Columbia, Manitoba, Quebec, and Ontario) and California to develop infrastructure and administrative tools to support a regional GHG trading framework. Sources: Ontario Ministry of the Environment. Climate Change Action Plan. Annual Report 2008-09. <http://www.ene.gov.on.ca/stdprodconsume/groups/lr/@ene/@resources/documents/resource/std01_079210.pdf>; Ontario Ministry of the Environment. Participating In Cap And Trade. Accessed December 2012. <http://www.ene.gov.on.ca/environment/en/category/climate_change/STDPROD_078899.html>

[39] Quebec adopted the emissions trading scheme on December 14th, 2011. Source: Western Climate Initiative. "Discussion Draft Economic Analysis Supporting the Cap-and-Trade Program. California and Québec." May 7th, 2012. <http://www.evomarkets.com/pdf_documents/evo/discussion_draft_economic_analysis_supporting_ca_and_qc_linking.pdf>

[40] Change of law provisions in some OPA contracts may mean that some IPPs would pass through costs of ERCs to consumers through the GA; a cap and dividend approach would offset the impact on consumers. A drawback of the cap and dividend method, however, is that it mutes the pricing of negative externalities for consumers. An alternative approach would be to use the proceeds to reduce the harmonized sales tax ("HST"), thereby maintaining the clarity of the price signal.

mechanisms, including "safety valves" involving greater use of emissions offsets, to manage ERC price volatility.[41]

Figure 12. Implied carbon price embedded within wind FIT at varying natural gas prices



Note: Wind LCOE based on 30% capacity factor,[42] 24-month construction period and $2,014/kW capital cost; gas prices range from a low of slightly above January 2013 levels to a level that is less than that which prevailed in 2008 prior to the world financial crisis.
Sources: OPA FIT 2.0 Price Schedule April 5th, 2012; LEI analysis

Figure 12 above shows the level of carbon pricing and natural gas pricing that would produce similar revenue to a wind producer as it currently receives from the Ontario FIT. Were delivered natural gas prices to rise to $10 per MMBtu, a carbon dioxide ERC price of $18 per ton would be needed for a wind generator to achieve the same revenues as it would under the FIT.

A similar logic applies to programs to support energy efficiency ("EE") and conservation and demand management ("CDM"). By exposing customers to transparent and comprehensive real time price signals, and appropriately pricing negative externalities, the market itself will determine an equilibrium and signal appropriate levels of investment in EE and CDM. Instead of directing subsidies towards EE and CDM, efforts should focus on enhancing ways in which load can be offered into the market as a resource; the IESO is already exploring various

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[41] In January 2013, the Ontario Ministry of the Environment published a discussion paper on ways to reduce greenhouse gas emissions including applicability of a cap-and-trade scheme. Ontario Ministry of the Environment. "Greenhouse Gas Emissions Reductions in Ontario: A Discussion Paper." January 21st, 2013. <http://www.ebr.gov.on.ca/ERS-WEB-External/displaynoticecontent.do?noticeId=MTE4MzMy&statusId=MTc3MDg5&language=en> and Melnitzer, Julius. "Ontario moving forward on cap-and-trade system." February 21st, 2013. <http://business.financialpost.com/2013/02/21/ontario-moving-forward-on-cap-and-trade-system/>

[42] The intermittency of wind is irrelevant to this analysis, which examines the carbon dioxide emissions displaced when the wind generator is actually operating.

alternatives in this regard.[43] As presented in Figure 13, developments in demand response in Ontario are in line with other markets in North America, with the exception of the ability to participate in a capacity market. However, to the extent that Ontario does develop a long-term resource adequacy market, load management should be allowed to participate on an equal footing with generation. Encouraging demand response aggregators, and allowing them to participate in capacity auctions, will ultimately result in the provision of economically efficient levels of demand management.

Figure 13. 2011 levels of demand response in selected North American markets

Market	Demand Response (MW)	Peak Demand (MW)	DR as % of Peak Demand
AESO (Alberta)	742	10,226	7%
CAISO (California)	2,296	45,545	5%
IESO (Ontario)	1,168	25,450	5%
ISO-NE (US Northeast)	2,725	27,707	10%
NYISO (New York)	2,173	33,865	6%
PJM (US Mid-Atlantic)	14,188	158,450	9%

Sources: AESO *2011 Annual Market Statistics*; CAISO *2012 Summer Loads and Resources Assessment* and Peak Load History 1998-2011; ISO-NE *2012Demand Resources Asset Enrollments*; IESO 18-month Demand Forecast February 24th, 2012; NYISO *Power Trends 2012*; PJM *2011Annual Report* and "Demand Resources and Energy Efficiency Continue to Grow in PJM's RPM Auction," May 13th, 2011

[43] IESO is engaged in a number of demand response initiatives which include both reliability and real-time price demand response programs. In particular, IESO is responsible for activating and settlement and verification services of Demand Response 3 ("DR 3") program that was developed by OPA to provide economic incentives for participants to reduce consumption (large businesses with at least 50 kW annual peak demand and that are available for about 1,600 hours per year can get "capacity" and "energy" payments for each hour and amount curtailed during an event by committing to participate in activation notices). Another DR program currently active in Ontario is peaksaver PLUS For Small Businesses whereby small businesses with central air conditioning and annual electricity demand of less than 50 kW working together to manage electricity use via installation of devices (including central air conditioner, electric water heater and/or in-ground pool pump) that are remotely activated for demand curtailment (although this program is not yet province-wide). Sources: IESO website. Demand Response. Accessed December 2012. <http://www.ieso.ca/imoweb/consult/demandresponse.asp>; OPA. SaveONenergy website, Demand Response. Accessed December 2012. <https://www.saveonenergy.ca/Business/Program-Overviews/Demand-Response.aspx>

5 Next steps for the province

5.1 "Press pause"

To assure a sound foundation for future power sector policies, the provincial government should put all new contracting initiatives on hold, and announce a moratorium on new decisions affecting the wholesale generation market, until a comprehensive and transparent policy review can be performed by a specially appointed review panel. Such a review should be time-limited, and include a consultative process with terms of reference focused on how to create a durable structure for the Ontario power sector to provide reliable electricity supply at long-run least cost. This review provides an opportunity for the province and stakeholders to consider the optimal structure for the industry and how to attain it. Arguably, there has not been a thoughtful comprehensive examination of the Ontario wholesale generation market since the Ontario Market Design Committee ("MDC")'s work in 1998/99; while the wholesale generation market review need not take as long as the MDC's work did – the MDC was examining the entire power sector, rather than one segment of the value chain – this may nonetheless be a four to six month process.

To inform the review, OPA and IESO should perform a high level ten year forward analysis of potential generation needs under various demand scenarios. Such an analysis should be technology and ownership neutral, but should highlight when and where on the supply curve (baseload, mid-merit, or peaking), needs are likely to arise. In spring 2013, the Ontario Minister of Energy announced a start of a formal review of the Long-Term Energy Plan. The Minister's directive to OPA and IESO mandates an update of long term supply and demand forecasts, focusing on diversity of supply mix, conservation and creation of predictable and sustainable clean energy procurement process[44].

5.2 Indicative timeline

If the recommendation for implementing a RAM is adopted, it could be in place before significant future capacity needs arise. An indicative timeline is outlined in Figure 14.

Figure 14. Indicative timeline for consultative process

Source: LEI

[44] Ontario Ministry of Energy. <http://www.energy.gov.on.ca/en/ltep/> (accessed on June 28, 2013)

In the past, Ontario has tended to attempt to make too many changes to the power sector simultaneously, or to issue policy course changes too rapidly. Ideally, during the above three year period, no other major changes in the power sector would be contemplated, at least on the generation side.

5.3 Assuring political viability

To avoid further cost increases and the risk of continued supply-demand mismatches, Ontario needs to have a comprehensive conversation about how to create a durable power market design. Power market design evolutions are best implemented during a period of supply surplus, meaning that Ontario has a unique opportunity over the next eighteen months to examine and implement changes that will put the power sector on a sound foundation for future investment. Doing so will benefit customers by returning the focus of power sector planning to long-run least cost principles, reducing the ability of policymakers to implement politically expedient measures that turn out to have hidden future costs.

In considering the political economy of the proposed changes, it is important to emphasize the focus on decreasing long-term electricity costs while strengthening the Ontario economy. Consumers will welcome adjustments if they are convinced that costs will ultimately be contained. Rural Ontario will likely support the plan, provided it is clear that it does not entail any loss of local control: LDCs will not be forced to consolidate or become LSEs; renewable energy projects will be market-based and not subsidized. Three sources of potential opposition are possible, in declining order of political influence: labor interests, environmental activists, and rent-seeking corporations.[45] Each can be assuaged if the program is properly communicated and measures are taken to address specific concerns.

While the proposed changes do not rely on privatization, in the event a sale of parts or all of OPG is envisioned, unions should be encouraged to participate as owners. Furthermore, given current demographics, protections for the existing workforce can be built into any sales agreements. The proposed changes in no way undermine environmental protection, and can be bundled with a meaningful climate change action plan – joining WCI would demonstrate continued long term commitment to the environment, as would focusing on economic demand response programs.

Although corporate interests will complain about the lack of long term contracts, businesspeople recognize that the Ontario power sector as currently constructed is unsustainable; under the current structure, prospects for additional contracts are increasingly slim, and the viability of existing contracts relies on the ability of Ontario customers and businesses to pay for the power

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[45] Policymakers should not underestimate the extent of rent-seeking embedded in current Ontario arrangements, whether on the part of unions at provincially-owned enterprises or clean energy advocates in designing the feed-in tariff. The proposed framework would improve transparency and diminish the ability of parties to increase rents by bypassing the market in favor of government sanctioned support from taxpayers or ratepayers.

being sold. A credible plan for reducing electricity costs using market forces will ultimately win favor from investors.

The plans need not involve acknowledging any previous mistakes in electricity market development and oversight. A "mission accomplished" approach would focus on the fact that coal has been successfully eliminated, significant zero-emitting capacity has been contracted for, and a surplus has been established. The argument can be made that the institutions have matured to the point where independence is beneficial, and that the Government is proceeding as it always intended by phasing out the OPA when conditions warrant. Careful attention to messaging, and repeated focus on how the plan reduces costs without harming labor or the environment, will contribute to its success.

Common-sense solutions exist that will allow for a reduction in long-term power costs in Ontario. These solutions do not require the creation of new institutions, nor do they require abandoning key policy objectives. Economically efficient power prices contribute to economic development; price transparency can be achieved without sacrificing environmental protection.

6 Appendix A: Back up to LCOE calculations

Figure 15. Calculating long-run LCOE for different plant types

[2012 dollars]	CCGT	CCGT (high)	Biomass (Atikokan)	Onshore Wind (high)	Nuclear (Bruce A units 1 & 2) (high)	Nuclear Refurbishment (low)	New Nuclear (low)
Capital cost [$/kW]	1,016	1,230	8,500	2,535	3,200	3,338	5,339
Leverage	60%	60%	60%	60%	60%	60%	60%
Debt interest rate	8%	8%	8%	8%	8%	8%	8%
tax rate	40%	40%	40%	40%	40%	40%	40%
After-tax required equity return	15%	15%	15%	15%	15%	15%	15%
Debt financing term	18	18	18	18	18	18	18
Equity contribution capital recovery term	20	20	20	20	20	20	20
Construction time	36	36	48	24	72	60	72
Heat rate [Btu/kWh]	7,050	7,050	13,500		10,460	10,460	10,460
Nominal variable O&M [$/MWh]	3.6	3.6	5.2		2.1	2.1	2.1
CO_2 content [lb/MMBtu]	120	120					
Carbon cost [$/ton]		20.0					
CO_2 adder [$/MWh]		8.5					
Nominal fixed O&M [$/kW/year]	15.0	15.0	104.6	29.2	92.3	92.3	92.3
Capacity factor	85%	70%	85%	30%	90%	90%	90%
Fuel price [$/MMBtu]	$ 6.9	$ 7.5			$ 0.4	$ 0.4	$ 0.4
All-in fixed cost [$/kW-yr]	$144	$171	$1,215	$340	$536	$542	$833
Levelized non-fuel cost of new entry [$/MWh]	$23	$40	$168	$129	$70	$71	$108
Levelized cost of new entry ("LCOE") [$/MWh]	**$71**	**$93**	**$168**	**$129**	**$75**	**$75**	**$112**
carrying charge until commissioning [$/kW]	$146	$177	$1,632	$243	$922	$801	$1,538
amortized carrying charge over debt term [$/kW/year]	$12	$15	$137	$20	$78	$67	$129
debt-financed portion [$/kW]	$610	$738	$5,100	$1,521	$1,920	$2,003	$3,203
annual debt repayment [$/kW/year]	$51	$62	$429	$128	$162	$169	$270
equity-financed portion [$/kW]	$407	$492	$3,400	$1,014	$1,280	$1,335	$2,136
annual equity return [$/kW/year]	$65	$79	$543	$162	$204	$213	$341
CCGT LCOE (low) [$/MWh] ($20/ton carbon cost)	$80	Wind FIT 2.0 Contract Price (low) [$/MWh]		$105			
CCGT LCOE [$/MWh] ($40/ton carbon cost)	$91						
CCGT LCOE [$/MWh] ($60/ton carbon cost)	$99	Nuclear Bruce A units 1 & 2 OPA Contract Price (low) [$/MWh]			$68		
CCGT LCOE [$/MWh] ($80/ton carbon cost)	$108						
CCGT LCOE [$/MWh] ($100/ton carbon cost)	$116		Nuclear Refurbishment LCOE (high) [$/MWh] ($4,285/kW capital cost)			$92	
CCGT LCOE [$/MWh] ($120/ton carbon cost)	$125						
CCGT LCOE [$/MWh] ($140/ton carbon cost)	$133				New Nuclear LCOE (high) [$/MWh] ($6,797/kW capital cost)		$138

Sources: LCOE as of 2012. All figures nominal Canadian dollars and assuming exchange rate CA $1/US$. EIA *EAO 2012*; OPG *2011 Annual Report*, FIT 2.0 Price Schedule April 5th, 2012, "A progress report on contracted electricity supply (Draft). 2012 First quarter;" and "Bruce Power update, August 2012;" NB Power *Annual* and *Sustainability Reports 2008-2012*; NB Power and *Edmonton Journal* Point Lepreau articles November 23rd, 2012; Hydro Quebec "Documents related to Gentilly-2 closure. Executive Summary;" *CNBC* and *World Nuclear News* articles on EPR nuclear plant costs; AREVA EPR nuclear plant projects <http://www.areva.com/EN/operations-2542/the-epr-reactor-projects-worldwide.html>; and commercial database

7 Appendix B: List of works consulted

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8 Appendix C: List of common acronyms

BA	Balancing Authority
CAISO	California Independent System Operator
CCGT	Combined Cycle Gas Turbine
CCM	Capacity Credit Market
CDM	Conservation and Demand Management
CfD	Contracts for Differences
CPUC	California Public Utilities Commission
CTC	Competitive Transition Charge
DR	Demand Response
DRC	Debt Retirement Charge
EE	Energy Efficiency
ERC	Emissions Reduction Credit
ERCOT	Electricity Reliability Council of Texas
FCA	Forward Capacity Auction
FIT	Feed-in-Tariff
GA	Global Adjustment
GEA	Green Energy Act
GHG	Greenhouse Gas
HOEP	Hourly Ontario Electricity Price
IESO	Independent Electricity System Operator
IRP	Integrated Resource Plan

LCOE	Levelized Cost of Energy
LDC	Local Distribution Company
LRZ	Load Resource Zone
LSE	Load Serving Entity
LTEP	Long-term Energy Plan
MDC	Market Design Committee
MISO	Midwest Independent Transmission System Operator
MOPR	Minimum-Offer Price Rule
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OEFC	Ontario Electricity Financial Corporation
OPA	Ontario Power Authority
OPG	Ontario Power Generation
PURPA	Public Utility Regulatory Policy Act
RAM	Resource Adequacy Market
RAR	Resource Adequacy Requirement
RPM	Reliability Pricing Model
RPP	Regulated Price Plan
SBC	System Benefits Charge
TOU	Time-of-Use
VoLL	Value of Load Lost
WCI	Western Climate Initiative