Using Demand Response to Lower Actual Electricity Prices During Natural Gas Shortages

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***Abstract*—A new method for optimizing the procurement of Demand Response (DR) to minimize electricity prices for remaining consumers is proposed in this paper. While this method can be applied anytime electricity prices are positive, its greatest impact occurs during times of extreme peak prices, such as during natural gas shortages. Independent System Operators (ISOs) need to determine the optimal quantity of DR resources to procure and the optimal price to pay DR resources.**

Traditional market settlement methods are designed for the procurement of only one commodity: generation. DR services are a second commodity that is not captured fully by traditional methods. Furthermore, the procurement of DR and generation are interdependent, and this relationship is not fully understood.

In order to optimally settle both the generation and DR markets simultaneously, a new method is proposed: (1) The concept of actual price is explained. Actual price comprises the costs for both generation and DR services, and it accounts for the smaller paying consumer base after DR services are procured. (2) A new demand curve for DR is constructed to minimize the actual price to remaining consumers. (3) Both the DR and generation markets are settled at their respective Nash equilibrium points.

This method ensures that remaining consumers benefit from the lowest possible actual prices through the procurement of DR services.

This method was applied to Ontario's electricity system using both historical patterns and future patterns. The collective savings to remaining consumers due to DR increased as the percentage of extreme prices due to climate change grew.

***Index Terms*—Demand response, electricity market, power system economics.**

I. Nomenclature

a_t, b_t, c_t, d_t	Constants for generator cost and bid curves at hour *t*
a_s, b_s, c_s, d_s	Constants for generator costs and bid curves under gas shortage conditions
t	Time period
PG_t	Total generation produced by all generators at hour *t*
$\overline{PG_t}, \underline{PG_t}$	Maximum and Minimum generation limit of all generators combined at hour *t*
F_t	Aggregate generator cost at PG_t
PD_t	Total demand from all loads at hour *t*
PR_t	Total demand response resources dispatched at hour *t*
$\overline{PR_t}$	Optimal level of demand response resources dispatched at hour *t*
BCG_t	Buyers' cost for generation at hour *t*
BCR_t	Buyers' cost for demand response at hour *t*
λ_t	Aggregate generator price bid at PG_t
$\lambda 0_t$	Market clearing price with no demand response at hour *t*
λN_t	Price paid to generators, with PR_t at hour *t*
λA_t	Actual price for remaining consumers, with PR_t at hour *t*
λPRD_t	Price remaining consumers are willing to pay for PR_t at hour *t*
λPRS_t	Price demand response service providers are willing to accept for PR_t at hour *t*
λPR_t	Price for $\overline{PR_t}$ at hour t
$\overline{\lambda PR_t}$	Optimal price for PR_t at hour t
e_t, f_t, g_t	Constants for demand response resource bid curve at hour *t*

II. Introduction

IN light of recent events in the United States (US) in which the supply of natural gas was temporarily constrained, Ontario's Independent Electricity System Operator (IESO) requested insight into the potential role of Conservation and Demand Management (CDM) and Demand Side Management (DSM) in mitigating electricity price impacts caused by a similar situation in their jurisdiction. Specifically, the IESO asked, "Examining recent situations where natural gas supply was severely constrained (e.g. the recent Aliso Canyon gas leak in California and the US NE during the 2013-2014 Polar Vortex) to understand the impact on electricity prices, how CDM/DSM could have or was deployed to mitigate impacts, and identify transferrable lessons for a potential constrained situation in Ontario."

A. Supply, Delivery, and Storage of Natural Gas in Ontario

In 2015, Ontario purchased 26,053,487 m^3 of natural gas – about 30% of the total for Canada. [1] Due to Ontario's very limited ability for natural gas production, natural gas must be sourced and imported from external jurisdictions. In the past, the Western Canadian Sedimentary Basin provided the vast majority of natural gas for Ontario; however, in the future, the Northeastern US is expected to supply a greater share due to shale gas extraction technology and transmission pipeline infrastructure advancements. [2]

Natural gas is delivered to Ontario through high-volume transmission pipeline infrastructure. Within the province, natural gas travels through transmission and distribution pipeline networks. [3]

Ontario has natural gas storage capability, which is used to

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mitigate the risks of supply disruption, price fluctuations, and reliability. The Dawn Hub near Sarnia, Ontario is the largest integrated gas storage facility in Canada and has a capacity of 160 billion cubic feet (Bcf), or 175 petajoules (PJ). It receives natural gas supplies through diverse pipelines – up to 10 Bcf a day from direct pipelines and another 1.4 Bcf a day from pipelines via Niagara. [4] In the summer, the Dawn Hub injects an average of 0.65 PJ of natural gas a day into its storage facilities, and in the winter, it withdraws an average of 1.04 PJ a day. [5] Its storage levels fluctuate seasonally, and it has its highest levels typically in October and its lowest levels in March. [3] Therefore, the Dawn Hub is used to manage natural gas prices for consumers by purchasing during low-priced summers and supplying gas during high-priced winters.

Due to the Dawn Hub's strong interconnectivity with other North American natural gas markets, the price of natural gas at the Dawn Hub tracks closely with those of other markets. Any price differences can usually be attributed to transportation costs. [6]

B. Demand and Consumption of Natural Gas in Ontario

Consumption patterns of natural gas in Ontario is cyclical, both seasonally and daily. The time of highest usage is in winter when both natural gas and electricity consumption peak together. During cold weather conditions, space heating is necessary. In urban areas, spaces are usually heated with natural gas because natural gas distribution infrastructure is present in those areas, and the cost of heating by gas is much less than by electricity. In areas with no natural gas distribution infrastructure, spaces are typically heated with electricity. Together, these cause coincident peaks for both natural gas and electricity demand in winter, thereby making wintertime the most critical and highest risk period for disruptions to natural gas supply and potentially resulting price spikes for electricity.

C. Role of Natural Gas in Electricity Generation for Ontario

In 2016, natural gas supplied 12,760 GWh of electricity – approximately 8% of the total. [7] The role of natural gas is expected to decrease to 7,494 GWh (4.8% of total) in 2020 and then increase to 40,403 GWh (24%) in 2025. [2] The initial decrease in natural gas for electricity generation in Ontario is due to an expected increase in renewables and also the institution of a carbon price through a cap-and-trade market. The later increasing dependence on natural gas is due to the refurbishment and replacement of nuclear facilities and an anticipated slower pace of new renewable generation. [2]

These forecasts suggest that in the near-term until 2020, the risk of electricity price spikes driven by natural gas price spikes would be less than in the longer term past 2020. At that time, natural gas is expected to play an increasingly greater role in electricity generation in Ontario.

Since the price for electricity in Ontario is determined by settling the IESO-controlled market, a spike in the price in natural gas would pose the greatest risk for electricity prices when a natural gas unit is the marginal unit dispatched. In Ontario, this typically happens during peak electricity demand periods.

D. Potential Impacts of Climate Change on Ontario's Natural Gas Supply

The security of natural gas supply in Ontario could be affected by climate change. Extreme rainstorms are predicted to become even more extreme in Toronto. [8] Furthermore, extreme weather events affecting any point along the supply chain of natural gas production and transmission, covering vast geographical distances, have the potential to disrupt natural gas supply to Ontario. Unlike oil, natural gas is primarily transported through pipelines. This means that natural gas transmission companies are limited in their ability to re-route natural gas in the event of a major disruption; they can only use existing alternate lines with excess capacity, if they exist.

Depletion of natural gas reserves could also be aggravated by climate change. An unusually cold spell would induce greater than anticipated demand for natural gas for heating, which in turn could exhaust the natural gas Ontario has in storage. [9] However, this risk is mitigated by climate modelling that show that the areas around Toronto would expect warmer average temperatures of 4.4 degrees Celsius as a result of climate change, thereby lowering the demand for heating from natural gas. [8]

E. American Experience of Natural Gas Shortages, Electricity Prices, and Demand Response Regulation

In selecting this paper's topic, the IESO cited two events that caused natural gas shortages in the US: the Polar Vortex in early 2014 and the Aliso Canyon gas leak in 2015 and 2016. Further, the Federal Energy Regulatory Commission (FERC) issued Order 745 regarding the Net Benefits Test (NBT) for Demand Response (DR), which is also relevant for context.

1) Polar Vortex

In early 2014, unusually cold temperatures affected large portions of central and northeastern North America in an extreme weather event termed the Polar Vortex, in which natural gas supplies were disrupted and electricity prices spiked. There were a series of cold weather events, the most extreme one on January 6 and 7, 2014, and subsequent events later in January, February, and March 2014. [10] Temperatures reached around 20 degrees Celsius lower than seasonal averages. [11] Due to emergency actions – including public appeals for conservation, voltage reductions, activation of interruptible loads, and DR – taken by Independent System Operators (ISOs), less than 0.1% of total load was shed. [11]

Wholesale electricity prices soared, peaking around \$2,000/MWh, while average prices were in the \$300/MWh to \$700/MWh range during peak times in the Pennsylvania-New Jersey-Maryland (PJM) Interconnection and the Midcontinent Independent System Operator (MISO). [12]

Key factors for high electricity prices during the Polar Vortex include:

(a) *High electricity demand* – High electricity demand drives up prices in electricity markets because more expensive supply units were forced to be dispatched. This was the main driver for the high electricity prices in early January 2014. [12] PJM's peak demand during the Polar Vortex was around 25% more than expected for January [13], while MISO's peak demand during the Polar Vortex exceeded the previous record for winter peaks by about 9%. [10]

(b) *High natural gas demand* – The extremely cold weather caused demand for natural gas to increase to serve direct consumers for space heating needs. Natural gas generation facilities that do not have contracts for firm natural gas supply are considered interruptible and can have their supply curtailed, forcing some them to become unavailable. [11] [14]

(c) *High natural gas prices* – The price of natural gas spiked due to both increased natural gas demand and pipeline restrictions. Therefore, even the natural gas generating facilities that were able to obtain fuel were forced to bid higher prices in the electricity market to account for their higher fuel costs. This was the main driver for high electricity prices in late January, February, and March 2014. In fact, FERC granted several ISOs exemptions from the $1,000/MWh offer cap because natural gas generation facilities would not otherwise be able to recover their fuel costs. [12] Since the Polar Vortex affected regions closest to the Dawn Hub, the price of natural gas increased much more there than the other hubs, as shown in Fig. 1. [6]

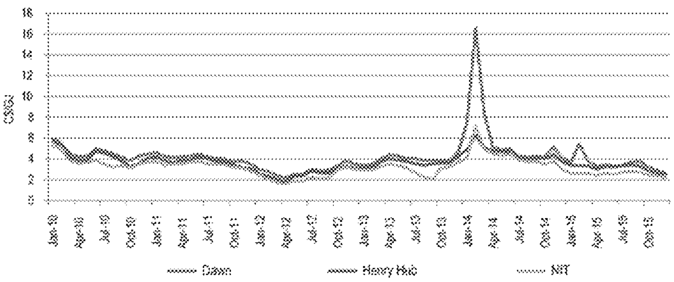

Fig. 1. Natural gas prices at major North America hubs. [6]

(d) *Generation limitations* – Equipment issues forced outages of more generation units than usual. In PJM, the forced generation outage rate was two to three times more than usual, and the natural gas supply curtailments mentioned earlier were responsible for around a quarter of these outages. [13] Weather-related gas restrictions caused natural gas generation facilities to be unavailable in MISO as well, and the cold weather triggered the de-rating of other generators. [10]

As part of their operations management strategy during the Polar Vortex, ISOs used the following CDM measures:

(a) *DR* – PJM could draw on only voluntary DR resources because DR was voluntary in winter and mandatory in summer. PJM activated DR jurisdiction-wide three times during the Polar Vortex, and around 25% of DR capacity responded despite it being a voluntary gesture. Additional localized DR events were called as well. [13] MISO also called on DR resources, although there was more DR registered than responded. [10]

(b) *Public appeals for conservation* – PJM appealed to the public through its transmission owners, and while PJM believes the appeals has positive effects, the impact is not measureable. [13] MISO did not issue any public appeals for conservation during the Polar Vortex. [10]

Several agencies issued public reports containing recommendations in light of the Polar Vortex, however, CDM measures were not a major part of the suggestions. In its review of the Polar Vortex, the North American Electric Reliability Corporation (NERC) did not include CDM as part of its recommendations, although it did mention demand management techniques such as DR as helpful strategies that were undertaken to maintain electric reliability. [11] PJM's action items focused on the supply side and generator availability. [13] However, MISO did cite the need to obtain more data about DR resources. [10]

2) Aliso Canyon Gas Leak

The Aliso Canyon Natural Gas Storage Facility serves the Greater Los Angeles area in California and suffered a major natural gas leak on October 23, 2015. The leak discharged around 90,000 metric tonnes of methane [14] and forced the disruption of the facility's operations. While the leak was finally sealed on February 17, 2016 [14], the Southern California Gas Company (SoCalGas), Aliso Canyon's owner, was prohibited from injecting new gas into its reservoirs until safety inspections and reviews were completed. This depleted the gas reserves to about 20% of Aliso Canyon's storage capacity, or 15 Bcf, by the spring of 2016. [15]

There were concerns that the reduced operations at Aliso Canyon could potentially disrupt natural gas or electricity services through outages or high prices. In California, electricity demand peaks in the summer and natural gas demand peaks in the winter. To prepare for the upcoming electricity peak in the summer of 2016, four energy agencies conducted a joint technical assessment recommending reliability risk mitigation measures that fall in the following five categories, in declining order of importance: (a) "prudent Aliso Canyon use;" (b) "tariff changes;" (c) "operational coordination;" (d) "Los Angeles Department of Water and Power operational flexibility;" and (e) reduction of "natural gas and electricity use." CDM measures were in the lowest priority and comprised five specific actions: (a) "use new and existing programs asking customers to reduce natural gas and electricity energy consumption;" (b) "expand gas and electric efficiency programs targeted at low income customers;" (c) "expand demand response programs that target air conditioning and large commercial use;" (d) "focus and reprioritize existing energy efficiency towards projects with potential to impact usage this summer and coming winter;" (e) "reprioritize spending in existing solar thermal program to fund projects installable this summer and by end of 2017." [15]

Despite the restrictions in Aliso Canyon's operations, wholesale prices for electricity in Southern California do not appear to be materially impacted by the gas leak. Prices in 2016 were in line with previous years' prices. [16] Risk assessments conducted by energy agencies did not identify electric reliability to be a concern in neither winter 2016 [17] nor summer 2017 [18], even assuming the absence of supply from Aliso Canyon to natural gas generation facilities.

However, CDM was credited with avoiding electricity outages during heat waves in the summer of 2016. Measures included "Flex Alerts, requests for conservation in state buildings, and intense monitoring by officials in various agencies." DR was also activated. [19]

CDM was not a major part of the recommendations arising from the federal task force which analyzed the event, however, the Flex Alert program, which notifies electricity consumers to reduce usage, was mentioned. [14]

With respect to electricity impacts of Aliso Canyon, California's energy agencies were primarily focused on the avoidance of outages rather than managing price spikes. DR was used to avoid electricity outages and followed FERC Order 745, which is described next.

3) FERC Order 745

On March 15, 2011, FERC issued Order 745, "Demand Response Compensation in Wholesale Energy Markets," in which it outlines a NBT to ensure that DR purchases will not drive up rates. [20] The NBT makes sure that the collective benefits of DR to buyers outweighs the costs of DR. DR resources that pass the NBT are compensated at market rates for their services. ISOs are required to submit the NBT implementation plans to FERC, which has the authority to approve those plans. California Independent System Operator (CAISO) has a FERC-approved plan that is publicly available and in use for their DR programs. [21] CAISO announces a monthly threshold price beyond which DR would not be activated, and the threshold price is the point on the forecasted generator price bid curve at which elasticity is one.

While the NBT is a laudable step in the right direction, it does not ensure that consumers benefit from *optimal* rates from DR – it only ensures that consumers would not be worse off with DR than they would have been without DR. In this paper, we use an optimized method that would deliver greater benefits to consumers than the minimum required under FERC Order 745.

F. Problem Definition and Scope

The risk of natural gas disruptions to Ontario's electricity differs from the US cases examined above because of the following reasons:

(a) *Role of natural gas for electricity* – The US jurisdictions were much more reliant on natural gas for electricity than Ontario. In 2016, natural gas was responsible for about 27% of total generation for MISO [22], 23% for PJM [23], and 46% in California [24], whereas natural gas comprised only 8% of total generation in Ontario [7]. Therefore, a restriction in natural gas supplies can have a much greater impact on electricity markets in those US jurisdictions than in Ontario. However, in the future, Ontario will become increasingly vulnerable if forecasts about the growing role of natural gas for electricity are accurate.

(b) *Surplus generation* – Due to both the declining demand and the commissioning of new generation facilities, Ontario has ample surplus generation capacity under normal weather conditions in the short term. In summer 2018, the peak demand during extreme weather is forecasted to be 24,656 MW, however, there is expected to be 10 to 16 weeks during extreme weather when generation is not sufficient to meet demand and reserve requirements due to planned outages for generator maintenance, which can be denied if those extreme conditions materialize. [25] A natural gas disruption during this time could further aggravate the situation, but healthy levels of natural gas in storage in summer could mitigate this. However, the future refurbishment of nuclear facilities and the slowdown of the development of new renewable generating facilities will narrow the surplus margin and make Ontario more susceptible to natural gas disruptions in the medium to long term.

(c) *Natural gas infrastructure* – As the northeastern US produces more natural gas supply through shale technologies, Ontario is expected to lessen its reliance on natural gas from Western Canada. While the diversification of natural gas supply is driven by economic factors, it has the added benefit of improved resilience if a severe weather event disrupts supply from a particular location. City of Toronto staff considered the city's natural gas infrastructure generally resilient to extreme weather events, and gas distributors have to ability to draw upon diverse supply sources. [9]

(d) *Agencies' main objectives* – During the both the Polar Vortex and Aliso Canyon events, the agencies' primary focus was the *reliability and continuity* of electricity service. By contrast, Ontario's IESO was interested in the impact of these extreme weather events on electricity *prices*. The US agencies' goal was to avoid blackouts, not to mitigate rate impacts. Different objectives can call for different tactics, so the outcomes from the US cases cannot be simply transferred to Ontario.

In summary, while Ontario's situation differs from that of the US, Ontario's growing dependence on natural gas for electricity in the medium to long term makes it increasingly vulnerable to electricity price spikes due to natural gas supply disruptions. Therefore, it is timely for the IESO to request the examination of the role of CDM to actively manage electricity prices today so that there is still room for proactive implementation of mitigation strategies for the future.

In the US cases, CDM in the form of public appeals and DR was used, however, CDM was not a major part of the recommendations arising from the events. While public appeals are also possible in Ontario, the more purposeful and thoughtful use of DR can be enhanced to lower electricity prices through the new ideas presented in this research.

Acute situations such as a temporary natural gas shortage requires a response within a narrow timeframe. Therefore, traditional time-independent conservation efforts will not help in this situation. A time-specific solution such as DR is the most useful CDM measure for these acute situations. DR is "changes in electric usage by demand-side resources from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized." [26]

During times of severe gas storages, gas spikes will be foreseen because the natural gas in Ontario's storage facilities will be consumed first. The declining gas reserve levels will be observed, and this advanced warning presents an opportunity to activate DR in the day ahead market. As such, impacts to ancillary markets and other charges such as fixed costs are negligible and out of scope for this analysis. The allocation of DR costs to capacity and energy payments are also out of scope for this paper; only the total combined payments to DR are considered in this analysis. Future work can examine optimal allocation schemes. For simplicity, transaction costs such as program costs are also out of scope for this analysis and can be incorporated in the future.

In Ontario, late winter is the time of greatest risk for a natural gas shortage causing a temporary electricity price spike. Both electricity and natural gas demand are high due to the need for space heating, and natural gas reserves are at their lowest points.

In these situations of natural gas shortages causing a temporary rise in electricity prices, ISOs wishing to use DR to alleviate the price rise would need to decide: (a) how much DR to procure; and (b) at what price to pay the DR services. The success of the DR procurement must be measured by the impact on the resulting electricity price for remaining consumers.

G. Contributions of This Paper

In this paper, a new method is proposed for the optimal procurement of DR with the objective of minimizing actual prices of electricity for remaining consumers. While this new method can be applied any time that electricity market prices are positive, it delivers the most savings per hour during extreme price spike events, such as during a natural gas shortage.

The simultaneous procurement of two commodities – both generation and DR – adds complexity to the optimization challenge. Conventional market settlement methods are designed for only a single commodity. Furthermore, the interdependence of DR and generation is not well understood from the perspective of remaining consumers. To solve this:

(a) The concept of *actual price* of electricity is explained. The actual price comprises both generation and DR costs spread among a smaller base of remaining consumers. Previous optimization methods would consider only generation costs or neglect to account for the smaller paying consumer base when DR is procured.

(b) A method to minimize actual price for remaining consumers is described.

(c) A new demand curve for DR was constructed to obtain the minimum actual price for every level of price paid to DR resources.

This information is then used to settle both the DR market and the generation market in the manner that delivers the greatest benefit to remaining consumers. The optimal prices and quantities for both DR and generation can then be determined.

This new method provides clarity and guidance to ISOs in deciding both the optimal *quantity* of DR to procure and the optimal *price* to pay for DR services. ISOs must be able to valuate DR accurately for remaining consumers to ensure that they are not buying too much or too little DR, or over- or under-paying for that DR. These would all lead to either: (a) leaving unclaimed value on the table; or (b) over-procuring DR, thereby driving up actual prices.

H. Organization of This Paper

This paper is organized as follows. Section III explains the fundamental economics concepts for electricity market settlements under normal and natural gas shortage conditions. Section IV examines the economic impacts of DR and explains the concept of the actual price of electricity, which accounts for the costs of both generation and DR shared among a reduced base of paying consumers. Section V introduces new conceptual developments to minimize the actual price of electricity through the creation of the demand curve for DR and market settlement methods for both DR and generation. Section VI presents the formulation for the proposed optimal settlement for both DR and generation markets. Section VII applies the formulation to the electricity market in Ontario, Canada, using historical data and under future natural gas supply conditions. Section VIII outlines the conclusions of this work.

III. Economic Impacts of a Natural Gas Shortage

During a shortage of natural gas and exhausted reserves, fuel prices for natural gas will rise, thus driving up the electricity bid prices from natural gas generation facilities.

A generic aggregated generator cost curve F_t is approximated by a third order polynomial (1) in which PG_t is total system generation at time t in MW, and a_t, b_t, c_t, and d_t are constants.

$$F_t = a_t + b_t \cdot PG_t + c_t \cdot PG_t^2 + d_t \cdot PG_t^3 \tag{1}$$

The aggregate generator price bid curve λ_t is then approximated by differentiating the cubic polynomial (1) to derive (2). This is a standard quadratic function used to model thermal or hydroelectric unit bids, such as in [27].

$$\lambda_t = \frac{df_t}{dPG_t} = b_t + 2 \cdot c_t \cdot PG_t + 3 \cdot d_t \cdot PG_t^2 \tag{2}$$

Higher prices bid by natural gas generation stations will shift the generator price bid curve to the left, as shown in Fig. 2 for the sample power system described in Table I.

TABLE I
Details of a sample power system

Constant	Value Under Normal Conditions	Value Under Natural Gas Shortage Conditions	Units
b_t	5	5	\$/MWh
c_t	0.0005	0.0007	\$/MWh^2
d_t	0.0000005	0.0000007	\$/MWh^3
PD_t	10,200	10,200	MW

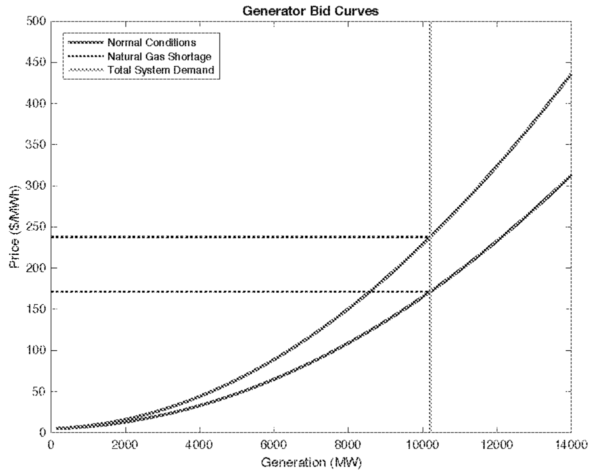

Fig. 2. Generator price bid curves under normal and natural gas shortage conditions.

In this sample power system, the natural gas shortage caused the market clearing price to jump from $171.26/MWh under normal conditions to $237.76/MWh during the gas shortage.

A similar change in the generator price supply bid curve could represent any situation in which generation supply is constrained, not just a natural gas shortage. Supply restrictions could also be caused by an extreme weather event, supply disruption, unexpected outage of critical units for corrective maintenance, or a combination of several aggravating factors.

IV. Economic Impacts of Demand Response and Concept of Actual Price

The economic impact of DR can be shown by considering the single-ended auction shown in Fig. 3.

In the absence of DR, total system demand PD_t is entirely satisfied by generators, and the resulting market clearing price is $\lambda 0_t$, which is calculated in (3).

$$\lambda 0_t = b_t + 2 \cdot c_t \cdot PD_t + 3 \cdot d_t \cdot PD_t^2 \tag{3}$$

Therefore, buyers collectively pay a total cost of $PD_t \cdot \lambda 0_t$ to generators for their supply; this is the Buyers' Cost for Generation (BCG_t) as shown in Fig. 3.

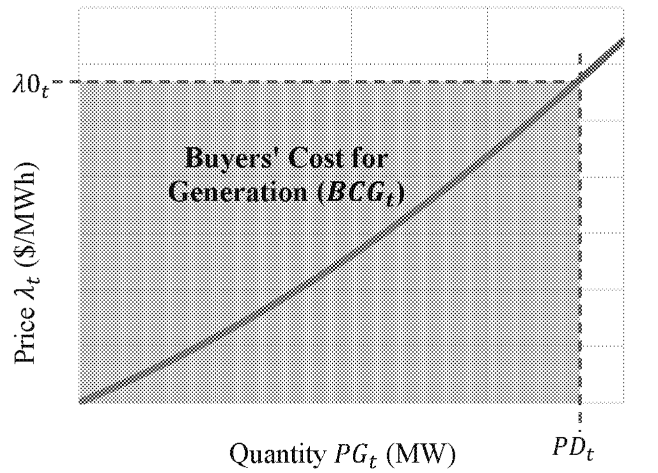

Fig. 3. Electricity settlement graph for a single-ended auction at hour t with no demand response.

With the procurement of quantity PR_t of DR, several key changes happen simultaneously to the electricity settlement graph as shown in Fig. 4.

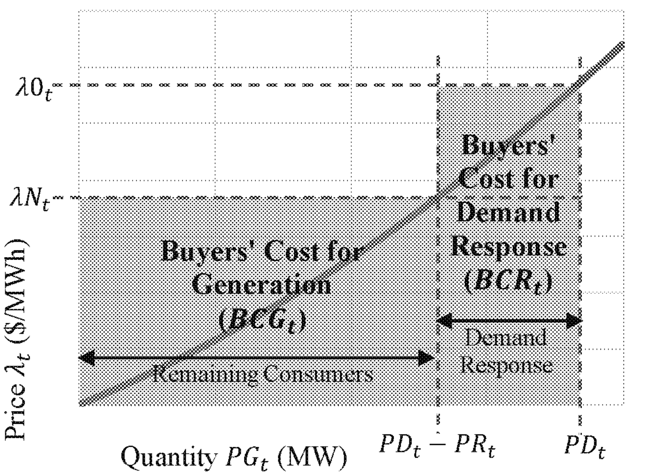

Fig. 4. Electricity settlement graph of a single-ended auction at hour t with demand response.

(a) First, a portion of the consumer group of size PR_t converts from being *paying* consumers to becoming DR service providers, who are instead *paid* for their DR service. Therefore, the size of the remaining consumer group that pays becomes $PD_t - PR_t$.

(b) Second, DR services totaling PR_t are paid at a rate λPR_t. In Fig. 4, λPR_t is shown as $\lambda 0_t$ for illustrative purposes, but it can be at any level determined by the market designer. In this paper, methods to determine optimal values of λPR_t will be proposed. The total cost paid to DR service providers BCR_t is:

$$BCR_t = \lambda PR_t \cdot PR_t \tag{4}$$

(c) Third, BCG_t shrinks as less generation is needed to serve the remaining consumers $PD_t - PR_t$. The new market clearing price becomes λN_t as calculated in (5), and BCG_t becomes (6).

$$\lambda N_t = b_t + 2 \cdot c_t \cdot (PD_t - PR_t) + 3 \cdot d_t \cdot (PD_t - PR_t)^2 \tag{5}$$

$$BCG_t = \lambda N_t \cdot (PD_t - PR_t) \tag{6}$$

(d) Fourth, the remaining consumers $PD_t - PR_t$ must share the total costs, which comprise both generation and DR services. Using only λPR_t or λN_t in isolation as a measure of the impact of DR would be incomplete as those prices represent the rates paid to DR services and to generation respectively. The Actual Price λA_t of electricity is the sum of the generation and DR costs shared among the remaining consumers:

$$\lambda A_t = \frac{BCG_t + BCR_t}{PD_t - PR_t} \tag{7}$$

Substituting (6) and (4) into (7), λA_t becomes:

$$\lambda A_t = \lambda N_t + \frac{\lambda PR_t \cdot PR_t}{PD_t - PR_t} \tag{8}$$

This concept of actual price is the most comprehensive and accurate measure of impact to the remaining consumer pool. For example, studies whose objective function is to minimize total costs do not account for the smaller pool of paying consumers due to DR, so minimizing *total costs* does not equate to minimizing *rates*, or actual price λA_t, to remaining consumers. Furthermore, tracking the new market clearing price λN_t accounts for neither the costs paid to DR nor the smaller pool of remaining consumers and is therefore inaccurate.

The electricity market settlement graph in Fig. 4 is intended to capture only the generation purchased; DR was added to it, when in fact it is a second commodity and has its own settlement graph, which will be introduced later in this paper.

V. Optimization of Demand Response Procurement to Minimize Actual Price: Conceptual Developments

A. Demand Curve for Demand Response

Having established in the preceding section that λA_t is the best metric to assess the impact of DR to the remaining consumers, the optimal outcome for those remaining consumers is the lowest possible λA_t. λA_t is minimized by taking its partial derivative with respect to PR_t and setting it to zero to determine the optimal quantity of DR PR_t using (8) and (5):

$$\lambda A_t = \lambda N_t + \frac{\lambda PR_t \cdot PR_t}{PD_t - PR_t} \tag{9}$$

$$\frac{\partial \lambda A_t}{\partial PR_t} = 6 \cdot d_t \cdot PR_t - 2 \cdot c_t - 6 \cdot d_t \cdot PD_t + \frac{\lambda PR_t}{PD_t - PR_t} + \frac{\lambda PR_t \cdot PR_t}{(PD_t - PR_t)^2} = 0 \tag{10}$$

Defining a demand response demand price function:

$$\lambda PRD_t(PRD_t) = \frac{6 \cdot d_t}{PD_t}\left[(PD_t - PRD_t)^3 + \frac{c_t}{3 \cdot d_t}(PD_t - PRD_t)^2\right] \tag{11}$$

Equations (10) and (11) describe the relationship between PR_t and λPRD_t, the price remaining consumers are willing to pay for DR, under the optimal condition of minimum λA_t. They also form the DR demand curve, which shows at each price λPRD_t, the maximum amount of PR_t the remaining consumers are willing to buy.

The demand curve for DR is important for market designers to understand the value of DR services to remaining consumers so that actual prices will be kept at a minimum. Paying prices above λPRD_t for DR would be detrimental to λA_t, while paying prices below λPRD_t would mean that consumers can enjoy a surplus.

The demand curve for DR is also necessary for operating and settling the market at the most efficient point.

For a sample market with the same characteristics shown in Table I under natural gas shortage conditions, the demand curve for DR was calculated and illustrated in Fig. 5.

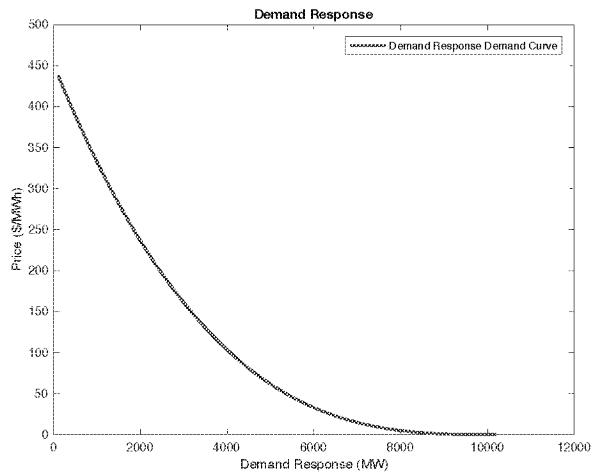

Fig. 5. Demand response demand curve for a sample power system.

B. Demand Response Market Settlement

In order to settle the DR market, a supply curve from DR service providers is needed. The optimal settlement point, or Nash equilibrium, is the point at which the DR supply and demand curves intersect and total social welfare is maximized.

The supply curve for demand curve is constructed by stacking the bids from DR service providers from lowest to highest. It is approximated by a second order polynomial curve of the form in which λPRS_t is the minimum price DR providers are willing to accept for PR_t of DR.

Defining a demand response supply price function:

$$\lambda PRS_t(PRS_t) = e_t + f_t \cdot PRS_t + g_t \cdot PRS_t^2 \tag{12}$$

The objective function is to maximize social welfare:

$$Maximize: \quad \lambda PRD_t(PRD_t) \cdot PRD_t - \lambda PRS_t(PRS_t) \cdot PRS_t \tag{13}$$

The objective function is subject to this constraint:

$$PRS_t = PRD_t \tag{14}$$

This is a nonlinear optimization function, and a classic nonlinear optimization technique can be used to solve it.

Using sample data in Table II, Fig. 6 shows both the supply and demand curves for a sample DR market. The settlement point is at an optimal DR quantity $\overline{PR_t}$ of 670 MW and an optimal price for DR $\overline{\lambda PR_t}$ of \$369/MWh.

TABLE II

Details of a sample demand response supply bid curve

Constant	Value	Units
e_t	50	\$/MWh
f_t	0.007	\$/MWh^2
g_t	0.0007	\$/MWh^3

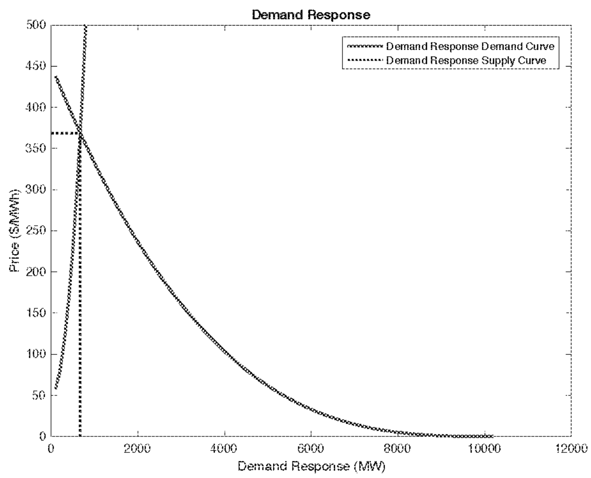

Fig. 6. Demand response supply and demand curves for a sample power system.

C. *Optimal Electricity Market Settlement with Demand Response*

The electricity market can now be settled at its optimal point using the information developed up to this point. The actual price λA_t can be calculated by substituting the values for $\overline{PR_t}$ and $\overline{\lambda PR_t}$ determined in the preceding section into equations (5) to get λN_t and (8) to get λA_t.

For the sample system with characteristics from Tables I and II, λA_t is \$235/MWh, which is lower than the original market clearing price $\lambda 0_t$ of \$238/MWh. The key characteristics of the optimal conditions are shown in Table III and Fig. 7. The total savings for remaining consumers, which amounts to \$26,354 in this case, is found by multiplying the price difference between λA_t and $\lambda 0_t$ with the remaining consumers. In Fig. 7, the grey area is the new BCG_t, while the blue area is the BCR_t.

TABLE III

Optimal conditions of sample power system

Characteristic	Value	Units
Actual price λA_t	235	\$/MWh
Price paid to demand response $\overline{\lambda PR_t}$	369	\$/MWh
Quantity of demand response procured $\overline{PR_t}$	670	MW
Price paid to generators λN_t	209	\$/MWh
Original market clearing price without demand response $\lambda 0_t$	238	\$/MWh
Remaining consumers $PD_t - \overline{PR_t}$	9,530	MW
Total savings for remaining consumers due to optimal purchase of demand response	26,354	\$

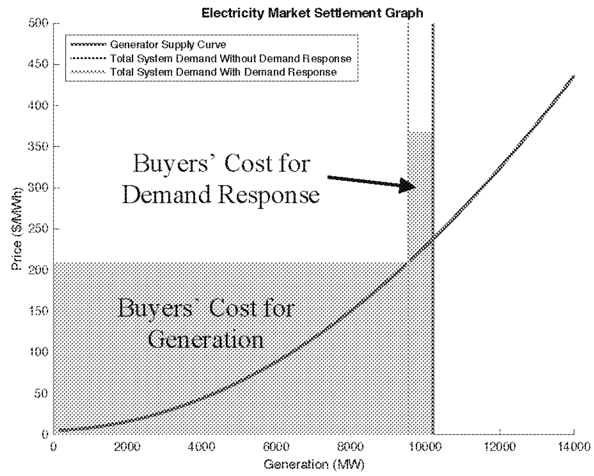

Fig. 7. Electricity market settlement graph with optimal demand response.

The relationship between λA_t, PR_t, and λPR_t is shown in Fig. 8. The supply and demand curves for DR have been superimposed in red and blue respectively. At every level of λPR_t, the DR demand curve (in blue) represents the lowest λA_t on that plane and is the optimal situation from the perspective of remaining consumers.

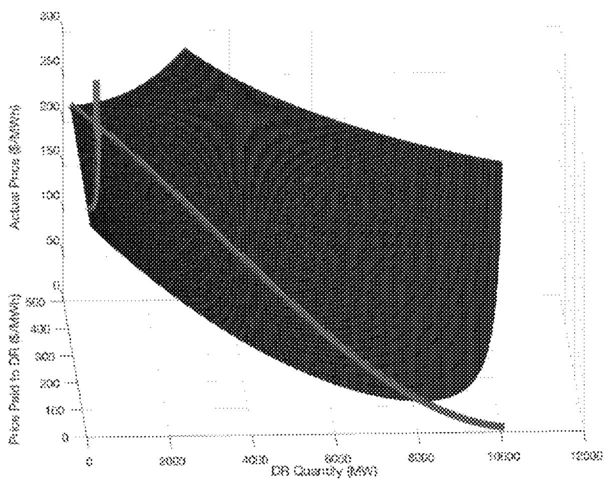

Fig. 8. Relationship between actual price, demand response quantity, and price paid to demand response.

VI. FORMULATION

The following procedure was used to ensure that consumers pay the lowest actual prices.

Step 1: Create the generation supply bid curve using bids from generators to determine a_t, b_t, c_t, and d_t.

Step 2: Determine PD_t from load forecasts.

Step 3: Create the DR demand curve from equation (11) and PD_t, a_t, b_t, c_t, and d_t.

Step 4: Create the DR supply curve using bids from DR resources to determine e_t, f_t, and g_t.

Step 5: Determine for $\overline{PR_t}$ and $\overline{\lambda PR_t}$ by settling the DR market. This is the point at which the DR supply and demand curves intersect, and the settlement method is described in

Section V.

Step 6: Settle the market with the formulation outlined in (15) to (18).

Step 7: Determine λA_t using equations (5) and (8).

The objective function is to minimize total cost:

$$minimize \quad a_t + b_t \cdot PG_t + c_t \cdot PG_t^2 + d_t \cdot PG_t^3 \qquad (15)$$

The objective function is subject to the following constraints:

(a) Supply-demand balance using DR resources in addition to generation:

$$PD_t = PG_t + PR_t \qquad (16)$$

(b) Generation limits:

$$\underline{PG_t} \le PG_t \le \overline{PG_t} \qquad (17)$$

(c) DR resource optimization limits:

$$0 \le PR_t \le \overline{PR_t} \qquad (18)$$

This is another nonlinear optimization challenge and can be solved with classic nonlinear optimization techniques. To more clearly illustrate the performance of this DR optimization method, the constraints were limited to power balance, generator equipment limits, and DR limits. Additional constraints, such as ramping, start-up/shut-down, and spinning reserves, can be also incorporated into the model as necessary. Also, a discrete price curve for generators can be incorporated. Since congestion was not considered, the price at every node in the system was assumed to be equal, as it is in Ontario.

VII. Probabilities and Expected Impact of Demand Response Optimization in Ontario

A. Historical Market Performance

The new concepts presented in this paper were applied to the electricity system in Ontario, Canada to examine the scope of expected impact. The hourly electricity prices for Ontario were obtained for 12 years, 2005 to 2016 inclusive, and are depicted in Fig. 9. [28] The prices are the sum of the Hourly Ontario Energy Price and the Global Adjustment charge. All other charges, including delivery, regulatory, and taxes, were not considered for this analysis.

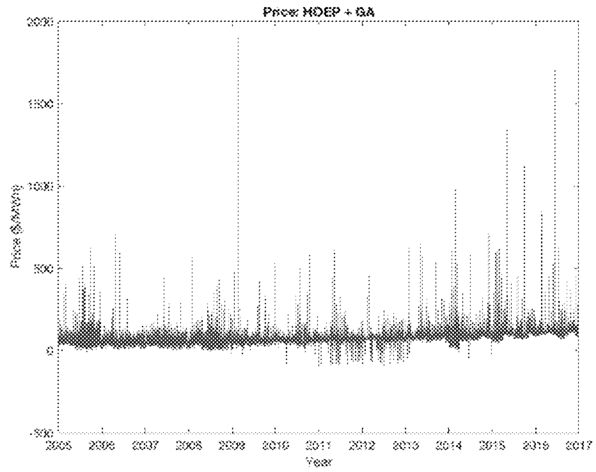

Fig. 9. Hourly electricity prices in Ontario, 2005 to 2016.

Re-ordering the electricity prices from largest to smallest yields the price frequency curve, as shown in Fig. 10. This curve was then divided into four periods by price: extreme peak prices (P1); shoulder peak prices (P2); moderate prices (P3); and extremely low prices (P4). The median price point in each of these regions were used to represent each region in the analysis.

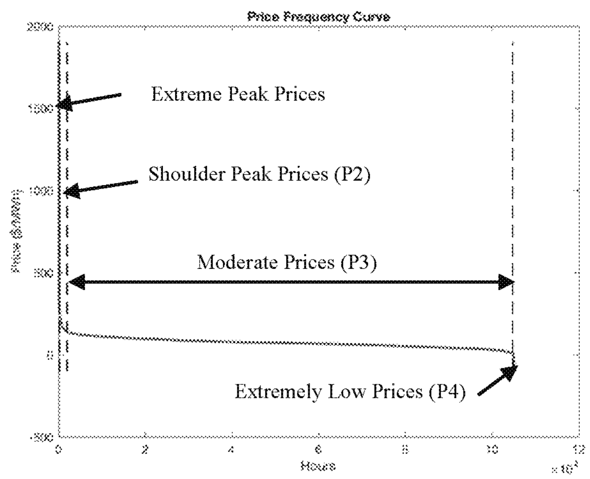

Fig. 10. Ontario electricity price frequency curve, 2005 to 2016.

For all four periods, the supply bid curve characteristics for DR was assumed to be the same and in the form of (12) with the constants in Table IV. For simplicity, it is assumed that the historical price and quantity data does not include DR.

TABLE IV

Details of a sample demand response supply bid curve

Constant	Value	Units
e_t	100	\$/MWh
f_t	-0.00000103	\$/MWh^2
g_t	0.0000689	\$/MWh^3

Table V shows each of the four periods under optimal procurement of DR. Values were calculated using the methods proposed in the preceding sections. The optimal quantity of DR and corresponding savings were weighted with the percentage duration of that period.

TABLE V
Expected values of optimal conditions for Ontario's historical electricity system

	Units	Extreme Peak Prices (P1)	Shoulder Peak Prices (P2)	Moderate Prices (P3)	Extremely Low Prices (P4)	Annual
Median price in region $\lambda 0_t$	\$/MWh	360.45	160.41	70.28	-0.46	-
Median quantity in region PD_t	MW	22,371	20,171	17,073	13,741	-
Percentage of duration	%	0.16%	1.66%	97.81%	0.37%	100%
Hours per year	hours	14	145	8,568	32	8,760
Generation supply bid curve characteristic a_t	\$	1	1	1	-	-
Generation supply bid curve characteristic b_t	\$/MWh	10	10	10	-	-
Generation supply bid curve characteristic c_t	\$/MWh^2	-3.50E-07	-1.85E-07	-1.03E-07	-	-
Generation supply bid curve characteristic d_t	\$/MWh^3	2.33E-07	1.23E-07	6.89E-08	-	-
Minimum actual price λA_t	\$/MWh	349.18	158.24	70.17	-0.46	-
Price paid to generators λN_t	\$/MWh	289.18	139.82	67.38	-0.46	-
Optimal price paid to demand response $\overline{\lambda PR_t}$	\$/MWh	498.37	241.22	111.95	0	-
Optimal quantity of demand response procured $\overline{PR_t}$	MW	2,400	1,430	416	0	-
Expected quantity of demand response purchase per year	MWh	33,693	208,134	3,568,113	0	3,809,940
Expected savings due to demand response for remaining consumers per year	\$	\$3,154,149	\$5,898,376	\$15,099,354	0	\$24,151,879

Table V shows that Ontario consumers could have collectively saved over \$24 million annually through optimal procurement of DR in 2005 to 2016 inclusive for the assumed DR supply bid with characteristics in Table IV. The extreme peak price period (P1) occurs for the shortest amount of time – about 14 hours per year – and can represent extreme events such as natural gas shortages. The highest optimal prices and quantities for DR occur in P1 as that is when there is the greatest need for DR. However, the greatest collective savings are found in the moderate price period (P3) because the vast majority of the time – 97.81% – is in this category. Since the median starting price for P4 is already negative, no DR is necessary to further lower the price.

While the consumption data used in this example was based on historical data, the DR supply price data was unavailable. Assumed values shown in Table IV were used. While this introduces uncertainty around the absolute values of the results, the *relative* performance of DR in each of the four periods still holds. Furthermore, DR supply bids were assumed to be constant throughout the year. Additional data about seasonal variations for DR supply can be incorporated as it becomes known in the future to improve the accuracy of the forecasts.

It is evident that DR, when procured optimally, has the potential to deliver savings to consumers during the vast majority of the year, not only during natural gas shortages.

B. Future Market Performance with Increased Duration of Severe Weather Events

In commissioning this paper, the IESO has expressed interest in the role of CDM in lowering electricity prices should there be severe weather events that constrict supply such as natural gas shortages. (This situation is shown in the market settlement graph in Fig. 2.) These events are also represented in P1, the extreme peak price period, of the preceding section.

Should extreme weather events have longer duration in the future, the duration of P1 and P2 are expected to increase, while P3 and P4 are expected to decrease. An example of this situation is summarized in Fig. 11 and Table VI using the same system data in the preceding section and varying the relative durations of the four periods. Longer extreme weather events that restrict supply would instigate additional procurement of DR, while the total collective savings to remaining consumers due to DR would also increase to almost \$69 million – more than double the potential collective savings under historical patterns. Furthermore, the collective savings realized during P1 and P2 are now higher than P3 due to the duration shifts.

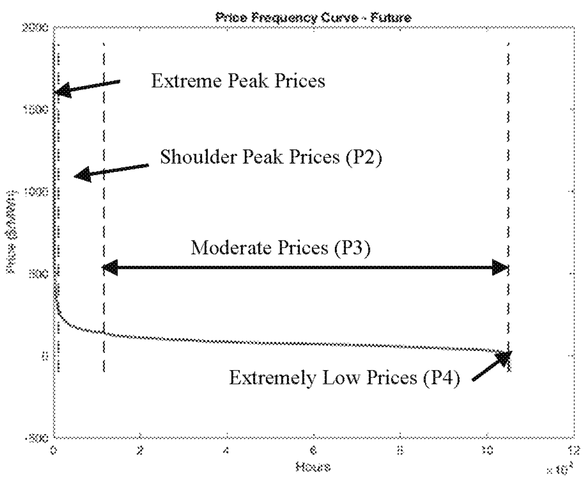

Fig. 11. Ontario electricity price frequency curve of future scenario.

TABLE VI
Expected values of optimal conditions for Ontario's future electricity system

	Units	Extreme Peak Prices (P1)	Shoulder Peak Prices (P2)	Moderate Prices (P3)	Extremely Low Prices (P4)	Annual
Percentage of duration	%	1.00%	10.00%	88.80%	0.20%	100%
Hours per year	hours	88	876	7,779	18	8,760
Expected quantity of demand response purchase per year	MWh	210,582	1,253,819	3,239,428	-	4,703,829
Expected savings due to demand response for remaining consumers per year	$	$19,713,434	$35,532,383	$13,708,441	-	$68,954,258

As the percentage of duration of extreme peak prices increases, both the total quantity of DR purchased per year and the total savings due to DR for remaining consumers per year increase as well. Fig. 12 illustrates these patterns as the duration of P1 increases from 0% to 5% per year.

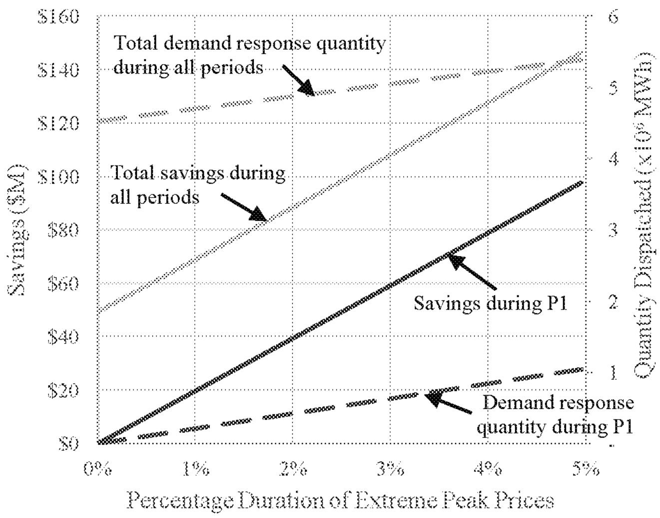

Fig. 12. Expected annual collective savings for remaining consumers due to demand response and expected quantities of demand response dispatched under various percentages of duration of extreme peak prices.

VIII. CONCLUSIONS

When procured optimally, DR is a tool to help ISOs lower electricity prices for consumers. DR can deliver savings not only in periods when extreme weather events cause natural gas supply restrictions, but also any time when the electricity market price is positive.

The main contribution of this paper is a new method to optimally procure DR to deliver lowest electricity prices and highest collective savings to remaining consumers. Since there are two commodities procured simultaneously – generation and DR – traditional market settlement methods, which are designed for a single commodity, are insufficient to handle this complex scenario. To overcome this:

(a) the concept of the actual price, which accounts for (i) both generation and DR costs and (ii) the smaller base of remaining consumers who share in paying costs after DR, was explained;

(b) actual price was minimized for remaining consumers; and

(c) a resulting demand curve for DR was created.

These new conceptual developments enable ISOs to optimally and simultaneously settle markets for DR and generation in the best interests of remaining consumers.

This new method was applied to the electricity system in Ontario, Canada to demonstrate probabilistic results and performance. Using historical data, it was demonstrated that DR prices and procured quantities per hour are highest during extreme peak periods (P1) and decline as $\lambda 0_t$ decreases. However, since moderate prices (P3) comprise the vast majority of the time, most of the collective savings due to DR was realized during P3.

If Ontario experiences longer durations of extreme peak price periods in the future, perhaps due to climate change, the collective savings delivered by optimal procurement of DR would be even higher. The collective savings attributed to P2 and P1 can also outstrip those of P3.

If the percentage duration of extreme peak prices increases in the future, both (a) the total collective savings for remaining consumers due to DR and (b) the total quantity of DR dispatched will increase as well.

Future work could examine the optimal allocation of DR costs to capacity and energy payments.

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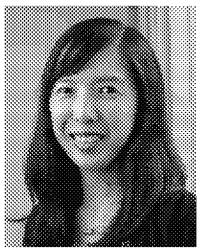
X. Biographies



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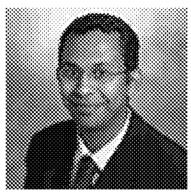

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