



**This article was presented at the Demand Response Expo, Toronto, December 2007.**

## **Demand Response – the Shape of Things to Come in Ontario, Canada**

(an educational perspective on Demand Response in Ontario, Canada )

In August, 2007, the Ontario Power Authority (OPA) in Canada issued its final rules for its new DR3 Demand Response program. The program is aimed at creating an availability of some 1500 MW of power through the curtailment of demand by subscribers during contracted windows of availability. The key objective is to trim the peak demand in Ontario, which has been as high as 27,005 MW in August, 2006.

The interesting issue which we expect will ultimately arise is that once the first phase of DR has been implemented in Ontario, the shape of the predictable daily demand pattern will begin to change, and the objective of avoiding upward of 1,500 MW of demand will evolve to an objective of better prediction matching for cost efficiency. This will likely result in a changing DR environment over the next several years, which will affect the manner in which DR is implemented both at customer sites and in the Province of Ontario.

This paper will look at the new program in Ontario, how it relates to building automation systems and how to scale the opportunity beyond the present program guidelines.

### Author:

Paul Silverthorne, P.Eng., CEO, Dimax Controls, Toronto, Canada  
[psilverthorne@dimaxcontrols.com](mailto:psilverthorne@dimaxcontrols.com)

Dimax Controls  
242 Galaxy Blvd.  
Toronto, ON M9W 5R8  
416-674-8830, ext. 201  
[www.dimaxcontrols.com](http://www.dimaxcontrols.com)

### Bio:

#### **Paul Silverthorne – Founder & CEO, Dimax Controls**

Paul Silverthorne, founder and CEO of Dimax Controls, is also the founder and CEO of Incerno Limited. He is a registered Professional Engineer and has worked in the consulting and control industries in North America since 1968.

Paul has launched a number of intriguing and visionary businesses during his career. Paul is well published, he has acted as a specialist consultant in engineering and in business, he has developed a number of significant software packages for accounting, life cycle costing and building performance simulation, and he holds a number of patents. He has been the keynote speaker at international conferences and taught part time at the School of Architecture at the University of Toronto.



## Table of Contents

<b>1. Introductory Comments .....</b>	<b>3</b>
<b>2. The Administration of Power in Ontario Canada .....</b>	<b>3</b>
<b>3. A bit of History .....</b>	<b>4</b>
<b>4. How does the DR-3 Program Work in Ontario? .....</b>	<b>4</b>
<b>5. What Does a DR Measure Look Like? .....</b>	<b>8</b>
<b>6. Typical Measures .....</b>	<b>9</b>
<b>7. Why is DR Important in Ontario? .....</b>	<b>9</b>
<b>8. What are the Demand Profiles in Ontario?.....</b>	<b>11</b>
<b>9. How will the picture change as more DR-3 contracts are implemented? .....</b>	<b>14</b>
<b>10. What is wrong with the picture? .....</b>	<b>14</b>
<b>11. The Future of DR-3 in Ontario .....</b>	<b>16</b>



## 1. Introductory Comments

The Ontario Power Authority Demand Response program known as DR-3 applies to DR initiatives in the Province of Ontario, Canada. While some of the program has elements specifically tailored to the Province, the majority of the aspects of the program are consistent with those which are being used in various other locations in North America. The information in this paper is drawn in part from the OPA DR-3 program, but the principals are applicable to most DR programs.

## 2. The Administration of Power in Ontario Canada

The administration of power in Ontario changed with the implementation of a competitive market environment in 2004. At that time, four different bodies emerged: Ontario Power Generation (OPG), Ontario Power Authority (OPA), Independent Electricity System Operator (IESO) and the Independent (Electricity) Market Operator (IMO). Of these bodies, OPA and IESO assumed the responsibility for the power grid, taking over the majority of the IMO's function.

OPG is a Crown Corporation which is responsible for the majority of production of energy in Ontario. The IMO was the agency responsible for monitoring Ontario's electrical system. The IMO was the hub of the electricity wholesale marketplace, connecting all participants. The IESO took over these responsibilities under the Electricity Restructuring Act of 2004.

The OPA and the IESO are responsible for managing electricity markets in Ontario and ensuring a reliable supply of power. OPA is a non-profit organization which reports to the Ontario Legislature through the Ministry of Energy in Ontario and it is responsible for long term planning, the development of new generating resources and conservation measures and ensuring that there is a reliable power system for the Province. IESO is also a non-profit organization which establishes, monitors and enforces reliability standards in Ontario. It manages electricity markets and balances supply and demand in real time to provide the required amount of power to homes and businesses in Ontario. These entities are the outgrowth of the original operation under Ontario Hydro, which was restructured under the Electricity Restructuring Act of 2004. The OPA has developed the DR-3 program for Ontario, and it is the entity which enters into DR contracts with direct and aggregating partners in the Province. The IESO is the entity which will administer the DR-3 program.



### 3. A bit of History

Demand response has existed in Ontario in various forms for some time. Back in the 1950s-1960s, it was common place for there to be a 4 wire entry into houses. Three wires served power into the house, while the fourth wire was switchable from the utility and was generally used to feed electric water heaters. In industry, there were situations where interruptible power and gas were used so that the utilities could access capacity through a telephone call. Toronto Hydro has had a DR plan in place in recent years before the OPA brought in their DR-3 program in August of this year. So DR is not a totally new concept to some industrial and commercial operations in Ontario. However, the DR-3 program is new, it operates to a different financial incentive model, and it requires more technology to administer.

### 4. How does the DR-3 Program Work in Ontario?

The objective of the DR-3 program is to acquire some 1500 megawatts of power during daily peak demand periods to improve grid reliability, to improve the financial picture of power distribution in Ontario (capital and delivery), to better manage energy demand and to address environmental sensitivity. The OPA is the non-profit agency which is setting the operating rules for DR in Ontario which will be managed through the IESO.

The OPA DR-3 program is very new in Ontario, so it has some areas which can change as the program develops. However, it has been set up based on other models in North America and on the basis of market research and data accumulated through the Ministry of Energy in Ontario over the past 3 years, so the basic rules will likely be reasonably stable. The initial program works to the following basic rules:

1. There are two types of arrangements, namely direct and aggregator. Direct users must have a minimum availability of 5 MW and aggregators, a minimum of 25 MW. For the aggregators, a "site" minimum availability is 50KW.
2. As the Province of Ontario is large (Great Britain could fit into it 4 times over), Settlement areas have been set up as Premium (Toronto, for example), Standard ( East which includes Cities such as Peterborough), Discount (Niagara, for example) and Non-Participating (York, for example). The difference for the first three settlement areas is the rates for availability and utilization.
3. There are two contract options available, one for 100 hours per year, one for 200 hours per year. Note that aggregators could offer different hours per year, but their contracts have to abide by these options.



4. The year is broken into three season categories, namely Summer, Winter and Shoulder. The event windows for each of these are 12:00 PM to 9:00 PM, 4:00 PM to 9:00 PM and 4:00 PM to 9:00 PM respectively. All times are based on Eastern Standard Time. The switchable load availability during these windows must be 100% in the summer, 80 % in the winter and 66% in the shoulder seasons.
5. Event durations are 4 hours each, but participants have opportunities to increase the duration for additional compensation. The total accumulation of events through a year must total the contracted commitment (100 or 200 hours), and participants are to notify OPA when they reach the 90<sup>th</sup> or 190<sup>th</sup> hour of plan usage in a given year.
6. Notification of an event is given either the day ahead between 12:00 PM and 5:00 PM or the day at hand between 12:00 AM and 7:00 AM. Any confirmation required by a participant is to be given by 6:00 PM the day ahead or by 8:00 AM on the day at hand.
7. There must be a measurement and verification plan for direct or aggregator participants which is submitted to validate the project base line and the project net reduction during an event, such plan to be validated with the OPA at the time of entering a contract. These reports are submitted for approval and/or audit regularly throughout the contract.

There are other details to the plan, but the above rules summarize the majority of them.

The chart below presents how DR-3 events will be administered in Ontario.



*Summer Season*

Time (EST)	Day Ahead	Day at Hand
12:01 AM		
1:00 AM		
2:00 AM		
3:00 AM		
4:00 AM		
5:00 AM		
6:00 AM		
7:00 AM		
8:00 AM		
9:00 AM		
10:00 AM		
11:00 AM		
12:00 PM		
1:00 PM		
2:00 PM		
3:00 PM		
4:00 PM		
5:00 PM		
6:00 PM		
7:00 PM		
8:00 PM		
9:00 PM		
10:00 PM		

*All Other Seasons*

Time (EST)	Day Ahead	Day at Hand
12:01 AM		
1:00 AM		
2:00 AM		
3:00 AM		
4:00 AM		
5:00 AM		
6:00 AM		
7:00 AM		
8:00 AM		
9:00 AM		
10:00 AM		
11:00 AM		
12:00 PM		
1:00 PM		
2:00 PM		
3:00 PM		
4:00 PM		
5:00 PM		
6:00 PM		
7:00 PM		
8:00 PM		
9:00 PM		
10:00 PM		

Confirmation by Participant

Earliest Activation Notice from IESO

Confirmation by Participant





Available payments under the DR-3 program vary according to the settlement area and the contract type and duration, and they are broken down into an availability payment and a usage payment. Current rates are shown in the table below.

**DR 3 Rate Schedule**

The rate schedule for DR 3 under Option A (100 hours of demand response) and Option B (200 hours) showing the associated payment based on the various categories of compensation

	Option A (100 h)			Option B (200 h)		
Reliability Rates	95%			95%		
Schedule Term (Years)	1	3	5	1	3	5
Availability Rate (\$/MW)	35	50	65	40	60	80
Adjusted Availability Rate (Premium) (\$/MW)	43.75	62.5	81.25	50	75	100
Adjusted Availability Rate (Discount) (\$/MW)	17.5	25	32.5	20	30	40
Availability Over-Delivery Rate (\$/MW)	10			10		
Consecutive Hour of Utilization	Utilization Rate (\$/MWh)					
1	200					
2	200					
3	200					
4	200					
5	300					
6	300					
7	300					
8	300					
9	300					

Note that the above rates apply as follows. For 1 MW of availability used 100 hours per year in a Premium Zone on a 1 year contract with 4 hours consecutive hours of utilization for 25 events per year, the payment would be:

$$12 \text{ months} \times (\$43.75 \times 100 \text{ hrs/yr}) + 100 \text{ hrs/yr} \times 200 = \$52,500 + \$20,000$$

or \$72,500 for the year.

There are penalties for non-performance which can potentially exceed the value of the rebate available for a given month. Such penalties or “set-offs” apply if a participant does not meet 95% reliability during any 5 minute interval in a given hour during an event, and non- performance is accumulative for each hour during which reliability is below the requirement. Offset factors applied to the availability and utilization rebates can be as high as 2.0, so that not meeting the reliability hurdle on a continuing basis can be cause for a sizable penalty. Participants are allowed up to two non-performance events in a settlement area in a year, and they must notify the OPA of these events.



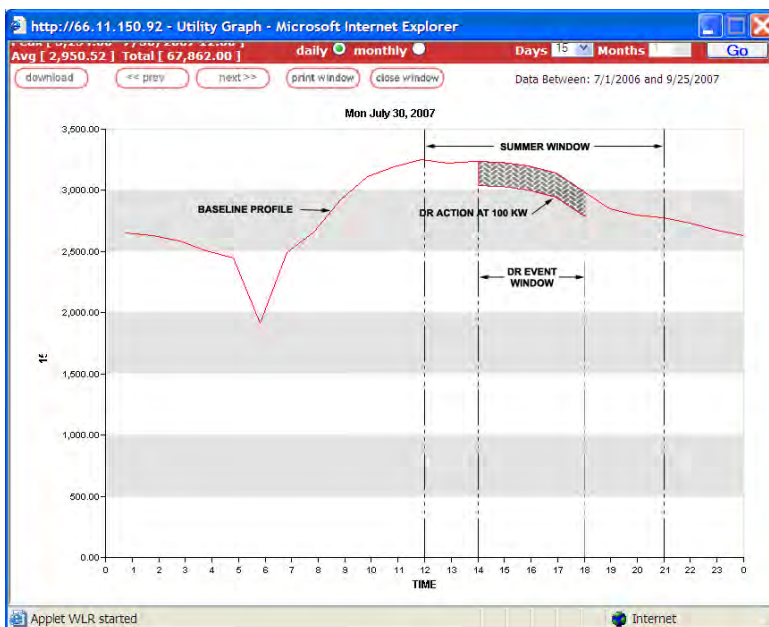
## 5. What Does a DR Measure Look Like?

The key requirement in the DR-3 program is that the demand profile during a DR event be demonstrated to have provided 95% reliability measured in 5 minute intervals. That is, no less than 95% of the DR commitment must have been met during each 5 minute interval during the event, which is 4 hours at minimum. If the DR commitment for a site is 100KW, then the base line profile must have been reduced by 100 KW over the duration of the event.

Below is a base-line demand profile for a Hospital for July 30, 2007. The data comes from our Utility Profiling Service, which reads the actual power meters at the site (2 such) and aggregates them. The profile shows a peak demand during that day of about 3250 KW at about 12 noon. Overlaid on the same profile are the following:

1. The overall Summer Demand Response Window
2. The agreed-upon event window of 4 hours
3. The adjustment to the profile during the event, based on 100 KW

The graph demonstrates that the profile must be met. It is not simply a “peak-shaving” event. For example, if equipment had been switched off at 3 PM in the base line, imposing a step reduction, the profile under DR would have to demonstrate the same step function.





## 6. Typical Measures

In the simplest of terms, typical measures fall into two categories: switchable loads and onsite generation (behind the meter). From an implementation cost point of view, if there is no existing metering or controls, then the measures tend to be simple so as to minimize the cost impact. Metering must be installed and meter data must be available as outlined in the accepted measurement and verification plan. However, the control for accomplishing the plan can vary.

Many buildings have Building Automation Systems or other forms of intelligent or programmable controllers which include energy conservation measures, switchable and variable loads and meter reading. In such cases, so long as the time intervals for reading and controlling are suitable, a proposed DR program can be implemented through the existing BAS. These cases can allow for more sophisticated forms of control, making the potential to deliver DR better. As an example, with a typical event period being 4 hours, with a BAS connected to a gateway device, measures such as load cycling resistance heaters, heat pumps and the like can be contemplated as a cost effective measure. Likewise, rolling back on variable speed drives can be used as an effective means of acquiring loads which can be shed for DR purposes.

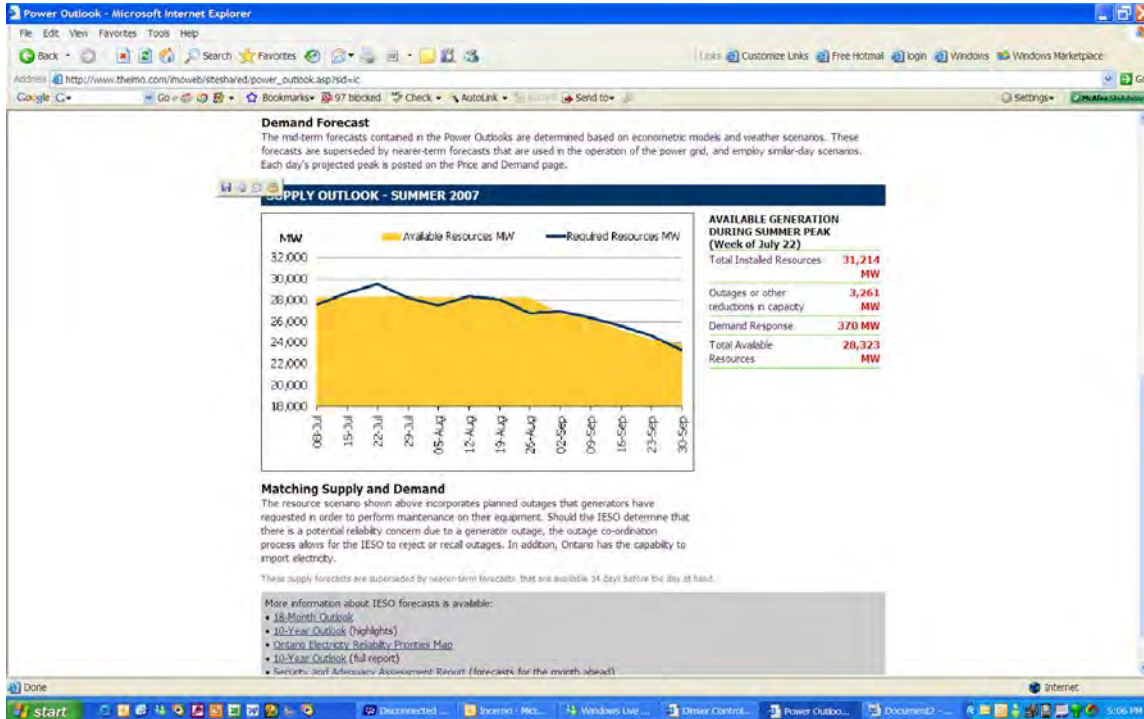
One of the advantages of working through an existing building control system is that the control system can be programmed to simplify the action requirements for a scheduled event. A “prescribed event” can be programmed so that the BAS only has to be aware that an event is to start or end. Furthermore, a BAS can be set up so it can identify the load which is available at any given instant, so that when the prescribed event is to be enabled, the exact amount of reduction in demand is known. This can be of particular advantage to aggregators. In fact, one company we have worked with in the past has set up to be able to select the amount of demand load reduction it intends to use at any specific site so that it can exactly tune the availability to the requirement to optimize the cost to OPA for the availability.

## 7. Why is DR Important in Ontario?

As is the case with many power providers on the various North American grids, increasing demands for power have altered the “cushion” of available power demand. Historically, cushions were upward of 20%. However, due to growth in demand for service, these have eroded, and the buffer is becoming smaller. This is the case in Ontario. Growth in demand is running at 3-4% per annum, and in Ontario, we have been closing coal fired plants. We have not been constructing new plants, but we have put some major facilities back on line. The picture below shows the seasonal norms and extremes in Ontario. The peak in the extreme case is around 28000 MW.



The next figure shows the availability of resources in Ontario and the required resources projected for the summer of 2007. The key point to be noted is that already, the projected worst case peak exceeds available resources.



If we look at the peak experienced in August 2006 versus our net capacity, we are within 1000 MW of capacity, and could be below capacity at any time. This accentuates the immediate need for DR in Ontario. If we had a 4% growth in demand over the next year, based on the peak established in 2006, we would be out of capacity next summer, with little or no buffer. Looking at the growth rate in Toronto and surrounding areas (which represent more than 50% of the population base of Ontario), this is quite likely to happen. And while we may be able to purchase excess power into our grid, we cannot count on it (the demand may come at a time when it is simply not available), and we are not building power plants to suit growth. In the limit, which not acknowledged openly, there is a crisis brewing. Demand Response is a short term answer, and we must institute it quickly in Ontario if we are to cope with the limitations of our grid.

## 8. What are the Demand Profiles in Ontario?

Let's look at a typical summer profile for Ontario to establish what is happening at present and to understand how the above program will cause positive change. The following capture from the OPA website was taken on July 18, 2007, and it is quite informative.



## ONTARIO DEMAND

**21,207 MW**

at 4:00 p.m. EDT  
July 18, 2007

Projected Demand at 5:00 p.m. EDT

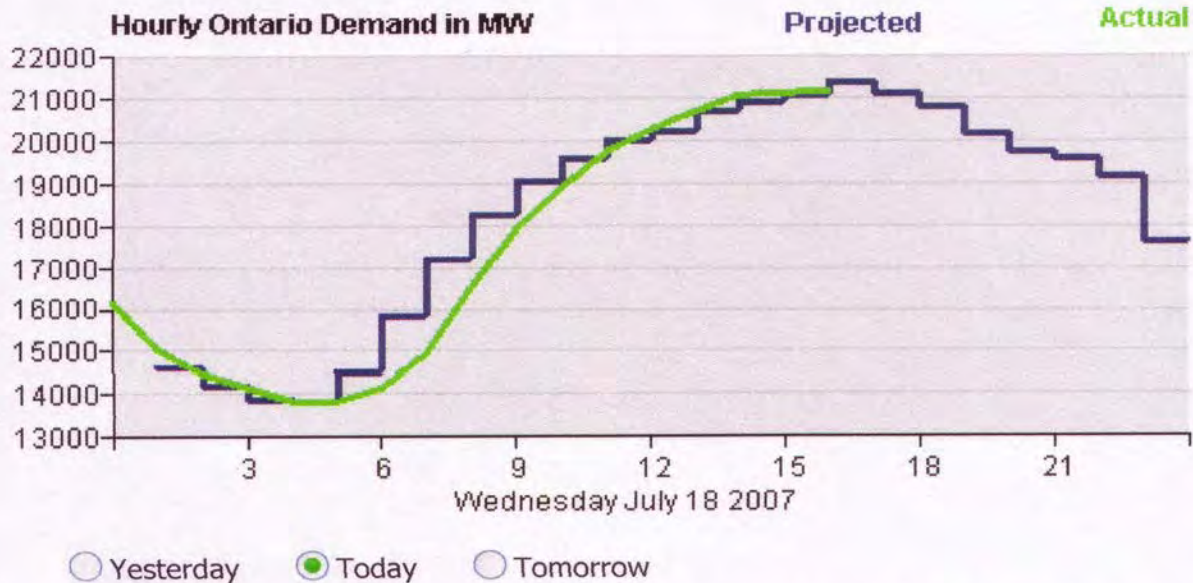
**21,375 MW**

Today's Projected Peak (at 5:00 p.m. EDT)

**21,375 MW**

Summer Record Peak (Aug 1, 2006)

**27,005 MW**



Note: Projected Ontario Demand uses a step graph to show the highest expected demand within the hour. Actual Demand uses a line graph to show average demand for that hour.

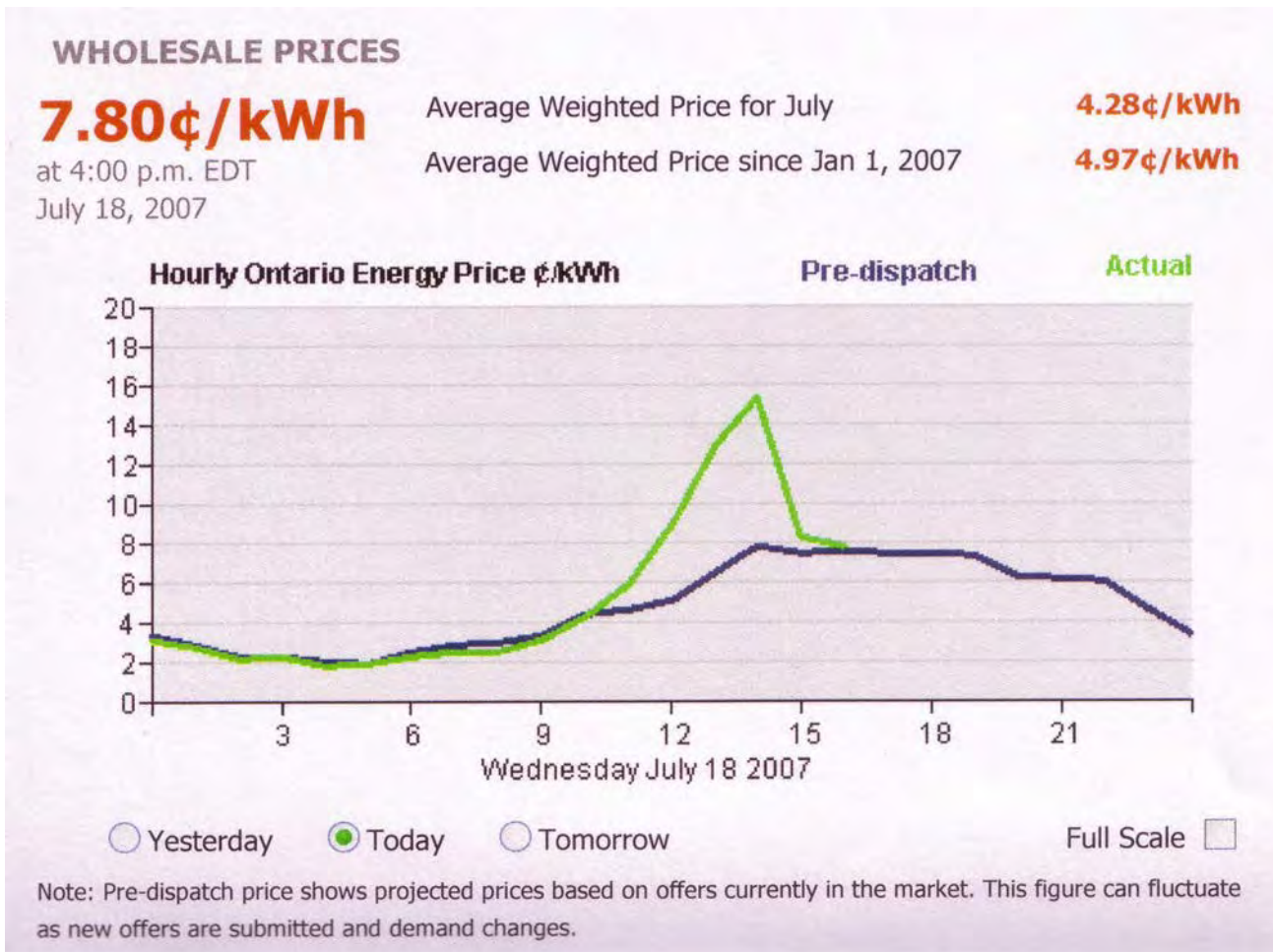
Looking at the above graph, several things are noteworthy. The demand profiles show a projected demand versus an actual demand. The projected demand represents what planned production will be for the day, the actual demand showing what was used. There are other important pieces of information such as the projected peak demand and the time it is expected. It is interesting to note how closely projections and actual experience align, but it is also important to note where they do not and the resulting impact. The above profile was taken before the implementation of the DR-3 program in Ontario.

Looking at the above graph, the peak demand was expected at 5:00 PM and the actual demand at 4:00 PM was close to the projected peak. Looking at the OPA summer event window between 12 noon and 9:00 PM EST, the present program would attempt to bring the day's bulge to 20,000 MW, thus curtailing 1,375 MW off the projected maximum. Interestingly, this goal could be met between the hours of 12 noon and 7:00 PM EST, which we have found to be quite normal. However, event durations of 4 hours, per the rules, would not achieve the same goal unless site



event windows are overlapped to accomplish the goal, and this adds a degree of complication for the administration of the program.

There is another interesting issue which comes into play, namely the issue of cost. On the same OPA website is a projected versus actual graph for cost. The appropriate cost graph relating to the demand graph is shown below.



Of note on the above cost graph is that the cost can escalate quickly when actual demand exceeds the projected demand (16 cents wholesale rate as opposed to 8 cents), and that this escalation in cost can exist outside the defined demand response window under the DR-3 program. It also appears that the cost can vary significantly when the actual demand is below the projections.



## 9. How will the picture change as more DR-3 contracts are implemented?

Logically, when the DR-3 program begins to come online, the profile of demand in Ontario should change. The goal is to capture some 1500 MW, most importantly when the demand is closing in on the maximum available production capacity. However, the goal is not aimed at correcting the “worst day” only, it is aimed at reducing peak periods on a daily basis throughout the year.

Reducing the peak on a continual basis reduces the weighted average wholesale cost of power in Ontario, a matter of some urgency considering that power costs to the user are underwritten in part by the Government. So the likely ongoing change will be to flatten the daily peak at least through the hours of 12:00 noon to 9:00 PM EST, and more likely between the hours of 2:00 PM and 7:00 PM. It is interesting to note that in Ontario, the daily peaking in demand use of power stretches into the evening hours whereas in other jurisdictions, it tends to fall off sooner.

The site requirement under the OPA rules, as noted above, requires DR to adjust the basic site profile down throughout the event. This could suggest a step function at the site when the load is reduced and then restored. However, for the profile for the entire Province is not likely to see a defined step function simply due to the large scale diversity. If it were to see any step function, it would be in the early days of the program when before there exists a significant number of DR managed contracts which add the necessary diversity.

## 10. What is wrong with the picture?

When we look at the typical profile for the demand use of power in Ontario (based on the profile below), the requirement rises from a minimum of about 14000 MW at 3:00 AM to a peak of as much as 25000 MW at mid-day in the summer. The new OPA DR-3 program addresses demand between the hours of 12:00 noon and 9:00 PM during the summer. If we look at a typical power demand profile for the Province, this seems fairly appropriate as the demand increases by approximately 2000 MW during this period of time. However, the program does not simply cap the demand, it attempts to change the profile for at least 4 hours during the event window, which in the example above, reshapes the demand curve lower throughout the period. If a curtailment event were to last from 2:00 PM until 6:00 PM for the example below, there would still be a peak at 6:00 PM, but the projected peak at 4:00 PM would be lowered as shown below (core effect). Obviously, by staggering event windows for different participants within the overall summer window, the IESO will likely shape the actual usage to curtail from 12 noon to 8 PM in the given example below to obtain a better result (shoulder effect). However, the present DR-3 program operates on the principal of projecting what needs to be done a number of hours ahead. It cannot dynamically switch available loads.



## ONTARIO DEMAND

**21,207 MW**

at 4:00 p.m. EDT  
July 18, 2007

Projected Demand at 5:00 p.m. EDT

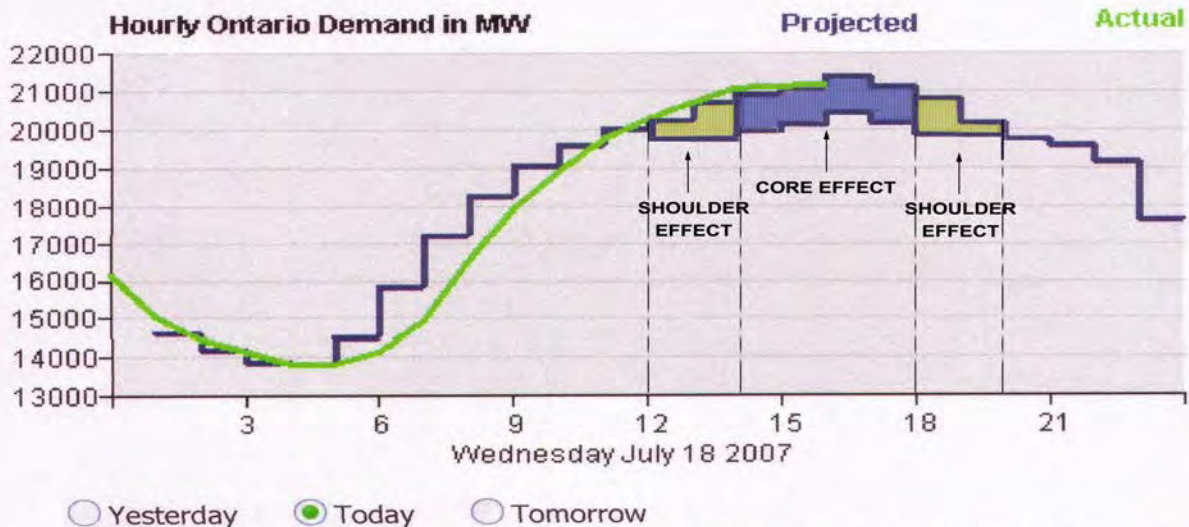
**21,375 MW**

Today's Projected Peak (at 5:00 p.m. EDT)

**21,375 MW**

Summer Record Peak (Aug 1, 2006)

**27,005 MW**



Note: Projected Ontario Demand uses a step graph to show the highest expected demand within the hour. Actual Demand uses a line graph to show average demand for that hour.

One of the pitfalls of the current process for DR in Ontario is that, as we have seen, the actual load can vary significantly from the projections. The DR program has no means for dynamic change as a result of real-time conditions.

What becomes apparent from this is that the program as designed looks to switch loads to change the profile of demand during an event window which is contained within a seasonal window of a larger size. However, what about the periods of time beyond the event window? Clearly, load shifting to the off hours would be beneficial as there is significant capacity available and wholesale prices are much lower at these times, but DR-3 does not address this. Instead, a proposed DR-2 program for shifting loads to off peak periods is being proposed, but the use of it is proposed to preclude the use of DR-3. Clearly, DR-3 should integrate some form of off peak incentive.

If we look at a profile of the cost incurred during a day, one can see that there are other issues at play. The cost for wholesale energy purchases is projected each day, but it is noteworthy that during certain periods, the cost escalates, in part because projected load is exceeded, in part due to market conditions. Having switchable loads outside the present program window, albeit with lower rebates, would help reduce the cost of power production in Ontario (look at the area under



the curve times the cost to see what the excess cost over projections might be). The present DR-3 program does not address this situation.

Another issue which will become apparent is that of energy conservation programs coming into play in the future at participating sites, especially those which affect demand. Consider a specific example we are working with at the moment. We have a building which represents a good DR candidate for an aggregator. It has a switchable load which can affect a DR reduction in the summer of 100 KW and it can meet the hurdle of 80KW in winter and 66 KW in the shoulder season. As a result of looking at operating costs and energy usage, it has been determined that an energy retrofit is also a good program for the building. So while it can be part of the DR program for a year, as the energy retrofit goes ahead, the retrofit will reduce the building demand use of power by 200 KW in the summer and by 40 KW in winter. Therefore, within a year, two things happen. First, the building may no longer be a candidate for DR under the present program rules, and its impact on demand use of power will be lowered by more than the original DR program. If this pattern of change were to occur in the majority of buildings over the next several years, then the demand load profile for Ontario will be altered to have a lower daily maximum and a higher or equal daily minimum. Power costs in Ontario which are low due to Government subsidy, are likely to change dramatically over the near term, which will motivate many buildings to undergo more aggressive energy retrofits. Present rates for power plus distribution average 8-9 cents per KWH. But if the OPA is offering utilization rebates of 20-30 cents during DR events, what does this suggest power rates in Ontario will become?

One further issue which is apparent from the DR-3 program rules is that sites with a high DR load availability in winter and only a small load availability in summer will not represent good candidates under the program. Likewise, sites with a high summer load, but no appreciable winter load, will not represent a good fit. As noted before, there is a relationship required between summer, winter and shoulder availability which must be met.

## **11. The Future of DR-3 in Ontario**

So what is likely to become the future of DR in Ontario? This is a tough question. However, the one thing that will surely happen is that it will change. And the present DR-3 program rules allow for change at the sole discretion of the OPA. What changes might be likely?

First, I would put forth the thought that event windows will be expanded to allow for improved energy purchases. While time-of-day rates loaded into power meters will allow users to optimize power cost, the Power Authority can ultimately manage better if it can reshape the demand for power dynamically as a function of wholesale costs.



Second, the present program limits “sites” by requiring a minimum availability for an aggregator of 50KW in a specific site. However, what is important is the availability of switchable loads. So I would project that at some point, aggregation of a significant number of sites into one switchable load, if it can meet the reliability requirements, will be a future addition to the program. This would work well for aggregators who could “partner” sites which have a suitable load in one season but not in another. The aggregator could pair a site with a good winter load with a site with a good summer load, thereby increasing the reach of Demand Response in Ontario.

Third, the present program will need to be altered to maintain connection to sites which, through energy conservation measures, significantly alter the switchable load, but are still “customers”.

Fourth, it would seem logical as technologies for managing DR develop, Demand Response programs in general will likely look to more “in-real-time” processes and event switching. This would allow for better dynamic production and cost balancing, and would not rely on projected demand and advance notification of several hours to participants. Incentives for participants who could allow dynamic DR could be higher than that for those requiring advanced notification of an event.

Finally, I would suggest that the Ontario DR-3 program will be altered in the future to integrate forms of off-peak power usage incentives into the plan. With a diurnal swing in demand of some 10,000 megawatts, surely integrating parts of DR-2 into DR-3 will be a good thing to do. Customers who implement DR-3 measures may not really be load shifting. Those generating power behind the meter are substituting alternative sources. They are not relocating the usage. Those switching off loads or curtailing demand by “pinching” the internal environment are not relocating the usage. Only those participants who can change the times for shift work or for production to times outside the DR window will actually be relocating usage, and one could argue that if they could do it for DR, they would do it all of the time under an off-peak power plan.

In summary, then, I would expect to see some significant changes in Demand Response programs over the next 3 to 5 years as the present programs begin to evolve. It is quite likely that some of the earlier programs in the US have already made some changes, and these are likely to be adopted by others over the next few years. And, watch for signs of some of the above suggestions becoming part of the future of DR programs.