Comments on "Demand-Side Management and Demand Response in the Ontario Energy Sectors" [RP-2003-0144]

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February 4, 2004

The referenced January 23, 2004 Staff Report to the Ontario Energy Board presents the staff's recommendation to the Board based on the December 12, 2003 report by the advisory group on demand-side management (DSM) and demand response (DR),[2] and related stakeholder submissions. The advisory group (AG) report summarized the conclusions reached in a series of stakeholder meetings held between October and December 2003. These comments refer primarily to Section 4 of the Staff Report and Sections 3.2 and 3.6 of the advisory group report, dealing with demand response.

The *AG report* emphasizes that the participants struggled to reach common ground on DR policy recommendations for the province. Advisory group participants offered two widely different viewpoints on demand response. The viewpoints begin with different objectives, and lead to different policy concerns and recommendations. In one view, the primary objective of DR is to *reduce energy costs* for all consumers, and the mechanism by which that would be accomplished is for DR load reductions to cause lower wholesale market prices. In another view, the primary objective of DR is *efficient pricing*, and a concern is expressed that DR payments represent artificial subsidies that could produce artificially low wholesale prices that will in turn discourage needed investment in generating capacity. As a result of the differing views on DR, the report reaches no clear consensus regarding recommended DR program design, except to refer to the DR programs that have been implemented in the northeast region of the U.S. as transitional efforts.

The *Staff Report* recommends that the IMO "design and develop economic DR" as a transitional measure. The report characterizes a DR payment as a mechanism that "distorts the market," but that is justified by the reductions that can be expected in wholesale energy market prices. It also views the DR payments as requiring funding "through the uplift charge."

These comments have the following objectives:

- to describe the two viewpoints on DR objectives advanced in the advisory group report,
- to point out that the inferences drawn by the AG participants from the alternative objectives illustrate certain common misconceptions about DR programs,
- to suggest that the Staff Report suffers from the same misconceptions,

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[2] "Report of the Advisory Group on Demand-Side Management and Demand Response in Ontario," December 12, 2003.

- to demonstrate a resolution of the apparently diverse viewpoints, and
- to recommend alternative price-responsive demand mechanisms that do not involve subsidies, and therefore do not distort markets or require cost recovery through uplift charges.

An appendix provides technical details on the design of effective dynamic pricing and economic DR programs that are self-financing, rather than requiring cost recovery from all consumers.

1. How DR is characterized in the two reports

1.1 The AG report

The AG report makes the important point that "customers in both [retail and wholesale] markets should be enabled to respond to price. In a well functioning market ***all*** consumers would be exposed to price signals of some type and would be able to adjust their consumption according to their preferences and self-interests." The report then suggests that the evidence from Ontario is that consumers are not responding to price, even though large commercial customers face a spot market price pass-through. The report suggests that one likely reason for the lack of price response is the short notice provided by the spot market prices. The implication is that in the absence of customer response to retail prices, some type of DR program is needed to create price responsive demand.

Section 3.2 begins with a description of two "strong and often divergent viewpoints" regarding the objectives of DR. The two DR viewpoints are described as follows, beginning with a stated objective, and then a series of implications and concerns that are believed to follow from the objective:

- Objective 1 – *reduction of energy costs*. One set of advisory group members argued that reducing energy costs for all consumers was the primary objective of DR. They suggested that the mechanism by which DR would produce this result was that "by having *some* consumers reduce demand during times of supply shortage, market prices are reduced for *all* consumers (the so called collateral effect)." Furthermore, this process "can be viewed as a transfer of wealth from generators to consumers. Consistent with this is the position that reducing demand by 'X' MW is fully equivalent to supplying 'X' MW of generation, and should be compensated accordingly (i.e., *economic* demand response)."
- Objective 2 – *efficient pricing*. Another set of participants offered an "opposing view" that the objective of DR should be "efficient pricing," not necessarily "lower pricing." In this view, a payment "for loads to *not* consume is an artificial subsidy that provides incorrect market signals." This view also included a concern that the resulting reduction in wholesale prices would "discourage needed investment in new generation supply."

1.2. The Staff Report's DR recommendations

The Staff Report recommendations reflect a combination of the two viewpoints on DR in the AG report. First, it assumes implicitly that an economic DR program payment automatically represents a subsidy that "distorts the market" (p. 27), and must be recovered "through the uplift charge" (p. 30).[3] Second, in discussing the benefits of economic DR, it focuses exclusively on reductions in wholesale market prices that it assumes will be caused by the DR, arguing that the price reductions will produce large savings in energy costs to all consumers.

2. Comments on the DR recommendations

2.1 Misconceptions in the two reports

The two diverging viewpoints in the AG report regarding the appropriate objectives of DR actually represent a *false dichotomy* brought on by apparent misconceptions about how DR programs operate in wholesale and retail power markets, and what effects they can have. Both views present reasonable objectives that should be at the heart of any well-designed DR program. However, both groups of participants draw invalid conclusions about the effect of the two objectives, thus leading to a stalemate regarding consensus policy recommendations.

The Staff Report also reflects these misconceptions about economic DR programs, leading to DR recommendations that are likely to impose higher costs than needed, and produce smaller benefits than anticipated.

2.2 Fundamental facts about DR -- overview

In fact, a well-designed DR program should result in *both* efficient pricing and lower energy costs for all consumers, as indicated in the following fundamental facts about DR:

1. Price responsive demand can serve as a direct substitute for an equivalent amount of generation; therefore, appropriately measured load reductions should be compensated at the same price paid to generators. Payments of this type mimic efficient retail pricing, and do not involve artificial subsidies. That is, a payment from one market participant to another is fully offset by a cost savings to the paying party.[4]
2. DR load reductions during periods of high wholesale power costs will reduce overall energy costs to all consumers. However, the lower energy costs derive

[3] The Staff Report never defines "economic DR" explicitly. I assume that the term refers to some form of demand-bidding program in which participants offer load curtailments into a day-ahead or hour-ahead wholesale energy market at a particular price, and if accepted by the ISO are paid the market price for a measured load reduction relative to a baseline load level.

[4] For example, an industrial customer that has contracted with its energy provider to purchase 5,000 kW each hour at a fixed retail price, but offers to reduce load by 500 kW on a day in which wholesale prices reach $500/MWh, should expect to receive a payment that approximates the market price for the amount of its load reduction (after having purchased the full contract amount). This load reduction in turn allows the energy provider to either avoid the cost of purchasing that amount at the high price, or sell that amount back into the market if it has sufficient generation or contract purchases.

from resource cost savings produced by the *load reductions*, not from reductions in wholesale prices.

3. While it is possible to design market-based, self-financing DR payments, the payments made in a number of current ISO-sponsored DR programs do in fact include subsidized *incentive payments* that go beyond the "equivalent-to-generation" payments described above. Thus, while DR payments do not inherently represent subsidies, in practice many programs do include subsidized "incentive payments" whose cost must be recovered from all consumers.

These facts are discussed in further detail below.

2.3 Fundamental facts about DR – Q & A

I summarized some of the above common misconceptions about DR in a recent article, which suggests the following answers to the concerns expressed by the two divergent sets of advisory group members, and concerns about the staff's recommendations:[5]

- *Q: Do DR payments represent subsidies? A: Not inherently, however a number of current programs do offer subsidized payments*. There is considerable confusion in the industry about whether DR payments for load reductions do or do not represent artificial subsidies whose cost must be recovered from other consumers. The facts are that there is a clear economic rationale for *self-financing, market-based* DR payments that accurately reflect the wholesale cost of power, and value a customer's load reduction appropriately as equivalent to a unit of generating capacity (*i.e.*, efficient pricing). Economic incentives exist for both energy providers and consumers to take advantage of the cost-saving and net revenue enhancing opportunities offered by such payments. For example, energy providers can avoid the cost of purchasing power for the amount of the DR load reduction, or, alternatively, can sell that amount back into the market at high prices if they have already contracted for it. They can also share the resulting savings with the DR customers who actually provide the load reductions – a "win-win" proposition. ***Since market-based DR payments are self-financing, they involve no artificial subsidies that require cost recovery from other consumers***.

  Historical precedents for such self-financing DR mechanisms have been implemented successfully in existing markets, as illustrated by the following examples. First, some utilities in the U.S. set up informal "buy-back" programs after wholesale prices spiked in the late 1990s. The utilities saw an opportunity to either save on the cost of purchased power to meet their customers' non-price responsive demands, or take advantage of the high prices by selling freed-up power back into the market. They did so by offering to share the cost savings (or extra revenue) with some of their largest customers if they would agree to curtail load below their normal usage level. For example, if wholesale prices spiked to $1,000/MWh, the utility might offer to pay a customer $500/MWh to reduce load by 500 kW for a few hours in the afternoon. The "DR

[5] S. Braithwait, "Demand Response is Important – But Let's not Oversell (or Over-price) It," *The Electricity Journal*, June 2003. Also, see L. E. Ruff, *Demand Response: Reality versus "Resource," The Electricity Journal*, December 2002 for further discussion of these points.

payment" of $500/MWh was sufficient incentive for the customer to incur the cost of temporarily foregoing the 500 kW of consumption. However, the utility more than made up for the cost of the payment by either reducing his energy purchases by $1,000/MWh for the amount of the load reduction, or selling the amount of the load reduction into the wholesale market at that price if he had available capacity. Either way, such a DR payment is not a subsidy, does not distort the market (in fact it improves the market by giving the customer a more accurate price signal), and requires no cost recovery from other consumers.

A second example is provided by the two-part real-time pricing (RTP) programs offered by utilities such as Georgia Power Company and Duke Power Company. Briefly, under this retail pricing design, which is described in more detail in the appendix, RTP customers pay a fixed price for a baseline level of consumption. Any usage in excess of the baseline is billed at RTP prices that reflect wholesale market costs, and any usage below the baseline level is *credited* at RTP prices. During a wholesale price spike episode, an RTP customer who reduces load below his baseline level receives a credit from the utility that is completely analogous to a "DR payment" (*i.e.*, it is a payment from the energy provider, tied to the wholesale market price, for a load reduction relative to a baseline load level). As in the previous example, the load reduction allows the utility to avoid purchasing that amount of power at the high wholesale prices, or to benefit by selling that amount of load into the market. Again, the cost of the payment that provides the incentive to the customer to reduce load is fully covered by a corresponding reduction in the utility's cost of energy, or an increase in his revenue.

Though these examples of efficient, self-financing DR payments exist in the market, a number of existing ISO-sponsored economic DR programs have been designed with DR payment mechanisms that include *incentive payments* to energy providers. These incentive payments go beyond market-based payments, and thus represent subsidies that must be recovered from all consumers. In some cases, these subsidies are acknowledged explicitly as "incentive payments." In other cases, an invalid characterization of what constitutes a load reduction leads proponents to argue that the payments are not really subsidies (*e.g.*, an energy provider measures a load reduction relative to a baseline load level, but is not required to schedule, and pay for, the baseline load before receiving payment for the load reduction), even though they require cost recovery from all consumers.

Consider for example the description of a possible IMO DR program in the Staff Report (p. 29). As the saying goes, "the devil is in the details." Depending upon how the rules for the simple example are interpreted, the DR payment could represent a self-financing payment like the previous two examples, requiring no extra cost recovery, or it could represent a subsidized incentive payment whose cost would have to be recovered through uplift charges, as assumed in the report (p. 30). One possible version of the rules might state that the wholesale DR participant (*e.g.*, a load aggregator) in the example is required to schedule and be charged for his entire load, including the potential 2 MW load curtailment in the example, regardless of whether the DR bid is accepted (*i.e.*, the amount of potential curtailment is measured relative to a baseline load level, and the entire baseline load is scheduled). Then, if the offer is accepted by the IMO, the aggregator would receive the DR payment for the curtailment at the threshold bid price. In this version, the IMO is indifferent between paying a generator to provide the amount of the full baseline load, including the amount of potential curtailment, or paying the DR participant to curtail – that is, the load curtailment is equivalent to the generation alternative. Since the IMO receives the same amount of revenue in each case, and pays out the same amount to either the generator or DR participant, there are no extra costs to be recovered through uplift charges.[6]

An alternative set of rules might state that if the DR bid is accepted, then the DR participant receives not only the threshold price for the amount of curtailment (after having been charged in settlement for the amount of potential curtailment), but also receives an "incentive payment" equal to the threshold price. This version effectively relieves the DR participant of the requirement of paying for the full baseline load before receiving the DR payment, and is equivalent to being paid twice the threshold price for the load curtailment. In this version, the IMO is left with an extra cost for the DR incentive payment, which it will want to recover through the uplift charge.[7]

Note that in either case the load aggregator cannot merely decide to curtail load; it must offer its customers an incentive to curtail so that the aggregator can bid the resulting load reduction into the wholesale market. For example, as in the shared-savings program above, he could offer to pay half of the threshold price to the customer, or up to 80 to 90% depending on his transaction costs. Under the first set of rules, the load aggregator's return for participating in economic DR is the remainder of whatever share of the DR payment it agrees to pay the curtailing customers. Under the second set of rules, the load aggregator receives not only that share but also the full incentive payment.

- *Q: Will DR reduce energy costs? A: Yes, but not because of wholesale price reductions*. One clear goal of dynamic pricing or DR programs is to reduce energy costs. However, the energy cost savings will come not from wholesale *price reductions*, but from real resource cost savings resulting from consumers' *load reductions*. That is, when consumers respond to prices through dynamic pricing or DR programs, their load reductions on high-cost days effectively replace the need for a comparable amount of generation capacity at high market prices. These load reductions result in lower real economic resource costs for the

[6] Actually, the example in the Staff Report differs from most existing economic DR programs in that it suggests paying DR participants their bid price rather than the ultimate market price. This design raises a number of other questions that could be subject to further discussion.

[7] This example represents essentially the rules of the NYISO economic Day-Ahead DR program, except that DADR curtailments receive the market price rather than the threshold bid price. Interestingly, the NYISO rules state that if the load curtailment is provided by customer self-generation, then no extra "incentive payment" is made; only the self-financing DR payment is offered.

entire system, such as fuel that is not burned, high-cost imports that are avoided, and a reduction in the likelihood that additional generation capacity is needed (*i.e.*, it increases the amount of available reserves given the currently available capacity).

It is important to neither discount nor over-state the potential benefits from improving the price-responsiveness of demand. In previous research we have estimated the magnitude of potential cost savings from various types of dynamic retail pricing to lie in the range of 0.5 to 2% of consumers' total energy bill. This potential magnitude of cost savings is reasonable when the more efficient pricing is viewed analogously to an improvement in productivity. However, claims that wholesale price reductions will result in large benefits in the form of "wealth transfers" from generators to consumers are based on fallacies about the nature of energy costs and contracting.

In contrast to the true savings in economic resource costs described above, short-term reductions in wholesale prices during a few high-cost hours represent largely offsetting financial exchanges between market participants who have typically locked in fixed energy costs for most, if not all of their load. ***The wholesale price reductions thus cause no change in most consumers' bills***.[8] And in the long term, continued wholesale price reductions can't be counted on due to likely changes in future levels of generating capacity (*i.e.*, today's wholesale prices are conditional on the existing generation capacity; tomorrow's prices will depend on how that capacity changes).

- *Q: Will DR-induced wholesale price reductions reduce incentives for needed generation capacity? A: Only for uneconomic levels of capacity.* In the absence of DR, occasional high wholesale market prices provide an incentive to build *uneconomic* amounts of capacity, resulting in costs in excess of what customers would be willing to pay if they actually faced market-based prices.[9] The reduced price spikes that may occur in the presence of market-based (non-subsidized) DR

[8] This argument is developed more fully in the Braithwait and Ruff articles cited above. Briefly, the logic behind this conclusion is the following: consumers generally pay fixed retail energy prices that reflect only generally an average of historical, or expected hourly wholesale energy costs (Small consumers in Ontario currently pay a fixed energy price. Non-protected customers nominally pay *ex post* spot market prices, although many of them presumably have signed bilateral contracts at fixed prices.). Energy providers also typically lock in fixed wholesale costs for most of the energy that they need for supplying their customers (*e.g.*, by owning physical generation capacity or contracting with a generator). Thus, while DR load reductions can result in large reductions in wholesale energy prices during a few hours, which in turn can result in large changes in an energy provider's daily settlement charges, the actual financial impact is minimal because his fixed-price contract has already locked in his energy costs (think of the contracts as risk insurance, where the premiums are paid through higher energy prices on all low-cost days, in return for payouts on a few high-cost days). As a result, wholesale *price reductions* on a few high-cost days have little effect on either the energy provider's actual energy costs, or his customers' bills. (Any claims that wholesale price reductions caused by DR will represent continued "wealth transfers" from generators to consumers place a naïve faith in the lack of generators' ability to respond to such transfers through modifying their bidding strategies or changing investment plans.)

[9] This has been the typical outcome under traditional regulation, in which reserve capacity is built and maintained to meet arbitrary reliability standards under conditions in which consumers face fixed retail electricity prices, and thus have no incentive to offer price-responsive demand.

provide investors with appropriate incentives for the amount of capacity for which consumers are willing to pay.[10]

- *Q: In what ways might economic DR be viewed as a "transition tool"? A: Market-based self-financing DR can substitute for a lack of dynamic retail pricing; subsidized DR logically must be justified on the basis that market-based DR cannot support itself.* As pointed out in both reports, "natural DR" through customer price response to efficient retail prices will provide the price responsive demand that all experts agree is needed for efficient operation of wholesale and retail power markets. If such pricing is not available, due to regulatory or government policy, or inertia on the part of regulated energy providers, then market-based economic DR, as described above, can serve as a proxy for natural DR. As indicated, self-financing, market-based DR payments approximate efficient retail prices during high-cost periods, and provide customers with an incentive to curtail load, a process that does not involve subsidies or incentive payments, and requires no cost recovery through uplift charges.

  Logically, only if it can be demonstrated that efforts to encourage even the largest electricity customers to accept a well-designed dynamic pricing product or market-based economic DR, and to respond to occasional high wholesale market prices have failed, can it be argued that subsidized incentive payments are needed to "jump-start" the market. However, the evidence is that well-designed dynamic-pricing programs have attracted customers where they have been offered (*e.g.*, Georgia Power and Duke Power), even for residential customers (see Gulf Power Company's GoodCents Select critical peak pricing program and the Tempo tariff in France). Furthermore, nearly every study of customer response to time-varying prices undertaken over the past twenty years, including several reported by Ontario Hydro in the 1980s, has found that at least some portion of customers who face time-varying prices (including residential, as well as large commercial and industrial) make statistically significant changes in their usage pattern.

  Finally, there is some evidence that consumers will prefer the natural approach in which they receive retail prices that reflect market costs and decide on their own how to respond to those prices, to the DR program approach in which they must think like a generator and decide how much of a load reduction to commit to, and at what price to bid that curtailment into the wholesale market.[11]

3. Alternative policy options

Before turning to subsidized DR programs to provide needed price-responsive demand, the province may wish to consider giving efficient retail pricing a try. Successful

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[10] There are valid concerns about whether spot market energy prices alone can provide sufficient incentives for timely investment in sufficient capacity. Several jurisdictions have implemented capacity markets to provide more stable incentives to maintain adequate capacity. However, the debate about the appropriate role of capacity and energy payments does not affect the above characterization of the effect of DR on market prices.

[11] Customers responding to surveys concerning the NYISO DR programs cited uncertainty about bidding strategies as a barrier to participation.

dynamic pricing programs must have two primary features – *efficient prices* that convey wholesale cost signals, and some form of *financial risk management* to protect consumers against the risk of volatile prices. The two most common types of retail pricing have only one of these features, but not the other. *Fixed prices* protect consumers against volatile wholesale costs, but provide no incentive to reduce load when costs are high. *Spot market pricing* sends accurate price signals, but leaves consumers open to price risk. The only successful price structure that combines both features is *two-part RTP*, or spot pricing (typically, firm day-ahead hourly prices) with a financial *contract for differences* to lock in fixed prices on a baseline load level. The financial portion of the contract may also be used to address other issues such as utility recovery of allowed revenue on a corresponding base tariff and an appropriate allocation of limited low-cost generation.

One of the most successful examples of dynamic pricing in recent years is Georgia Power Company's two-part RTP program, in which more than 1,500 industrial and commercial customers comprising 5,000 MW of peak demand subscribe to face hourly prices that are announced on either a day-ahead or hour-ahead basis. Georgia Power has reported price-responsive load reductions ranging from 750 to 1,000 MW during infrequent cases of high RTP prices.[12] In contrast, utility efforts to offer one-part RTP (spot pricing with the prices marked up to recover all allowed revenues) have generally led to few satisfied subscribers.

4. Conclusions

The AG report identified two important DR objectives – efficient pricing and lower energy costs. However, certain misconceptions regarding the nature and effects of DR led the advisory group participants to reach diverse opinions about the design of DR programs for the province. The Staff Report repeated those misconceptions in justifying its recommendation that the IMO develop a subsidized economic DR program, with costs recovered through the uplift charge. The purpose of these comments has been to clarify these misconceptions, and to demonstrate that an economic DR program does not necessarily imply subsidized payments that require cost recovery from all consumers. Instead, a non-subsidized, market-based economic DR program design could address the province's need for achieving price-responsive demand at a lower cost.

The OEB essentially has three choices for increasing the amount of price-responsive demand in the province:

1. encourage energy providers to develop effective *dynamic retail pricing* programs, with prices that reflect wholesale market costs (and financial hedges against price risk), thus giving participating customers an incentive for "natural demand response" when capacity is constrained and wholesale costs are high;
2. develop a *market-based* economic DR program, with self-financing payments for load reductions that are based on wholesale market prices, as described in these comments, or

[12] See S. Braithwait and M. O'Sheasy, "RTP Customer Demand Response – Empirical Evidence on How Much Can You Expect," in *Electricity Pricing in the Transition*, A. Faruqui and K. Eakin, eds., Kluwer Academic Publishers, 2002.

3. develop a *non-market-based* economic DR program patterned after the NYISO and ISO New England day-ahead programs, in which the cost of incentive payments is recovered through uplift charges.

The first two options, which have precedents in several markets in the U.S., are self-financing. Only the third choice involves market-distorting incentive payments whose cost must recovered from all consumers. If the third choice is adopted, then it should be acknowledged explicitly that subsidized incentive payments are being offered in addition to market-based payments.

Before committing to a formal DR program, the OEB may wish to examine the alternative of offering a well-designed dynamic pricing product such as two-part RTP to at least large commercial and industrial customers. This type of product has the two important properties of sending efficient retail price signals that give customers an incentive to respond to high market prices, while providing risk management to limit customers' financial exposure to price volatility. However, a probable market requirement for a successful RTP program is a day-ahead wholesale market that provides a mechanism for customers to receive firm prices with sufficient notice to make production or operational changes.

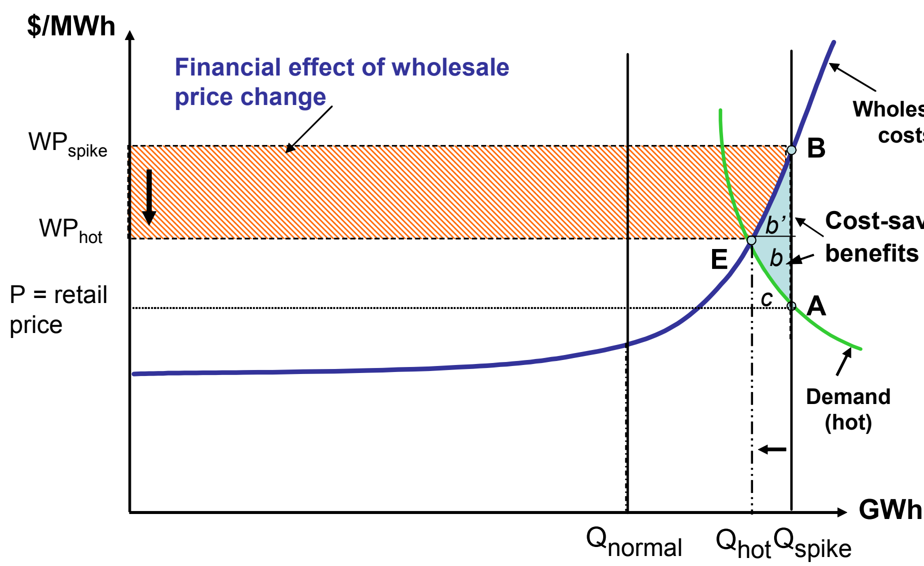
Appendix

Economic Benefits from Price Responsive Demand

Figure 1 illustrates the potential beneficial effects of dynamic pricing and DR programs. It represents conditions in a representative hour in the day-ahead energy market. The figure shows a steeply-sloping *supply curve* in the range of high load levels relative to available capacity. It also contains two vertical lines representing system loads under "normal" and "hot" summer conditions when consumers face fixed retail prices and are therefore not price responsive, and a sloping demand curve labeled Demand (hot), which represents price-responsive demand in the presence of dynamic pricing or a DR program. Key elements of the figure are as follows:

- On a hot summer day *without price responsive loads*, consumer demand increases from Q_{normal} to Q_{spike}, causing wholesale prices to rise to WP_{spike}.
- The incremental *cost* of producing the last unit of power to meet demand under the unresponsive scenario is given by the distance from the horizontal axis to point *B* on the supply curve (which represents incremental power costs at different levels of demand). The incremental *value* to consumers of that increment of load is shown by the height to point *A* on the aggregate demand curve (which represents consumers' incremental value of electricity at different levels of consumption) at the fixed retail price *P*. Thus, the cost of producing the last unit of power far exceeds its value to consumers.
- If some consumers face dynamic prices that reflect wholesale costs, or can offer load curtailments into the wholesale market through a DR program, then aggregate demands are shown by the sloping demand curve, total quantity demanded falls to Q_{hot}, and the wholesale market clears at point *E* at WP_{hot}.

Figure 1. Changes in benefits and costs associated with price responsive load programs.



- Price-responsive consumers' load curtailments allow the market to *avoid costs* equal to the area under the supply curve for the amount of the load curtailment. At the same time, consumers *forego value* from the electricity not consumed, which is equal to the area under the demand curve for the amount of the curtailment. The difference between those areas (indicated by the lightly shaded area *b* + *b'*) represents the net *cost-saving benefits* of price responsive loads. Depending on how dynamic pricing or DR programs are designed, those benefits may be *shared* in varying degrees between the consumers who curtail load, their energy suppliers who experience reduced supply costs, and potentially all consumers due to lower average power costs (*e.g.*, lower capital costs from avoiding the cost of generators needed to meet unresponsive demand).
- The *financial effects* of the wholesale price spike reduction, shown in the darkly shaded horizontal rectangle, are often described as examples of the large potential benefits of DR programs. However, there are several problems with this interpretation. First, bill and revenue effects resulting from *price changes* are treated by economists as *transfer payments*, not changes in economic benefits, because they do not reflect changes in real economic resource cost or value, such as those described above, which are caused by consumers' *load changes*.

  Second, the volatility of wholesale prices causes most market participants to manage their price risk by either owning generation, or entering financial contracts to buy and sell fixed quantities of energy at fixed prices. As a result, short-run changes in wholesale prices have little financial effect on either consumers or energy providers; they are not financially hurt by wholesale price spikes, nor helped by reductions in the price spikes. In the long term, wholesale prices reflect the capacity investment decisions made in response to historical prices. Thus, while DR programs may indeed serve to hold down short-term price spikes, *conditional on the existing generating capacity mix*, from levels they would otherwise reach, generators will take such reductions into account when making investment decisions for the future. As a result, short-term price effects cannot be assumed to hold into the future.

Dynamic Pricing – Two-Part RTP

Given the option, most consumers will choose not to face the volatility of wholesale power prices directly (*e.g.*, spot market pricing) without the financial protection provided by some type of price risk management mechanism. That is the primary reason that the only RTP programs that have proven successful to date have been *two-part* designs. These programs effectively offer customers a financial *contract for differences (CfD)*, which guarantees a fixed energy price for a *fixed baseline level of usage*. Under this design, customers pay market-based RTP prices for their entire load, but then also receive a financial adjustment to their bill, based on the CfD, that ensures that they pay the guaranteed price for their baseline load. (This design is also often described by the equivalent characterization that customers pay the fixed price for their baseline load, and then *pay* RTP prices for any load in excess of the baseline level, and receive *credits* at RTP prices for reductions below the baseline level.)

How two-part RTP operates in a period of high wholesale costs may be illustrated using Figure 1. Let us define Q_{spike} as the load level that includes RTP customers' baseline load, and the contract price for the baseline load as *P*. In a period in which the market price rises to WP_{hot}, the RTP customers reduce consumption by the amount of the difference between Q_{spike} and Q_{hot}. Focusing on the portion of the two-part RTP bill related to the load reduction, the RTP customers first pay for that amount of load (as part of their baseline load) at *P*, and then receive a financial *credit* for the amount of the load reduction at the RTP price, WP_{hot}, for a net payment shown by the area $b + c$. However, in making the load curtailment, RTP customers incur a cost equal to their foregone consumer surplus, shown as the area under the demand curve for the amount of the curtailment (*c* in the figure). (Load curtailment costs include, for example, the cost of rearranging daily production schedules.) The RTP consumers' net overall gain from their load response is thus the area *b*.

Note that while the LSE effectively pays RTP customers for the load reduction, the LSE also avoids the cost of buying that amount in the wholesale market at WP_{hot}, and thus is no worse off. If the supply curve were horizontal in this range, then that would be the end of the story; the RTP consumers would receive all of the welfare gain from the load response.[13] However, given the rising supply curve in the figure, suppliers in aggregate achieve net cost savings equal to the area *b'*. Regulated utility LSEs would ultimately pass these cost savings on to all consumers in the form of lower average prices.

The above description of the design, operation, and net benefits effects of two-part RTP illustrates how dynamic pricing can create cost-saving benefits relative to the alternative of inefficient fixed retail tariffs, *without the need for financial incentive payments provided by non-participants*. It is only natural to ask – if two-part RTP can achieve this feat by giving customers dynamic pricing signals *all of the time*, can a DR program be designed to accomplish the same objective by allowing customers to bid load reductions at specified prices only *occasionally*, such as during the relatively infrequent periods of high wholesale costs? The answer is yes, as shown next.

Market-Based DR Program Design and Impacts

We now specify a *market-based DR program*, and analyze the resulting changes in benefits and costs. The program applies to consumers who face a fixed retail price, but have the opportunity to respond to and benefit from a payment that reflects cost conditions in the wholesale market. The program has the following properties:[14]

- LSEs bid DR load reductions (relative to a baseline level of demand that they would otherwise schedule) into the day-ahead market at specific prices.

[13] This outcome suggests a variation on this design in which the supplier credits the RTP customer at something less than the market price for load reductions below the baseline level, as is the case in buy-back programs or a market-based DR program, and thus shares in some of the gain.

[14] This market-based DR program design is developed in greater detail, including the associated economic benefit and cost impacts in Braithwait, *op. cit*.

- If the LSE's bid price is less than the cost of the generators that would otherwise be scheduled to meet the total market load (including the LSE's total baseline load), then its load reduction bid is accepted, and the LSE is paid the day-ahead wholesale market price for the scheduled load reduction.
- In the ISO financial settlement for the day-ahead market, the ISO follows the usual practice of *charging* the LSE the market price for the LSE's total scheduled *baseline* load (*i.e.*, including the amount of the potential DR load reduction). Since the DR bid is accepted, it then *credits* the LSE with a DR payment at the market price for the amount of the scheduled load reduction. The net effect is that the LSE is responsible for purchasing only its *actual* load, net of the DR load reduction. [In addition, the ISO facilitates the clearing of any bilateral supply contracts that the LSE may have with generators at fixed prices.]
- To achieve the DR load reductions, LSEs must offer some incentive mechanism to entice their DR customers to curtail load. For example, the LSE and customer first agree on a method for calculating a baseline load that represents what the customer would otherwise have used. The customer pays its fixed retail price for that baseline level of usage. Then the LSE credits the customer for any load curtailment below the baseline level, where the payment is at a price tied to the wholesale market price.[15]

Now review the changes in costs and benefits to each of the parties. For simplicity in using Figure 1 to illustrate the results, we assume that the LSE passes on the full market price to the customer for any load curtailments. A more realistic case would have the LSE pay some fraction of the market price, retaining a portion to cover its costs. The effects on each party are as follows:

- After paying the retail price *P* for his baseline load, including the amount of the potential load curtailment, the *customer* receives the DR payment (equal to WP_{hot}) for his curtailment. The net effect for the customer is additional revenue equal to the area (*b* + *c*). Since the customer voluntarily offers this curtailment, the net payment logically exceeds his incremental forgone value, or cost of the curtailment (shown by *c,* the area under the demand curve and above the fixed price *P*), resulting in a net DR benefit equal to the area *b*.
- The *LSE's* transaction with the ISO is a wash; its DR payment from the ISO completely offsets the settlement charge at the market price for the amount of the load reduction. For a given market price, he is able to avoid the cost of buying the amount of the load reduction at that price by paying the customer the market price to curtail. To the extent that the LSE actually splits the DR payment with his customers, he is able to retain a portion of the area *b* as his net gain.
- Suppliers in aggregate avoid energy costs in the amount of area *b'* as a result of the customers' load curtailments. Those LSEs that are regulated utilities presumably pass on these cost savings to all consumers. The combined *increase in net economic benefits* to consumers and suppliers amounts to (*b* + *b'*), the same amount as in the dynamic pricing example.

[15] Our understanding is that the standard practice of the New York distribution utilities is to not charge their day-ahead DR customers for the amount of the load reduction at retail rates, and to credit them for their load reduction at 90 percent of the market price.

- Finally, the *ISO* is indifferent between paying a generator the market price for supplying power to meet the LSE's total baseline load, and paying the LSE the market price for a DR load reduction from that baseline level. In either case, the LSE pays the ISO the market price for the amount of the load reduction up to the baseline level. ***No uplift charges to non-participants are needed.***

The key feature of the market-based DR program outlined above is that both DR payments – the one from the ISO to the LSE, and the payment from the LSE to the customer are fully covered by offsetting revenues or avoided costs, implying that the payments are *self-financing,* as with two-part RTP or other dynamic pricing methods. One possibly important difference between RTP and the market-based DR program is the method for estimating the consumer's baseline load. Under RTP, the baseline load is set in advance, thus alleviating the need for calculating moving-average baseline loads each day under most DR programs, which makes the process subject to potential gaming on the part of consumers.

Comparison with Typical Current DR Program Designs

The design of some current ISO DR programs differs in an important way from the above market-based design. For example, the NYISO economic day-ahead DR program (DADRP) operates much like the above design, but with one crucial difference – in addition to the self-financing DR payment from the ISO to the LSE for the amount of the load reduction, the program also includes an *incentive payment* from the ISO to the LSE. The amount of this incentive, or rebate payment equals the market price times the amount of the load reduction. Thus, in effect the ISO pays the LSEs *two times the market price* for load reductions relative to their scheduled baseline load.[16] The LSE in turn passes on 90% of the market price to the DR customer, retaining the 10% of market price plus the incentive payment (less the fixed retail price that it does not charge the customer on the amount of the load reduction).

[16] The NYISO does not offer this additional incentive payment for customer load curtailments that are achieved through operation of a local distributed generator.