FINAL

The California ISO's Proxy Demand Resource (PDR) Proposal

by
Frank A. Wolak, Chairman
James Bushnell, Member
Benjamin F. Hobbs, Member
Market Surveillance Committee of the California ISO

May 1, 2009

Executive Summary

Final demand that actively participates in the day-ahead and real-time markets is a critical component of the long-term robustness, efficiency, and competitiveness of wholesale electricity markets. The members of the MSC have stressed the need for active participation by final demand in the wholesale market for over a decade. We fully support any activities that are effective in taking wholesale markets toward this goal. However, ultimately the only completely reliable way to achieve truly price-responsive demand is to charge customers the appropriate prices to begin with. We are concerned that the current paradigm, which treats price-responsive customers as supply resources with an administratively set baseline, will limit participation and, of even more concern, provide the ISO with ultimately unreliable resources.

Any initiative that pays customers *not* to consume something, be it water, CO_2 emissions, or electricity, faces a serious challenge of measuring what the consumer *would have* done without the payment. We refer to this problem as the "baseline" problem. Put simply, firms and customers have a strong incentive to inflate the measurements of their baseline, because they are paid based upon the comparison of their actual consumption to this baseline. In many cases, customers can be given a perverse incentive to over-consume as a means to inflate their baselines. We are concerned that several of the options contained in the ISO's proposal will be very vulnerable to this problem. This would be a serious problem for two reasons. First, it will result in the ISO, and ultimately customers paying for more capacity resources than they are truly getting. Second, the option to sell "reductions" from an exogenous baseline will crowd-out the adoption of direct pricing options such as critical peak and real-time pricing. Thus, we fear that the adoption of this weak form of demand response will ultimately work against the adoption of a truly symmetric treatment of load and generation that is an essential component of an efficient wholesale electricity market.

There is no complete solution to the baseline problem as long as setting the level of the baseline is viewed as costless. We therefore recommend that, for the provision of energy, the setting of a baseline be linked to the purchase of a firm financial forward market commitment. This approach is known as "buying your baseline." With regards to Ancillary Services, the baseline problem is less severe. We believe it is sufficient to accurately measure the consumption of customers before and after they are called upon as a resource to measure compliance with the provision of an ancillary service. Their compliance with the dispatch

instruction and the provision of the ancillary service can be measured by monitoring the resulting change in their consumption.

We also express our concern about the potential double payment for demand response that arises if the demand response provider receives a payment that exceeds the difference between the locational marginal price (LMP) and the implied wholesale price in the current retail price. Such double payments increase rates and could incent inefficient demand response whose costs to the market exceed its benefits. The PDR proposal lessens but does not eliminate the possibility of such double payments. We recommend that the process to be used by utilities to determine payments to Curtailment Service Providers (CSPs) be transparent and involve low transaction costs, and that payments be limited to the difference between the relevant LMP and retail rates.

Finally, we discuss our concern about the potential for a "money pump" that could arise in the form of arbitrage between a low Load Aggregation Point (LAP) price and higher nodal price. This problem can be limited in magnitude but not eliminated by constraining the number of hours that a PDR resource can be dispatched and by requiring the presence of physical control devices. Unfortunately, corralling the money pump problem by limiting the number of hours is likely to handcuff the long run potential of active demand side participation. We would like to see final demand become a full participant in the market in all hours, not just during a few hours of high system stress.

1. Introduction

The California Independent System Operator (ISO) is proposing to implement enhancements to its pre-existing mechanisms for allowing final demand to be an active participant in the ISO's markets. We understand that the policy of using customer curtailment in response to price rather than directly charging a retail price for consumption that reflects the real time price is a national policy directive that the Federal Energy Regulatory Commission (FERC) has issued to the organized markets under its jurisdiction, most recently in Order 719[1]. The Proxy Demand Resource (PDR) proposal is the ISO's new demand response product designed to meet the requirements set out by FERC. The FERC order requires that ISOs permit a demand response aggregator or Curtailment Service Provider (CSP) to bid demand response into its markets on behalf of final consumers. These CSPs may be affiliated with an existing load-serving entity (LSE) or they may be separate from the LSE.

Since the autumn of 2008, the Market Surveillance Committee (MSC) has participated in several formal and informal meetings with ISO staff and stakeholders during the development of the PDR. Most notably, on March 12, 2009, the MSC held a joint MSC/stakeholder meeting at the ISO to discuss the details of the demand response proposals. On March 20, 2009, two MSC members participated in a stakeholder conference call on this proposal. This proposal is described in the document, "Draft Final Proposal for the Design of Proxy Demand Resource (PDR)," April 15, 2009.

[1] FERC Final Rule re Wholesale Competition in Regions with Organized Markets (125 FERC ¶ 61,071) (Issued in Docket Nos. RM07-19-000 and AD07-7-000 on October 17, 2008).

The PDR proposal addresses three challenges. First, it allows the CSP to participate directly in the ISO's markets as a distinct entity from the consumer's LSE, consistent with the requirement of FERC Order 719. Second, it allows for retail demand response programs that involve active participation in the ISO's energy and ancillary services markets by final consumers that are served by their incumbent LSE. Third, the PDR proposal does not require the baseline consumption by the demand response resource to be pulled out and forecast by the LSE or CSP. Instead, this baseline consumption is included in the LSE's overall load schedule at its default LAP and a separate bid for demand response by the CSP is submitted to the wholesale market as a proxy generation unit. Although the MSC has been a persistent supporter of California and national policies that foster active participation of final customers in the ISO's markets, we do not believe that a PDR proposal that addresses these three challenges will necessarily improve the efficiency of the ISO's energy and ancillary services markets.

Several aspects of the current PDR proposal create opportunities for final consumers and the CSP to provide a demand reduction product that is substantially less reliable than the equivalent MWs of generation capacity. These shortcomings stem from the reliance of the current PDR proposal on an assumed baseline consumption level relative to which demand reductions sold by the CSP are measured. Therefore, final consumers providing demand reduction services can receive subsidies from all other electricity consumers because their actual but unobserved reduction in consumption due to the demand response event could be significantly less than the difference between their administratively determined baseline consumption and their actual consumption. In addition, there is a possibility of inefficient double payments to demand response providers, and opportunities to use the PDR to arbitrage differences between a low LAP and a high LMP.

We recognize that this inefficient demand-response product design is motivated by the desire of the ISO to comply the requirements of the FERC order to allow CSPs to participate separately from LSEs in the provision of demand reduction services. However, we believe it is possible for the ISO to design a demand response product that achieves the goals of FERC Order 719 without creating these market inefficiencies and potential cross-subsidies. This will require CSPs, rather than all other final consumers, to bear the full cost of their customers failing to provide the demand reduction services they actually sold.

2. The Problem of Customer Baselines

Under the current PDR proposal, when a demand response resource is accepted to deliver a 1 MWh demand reduction, compliance with this obligation is measured against an assumed baseline consumption level that will be set using a methodology determined by the ISO and the California Public Utilities Commission (CPUC). Despite the best intentions of the designers of this mechanism, it is impossible for any entity to know precisely what the final consumer would have consumed during a given time period if it had not been called upon by its CSP to provide curtailment services. The customer's meter can only measure its actual consumption during the demand reduction period. The customer's baseline consumption level is an administratively set value based on some model of how its consumption varies with weather conditions, system load, and other factors likely impact the customer's electricity demand.

This administrative process for setting the customer's "but for the demand response event" level of consumption creates strong incentives for this customer to take actions to increase this baseline, because it is paid for the difference between this baseline and its actual consumption during a demand response event. For example, if a final consumer is paid 30 cents/KWh for demand reductions relative to a baseline, then this customer earns 30 cents times the number of demand response events for increasing its baseline by 1 KWh.[2]

In addition, under the current PDR proposal, there are no adverse financial consequences to the customer or the CSP associated with a higher value of the customer's baseline. Neither the customer nor its CSP must purchase this baseline. Instead, the cost of any inflation in the level of this baseline is borne by other ratepayers. Under the current PDR proposal the CSP makes an offer to supply a demand reduction or what is often called "negawatts" to the day-ahead or real-time market. Compliance with this sale of negawatts is measured by the difference between the administrative baseline and the supplier's actual consumption. In contrast, generation unit owners do not have an administratively set baseline that allows them to sell more energy in the day-ahead market than they actually provide. That is because the baseline level of production relative to which they sell energy is zero. Compliance with a day-ahead sale of energy is measured by the difference between the actual output of the generation unit in real-time and this baseline.

The natural baseline for demand is also zero. To determine how much energy is consumed, the ISO measures the customer's actual consumption and subtracts this natural baseline. A multi-settlement market as exists in California also provides a mechanism for consumers to sell demand reductions and generation unit owners to sell supply reductions. In an earlier market, the customer purchases a given quantity of energy relative to its natural baseline, and then in a subsequent market that customer sells back some of this consumption as negawatts. In the case of a generation unit, the owner sells energy in an earlier market relative to its natural baseline, and then sells it back in a subsequent market. A demand reduction product that respects this feature of a multi-settlement market avoids the market inefficiencies of an administratively set baseline.

3. The Economic and Reliability Costs of Customer Baselines

The use of an administratively set baseline for demand response resources combined with a verifiable baseline of zero for generation resources together create an asymmetry in the contribution of these resources to system reliability and market efficiency. When the ISO operators call upon a 250 MW unit to provide 200 MWh of energy, it is straightforward to verify that the 200 MWh of energy was provided. The ISO operators take a meter reading at the generation unit to verify that 200 MWh was produced. In contrast, for a PDR resource, if the

[2] Wolak, F.A. (2006) "Residential Customer Response to Real-Time Pricing: The Anaheim Critical-Peak Pricing Experiment" CSEM WP-151, at http://www.ucei.berkeley.edu/PDF/csemwp151.pdf, documents evidence that residential customers paid for demand reductions took actions to increase the baseline relative to which these demand reductions were measured.

ISO operators purchase a 10 MWh of energy demand reduction, they have no way of verifying that 10 MWh less of energy was consumed as a result. The ISO can only measure actual consumption of electricity by the consumer. It can never know what the consumer might have consumed if the demand reduction offer had not been accepted.

For instance, under the current PDR proposal, if a CSP knew that a market participant's actual load is lower during certain weather conditions than was predicted by the methodology used to set the customer's baseline, the CSP could simply sell this forecasted consumption difference as demand response and never have to notify the customer of the need for a demand reduction. In this case, the CSP would be paid not for providing a demand reduction, but for its superior knowledge of the determinants of the customer's consumption. This possibility implies that when the ISO purchases a PDR resource to provide either ancillary services or energy, it will be buying a product that is significantly different from the product provided by a generation unit. For the case of the PDR, the ISO is paying for errors between its methodology used to set the customer's baseline and the customer's actual consumption. This "demand reduction" will occur regardless of whether the CSP's offer to supply negawatts is accepted by the ISO, because it is just the difference between the baseline and the customer's actual consumption. This logic suggests that demand reduction measured as defined in the current PDR proposal provides a product that contributes less to system reliability than additional energy from a generation unit, because the energy from the generation unit will not be produced unless the supplier's offer is accepted in the day-ahead market.

4. The Problem of Double Payment

In addition to the incentive problems created by the use of a baseline, another incentive problem arising from the payment for energy demand reductions rather than energy use is the so-called "double payment" problem. This problem has been identified as the major issue in DR design in ISO-New England, and has long been a concern with demand-side management in general.[3] This problem arises when a consumer that reduces her load by 1 kWh saves money by avoiding having to pay the retail rate associated with that kWh, and in addition is given a payment for reducing load. This can provide an over-incentive for demand reductions if the sum of the retail rate and payment exceeds the marginal cost of providing power.

The solution to this problem is to limit the payment to no more than the difference between the relevant LMP and the wholesale price implicit in retail price, as proposed in ISO-New England. We note that the ISO's current PDR proposal provides an incentive to the utilities to limit payments in this manner by having utilities pay for the load that would have occurred without the DR, and then negotiate the payment to be made to CSPs. If a utility pays any more than the LMP-retail price difference, then there will be a revenue deficiency that the utility's other customers will need to make up. We recommend that the California PUC

---

[3]ISO-New England, "Status Report on the Future of Price-Responsive Demand Programs Administered by ISO New England Inc. ISO New England Inc. February 13, 2009 DRAFT Version 1.0" Feb. 2009, http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2009/feb202009/index.html; L. Ruff, "Least-Cost Planning and Demand-Side Management: Six Common Fallacies and One Simple Truth", *Public Utilities Fortnightly*, April 1988.

discourage rate recovery of such excess payments. Furthermore, we also recommend that the CPUC monitor the process for determining incentive payments with the objective of minimizing transaction costs and maximizing transparency in order to minimize obstacles to symmetric treatment of load and generation in the wholesale market.

5. The Problem of Buying at the LAP and Selling at the Node

In its review of the Market Redesign and Technology Upgrade (MRTU),[4] LECG identified a potential "money pump" in which CSPs can exaggerate the load reduction that would be provided under a PDR program. This would occur by first bidding a fixed demand schedule in the day-ahead market that is higher than what actually would be consumed; this load would pay the day-ahead LAP price. Then in real time, an amount of DR would be bid in equal to the difference between the exaggerated schedule and the actual load that the CSP anticipates will be realized. This difference, if its bid is accepted, would be paid the real-time LMP. Even though no actual demand reduction was planned and the consumers' load is unmodified, the CSP gains the difference between the LMP and the day-ahead LAP price times the amount of accepted demand reduction. (If the demand reduction bid is not accepted or if the realized load is different from what the CSP actually forecasts, then the settlement will be more complicated.) This strategy is likely to be profitable in locations and at times when the LMP is anticipated to be higher than the LAP price, such as in load pockets. In theory, as LECG points out, the CSP could earn huge profits at such times and places by providing a very large day-ahead schedule that is many times as large as the actual realized demand.

There is no sure-fire way to eliminate this money pump given the existence of a LAP pricing areas that are large enough so that real-time LMPs can be predictably and significantly higher than the day-ahead LAP price at some buses in that LAP. One solution is to define and implement much smaller LAP areas within which LMPs are fairly uniform; in other MSC opinions, we have argued for expedited definition of sub-LAPs within present LAP zones, and this artificial arbitrage opportunity is another reason to do so. Another solution, as described below, is to require that a CSP purchase its baseline at the nodal prices where the reductions are to occur. However, this still leaves similar issues regarding the need for possible transfers between LSEs and CSPs.

The CAISO's current PDR proposal proposes to address this problem by limiting the hours per year that PDR bids can be accepted to 200 hour per year and putting in place a very high minimum bid for DR from PDRs set to the Default LAP price that was exceeded for only 200 hours in the previous year. These two measures will have a similar effect, as a high minimum bid will constrain the number of hours that the bids are accepted to those with very high LMPs in excess of that minimum. We believe that these two measures are redundant, and for simplicity, an hours limit will be sufficient.

An alternative approach to limiting these opportunities is to set a default no-pay demand reduction percentage relative to the customer's actual consumption. For example, the ISO could only pay for demand reductions equal to some pre-specified percent reduction of its actual consumption, regardless of the difference between that customer's baseline and its actual consumption. Based on empirical studies of actual demand reduction by customers, 20 percent of the customer's metered consumption is a generous upper bound on the typical demand reductions achieved. For example, suppose a customer with a baseline of 100 KWh has a real-

---

[4] S.M. Harvey, S.L. Pope, and W.W. Hogan, Comments on the California ISO MRTU LMP Market Design, LECG, LLC, Cambridge, MA, Feb. 23, 2005, http://www.caiso.com/docs/2005/05/13/2005051314175518804.pdf, p. 62.

time consumption of 80 KWh. Under this mechanism, the customer would only be paid at most for 16 KWh of demand reduction, which is 20 percent of its actual consumption. If the customer would like to be paid for more than this demand reduction, then it would have to provide a convincing justification to the ISO that a larger demand reduction at this customer's premises is physically possible. This evidence would take the form of showing both the credibility of the customer's assumed baseline for that day and the extent of demand reduction actions that were taken that day.

A limitation upon the number of times a demand reduction can be accepted, as is the case in the PDR current proposal also limits the potential for active demand-side participation to improve wholesale market efficiency. We believe that active demand-side participation should not be limited to a few high priced hours, but should be eventually become a routinely used means of limiting peak prices and loads on a daily basis. Thus, an approach which sets a reasonable amount of demand response, that the ISO is willing to pay for and then disallows further demand reductions appears to be superior strategy to addressing this problem in the interim period when loads are still charged the LAP price rather than the LMP at their location. We fear that by encouraging demand to participate within the current PDR framework, which provides incentives that could result in exaggerated payments, the current PDR proposal will hamper the needed long term transition to the symmetric treatment of load and generation which is essential to an efficiency wholesale market.

6. Designing an Effective PDR

We believe there are two elements of an effective PDR proposal. These two elements amount to treating demand participation in the wholesale market the same as supply participation. First, one must be able to measure the actual hourly consumption of a customer. Second, for the provision of energy, the selection of an hourly baseline must reflect a firm financial commitment from the provider, rather than a statistical formula of based on past consumption.[5]

It is important to distinguish between the provision of Ancillary Services (AS) and the provision of demand response (non-consumption) for energy. In the former, the customer is providing an actual service, the ability to alter consumption if the system needs it due to a contingency. As long as measurement is accurate, the baseline issue is not a major concern. The ISO needs to be confident that the *change* in consumption it expects upon calling for it will occur.[6] In the case of AS, the ISO does not necessarily need to worry about the *level* of consumption from which this change is occurring, as long as it can measure the level of

---

[5] The concept of "buying your baseline" is also a tool that has been used to manage the total bill risk of customers on real-time pricing. See Borenstein, S. "Wealth Transfers from Implementing Real-Time Retail Electricity Pricing," CSEMWP-147, UCEI, available at http://www.ucei.berkeley.edu/PDF/csemwp147.pdf.

[6] We note, for example, that the recent Lawrence Berkeley Laboratory evaluation of Southern California Edison's use of air conditioner load controllers as a spinning reserve resource has provided convincing evidence that provision of AS by demand resources can be accurately monitored and verified (J.H. Eto, J. Nelson-Hoffman, C. Torres, S. Hirth, B. Yinger, J. Kueck, and B. Kirby, Demand Response Spinning Reserve Demonstration, Prepared for Energy Systems Integration Public Interest Energy Research Program, California Energy Commission, LBNL-62761, May 2007).

consumption when a change is requested and the change in consumption actually does occur. We therefore advise that AS performance simply be measured based upon the actual metered consumption of a customer before and after the demand is called upon to perform. While reliability concerns may necessitate ability to measure telemetry, we see no incentive problem from lacking it. It should be understood that the provider should not sell a level of AS in excess of its measured demand (or a fraction of it), and that performance will be measured by the change in consumption from the appropriate interval before to after the resource is called upon. If this change is in fact less than what was offered as reliable AS, then penalties comparable to non-performance by a generator could be applied. Moreover, we can imagine testing the ancillary services sales by CSPs in the same manner that ancillary services sales by generation units are tested. If the ISO accepts 10 MW from the CSP in the non-spinning reserve market, then the ISO could test the provision of this service by asking the CSP to reduce its load by this amount with the appropriate advance notice and if the customer is unable to do so, then it would be assess the standard penalty for failing to provide non-spinning reserve when called upon that is assessed to generation units that fail to provide this ancillary service.

In the case of energy, the problem is more complex than one of simple measurement. This is because the DR paradigm is essentially paying customers to *not* do something (consume energy) rather than provide a specific service. By far the best way to deal with providing incentives to not consume something is to charge an appropriate price for that consumption. However, the proper incentives to provide true demand response can be created by establishing a baseline that must be subscribed to by the provider, rather than based upon a preset statistical formula.

The most straightforward way to design a PDR that addresses these concerns is to require the CSP to purchase the baseline relative to which a customer's demand reduction will be measured in a previous market at the same level of geographic aggregation that the CSP can offer to sell negawatts. For example, if a CSP would like to sell negawatts in the real-time market at a specific node in the ISO network, then the CSP should purchase the baseline relative to which that customer's load reduction will be measured in the day-ahead market at that node. It is important to note that purchase in the day-ahead market is a firm financial commitment in the sense that unless the customer actually consumes this baseline, the CSP will receive payment from the ISO for the amount that actual consumption is less than this baseline or pay the ISO for the amount that actual consumption exceeds this baseline, both at the real-time price. If the CSP would like to sell negawatts in the day-ahead market, then it should purchase the baseline relative to which this demand reduction will be measured in some earlier forward market. For example, the CSP could purchase this baseline from the LSE in advance of the day-ahead market at the wholesale price that is implicit in that customer's retail price, i.e., the retail price less the transmission charge, distribution charge, and retailing margin. In this way demand will be treated symmetrically with supply in the sale of incremental and decremental energy. It is important to note that the approach could allow a CSP to participate in the ISO's markets separate from the LSE in providing curtailment services. The only difference is that now the CSP, not all other electricity consumers, that bears the financial risk associated with an inaccurate baseline.

The following example illustrates one such way that this “buy your baseline” approach could work. In the day-ahead market the CSP would purchase Q_b, its baseline level of consumption for a given hour, at the nodal day-ahead price, $P_{DA.}$ This baseline is financially binding in the sense that it determines the refund or payment the CSP must make in a subsequent market. This day-ahead purchase could be conveyed in advance to the LSE serving that customer so that LSE could reduce its day-ahead purchases appropriately. The CSP could then submit a price-sensitive willingness-to-curtail curve in the hour-ahead or real-time market and if this offer is submitted ask this customer to reduce its consumption. If Q_a is the customer’s actual consumption and P_{RT} is the real-time nodal price, then the ISO would pay the CSP an amount equal to the consumption reduction times the real-time price, $P_{RT}*(Q_b – Q_a)$. This payment arises naturally as a settlement of a positive imbalance in the real-time market. Finally, there would be an additional payment that the LSE would be required to make to the CSP equal to the amount of energy the LSE did not have to purchase in the day-ahead market because the CSP purchased it on behalf of the LSE, which is the customer’s actual consumption times the day-ahead price, $P_{DA}*Q_a$. This sequence of financial transactions implies the following total payment or liability to the CSP of $(P_{RT} – P_{DA})*(Q_b – Q_a) = (P_{RT} - P_{DA})*Q_b - (P_{RT} - P_{DA})Q_a$. The first term implies that if the expected real-time exceeds the day-ahead price the CSP has an incentive to purchase a larger baseline, but this price difference also implies that the CSP also has an incentive to make the customer’s actual consumption as small as possible in real-time. Conversely, if the expected real-time price is less than the day-ahead price, the customer has an incentive to reduce its baseline and increase its actual consumption.

Figure 1 contains a numerical example of how payments would flow between the LSE and CSP for a specific customer. The step function demand curve of the customer has steps at both $40/MWh and $80/MWh. Each step of this demand curve gives the customer’s marginal willingness to pay for the associated quantity of energy. The CSP purchases 10 MW in the day-ahead market at price of $40/MWh, because it expects to be able to curtail the customer’s consumption in real-time. Suppose that the real-time price is $60/MWh and the CSP calls upon 2 MW of demand reduction. In this case, the LSE must pay the CSP for the customer’s actual consumption of 8 MW at the day-ahead price of $40/MWh. The CSP also receives payment in the real-time market for the difference between its day-ahead schedule and its actual consumption, in this case 2 MW. Consequently, the CSP would receive a total payment of $40 which is the demand reduction of 2 MW times the $20/MWh price difference.

One outstanding challenge with this approach is that LSE pays the CSP for the energy its customer actually consumed at the day-ahead LMP at the customer’s location. However, the LSE would be limited to scheduling that energy in the day-ahead market as LAP demand (subject to distribution factors) and at the day-ahead LAP price. For many demand nodes the LAP price is likely to be smaller than the day-ahead LMP at those locations. Consequently, the LSE can argue that it is paying the CSP a higher price for the energy the CSP scheduled than it would have cost the LSE to schedule it in the day-ahead market, because the LSE can schedule at the LAP price. More important, the day-ahead LMP at that location could also be smaller than the wholesale price implicit in the retail price the LSE is paid by this customer for the energy that she consumes. In this case, the LSE to paying more to the CSP for customer’s actual consumption than what the LSE receives from the customer for this consumption. This is just the reverse of the “buy at the zone and sell at the node” problem described earlier, because the LSE can schedule energy at the LAP price but the CSP can sell it at a specific node. Some transfers of funds between the LSE and CSP may have to be worked out to ensure that the LSE is willing to allow CSPs to sell curtailment services in regions with LMP higher than the quantity weighted-average of day-ahead nodal prices.

7. Concluding Comments

Although there are several shortcomings with the current PDR proposal, we believe that they can be addressed following the logic described above. We believe that any viable PDR proposal should address the three major problems we have identified: (1) an administratively set baseline, (2) the double payment to final consumers, and (2) the problem of buying at the LAP and selling at the node. We believe that approving a PDR proposal that does not address these issues could severely reduce the benefits that all customers achieve from active demand-side participation in the wholesale market.

Figure 1