Federal Energy Regulatory Commission

Docket # RM10-17-000

Comments by CPG Advisors, Inc. in response to FERC Notice of Proposed Rulemaking

April 13, 2010

CPG Advisors, Inc. hereby submits comments to the regulatory proceeding, docket # RM10-17-000, concerning Compensation for Demand Response Services:

Synopsis

The Federal Energy Regulatory Commission (FERC) issued a notice of a proposed rulemaking (NOPR) covering demand response ("D/R"). FERC expressed its wishes to encourage Price Responsive Demand ("PRD") programs but concerned itself in this NOPR only with D/R.

In order to further more efficient electricity markets, FERC now proposes to standardize compensation for D/R across market areas where it has been implemented differently. In particular, while some markets compensate D/R at the same local marginal prices (LMP) as paid to generators, one market (PJM) reduced its compensation in 2008 from this level. At the reduced incentive level, PJM now subtracts the effective retail tariff from the incentive compensation. That is, PJM now compensates at the local marginal price – retail rate ("LMP – RR"). This reduction in compensation coincided with a large reduction in MWh's participating in this incentive program. Therefore, FERC asserted the lower compensation level in PJM of (LMP – RR) created a barrier to the use of D/R that unjustly increased wholesale power prices in that market and discriminated against D/R customers in favor of generators.

FERC asserted that comparable treatment for D/R services and generation means identical compensation. To do otherwise would discriminate among otherwise comparable resources.

In an opinion dissenting in part and concurring in part, Commissioner Moeller stated there is insufficient information to propose a new rule. For example, the decline in the participation in PJM's D/R program could be due to the effects of the recession on power markets, such as depressed power prices and the reduced need for peak shaving. Therefore a NOPR process is not appropriate but rather a Notice of Inquiry that would collect data from stakeholders and guide a more informed rulemaking process.

Comment

In the NOPR, FERC set forth price responsive demand as a primary means of encouraging efficient energy markets, though focusing on D/R in the rest of the NOPR. Efficient markets use prices to allocate scarce resources, thus a price-based system should be preferred where feasible. If real time and other similar pricing programs were more widespread, D/R programs would become a secondary focus: exposing customers to actual prices allows them to make choices based on their perceived value of electricity. In real time pricing, sophisticated customers may choose to consume electricity during high-priced, peak periods when the utility of the electricity is greater than its price[1] and avail themselves of options to shift consumption to lower-priced periods when it is feasible.

Demand response can only provide an approximation to the economic efficiency of real time pricing since by and large, customers still remain shielded from the immediate economic consequences of power markets. However, the point of D/R services is to provide some incentives that would encourage customers to make the same informed choices they would have available under real time pricing. Demand response, implemented ideally, should replicate key economic features of real time retail pricing as closely as possible. Finally, D/R may be a transitional measure towards the more widespread adoption of true demand pricing for sophisticated customers or even for less sophisticated customers with smart-grid enabled energy management systems.

Real time pricing is explicitly a retail matter while D/R appears only implicitly as retail matter, with some wholesale element. In fact, retail pricing is core to the pricing and policy for D/R. Indeed, overlap between retail and wholesale markets is inescapable, with

[1] If real time pricing were mandatory, risk management purveyors would likely offer fixed price contracts to customers not wishing to be exposed to the volatility of real-time markets. Then, in periods of peak pricing, marketers might offer deals to fixed-price customers to curtail their demand, replicating D/R services. Similarly, in the wholesale power generation markets, from time to time a power generator has a gas supply contract at a price P0 below current spot prices, P. Such a generator might produce power at a marginal cost factoring gas price P0 below the current value of power, but with marginal costs above the current value of power using the spot price P. Marketers seek out these generators with offers to buy their gas. The generators stop generating, the marketers pay them for the spot price of the gas, less their margin. However the gas supplier still has to be paid the fixed contract price P0.

demand reduction from real time retail pricing having an impact on wholesale markets just the same as D/R. In this Comment we will assess the value of demand reduction of an individual retail customer to wholesale markets and assess the purchased price of power on retail markets as if there were no difference between retail and wholesale other than annual averaging. The retail price power is simply an annual average of the wholesale price[2].

D/R Scenarios and Economics

Demand Response typically occurs three different ways:

Scenario 1: (depiction identical to scenario 3) a retail customer responds to notification to curtail load during a time of peak pricing, reducing his demand. This may be particularly applicable for customers operating an industrial process, where the production is simply lost;

Scenario 2: (depicted below) A retail customer time shifts his load from a window covering some hours of peak pricing to a shoulder or off-peak time. This could be applicable to a commercial customer with an air conditioning load who is able to pre-cool his premises, for example;

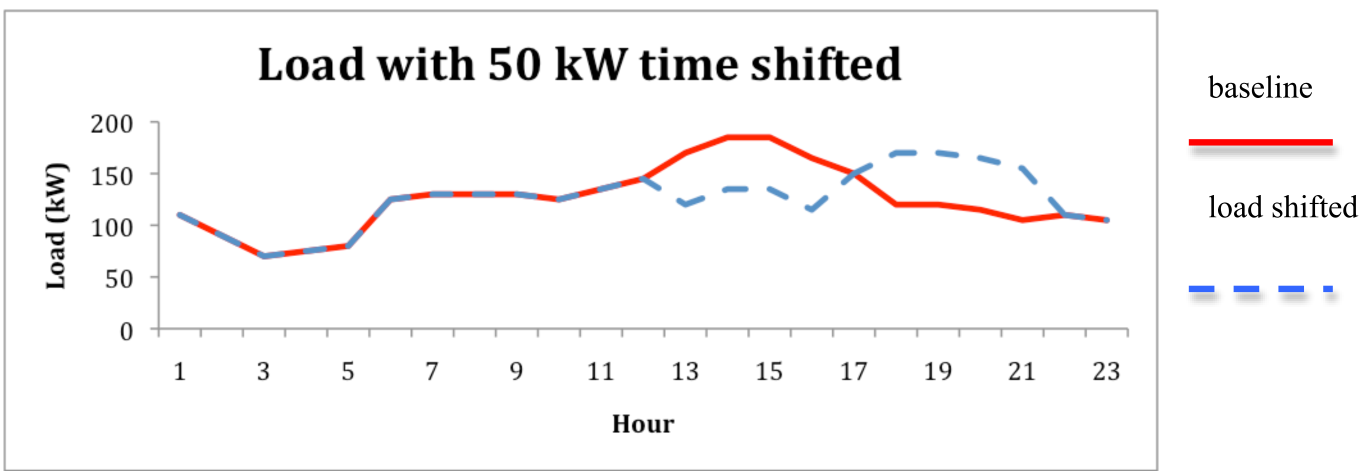
Scenario 3: (depicted below) A retail customer with backup generation activates his generator. The customer could disconnect from the grid, supplying his entire load from self-generation, or he might remain tied to the grid with the output from the generation

[2] A relation between retail and wholesale prices should be an annual average of the wholesale prices weighted by the customer load factor. To simplify the discussion we neglect demand charges for transmission capacity or other fixed costs.

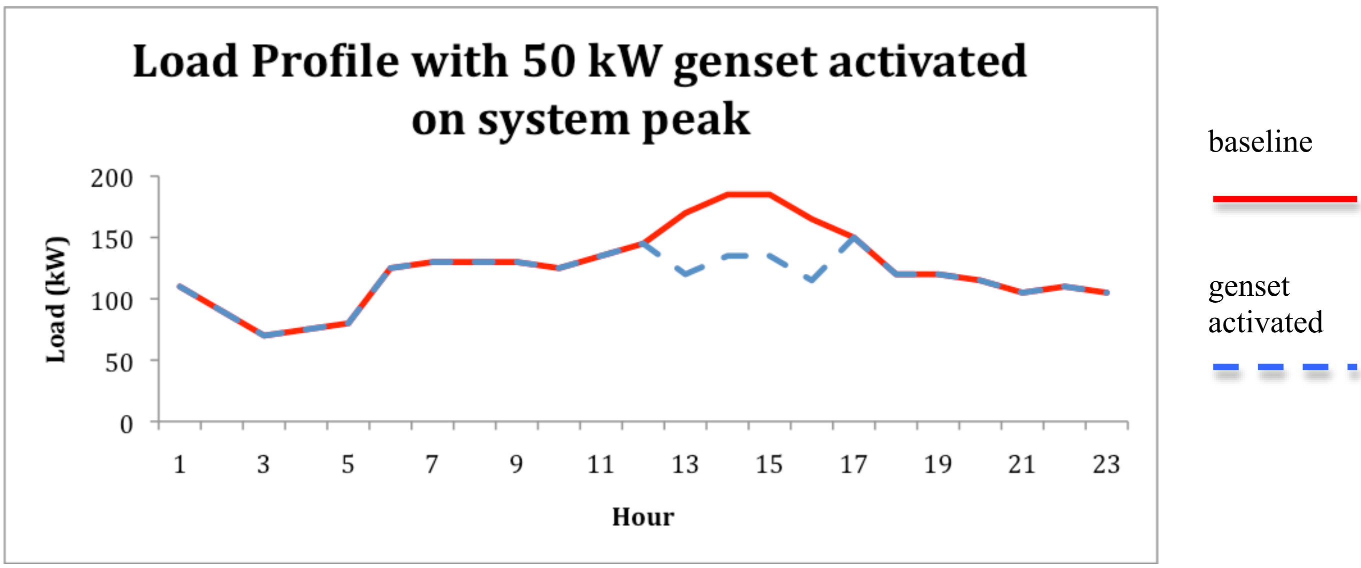
acting to reduce his net metered load, or the generator might be connected to the grid through a separate meter.

It is thought that Scenario 2 (load shifting) is the most common, with Scenario 3 (backup generation) gaining ground but without data collected, as through a Notice of Inquiry process, it is difficult to know for sure.

Scenario 2



Scenario 3



Scenario 3 (backup generation) is the most straightforward to analyze: assuming the generation is tied to a separate meter and further assuming that the customer maintains his load while activating his generation, in an efficient market the customer should receive payment of LMP for the quantity of power generated. But he must also pay a charge at the retail rate to cover his electric load. He recovers his operating costs (fuel plus variable maintenance) from the LMP collected.

Thus, net payment to customer = LMP – RR

reflecting the quantity of power generated by the backup unit, compensated at LMP, and costs incurred by the retail load, charged at the retail rate.

If the customer curtailed his consumption from his usage baseline at the same time as activating his genset *only then* does total payment to customer equal LMP, ie. the same payment as to a pure generator. Then the drop in net consumption from the grid would be *double* the amount of generation activated.

Similarly, if the generator's output passes through the same meter as the customer's load, the customer should receive payment of LMP for the full value of the generation, less the retail rate applied to the quantity of load reduced internally by the generator.

Paying the full LMP without netting against retail charges for the load the customer continues to operate allows the customer to operate their load ***at no charge*** – providing the customer free energy to the extent of their load, irregardless of their generation unit. Thus, surprisingly, paying full LMP to a customer in this scenario is not even pro-conservation.

Scenario 1 (customer reduces their baseline demand by some amount) is equivalent to Scenario 3. Referring to the load shape for scenario 3, if a customer were to reduce their consumption profile by some amount, say 50kW, it's exactly identical to the activation of a 50kW generator *while maintaining* the said load. The only difference from the generator case is that the virtual genset here has zero effective fuel cost, as if it were a wind or hydro unit.

Thus, equitable compensation to the customer = (LMP – RR).

Scenario 2, load-shifting (see depiction above) can then be analyzed simply as a composition of Scenario 3 (generator + existing load) + the existing load activated at a later time. So the customer compensation should be LMP – RR for the period of time when the load is switched off, and the customer should further be charged RR for the consumption during the shoulder period. In other words, the customer should pay 2 * RR – LMP for the quantity of load that is shifted, receiving a discount on the value of power consumed. This analysis assumes the customer should be treated as if they are exposed to the wholesale real time price during the peaks, providing an incentive for conservation, but otherwise paying the retail rate outside of peak demand period. This is not perfect economically but going the next step is the actual imposition of real time pricing on retail customers, whereby if the customer shifts load to an off-peak hour he receives a higher incentive than if he only shifts load to a shoulder period, as depicted.

These results are puzzling compared to the FERC assertion that demand reduction is comparable to generation and the seemingly logical conclusion that D/R should then be paid the same amount as a wholesale generator (LMP). It's puzzling and counterintuitive that it should be otherwise, including to this commenter. In fact the above analysis proves that paying demand reduction the full LMP is actually double counting because by reducing load, the customer already benefits by avoiding electricity charges at the retail rate RR. A true wholesale customer on a real time price tariff would not in fact receive any compensation but benefits **entirely** by avoiding payment of LMP through reducing her demand. To simulate the outcome as if the customer were exposed to real time pricing, at a time when the RTP exceeds RR, fair compensation is exactly the **difference** between LMP and RR.

Put another way, if a customer exposed to real time pricing shifted their load from the system peak to a shoulder period, they would realize savings equal to LMP (peak) – LMP (system average). This is approximately equal to LMP (peak) – RR. Providing a customer payment of full LMP (peak) is equivalent to providing the customer free electricity during the shoulder period in return for load shifting, significantly above and beyond the savings they would achieve in an efficient, real time wholesale market.

Limits on hours

It is not clear whether FERC contemplates the activation of D/R resources only during times when peak demand exceeds local resources available[3], thus using D/R to avoid

[3] In areas where generation is transmission constrained it's critical to activate only those D/R resources in the constrained zones. Economic waste results from activating D/R

involuntary load shedding, or whether FERC intends for peak demand to be reduced for economic reasons even if generation resources are available (though costly). The latter could be accommodated through a market based system of price-responsive demand however to approximate the results of this ideal economic solution with a D/R proposal requires clear guidelines when resources should be called since D/R only approximates the incentives and price signals in a true market based system.

Some limiting cases illustrate this point: during shoulder or off-peak periods, (LMP – RR) ≤ 0, so a customer is not incentivized under (LMP – RR) compensation to reduce load during an off-peak or shoulder period only to shift to another shoulder period. The customer only receives a net incentive when his load-shifting action actually improves the system load shape.

On the other hand, under full LMP compensation the customer could receive payment for unproductive load-shifting (shoulder or off-peak period to shoulder period) unless a limit on hours is set. This provides a simple and logical answer to the question raised in the NOPR whether there should be a limit to the number of hours when an incentive is provided: when providing the exact compensation, (LMP – RR) that duplicates the action of the wholesale markets, there needs be no limit on the number of hours that incentives are provided. The structure of the incentive logically goes to zero when the system benefit from customer action goes to zero. On the other hand, under LMP

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resources in a far larger geographic area. This has been a historical problem in New England, for example.

compensation, without some limit, the customer can be compensated for actions that do not benefit the system load shape.

Interpretation

Therefore, compensation for D/R at full LMP constitutes a significant subsidy, contrary to the statement articulated by Order 719 that "Commission policy does not favor granting preference for demand response.[4]" Conversely, the compensation FERC proposes for demand response services would reward D/R program participants far more than savings they could achieve from participating in real time pricing programs, discouraging innovative market based approaches. FERC's proposal creates market distortions, promotes excessive disruptions for insufficient benefit and reduces incentives for new peak shaving technologies.

New battery and other energy storage technologies hold promise in the long term for smoothing out the impact of intermittent renewable resources, such as wind energy. These technologies depend on substantial peak/ off-peak prices differences. But if FERC artificially depresses peak/ off-peak price differences then advanced technologies will have even greater hurdles to adoption than at present. Instead, FERC should adhere to its avowed policy "to eliminate barriers to demand response in organized power markets[5]" while remaining technology neutral, thus promoting efficient power markets with just and reasonable rates.

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[4] FERC Order 719, p. 9
[5] Ibid, p. 12

Barriers to adoption for D/R

Rather than creating outright subsidies for D/R services, it is important to eliminate as many barriers as possible. This commenter only has anecdotal information based on presentations from D/R providers so it would be helpful to have more complete data such as might be gathered from a FERC Notice of Inquiry. Nonetheless, typical feedback why D/R is not used as much as it could be includes:

- D/R is too much hassle. Varying degrees of automation exist among customers with some having fairly automated systems for implementation and others requiring manual switch flipping to de-energize circuits.
- Customer fatigue. Many customers are enthusiastic about D/R and start with a compliance rate over 50% but too many calls lead to lower compliance despite economic incentives.
- Difficulty in accurately predicting compliance and available demand reduction potential over long term periods as required by forward capacity markets.
- Implementation is costly, with much of economic benefits consumed by operations expenses.
- Insufficient compensation for classes of customers operating an industrial process whose value exceeds the benefits offered by a D/R provider. Non-industrial customers may also place qualitative value on, for example, the reduction of air conditioning during the hottest days of the year.

Taking the last barrier first, a demand response provider gave the example of a semiconductor manufacturer whose product line generated a margin, net of power costs of $1,000 per hour. Supposing power costs priced at spot market, LMP, are $1,200/ hour while power costs at the retail rate at $700/hour.

It follows that if provided an economic incentive per unit MWh of LMP – RR, the manufacturer would receive $500 per hour of curtailment – insufficient to curtail production. If the manufacturer received the full LMP value of power, $1,200/hr it would curtail production. While the lower value (LMP – RR) indeed fails to overcome the economic hurdle incentivizing the manufacturer to curtail production, it is inefficient to pay producers to curtail when the value of production with power prices at LMP exceeds the value of the power consumed.

Thus, overcoming the economic hurdle of a customer's lost production can not be considered a simple market "barrier" to be overcome through higher compensation. It is real and tangible. This highlights the need to perform analysis on data behind D/R participation, going beyond noting the correlation in D/R participation with the level of compensation as in the PJM. Otherwise one could, analogously, measure the success of an airline booking system simply by the number of passengers accepting voluntary compensation to change flight plans.

Customer hassles, preferences and compliance are a real barrier to D/R participation. At best, requiring a customer to comply with a directive to curtail power, often at short notice, creates inconvenience that may outweigh compensation. Curtailing 10MW of a

30MW load, with compensation at 100$/MWh creates a value of $1,000 per hour - moderate considering the potential inconvenience of reducing most of the air-conditioning on the hottest days of the year across a customer this size, such as a major university campus.

The costs of aggregating demand resources and managing them are significant. Some insight is gained from analysis of Enernoc's financial statements, disclosed[6] in their SEC filings and press releases. For 2009, Enernoc reports total revenue of $190,675,000, costs of sales of $104,215,000 and a gross operating margin of $86,460,00. Fixed operating costs consume the total gross margin, with a resulting net loss of $6,829,000, leaving the company near break-even.

Total revenue represents payments for demand response from ISO's[7]. Cost of sales includes both the cost of metering and IT implementation for demand response, a few % of revenue, together with the portion of revenue shared with end customers. Thus of the gross margin, 45% of revenue, approximately 47-48%, is economic revenue from D/R flowing to customers. If Enernoc were profitable, its net margin would also be added to the economic value captured from D/R but unfortunately the net loss must be added to

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[6] http://investor.enernoc.com/annuals.cfm

http://www.enernoc.com/press/releases/164/enernoc-reports-fourth-quarter-and-year-end-2009-financial-results.php?keepThis=true&TB_iframe=true&height=560&width=850

[7] This is approximate since Enernoc recently started a new line of business separate from D/R. However it's assumed that for 2009, this revenue was small and does not affect the overall analysis. Nonetheless, more precise information, such as could be gathered from a Notice of Inquiry process, would be helpful.

the cost of service delivery. Thus about 50% of the D/R revenue is distributed while the other 50% is consumed by service operation. But less than half of this revenue would exist if compensated at (LMP – RR) rates. Therefore it is critical for FERC to stimulate ways to reduce D/R delivery costs such that D/R may be profitable at the lower, economically efficient rates.

Not surprisingly, customer compliance dwindles in the face of numerous curtailment requests. Some customers have a degree of automation in the interconnection of their circuits, with air-conditioning dispatchable by a utility or another third party. Others prefer an actual phone call and physical switching of circuit breakers as to retain control of their circuits. For on-demand services, the intervention of aggregators may be required to manage the resource portfolio: often the portfolio is overpopulated since the aggregators need to account for lack of compliance. They follow up with participants whose compliance has been falling to ensure proper training, etc.

A simpler alternative might be to encourage ISO's to maintain electronic bulletin boards so that demand response participants could interact directly with bids on the day-ahead and/or hour-ahead power markets. Simply put, any market participant who wished to avoid the forecast peak LMP's could opt to schedule curtailment of his load and receive the appropriate compensation directly from the market clearing mechanism.

The electronic bulletin board could be tied in with the customer's meter and track his baseline consumption. Any failure to curtail could then result in the appropriate imbalance penalties – high enough to encourage compliance but not so high as to discourage participation. To the objection that such a scheme places an undue burden on ISO's, in fact a number of real time metering programs are now in place to tie distributed generation to ISO's system so as to provide renewable energy certificates. The system could be fully automated so that no human intervention would be required even to understand the impact of non-compliance on ISO scheduling and imbalance markets. Such a system could be totally passive and non-dispatchable.

A need may exist for dispatchable resources in order to avoid involuntary curtailments during emergency conditions. A premium could be paid to demand resources willing to be tied directly to ISO control. Providing the ISO with dispatch control may have higher value than simply (LMP – RR) since this class of customer is essentially volunteering to go first during involuntary load-shedding, and accept substantial disruption while providing a level of system security beyond purely economic optimization.

Working together with state regulators, FERC may encourage ISO's and retail electric distribution companies to provide information to end customers on how to participate in D/R programs. Large customers could be signed up automatically and notified on a routine basis what their potential savings could be through a nominal participation in voluntary load-shifting or involuntary emergency load-shedding.

Thus, innovative tariffs and services may be deployed that take into account the advance notice and relative inconvenience of curtailments.

Conclusions and Recommendations

Comparable treatment of demand resources with generation does not mean identical treatment as if a retail load were an actual generator. In real time pricing markets, customers avoid *incurring* LMP by forgoing peak electricity purchases with no additional compensation. Retail participants in D/R programs should receive that but no more: when dispatching down a load a customer avoids incurring the retail power price. He should receive additional compensation of (LMP – RR) so the sum together with his avoided power cost equals LMP. To provide more compensation would discriminate in favor of demand response programs over real time pricing customers.

Alternatively, based on a scenario where a customer activates backup generation, compensation to demand response customers should equal (LMP – RR) considering a customer who continues to operate his load in tandem with the backup generation. A customer is not entitled to the higher value (LMP) proposed by FERC since basically, this provides the customer free electricity to operate his load even within the demand response time window.

Thus, the proposed rule is contrary to FERC policy of providing a level playing field among market options and is unjust and unreasonable.

We believe FERC may act positively by requiring ISO's to develop electronic bulletin boards and IT systems that collect large customer meter data, establish baselines and permit customers on retail tariffs to voluntarily reduce peak usage in exchange for appropriate compensation. FERC may also encourage ISO's to adopt innovative incentive tariffs that compensate customers to accept curtailments during system emergencies, thus mitigating the impact of involuntary load-shedding. Other stakeholders and market participants should develop innovative ideas that can help bring demand pricing to electricity markets.

We respectfully submit the above comments pursuant to the Federal Energy Regulatory Commission's Notice of Proposed Rulemaking on Compensation for Demand Response services, Docket # RM10-17-000.

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