Recommended ISO/RTO Markets for Demand Response Resources

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Developed by
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Principles for ISO/RTO Demand Response Resource Markets

Demand Response Resources (DRR) includes all load with the capability of reducing electric use, as well as all on-site generation, which include combined heat and power facilities that can interact with wholesale market institutions. DRR markets work by allowing consumers (or aggregators, acting on their behalf) to sell load curtailment into the market, much in the same way that generators offer to sell power.

The Federal Energy Regulatory Commission (FERC) has already determined that the benefits of DRR require its inclusion in the development of Regional Transmission Organizations (RTOs). It is being refined in Docket No. RM01-12-000, which is considering technical issues related to the development of a standard market design for electric wholesale markets.

This paper focuses on the practical realities of developing demand response resource markets. The content of this paper is based on the extensive experience of The E Cubed Company LLC in helping to develop Independent System Operator (ISO) and RTO institutions and their programs in the Northeast as well as the experience of our clients in developing DRR. E Cubed also participated extensively in "RTO Week"[1] and the Interconnection Standardization negotiations.

The E Cubed Company has identified the following five principles for use in developing markets in which demand response can be viable. The remainder of this paper consists of a discussion of these principles, a specific set of recommended DRR markets for ISO/RTO implementation, and recommended FERC actions that will converge existing DRR markets and enable functioning and robust DRR markets at the outset of an RTO.

- Demand Response Resource (DRR) markets are working, but they need certainty and encouragement to attract investment.

- Demand Response Resource (DRR) markets should be designed to encourage entry, eliminate barriers to entry, and be included at the outset of RTO development.

- DRR should be allowed participation in energy and ancillary service markets in competition with generators.

- Market mechanisms must be established that recognize the value that DRR can provide, including:

[1] E Cubed comments to RTO Week can be located at http://www.ferc.gov/electric/rto/mrkt-strct-comments/e3llc.doc

1. Energy value—reducing peak clearing prices by displacing more expensive generation
2. Replacement reserves value
3. Reliability and dispatch value
4. Locational value
5. Planning value
6. Capacity value
7. Alternative to transmission expansion
8. Congestion relief value
9. Enhanced competition, reducing the potential for market power and need for market mitigation
10. Decreased system losses, especially during peak loading periods, by reducing line loading
11. Decreased and more disperse emissions—resulting in improved air quality

- At a minimum, payment for DRR should include:

1. Market Clearing Price.
2. Curtailment initialization costs.
3. Compensation for other market value attributable to DRR.

Recommended FERC Action

The following represent a summary of our recommendations for the development of the DRR markets. We encourage FERC to take strong action to ensure proper representation of demand response resources.

- Establish standard market design for DRR by discrete order or inside the standard market design proceeding.
- From the results of DRR standard market design process and the FERC/DOE demand response workshop on February 14, 2002, FERC should issue an order laying out the blueprint for ISO/RTO DRR markets and rules.
- The order should encourage rapid evolution and convergence of current ISO/RTO DRR markets.
- Full mobilization of DRR, and the elimination of "seams" in demand-side responsiveness, will require compatible technical standards across the RTO. FERC should act now to promote open architecture software, and common measurement units including time increments to facilitate regional trading of benefits.

This will:

- Instill confidence in investors that markets and rules will be predictable.
- Encourage investment in DRR within current ISO DRR markets with assurance that such investment will have similar profitability risks in an RTO.
- Enable significant DRR entry and participation at the outset of RTO operation.

Crafting Markets for ISO/RTO Demand Response Resources[2]

Many of the panelists at recent RTO and Energy Infrastructure conferences organized by the Commission have stated that it is important to develop DRR markets promptly. As RTOs are formed, their markets should include DRR participants and provide price signals that encourage investment in DRR infrastructure and technology.[3]

It is also anticipated that DRR participation will discipline current markets that are not workably competitive (or are minimally competitive). It does so by reducing the ability of market participants to exercise market power and by preventing the "gaming" of market rules and procedures.

The four existing ISOs have all embraced DRR in one form or another through filings with this Commission. Other filings are expected. State Commissions have supported these filings with this Commission, in general. Some state commissions have taken an active part in past filings with this Commission. New York State's draft state energy plan for 2002, identifies demand reduction and distributed generation as primary components of a competitive market that interfaces with the ISO/RTO. That plan also states that New York's goal is to become a national leader in deployment of distributed generation.

Recent California experience provides an indication of the potential for DRR. In response to significant price increases and the threat of curtailments and blackouts, consumers reduced demand by an estimated 10%, which helped stabilize the market in 2001 and minimize the chance of rolling blackouts. This reduction occurred even without sending an accurate hourly price signal. A perhaps larger and more appropriate demand response would have been possible with the communication of better price signals.

Inviting DRR Entry

Regulatory risk—that is, the risk of frequent market rule changes—may be the greatest single barrier to DRR entry. This barrier can be significantly diminished by establishing the parameters of markets in which DRR will be allowed to participate, the structure required for participation, and the price to be paid for participation.

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[2] Since early 2000 the Commission has been paying growing attention to Demand Response Resources (DRR) as an important factor in enhancing and stabilizing markets. The four established ISOs are evolving demand response initiatives that provide valuable starting places for refining market rules regarding these resources, especially the ISOs in the Northeast. In reply to comments by The E Cubed Company, DPCA and its members on the Summer 2001 demand programs of the three Northeastern ISOs, the DPCA and its members were encouraged by the Commission to participate in the development of the market rules directly. They have filed proposals/comments extensively in all three Northeastern ISOs planning for 2001 and 2002, in the mediation on the Northeast RTO (July-September 2001), in RTO Week (October 2001), and in Docket No. RM02-01-000, Standardizing Generator Interconnection Agreements and Procedures.

[3] Panelists at RTO Week in October 2001 and the Regional Energy Infrastructure Workshops in November 2001 and January 2001 have called repeatedly for FERC to exercise leadership regarding DRR and promote market rules that facilitate DRR.

While these markets and structures will likely change over time in much the same way as generation markets historically evolved, it is critical for investors to be assured that market rules will be sufficiently predictable to realistically anticipate potential revenue streams and ability to participate in markets. Even existing opportunities for DRR market participation do not encourage significant investment in DRR due to the need to renew these opportunities annually.

Any Notice of Proposed Rulemaking (NOPR) (and subsequent orders) issued by this Commission should delineate, much as this paper does, the basic elements of workable DRR markets. This would enable the existing ISO markets to evolve toward an end state that would allow them to be easily incorporated into an RTO structure. This Commission action would also provide reasonable expectations of economic returns on investment for projects that require longer payback periods than the current tariff provisions (and even ISOs) can assure, allowing projects to go forward immediately. Otherwise, investors may be forced to stand on the sidelines pending final RTO market structures.

Regulators can help evolve the markets quickly and therefore attract investment and entry sooner rather than later by:

1. Establishing a clear blueprint for DRR markets.
2. Establishing the structure, rules and procedures for DRR participation.
3. Establishing clear tariffs that provide appropriate compensation.
4. Providing the certainty that DRR will have the opportunity to participate in all markets and will remain a critical element of a competitive market for electricity.

Capturing DRR Value

Because of the ease of siting DRR equipment or processes at load sites, in major urban centers, downstream of congestion and in locations that minimize losses, DRR provides locational, planning and reliability benefits that traditional central generation may not be able to provide. As a market response to congestion, DRR can help to reduce short, medium and long-term system costs. Proper market signals and access to the markets are required for effective DRR participation. DRR can often be "mobile" – relocating as needed to address the changing needs of dynamic grid.

Demand response can also enhance reliability by providing needed operating reserves and energy otherwise not available in emergencies. Some DRR is able to drop off the system without notice, providing instantaneous relief to the grid. No current market structures anticipate, much less compensate for, this unique value to the system. Reduced distribution and transmission loading due to DRR activation also provides reliability benefits that the markets need to value properly.

The proposed DRR markets in PJM (based on enhanced NYISO DRR markets) break down barriers to entry with a payment structure that includes:

1. Market clearing prices.

2. Curtailment initiation costs.
3. Compensation for other market value attributable to DRR.

The market clearing price is the price set by the most expensive resource needed to supply demand at a given time. All resources are considered, including generators and DRR, and each can set clearing price based on bids. Competition is enhanced and bidding is disciplined by the addition of DRR participants.

Curtailment initiation costs are the generator equivalent to startup costs. It is recommended that DRR be allowed to recoup at least its minimum curtailment initiation costs each time a curtailment is requested by the ISO/RTO to cover those times in which a one or two hour activation would otherwise result in the DRR entity losing money. A similar guarantee is offered to generators in Northeastern energy markets.

Finally, market mechanisms must be developed to adequately compensate for the identified value that DRR provides that cannot be recovered through existing market structures. In the absence of those mechanisms, it may be appropriate to compensate DRR through other means, such as the allowing the DRR customer to retain the savings associated with tariff savings during a curtailment of load.

Recommended DRR Markets

Based on Commission policy statements and existing market structures in the three Northeast ISOs (including identified "best practices" amongst those ISOs),the following fundamental energy and ancillary services markets should exist in an RTO:

- Day ahead bid-based energy market.
- Real-time bid-based energy market.
- Ancillary services markets, including operating reserves.
- Regional long-term capacity or generation adequacy market.

Specific recommendations for establishing these energy markets for DRR are discussed below.

All of the markets for ancillary services, including reactive support, spinning and non-spinning reserves, regulation and replacement of operating reserves, should be extended to DRR. All of these services can be provided by one form of DRR or another.

Forward markets that establish clearing prices more than a day ahead are also appropriate for DRR participation. While it is not necessary that an ISO/RTO operate a centralized forward market, such development should be encouraged. Forward markets could be devised on a bilateral basis or by a commercial, for-profit, centralized power exchange. If forward markets exist, however constructed, DRR should be allowed to participate. DRR should also be allowed to be the provider of ancillary services for those who wish to self supply, and to be the provider for bilateral energy and capacity transactions, just as generation can.

In conclusion, the set of recommended DRR markets listed below are markets that, for the most part, exist already or are feasible for immediate development and implementation. These markets represent the best practices of current ISO DRR markets as well as incremental improvements. It is further recommended that the three Northeastern ISOs include these recommended markets so that DRR entities can readily participate at the outset of formation of the RTOs that are evolving.

Summary of Recommended DRR Markets

At least six markets are ripe for inclusion of DRR and are listed below. In all of these relevant markets, rules should allow DRR to participate in much the same way that traditional generation participates. This holds true both in regions with locational marginal pricing as well as those without.

Energy Demand Response Resource Markets

- Bid in day-ahead market (settle day-ahead) (PJM proposal and NYISO DADRP).
- Bid in hour-ahead market (settle at real time) (proposed in NYISO and PJM).
- Voluntary in-day "price taking" feature to make it easy and simple to enter (ISO-NE modified market) (proposed in NYISO and PJM).

Ancillary Services Markets

- Ten minute spin.
- Ten minute non-spin.
- Thirty minute.
- Regulation.
- Voltage support.

(Note: For each of the above the NYISO has markets or provides the service in the case of voltage support but does not allow DRR participation. PJM is considering these markets and will allow DRR participation. ISO-NE allows DRR to provide ten minute operating reserve and compensates some DRR based on 30 minute operating reserve prices.)

Replacement Reserves

- Day ahead bid-based selection of DRR or generation.
- Highest accepted bid establishes the clearing price.
- Participants counted on by ISO/RTO to perform—possibly subject to penalties for non-performance.
- Replacement reserve providers cannot simultaneously, provide ten or thirty minute operating reserve.

Emergency Demand Response Resources—Voluntary

- Notification of participation.
- $500/MWh or energy market clearing price, whichever is higher. (A $500 generation being bid in during an emergency event would be accepted.)
- Four hour minimum run whenever resources are called.

- Voluntary response feature to make it easy to enter—no penalties for non-performance.

Capacity Market

- Allow for bilateral transactions
- Allow use of DRR to offset purchases of capacity
- Bid-based periodic auctions.
- Highest priced accepted bid sets clearing price—generation or DRR.
- Can have locational variances or separate locational auctions.
- Penalty for non-performance.

Green Market

- Loads agree to be supplied by specific green technologies, including DRR, based on the type of green technology and specific price bids, or a pool of green resources with an average price bid.
- Centralized exchange would match green resources, including DRR, that bid a price, with loads that bid MWs to enter, also based on price.
- No prohibition on DRR simultaneous participation in green and non-green markets.

Energy DRR Markets

DADRP

Currently, the NYISO operates a day-ahead demand response program (DADRP) in which DRR providers can bid into the day-ahead energy market competitively and receive settlement based on accepted bids. It is not a separate and distinct new market, but rather a means for DRR to participate in the existing day-ahead energy market.

In New York's DADRP, all DRR and generators bids are compared, and commitments and accepted energy schedules are based on economic merit order. DRR, as well as generation, is expected to perform and meet accepted schedules the next day; if bidders fall short, they pay for replacement energy at the higher of real time prices or day ahead prices plus a 10 % penalty. Accepted bids receive locational based marginal price (LBMP, which is the clearing price) and accrue savings associated with energy curtailments for DRR.

Current proposals at PJM would allow DRR to participate in its day-ahead energy market in much the same way as New York. However, there are some differences. Unlike New York, the PJM proposal does not include penalties above the requirement that DRR pay the higher of the Day Ahead or Real Time LMP. In addition, the PJM proposal provides LMP payment to DRR and allows DRR, including distributed generation resources (DG) to realize savings from curtailment. The NYISO offsets clearing price payments by the amount of savings from the energy curtailment for DG.

We believe that the proposed PJM structure for the day-ahead market provides a better balance between risk and reward and will be more successful in attracting needed demand response than its New York counterpart. For these reasons we recommend the proposed PJM day ahead DRR market. The details of market rules for our recommended day-ahead DRR energy market are transcribed from the current PJM proposal and are included in Appendix B.

Extend DADRP to the hour-ahead/real time market

A market very similar to the day-ahead proposal for PJM DRR participation is also proposed for the PJM real time market. It is also being proposed for New York. Generators not selected in the day-ahead market are allowed to bid into the hour ahead market and receive settlement payments at real-time prices. This feature of energy bidding should be extended to DRR. In principle, if day-ahead and hour-ahead markets are constructed for energy for ISOs and RTOs, then DRR should be able to participate and compete fully in these markets. The details of market rules for this recommended hour-ahead/real time DRR market are taken from the current PJM proposal and included in Appendix B.

Price Taker

Various possible participants fear that the competitive bidding process is too complex and therefore constitutes a barrier to entry, especially for smaller DRR applications. Smaller applications may not have the resources to hire expertise necessary to bid into energy markets. One approach alleviates this concern by allowing DRR to activate (curtail) at any time and be paid the clearing price.

In this approach DRR become price takers. Generators in all three northeast ISOs can self commit and take real-time clearing prices, and there is no justification for not extending this market to DRR. Activation of this form of DRR participation can proceed in parallel with day-ahead and hour-ahead bidding markets.

ISO-NE implemented a similar approach last year with one major restriction. DRR could only activate when ISO-NE forecast high prices for the next day (a floor price of $100/MWh or greater). As a result, ISO-NE only called the program on four days in 2001.

There is no need for the artificial restriction of a floor price for participation, which distorts the overall energy market by signaling that generators should bid up to $100/MWh every time price is expected to move in that direction. This will increase prices to just below $100/ MWh at times when prices might fall into the $70 to $80 range. In fact, generators can change their day-ahead schedules by submitting hour-ahead bids that beat DRR day ahead bids once the generators know that prices will be high and DRR will be activated.

PJM and the NYISO are considering allowing DRR to be price takers in their respective energy markets for summer 2002. ISO-NE considered ending its floor price but elected to continue with a floor, though it might re-consider the amount of that floor price.

Allowing DRR to be price takers is voluntary and, therefore, no penalties are assessed for failure to curtail. Payment is made based on real-time clearing prices and on the actual amount of curtailment. Participants must indicate to the ISO electronically how much and when they intend to curtail prior to curtailment (similar rules apply to generators who elect to be price takers).

It is recommended that DRR be allowed to participate in either the bidding-style markets or the voluntary market or both, but not both with the same megawatts. A resource could be accepted partially in the bidding markets and the portion not selected could then be used for curtailment in the voluntary market.

The general market rules that apply for the day-ahead and real-time energy markets are included in the PJM proposal included in Appendix B. Similar market rules in other regions are available through web sites listed in Appendix A.

Ancillary Service Markets and Services

Following the principles listed above, DRR should be allowed to participate in all the markets that are available to generators, including markets for ten minute spinning operating reserve, ten minute non-spinning operating reserve, thirty minute operating reserve and regulation. Moreover, some DRR can provide voltage support and should be eligible to receive equivalent payments that generators receive for provision of this service, even if voltage support is not a competitive market.

The New York reserve and regulation markets are competitive markets that accept bids from generating resources, and therefore should be open to bids from DRR. ISO-NE allows DRR to provide ten minute operating reserve, provided the resource is tested for response capability in ten minutes and is subject to penalties for non-performance when called on. DRR providing ten minute reserve get paid the ten minute reserve clearing price but do not bid to provide this service.

There has been little discussion of allowing DRR to compete in markets for existing ancillary services in NYISO and those being developed in PJM. There is no reason to preclude DRR from participating in ancillary services, especially since some load reduction activities can be activated in a manner of seconds and can therefore out-perform generators in the provision of the service. We recommend that DRR be allowed to participate in providing ancillary services.

The NYISO market rules for operating reserve and regulation and the provision of voltage support service are included on the NYISO web site and is listed in Appendix A for reference.

Emergency Demand Response—Replacement Reserves

Another ancillary service that DRR can provide is sometimes called replacement operating reserves or simply replacement reserves. This service is critical to short term reliability for ISOs and RTOs. For example, in ISO-NE, DRR, including DG, can provide ten minute operating reserve (TMOR). In this instance, the ISO counts on this operating reserve to recover from contingencies and therefore tests the response of these resources and subjects them to penalties if they do not perform when called on.

ISO-NE also commits extra generation to the grid on a day ahead basis (about 1000 MW daily) for the purpose of providing sufficient committed capacity that can provide replacement reserve in the event TMOR is used up in-day and in preparation for the next contingency. ISO-NE does this in compliance with NPCC reliability criteria that require that ten minute reserve be replenished within thirty minutes following a contingency.

While there are problems with ISO-NE methodologies for committing and paying generation for this service (essentially there is no market and no payment or recognition that this service is being provided by generators) a market should be developed that would allow both generators and DRR to bid on a day ahead basis to provide replacement reserves. Bids would establish a clearing price for this service. Participants should bid an availability price and an energy price with least cost bidders being selected. Similar to "quick start" gas turbines, DRR is, in many cases well suited to serve this ancillary need because, on many days, the energy price it would bid would be too high to be accepted and therefore its resource will sit idle and not "count" as capacity or replacement reserves.

With a market in place, DRR can bid both energy and replacement availability. If energy bids are rejected in the energy market, the ISO/RTO can accept the availability bid in the replacement reserve market and DRR should receive availability payments for replacement reserve. DRR should then receive operating reserve payments for those times when a contingency occurs—and they are counted—as operating reserve. Finally, if a double contingency occurs within thirty minutes requiring DRR actually to activate curtailment, it should be paid the real-time clearing price or its bid into the day-ahead or hour-ahead markets, which ever is greater.

Specific market rules can easily be developed similar to the NYISO operating reserve market rules. Appendix A includes the URL address where NYISO operating reserve market rules can be found.

Emergency Demand Response Resources—Voluntary

The emergency feature for DRR participation has worked well in New York and PJM in the brief time these programs have existed. Voluntary participation makes entry easier and, often, more feasible, because no penalties ensue for failure to perform. The payment of $500/MWh or the clearing price, whichever is higher, has induced a healthy response in New York and actual curtailments were at expected levels. (Some of this response may also be due to the close nexus between EDRP capacity and Special Case

Resource capacity and associated capacity payments.) Therefore, it is recommended that the voluntary emergency demand response resource market continue in the form that exists in NYISO and is proposed in PJM. All demand and distributed generation resources will be eligible to participate. The NYISO minimum run time of four hours is recommended to allow sufficient energy revenues to ensue each time participants are called on to produce energy (the two hour minimum in PJM and ISO-NE has proved a barrier to entry). The current NYISO EDRP manual provides details of the basic rules for this market.

Capacity Market

Clearly, DRR can and should be considered a Capacity Resource and should qualify to compete in Capacity markets, whether bilateral, self supply and/or auction based. Currently among the ISOs, capacity market design provides for periodic auctions open to bidders of any generating resource, and in New York, open to DRR bidders as well. Capacity may also be sold via bilateral contracts. This is recommended for all ISOs and RTOs. Exclusions that limit participation in capacity markets, like PJM's ALM program that is limited to LSE's, should be eliminated. The experience to date in New York, has been excellent. Resources responded according to the provisions of the tariff . Finally, it is recommended that DRR capacity be allowed to be traded across control area boundaries similar to trading of generator capacity.

The NYISO market rules for a periodic auction market for capacity are available on its web site, which is referenced in Appendix A.

Green Market

It is recommended that green markets (or those with a certain percentage of "clean" or "renewable" power production) be included in ISO and RTO markets. Such markets do not have to be offered by the ISO or RTO but could be provided by any commercial venture provided the schedules are coordinated with the ISO/RTO. Green markets should be constructed to allow customers to select the green resource that it wants for electricity supply, based on the type of green resource and its price. Green technologies should submit bids indicating the technology that produces the electricity and the price that is offered. Loads can then choose between price and green technology.

While customers traditionally have selected from among clean generating technologies or renewable generating technologies, it makes perfect sense for them to be able to choose curtailment, which is the most environmentally beneficial option, since it reduces the need for any generation, however clean. Load should have the option of bidding in a portion, or all, of its load to be supplied by the green technology provider of its choice.

The addition of green markets should provide additional revenues for prospective investors in DRR technologies, further easing entry into these markets. Distributed generation should be included as a green market resource if supplied by renewable resources or even gas since, in the latter case, the distributed nature of the resource reduces air emissions and reduces the need for extra transmission and distribution facilities.

A green market operated successfully for some time in California but ended with the end of retail access. A green market continues in Pennsylvania. It is provided by a commercial, for-profit, entity that does not take a position in the market but charges a fee per transaction. Since this model appears to work, it might prove a useful starting point for an ISO/RTO green market in the Northeast. Other kinds of green markets could also be considered. Since this is relatively new ground, detailed market rules are undeveloped for green markets. Development of detailed market rules should not prove a time consuming or particularly onerous task.

Evolution and Convergence of Northeastern ISO/RTO DRR Market Design

Two of the three Northeastern ISO DRR markets have made changes now in progress that will provide substantial DRR markets for summer 2002, if approved. PJM and NYISO DRR markets, if these changes are adopted, will provide for DRR participation in all of the recommended markets with only a few exceptions. Those include the real time market in NYISO, and in both ISOs, the green market and the replacement reserve market and several ancillary services markets. Despite well intended proposals that enhance DRR markets and allow DRR more widespread participation in energy and capacity markets, not all of the proposed changes are likely to be approved based on the record of past, rather contentious, debates within the ISO committees.

There are slight rule variations between PJM and the NYISO, with more convergence than divergence. ISO-NE has made some gains in its DRR markets as well but is limited because it does not yet have a day-ahead market in energy for generators. The day-ahead market for ISO-NE is expected to be implemented by the end of 2002 as part of implementation of Standard Market Design (SMD) that it has purchased from PJM. ISO-NE has indicated that it will consider a day-ahead energy market for DRR some time this year in anticipation of the implementation of SMD by year-end 2002.

If it has not already done so, it would be appropriate for PJM to include in its SMD the markets that are listed here, or, at a minimum, include the DRR market design changes that are on the table currently for approval at PJM. PJM has been instrumental in pushing its common market design with neighboring control areas, including PJM West, the Midwest ISO, ISONE and others. To the extent that the NYISO is extending its market design to its neighbors—ISONE or IMO (Ontario) and others—it too should consider exporting its DRR market design, including the elements listed above.

While substantial improvements are pending for this summer and will be pending before FERC, these improvements have taken a large and extended effort among extremely limited resources to work inside three ISO governance processes. Along the way some parties have objected to payment structures and even DRR participation in some markets for the purpose of minimizing competition for generators. The process has been difficult for new participants and not particularly effective considering that among the three ISOs in the Northeast, the amount of DRR development is well below its potential, except in the instance of PJM, where the existing Active Load Management (ALM) program would bring the total close to 5% of load. This is powerful evidence that significant barriers to entry remain. However, despite relatively small amounts of DRR participating in new York last summer, recent studies have suggested that its impact on lbmp and total market energy payments was substantial.

FERC needs to play a lead role in dictating the course of market development for DRR to prevent obstructionist voting within the ISO and RTO market rule development processes. Today's large market players have a greater voting share than new or future market participants, which is the case with many DRR entities. While consensus rulemaking in the three ISOs and possibly the RTO process is admirable for certain details of market development, it does not work well for preparation of markets that need to be designed to attract new market participants. It is therefore critical that FERC lay down at least a fairly detailed conceptual framework for DRR markets that will be adopted by an RTO.

With a conceptual framework in place, current ISO DRR markets can more easily and quickly converge toward a common RTO DRR market platform. Convergence is required so investors can be assured that dollars spent on participating in ISO DRR markets will be eligible to participate with equal profitability risks in RTO DRR markets. Convergence is also required to inspire investment in DRR to ensure that an active DRR market is up and running at the time of RTO startup. Hopefully, this document can be used as a blueprint for the FERC in establishing a specific framework for RTO DRR markets.

Recommended FERC Action

The following represent a summary of our recommendations for the development of the DRR markets. We encourage FERC to take strong action to ensure proper representation of demand response.

- Establish standard market design for DRR inside the standard market design proceeding.
- From the results of DRR standard market design, including comments filed in the standard market design proceeding and in response to the FERC/DOE demand response workshop, FERC should issue an order laying out the blueprint for ISO/RTO DRR markets and rules.
- The order should encourage rapid migration and convergence of current ISO DRR markets.

This will:

- Instill confidence in investors that markets and rules will be stable.
- Encourage investment in DRR within current ISO DRR markets with assurance that such investment will have similar profitability risks in an RTO.
- Enable significant DRR entry and participation at the outset of RTO operation.

Attachment A

The market rules for existing programs are available at the following web sites:

NYISO EDRP and DADRP
http://www.nyiso.com/services/documents/manuals/index.html

ISONE Load Response Manual:
http://www.iso-ne.com/Load_Response/Load_Response_Manual_07-17-2001.doc

Cal ISO:
http://www.caiso.com/clientserv/load/

Attachment B

PJM Load Response Program
Strawman Proposal dated January 9, 2002

PJM Load Response Program -Strawman

*** This document represents the opinions of the Demand-Side Response Working Group, as determined via straw votes at the January 9, 2002 meeting. It is a draft, and is to be used for discussion purposes only. ***

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PJM Load Response Program

The PJM wholesale energy market has enjoyed unparalleled growth and activity since its inception in April of 1997. As a result of its overall liquidity and the flexibility provided to its participants, the PJM market is widely regarded as one of the more liquid markets in existence. However, like other wholesale electric energy markets, when supply is short the wholesale price of energy in PJM can rise to extreme levels. Greater efficiency would exist in the PJM marketplace, and indeed the existing $1,000/MWh cap on generator bids might not even be necessary, if the load in PJM could respond to high prices and reduce demand during times of short supply.

The main obstacle to garnering price-responsive load in the PJM system is the fact that most end-use customers are not exposed to real time prices. Traditionally, Load-Serving Entities (LSEs) within the PJM control area have been required to provide retail electric service to their customers at rates approved by the applicable states' regulatory bodies. Limitations to these regulated retail rates continued even under wholesale deregulation and retail customer choice due to stranded cost agreements between existing, vertically integrated Investor-Owned Utilities (IOUs) and these same regulatory agencies. As a result of these retail price caps, LSEs may pay more for energy in the wholesale market than they collect from their retail customers during times when the wholesale energy price in the PJM market rises above the applicable retail rate.

In the past, the only entity in a position to request a customer to reduce load and share any such savings was the LSE that actually served that customer's load. However, that LSE may not desire or be able to provide the necessary infrastructure (metering, communications, accounting, etc.) to accomplish and monitor the load reduction at a cost that makes the reduction economically attractive for both parties. Other parties may be able to provide such services though, if they were able to benefit from the associated price differentials.

The PJM Load Response Program is divided into three options.

Emergency Load Response Program

This option is designed to provide a method by which end-use customers may be compensated for reducing load in an emergency.

The program will be effective June 1, 2002, and will be reviewed annually by the PJM Market Monitoring Unit.

Economic Load Response Program - Real Time

This option will provide a mechanism by which any qualified market participant may offer end-use customers the opportunity to reduce the load they draw from the PJM system during times of high prices and receive real time LMP for the reductions.

The program will be effective June 1, 2002, and will remain in effect until May 31, 2005. At that time, the program will continue unless it is terminated by a majority vote from the Members Committee.

Economic Load Response Program - Day Ahead

This option will provide a mechanism by which any qualified market participant may offer end-use customers the opportunity to commit to a reduction of the load they draw from the PJM system in advance of real time operations and receive day-ahead LMP for the reduction.

The program will be effective June 1, 2002, and will remain in effect until May 31, 2005. At that time, the program will continue unless it is terminated by a majority vote from the Members Committee.

None of the options is intended to be a replacement for Active Load Management (ALM), but rather an additional method by which distributed resources and customers capable of reducing load can participate in PJM operations and markets. This document provides a summary of and detailed procedures for the program.

All three programs are applicable to both the PJM and PJM West control areas.

Option 1: Emergency Load Response Program

EFFECTIVE PERIOD OF PROGRAM

The program will be effective beginning June 1, 2002, with no sunset date. The program will be reviewed annually by the PJM Market Monitoring Unit.

PARTICIPANT QUALIFICATIONS

Two primary types of distributed resources are candidates to participate in the PJM Emergency Load Response Program:

A participant that has the ability to supply required load via local generators

- These generators can be either synchronized or non-synchronized to the grid. Exports to the grid by local generators will be eligible for compensation under this program only if allowed under the interconnection agreement with the local utility.

A participant that has the ability to reduce a measurable and verifiable portion of its load

PJM membership is required to participate in the Emergency Load Response Program. Special membership provisions have been established for program participants, as outlined in the Attachment. Any existing PJM Member may act as a third party for non-members, in which case the third party will be referred to as the Curtailment Service Provider (CSP). All payments are made to the PJM Member. Participants must become signatories to the PJM Operating Agreement, as described in the ***PJM Manual for Administrative Services for the Operating Agreement of the PJM Interconnection, L.L.C.*** However, the $5,000 annual membership fee, the $1,500 application fee, and liability for Member defaults are waived, along with the following other modifications:

Limited to be PJM Market sellers

Waived voting privileges; waived sector designation

Thirty day notice for waiting period is waived

No requirement for 24/7 control center coverage

No PJM-supported user group capability is permitted

To participate in the emergency program, the distributed resource must:

Be capable of reducing at least 100 kW of load

Have the ability to participate for a total of at least 10 hours over a twelve-month period

Be capable of receiving PJM notification

METERING REQUIREMENTS

The Load Response Program participants must have metering equipment that provides integrated hourly kWh values, for market settlement purposes, that either meets the EDC requirements for accuracy or has a maximum error of two percent end-to-end (including PTs and CTs). The metering requirements can be met using either of the following two methods:

Metering that is capable of recording integrated hourly values for the actual net generation, not gross output (net of that used by the generator).

Metering that provides actual load change by measuring actual load before and after the reduction request, such that there is a valid integrated hourly value for the hour prior to the event and each hour during the event. This value cannot be estimated nor can it be averaged over some historical period.

Metered load reductions will be adjusted up to consider transmission and distribution losses as determined by PJM.

The installed meter must be one of the following:

EDC-owned hourly meter,

Customer-owned meter including one provided by an independent metering service provider or acquired from the CSP, approved by PJM, that is read electronically by PJM, or

Customer-owned meter including one provided by an independent metering service provider or acquired from the CSP, approved by PJM, that is read by the customer (or the CSP), the readings from which are forwarded to PJM.

Nothing here changes the existence of one recognized meter by the state commissions as the official billing meter for recording consumption.

SMALL CUSTOMER PILOT

PJM will also consider small customers without hourly metering for participation in a pilot program, provided the customers or their representatives propose an alternate method for measuring hourly load reductions. Participation in the small customer pilot will be limited to 25MW aggregate load reduction, and with the sole exception of the requirement for hourly metering, will be subject to the same rules and procedures as the Emergency, Real Time Economic or Day-Ahead Economic program, whichever is applicable.

REGISTRATION

Participants must complete the PJM Emergency Load Response Program Registration Form that is posted on the PJM web site (www.pjm.com) and included as an attachment to this document. The following general steps will be followed:

1. The participant completes the PJM Emergency Load Response Program registration form located on the PJM web site.

   PJM reviews the application and ensures that the qualifications are met, including verifying that the appropriate metering exists. PJM also confirms with the appropriate LSE and EDC whether the load reduction is under other contractual obligations. Other such obligations may not preclude participation in the program, but may require special consideration by PJM such that appropriate settlements are made within the confines of the existing contract. The EDC and LSE have two (2) business days to respond or PJM assumes acceptance.

2. PJM informs the requesting participant of the acceptance into the program and notifies the appropriate LSE and EDC of the participant's acceptance into the program.

3. Any end-use customer intending to run distributed generating units in support of local load for the purpose of participating in this program must submit to PJM the applicable environmental permits for running those generators. In the event no environmental permitting has been obtained, written justification for the lack of permits must be provided to PJM.

EMERGENCY OPERATIONS

PJM will initiate the request for load reduction following the declaration of Maximum Emergency Generation and prior to the implementation of ALM Steps 1 and 2. (Implementation of the Emergency Load Response Program can be used for regional emergencies.) The purpose of Maximum Emergency Generation is to increase the PJM Control Area generation above the maximum economic level. It is implemented whenever generation is needed that is greater than the highest incremental cost. PJM will revise the emergency procedures to reflect the following steps:

1. The PJM Dispatcher issues Maximum Emergency Generation.

2. The PJM Dispatcher notifies PJM OI Management, PJM OI public information personnel, and Local Control Center dispatchers.

3. The PJM Dispatcher indicates the need for emergency energy and contacts its neighboring control areas.

4. The PJM Dispatcher recalls off-system sales that are recallable (network resources).

5. The PJM Dispatcher begins to load Maximum Emergency Generation, requests load reductions from the Emergency Load Response Program participants, and begins to purchase emergency energy from PJM Members and from neighboring control areas based on economics and availability.

6. The PJM Dispatcher continues with the remaining emergency procedure steps (including ALM) as stated in the PJM Manual for Emergency Operations, and cancels them in reverse order when appropriate.

7. The PJM OI dispatcher cancels the load reduction request and then cancels Maximum Emergency Generation, when appropriate. The minimum duration of a load reduction request is two hours although the reduction request may be extended if necessary.

Due to the variety of conditions and the potential for the conditions to change rapidly, some emergency activities may not occur in this order. PJM posts the request for load reduction on the PJM web site, on the Emergency Conditions page, and on *e*Data, and issues a burst email to the Emergency Load Response majordomo. A separate All-Call message is also issued.

Verification

PJM requires that the load reduction metering data be submitted to PJM within 45 days of the event. If the data are not received within 45 days, no payment for participation is provided. Meter readings must be provided for the hour prior to the event, as well as every hour during the event.

These data files are to be communicated to PJM either via the Load Response Program web site or email. Files that are emailed must be in the PJM-approved file format (see attachment). PJM will forward directly metered data to the appropriate Distribution Company immediately following an event for optional review. Meter data submitted after-the-fact will be forwarded to the EDC and LSE upon receipt, and these parties will then have five (5) business days to provide feedback to PJM. All load reduction data are subject to PJM Market Monitoring Unit audit.

Market Settlements

Payment for reducing load is based on the actual kWh relief provided plus the adjustment for losses. The magnitude of relief provided could be less than, equal to, or greater than the kW amount declared on the Emergency Load Response Program Registration form.

PJM pays the higher of the appropriate zonal Locational Marginal Price (LMP) or $500/MWh to the PJM Member that nominates the load.

During emergency conditions, costs for emergency purchases in excess of the LMP are allocated among PJM members in proportion to their increase in net purchases from the PJM energy market during the hour in the real time market compared to the day-ahead market. Consistent with this pricing methodology, all charges under this program are allocated to purchasers of energy, in proportion to their increase in net purchases from the PJM energy market during the hour from day-ahead to real time.

An ALM Customer may participate in the Load Response program during ALM events as long as the customer's ALM contracts do not explicitly include energy. If the LSE that submitted the customer for ALM credit indicates that the customer is not eligible for simultaneous credit under the Load Response program and ALM is called for concurrent with the Load Response program, then payments will be made to the customer according to the Load Response program only for the time during which ALM obligations were not in effect. Any response in excess of the contracted ALM amount will be compensated under the Load Response program for the entire duration of response.

Program charges and credits will appear on the PJM Members monthly bill, as described in the ***PJM Manual for Operating Agreement Accounting*** and the ***PJM Manual for Billing***.

REPORTING

PJM will submit any required reports to FERC on behalf of the Load Response Program participants. PJM will also post this document, as well as any other program-related documentation on the PJM web site.

PJM will also report the names of those end-use customers who indicated that distributed generation would be run in support of the load reduction program to the EPA, together with the permitting information that was supplied upon registration.

On an annual basis PJM will prepare a report that summarizes the status of the program and will submit it to the PJM Board of Managers, the Members Committee, the Reliability Committee, the Energy Market Committee, and the Operating Committee for review.

Option 2: Economic Load Response Program – Real Time

Effective period of program

The program will be effective June 1, 2002, and will remain in effect until May 31, 2005. At that time, the program will continue unless it is terminated by a majority vote from the Members Committee.

Participant Qualifications

The same two types of distributed resources are also candidates to participate in the PJM Economic Load Response Program:

A customer that has the ability to supply required load via local generators

- These generators can be either synchronized or non-synchronized to the grid. Exports to the grid by local generators will be eligible for compensation under this program only if allowed under the interconnection agreement with the local utility.

A customer that has the ability to reduce a measurable and verifiable portion of its load

The Economic Option of the Load Response Program is intended to encourage broad participation in economic load reductions by any LSE's curtailable loads. LSEs arranging load reduction agreements with customers for whom they are the energy supplier are not required to register to participate in this program. These LSEs may wish to register for the program such that the load reduction calculations appear on their monthly bill as described in the Settlements section of these procedures. (In either case, data regarding expected load reductions is required from these LSEs, as described in the "Implementation/Operations" section of this document.) PJM membership is required to participate, although any existing PJM Member may act as an agent for non-members in which case the agent will be referred to as the Curtailment Service Provider (CSP). All payments are made to the PJM Member. Participants must become signatories to the PJM Operating Agreement, as described in the ***PJM Manual for Administrative Services for the Operating Agreement of the PJM Interconnection, L.L.C.***

To participate in the program, the applicant must also meet the metering requirements as described in the next section.

METERING REQUIREMENTS

The Economic Load Response Program participants must have metering equipment that provides integrated hourly kWh values, for market settlement purposes, that either meets the EDC requirements for accuracy or has a maximum error of two percent end-to-end (including PTs and CTs). The installed meter must be one of the following:

EDC-owned hourly meter,

Customer-owned meter including one provided by an independent metering service provider or acquired from the CSP, approved by PJM, that is read electronically by PJM, or

Customer-owned meter including one provided by an independent metering service provider or acquired from the CSP, approved by PJM, that is read by the customer (or the CSP), the readings from which are forwarded to PJM.

Nothing here changes the existence of one recognized meter by the state commissions as the official billing meter for recording consumption.

Note that various Internet applications now exist for transmission of real time metered data. Use of these applications is acceptable provided that PJM receives metered load reductions in a timely, reliable manner.

The metering requirements can be met using either of the following three methods:

Metering that is capable of recording integrated hourly values for generation running to serve local load, (net of that used by the generators).

Metering that continuously records the load drawn from a specific process or application and is capable of demonstrating that the process or application was halted for the purposes of a load reduction and not due to normal operations.

Comparing actual metered load to a Customer Baseline Load (CBL) calculated as described below.

CUSTOMER BASELINE LOAD (CBL)

For those program participants that wish to measure actual reductions by comparing metered load against an estimation of what metered load would have been absent the reduction, a Customer Baseline Load (CBL) shall be calculated. The Customer Baseline Load (CBL) is calculated using the following methodologies:

The Average Day Customer Baseline Load (CBL)

Average Day CBL formula for weekdays

Step 1. Establish the CBL Window. Establish a set of days that will serve as representative of participant's typical usage.

The ***CBL Window*** is comprised of the 10 most recent days, beginning with the day 2 days prior to the event day for which the CBL is being calculated, excluding the following day-types:

Holidays, as specified by PJM

Event days, which are defined as days on which:

- PJM declared an event for which the participant was eligible for payment for a curtailment, or
- the participant actually reduced load and submitted the measured reduction to PJM for compensation.

To define the days that comprise the CBL Window:

Begin with the 10-day period defined by the weekday that is two days prior to the event through the weekday that is eleven days prior to the event day. This creates a 10-day window.

Eliminate any holidays, and replace them with days beginning with the 12th weekday day prior to the event day continuing until a non-holiday is encountered. This results in a 10-day window.

Eliminate any event days, replacing them with subsequent prior days, picking up with the first day not yet included in the window after completing the holiday replacement requirement.

Final **Weekday CBL Window** must contain 10 weekdays.

Step 2. Establish the CBL Basis. Identify the five days from the 10-day CBL Window to be used to develop CBL values for each hour of the event.

For each of the 10 days in the CBL Window, create the *average daily event period usage* for that day, which is defined as the simple average of the participant's actual usage over the hours in the day that define the event for which the CBL is being developed.

Create the *average event period usage level* for the 10 days in the CBL Window, which is defined as the simple average of the 10 average daily event period usage values.

Eliminate low usage days. For any day in the 10-day window for which the day's average daily event period usage is less than 75% of the average event period usage level, eliminate that day, and return to (Step A.1.a) and add a day to restore the 10-day window and check the elimination criteria and proceed to create a new 10-day CBL window.

Order the 10 days in the CBL Window according to their average daily event period usage level, and eliminate the five days with the lowest average daily event period usage.

The remaining five days constitute the **CBL Basis**.

Step 3. Calculate Average Day CBL values for the event.

For each hour of the event, the CBL is the average of the usage in that hour in the five days that comprise the CBL basis.

Average Day CBL formula for weekends

Step 1. Establish the CBL Window

The CBL Window is comprised of the most recent three like (Saturday or Sunday) weekend days. There are no exclusions for Holidays or event days.

Step 2. Establish the CBL Basis.

Calculate the average daily event period usage value for each of the three days in the CBL Window.

Order the three days according to their average daily event period usage level.

Eliminate the day with the lowest average value

The Weekend CBL Basis contains 2 days.

Step 3. Calculate Weekend Average Day CBL values for the event.

For each hour of the event, the CBL value is average of usage in that hour in the two days that comprise the CBL basis.

Weather-Sensitive CBL formulation

Step 1. Calculate the Average Day CBL values for each hour of the event period described in (I) above.

Step 2. Calculate the Event Final Adjustment Factor. This factor is applied to each of the individual hourly values of the Average Day CBL.

Calculate the Adjustment Basis Average CBL

- Establish the adjustment period, the two-hour period beginning with the start of the hour that is four hours prior to the commencement of the event through the end of the hour three hours prior to the event.
- Calculate the Adjustment Basis Average CBL.

Apply the Average Day CBL formula as described in I. Average Day CBL (page 2), to the adjustment period hours as though it were an event period two hours in duration, but using the five days selected for use in the Average CBL Basis.

Calculate the average of the two usage values derived above, which is the Adjustment Basis Average CBL.

Calculate the Adjustment Basis Average Usage

The adjustment basis average usage is the simple average of the participant's usage over the two-hour adjustment period on the event day.

Calculate the gross adjustment factor

The gross adjustment factor is equal to the ratio of the Adjustment Basis CBL and the Adjustment Basis Average Usage

Determine the Final adjustment factor.

The final adjustment factor is as follows:

- If the gross adjustment factor is greater than 1.00, then the final adjustment factor is the smaller of the gross adjustment factor or 1.20
- If the gross adjustment factor is less than 1.00, the final adjustment factors are the greater of the gross adjustment factor or .80.
- If the gross adjustment factor is equal to 1.00, the final adjustment factor is equal to the gross adjustment factor.

Step 3. Calculate the Adjusted CBL values.

The Event Adjusted CBL value for each hour of an event is the product of the Final Adjustment Factor and the Average CBL value for that hour.

PJM may consider a metering basis other than those described above if the method accurately represents a customer's normal load profile during the event. Suggestions for alternative methods by which load reductions may be measured may be approved by PJM for use in this program if negotiated in good faith and agreed to by all appropriate parties. PJM will consider such suggestions on a case-by-case basis and intends to study alternative measurement methods during the life of the program and report the results.

Metered load reductions will be adjusted up to consider transmission and distribution losses.

REGISTRATION

Participants must complete the PJM Economic Load Response Program Registration Form that is posted on the PJM web site (www.pjm.com) and included in an attachment to this document. The following general steps will be followed:

1. The participant completes the PJM Economic Load Response Program registration form located on the PJM web site. A separate registration form must be submitted for each customer.
2. PJM reviews the application and ensures that the qualifications are met, including verifying that the appropriate metering exists. PJM also confirms with the appropriate EDC and LSE whether the load reduction is under other contractual obligation. Other such obligations may not preclude participation in the program, but may require special consideration by PJM such that appropriate settlements are made within the confines of the existing contract. The EDC and LSE have two (2) business days to respond or PJM assumes acceptance.

3. PJM informs the applicant of acceptance into the program and notifies the appropriate LSE and EDC of the participant's acceptance into the program.
4. Any end-use customer intending to run distributed generating units in support of local load for the purpose of participating in this program must submit to PJM the applicable environmental permits for running those generators. In the event no environmental permitting has been obtained, written justification for the lack of permits must be provided to PJM.

REAL TIME OPERATIONS

The Economic Load Response Program is not based on the declaration of emergency conditions in PJM, but rather on the economic decisions of the PJM market participants. That is, the participants in the Program are responsible for determining the conditions under which load reductions will actually take place and implementing the reductions should those conditions arise. The prime indicator of such conditions is assumed to be the Locational Marginal Price (LMP) of energy on the PJM system.

In order to maintain adequate system control, PJM operators will be required to know the amount of load expected to be reduced at varying price levels. These amounts may change on a daily basis. Each PJM market participant is therefore responsible for maintaining the load reduction information associated with each customer signed up for the program, including the amount and the price at which it will be reduced. The Load Response Program Registration/Update web site shall be used for this purpose. PJM will utilize the data that has been submitted via this site to compile daily aggregate load reductions on a zonal basis for use in operations.

Participants in the economic option may choose to reduce load whenever their zonal LMP dictates that it is economically beneficial for them to do so. Participants shall send an email to PJM (address to be supplied upon registration) concurrent with or up to one hour immediately prior to accomplishing the reduction. Load reductions due to this program will not be eligible to set real time price on the PJM system unless metered directly by PJM.

VERIFICATION

For load reduction that is not metered directly by PJM (i.e. – is collected by the EDC), data is to be submitted to PJM within 45 days of the event. If the data is not received within 45 days, no payment for participation is provided. Meter readings must be provided for each hour during which load reduction was accomplished.

These data files are to be communicated to PJM either via the Load Response Program web site or email. Files that are emailed must be in the PJM-approved file format (see attachment). PJM will forward directly metered data to the appropriate EDC and LSE immediately following an event for optional review. Data files submitted after-the-fact will be forwarded to the EDC and LSE upon receipt. The LSE and/or EDC have five (5) business days after receiving the data to provide feedback to PJM. All load reduction data is subject to audit by PJM.

MARKET SETTLEMENTS

Reimbursement for reducing load is based on the actual kWh relief provided plus the adjustment for losses. An LSE/CSP with a Demand Side Resource that curtails Load in real-time will be paid by PJM the Real Time Zonal LMP.

Payments under the Economic Load Response Program will be made by PJM to the LSE/CSP. The portion that will be transferred from the LSE/CSP to the Demand Side Resource is outside the scope of PJM, and must be arranged between the LSE/CSP and the Demand Side Resource.

The ISO shall recover the cost of the payments to LSE/CSP and allocate these costs as follows:

Charges to customer's LSE	**0%**
Members short energy in the hour (prorated)	**50%**
PJM LSE's (load-share ratio)	**50%**

Program credits will appear on the PJM Member's monthly bill, as described in the ***PJM Manual for Operating Agreement Accounting*** and the ***PJM Manual for Billing***.

REPORTING

PJM will submit any required reports to FERC on behalf of the Load Response Program participants. PJM will also post this document, as well as any other program-related documentation on the PJM web site.

PJM will also report the names of those end-use customers who indicated that distributed generation would be run in support of the load reduction program to the EPA, together with the permitting information that was supplied upon registration.

At the conclusion of both the summer period and the program, PJM will prepare a report that summarizes the program and will submit it to the PJM Board of Managers, the Members Committee, the Reliability Committee, the Energy Market Committee, and the Operating Committee for review.

Option 3: Economic Load Response Program – Day Ahead

Effective period of program

The program will be effective June 1, 2002, and will remain in effect until May 31, 2005. At that time, the program will continue unless terminated by a majority vote from the PJM Members Committee.

Participant Qualifications

The same two types of distributed resources are also candidates to participate in the PJM Economic Load Response Program:

A customer that has the ability to supply required load via local generators

- These generators must be either synchronized or non-synchronized to the grid. Exports to the grid by local generators will be eligible for compensation under this program only if allowed under the interconnection agreement with the local utility.

A customer that has the ability to reduce a measurable and verifiable portion of its load

The Economic Option of the Load Response Program is intended to encourage broad participation in economic load reductions by any LSE's curtailable loads. LSEs arranging load reduction agreements with customers for whom they are the energy supplier are not required to register to participate in this program. These LSEs may wish to register for the program such that the load reduction calculations appear on their monthly bill as described in the Settlements section of these procedures. (In either case, data regarding expected load reductions is required from these LSEs, as described in the "Day Ahead Operations" section of this document.) PJM membership is required to participate, although any existing PJM Member may act as an agent for non-members in which case the agent will be referred to as the Curtailment Service Provider (CSP). All payments are made to the PJM Member. Participants must become signatories to the PJM Operating Agreement, as described in the ***PJM Manual for Administrative Services for the Operating Agreement of the PJM Interconnection, L.L.C.***

To participate in the program, the applicant must also meet the metering requirements as described in the next section.

METERING REQUIREMENTS

The Economic Load Response Program participants must have metering equipment that provides integrated hourly kWh values, for market settlement purposes, that either meets the EDC requirements for accuracy or has a maximum error of two percent end-to-end (including PTs and CTs). The installed meter must be one of the following:

EDC-owned hourly meter,

Customer-owned meter including one provided by an independent metering service provider or acquired from the CSP, approved by PJM, that is read electronically by PJM, or

Customer-owned meter including one provided by an independent metering service provider or acquired from the CSP, approved by PJM, that is read by the customer (or the CSP), the readings from which are forwarded to PJM.

Nothing here changes the existence of one recognized meter by the state commissions as the official billing meter for recording consumption.

Note that various Internet applications now exist for transmission of real time metered data. Use of these applications is acceptable provided that PJM receives metered load reductions in a timely, reliable manner.

The metering requirements can be met using either of the following three methods:

Metering that is capable of recording integrated hourly values for generation running to serve local load, (net of that used by the generators).

Metering that continuously records the load drawn from a specific process or application and is capable of demonstrating that the process or application was halted for the purposes of a load reduction and not due to normal operations.

Comparing actual metered load to a Customer Baseline Load (CBL) calculated as described below.

CUSTOMER BASELINE LOAD (CBL)

For those program participants that do not wish to measure actual reductions by comparing metered load against an estimation of what metered load would have been absent the reduction, a Customer Baseline Load (CBL) shall be calculated. The Customer Baseline Load (CBL) is calculated using the following methodologies:

The Average Day Customer Baseline Load (CBL)

Average Day CBL formula for weekdays

Step 1. Establish the CBL Window. Establish a set of days that will serve as representative of participant's typical usage.

The ***CBL Window*** is comprised of the 10 most recent days, beginning with the day 2 days prior to the event day for which the CBL is being calculated, excluding the following day-types:

Holidays, as specified by PJM

Event days, which are defined as days on which:

- PJM declared an event for which the participant was eligible for payment for a curtailment, or
- the participant actually reduced load and submitted the measured reduction to PJM for compensation.

To define the days that comprise the CBL Window:

Begin with the 10-day period defined by the weekday that is two days prior to the event through the weekday that is eleven days prior to the event day. This creates a 10-day window.

Eliminate any holidays, and replace them with days beginning with the 12^{th} weekday day prior to the event day continuing until a non-holiday is encountered. This results in a 10-day window.

Eliminate any event days, replacing them with subsequent prior days, picking up with the first day not yet included in the window after completing the holiday replacement requirement.

Final **Weekday CBL Window** must contain 10 weekdays days.

Step 2. Establish the CBL Basis. Identify the five days from the 10-day CBL Window to be used to develop CBL values for each hour of the event.

For each of the 10 days in the CBL Window, create the *average daily event period usage* for that day, which is defined as the simple average of the participant's actual usage over the hours in the day that define the event for which the CBL is being developed.

Create the *average event period usage level* for the 10 days in the CBL Window, which is defined as the simple average of the 10 average daily event period usage values.

Eliminate low usage days. For any day in the 10-day window for which the day's average daily event period usage is less than 75% of the average event period usage level, eliminate that day, and return to (Step A.1.a) and add a day to restore the 10-day window and check the elimination criteria and proceed to create a new 10-day CBL window.

Order the 10 days in the CBL Window according to their average daily event period usage level, and eliminate the five days with the lowest average daily event period usage.

The remaining five days constitute the **CBL Basis**.

Step 3. Calculate Average Day CBL values for the event.

For each hour of the event, the CBL is the average of the usage in that hour in the five days that comprise the CBL basis.

Average Day CBL formula for weekends

Step 1. Establish the CBL Window

The CBL Window is comprised of the most recent three like (Saturday or Sunday) weekend days. There are no exclusions for Holidays or event days.

Step 2. Establish the CBL Basis.

Calculate the average daily event period usage value for each of the three days in the CBL Window.

Order the three days according to their average daily event period usage level.

Eliminate the day with the lowest average value

The Weekend CBL Basis contains 2 days.

Step 3. Calculate Weekend Average Day CBL values for the event.

For each hour of the event, the CBL value is average of usage in that hour in the two days that comprise the CBL basis.

Weather-Sensitive CBL formulation

Step 1. Calculate the Average Day CBL values for each hour of the event period described in (I) above.

Step 2. Calculate the Event Final Adjustment Factor. This factor is applied to each of the individual hourly values of the Average Day CBL.

Calculate the Adjustment Basis Average CBL

- Establish the adjustment period, the two-hour period beginning with the start of the hour that is four hours prior to the commencement of the event through the end of the hour three hours prior to the event.
- Calculate the Adjustment Basis Average CBL.

Apply the Average Day CBL formula as described in I. Average Day CBL (page 2), to the adjustment period hours as though it were an event period two hours in duration, but using the five days selected for use in the Average CBL Basis.

Calculate the average of the two usage values derived above, which is the Adjustment Basis Average CBL.

Calculate the Adjustment Basis Average Usage

The adjustment basis average usage is the simple average of the participant's usage over the two-hour adjustment period on the event day.

Calculate the gross adjustment factor

The gross adjustment factor is equal to the ratio of the Adjustment Basis CBL and the Adjustment Basis Average Usage

Determine the Final adjustment factor.

The final adjustment factor is as follows:

- If the gross adjustment factor is greater than 1.00, then the final adjustment factor is the smaller of the gross adjustment factor or 1.20

- If the gross adjustment factor is less than 1.00, the final adjustment factors are the greater of the gross adjustment factor or .80.
- If the gross adjustment factor is equal to 1.00, the final adjustment factor is equal to the gross adjustment factor.

Step 3. Calculate the Adjusted CBL values.

The Event Adjusted CBL value for each hour of an event is the product of the Final Adjustment Factor and the Average CBL value for that hour.

PJM may consider a metering basis other than those described above if the method accurately represents a customer's normal load profile during the event. Suggestions for alternative methods by which load reductions may be measured may be approved by PJM for use in this program if negotiated in good faith and agreed to by all appropriate parties. PJM will consider such suggestions on a case-by-case basis and intends to study alternative measurement methods during the life of the program and report the results.

Metered load reductions will be adjusted up to consider transmission and distribution losses.

REGISTRATION

Participants must complete the PJM Economic Load Response Program Registration Form that is posted on the PJM web site (www.pjm.com) and included in an attachment to this document. The following general steps will be followed:

1. The participant completes the PJM Economic Load Response Program registration form located on the PJM web site. A separate registration form must be submitted for each customer.

2. PJM reviews the application and ensures that the qualifications are met, including verifying that the appropriate metering exists. PJM also confirms with the appropriate EDC and LSE whether the load reduction is under other contractual obligation. Other such obligations may not preclude participation in the program, but may require special consideration by PJM such that appropriate settlements are made within the confines of the existing contract. The EDC and LSE have two (2) business days to respond or PJM assumes acceptance.

3. PJM informs the applicant of acceptance into the program and notifies the appropriate LSE and EDC of the participant's acceptance into the program.

4. Any end-use customer intending to run distributed generating units in support of local load for the purpose of participating in this program must submit to PJM the applicable environmental permits for running those generators. In the event no environmental permitting has been obtained, written justification for the lack of permits must be provided to PJM.

DAY AHEAD OPERATIONS

PJM will accept Demand Reduction Bids wherein an LSE/CSP can bid on behalf of a Demand Side Resource for a specific MW curtailment (in minimum increments of .1 MW). The Demand Reduction Bid would include the Day-Ahead LMP above which the Load would not consume, and could also include a start-up cost and/or a minimum number of contiguous hours for which the load reduction must be committed.

The objective function for day ahead commitment software will be to eliminate Demand Reduction Bids from Day-Ahead Bid Load when the total Bid Production Cost over the 24 hour Dispatch Day will be reduced compared to serving that Load, including consideration of paying the Demand Reduction Bid for the length of the minimum commitment time and any start-up cost. Thus, curtailments will not be scheduled unless they reduced total Day-Ahead production costs.

Demand Reduction Bids can set Day-Ahead LMP just as a comparably bid Generator

VERIFICATION

For load reduction that is not metered directly by PJM data is to be submitted to PJM within 45 days of the event. If the data is not received within 45 days, no payment for participation is provided. Meter readings must be provided for each hour during which load reduction was accomplished.

These data files are to be communicated to PJM either via the Load Response Program web site or email. Files that are emailed must be in the PJM-approved file format (see attachment). PJM will forward directly metered data to the appropriate EDC and LSE immediately following an event for optional review. Data files submitted after-the-fact will be forwarded to the EDC and LSE upon receipt. The LSE and/or EDC have five (5) business days after receiving the data to provide feedback to PJM. All load reduction data is subject to audit by PJM.

MARKET SETTLEMENTS

Reimbursement for reducing load is based on the reductions of kWh committed in the Day Ahead Market. An LSE/CSP with a Demand Side Resource that schedules a load reduction Day Ahead and is accepted by PJM will be paid by PJM the Day Ahead Zonal LMP plus Operating Reserves.

Payments under the Economic Load Response Program will be made by PJM to the LSE/CSP. The portion that will be transferred from the LSE/CSP to the Demand Side Resource is outside the scope of PJM, and must be arranged between the LSE/CSP and the Demand Side Resource.

The ISO shall recover the cost of the payments to LSE/CSP and allocate these costs as follows:

Charges to customer's LSE	**0%**
Members short energy in the hour in the day-ahead market (prorated)	**50%**
PJM LSE's (day-ahead load-	**50%**

share ratio)	

Program credits will appear on the PJM Member's monthly bill, as described in the ***PJM Manual for Operating Agreement Accounting*** and the ***PJM Manual for Billing***.

NON-PERFORMANCE

Load reductions committed in the day-ahead market that cannot demonstrate performance in real time equal to at least that of the day-ahead commitment will be charged the higher of day-ahead or real time zonal LMP for the amount of the shortfall, plus any associated day-ahead operating reserve credits. Any extra funds collected by PJM as a result of this charge will serve to reduce the overall day-ahead operating reserves charge for that hour.

REPORTING

PJM will submit any required reports to FERC on behalf of the Economic Load Response Program participants. PJM will also post this document, as well as any other program-related documentation on the PJM web site.

PJM will also report the names of those end-use customers who indicated that distributed generation would be run in support of the load reduction program to the EPA, together with the permitting information that was supplied upon registration.

At the conclusion of both the summer period and the program, PJM will prepare a report that summarizes the program and will submit it to the PJM Board of Managers, the Members Committee, the Reliability Committee, the Energy Market Committee, and the Operating Committee for review.