# DEMAND-SIDE RESPONSE
# BENEFITS SUBGROUP REPORT

(Updated: Sept. 30, 2004)

## Introduction

The Pennsylvania Public Utility Commission's Demand Side Response Working Group was created to collect information and data concerning issues related to the development of demand side response programs in Pennsylvania. The Working Group was divided into four subgroups: 1) Technology Deployment and Costs, 2) Cost Recovery Mechanisms, 3) Consumer Surveys, and 4) Benefits. This report summarizes the work of the Benefits subgroup.

The Benefits subgroup had three main objectives:

- To determine the proper methodology to evaluate the cost-effectiveness of DSR programs.
- To define benefits of DSR programs.
- To determine what data is needed to conduct the analysis.

Some of the general points made early in the process and agreed upon were:

- DSR benefits may accrue to: 1) customers, 2) utilities, 3) society, and 4) the market.
- Net Present Value (NPV) is the appropriate financial tool to measure the cost-effectiveness of DSR programs.
- Benefits can be viewed as falling into four categories: 1) Quantifiable-direct, 2) Quantifiable-non-direct, 3) Non-quantifiable-direct, and 4) Non-quantifiable-non-direct.
- Benefits rely on the effectiveness of any investment in motivating demand response to market-based values. Benefits are based on market response, enabled but not necessarily ensured by investments.

The subgroup organized into committees. One committee was to address how to measure quantifiable direct benefits, and the second to identify non-quantifiable benefits. The following sections will detail the work and findings of those committees.

## Quantifiable Benefits

The task of the quantification committee was to determine a methodology to measure the cost-benefits of quantifiable DSR programs. Two members of the committee (David Boonin, TBG Consulting and Skip Trimble, Chase Consulting) offered specific methodologies to evaluate the benefits of DSR programs. Their two models offered slightly different approaches, different levels of data collection, complexity, and cost to use. A small number of the Benefits subgroup provided comments and critiques of the models. There was not a consensus on the appropriateness of either model to accurately measure benefits or on which model would be preferable. Boonin and Trimble suggested that there is a place for both models in the evaluation process. The Boonin model is a tool for DSR public policy assessment. The Trimble model evaluates the cost-effectiveness of individual DSR programs for participants. Both models have distinct uses in evaluating the value of DSR benefits.

Both methods have some common limitations. They both employ historical data which may not be a good indicator of the future in light of the changing market structure. The uncertainty includes the structure of post-rate cap retail energy markets, effectiveness of the DSR programs, and the extent to which historical fuel and market energy pricing are good indicators of future prices. Any analysis which estimates the cost benefits associated with any DSR program needs to be done with data that represents the best estimate of what is likely to occur over the life of the programs.

It is critical to note that this work was done at a time when PJM, through their stakeholder process, is considering material changes to the definitions, processes and resulting values related to capacity and energy markets. The intent of these revisions is to provide increased long-term capacity adequacy and system reliability and to reduce volatility in the energy price market. New concepts being vetted through PJM processes include Forward Energy Reserve markets and Reliability Pricing Model. The models assessed in this process relate to existing PJM rules. New models will be needed to project values associated with new rules when adopted.

**Valuation Process Method (Skip Trimble's "Simple Model").** This methodology is a simple, replicable, and an inferential approach to valuing DSR potential. It is based upon public and standardized market information, utilizes basic mathematics, proven statistical inferences, and provides standardized results. It includes transmission congestion, operational changes, reliability, and changing control area dynamics. The model also considers market design, market elements (supply/demand, fuel prices, PJM DSR designs, credit and interest costs) and regulatory changes.

The process includes four basic steps: 1) LMP frequency analysis, 2) statistical analysis of that information in context of DSR value, 3) development of confidence level of that information, and 4) projection of the value of the forward market. For more details, see Appendix A- "Valuation Process Proposal Pa. Demand Side Response."

The following are some comments from the DSR Working Group members concerning the model with the person commenting named in parentheses.

"Does not calculate all values in DSR"; "Not a robust model, just an indicator or potential value"; "Reflects end-user value as opposed to utility, control area"; "Use this for a quick end-user analysis"; "If potential exists go to a more robust model" ( Skip Trimble)

"This method appears to be [a] good tool for the end-user to evaluate the benefits of a DSR program, however I don't believe using the forward market adds much to the analysis. In most cases the forward market is either above or below where the market actually delivers." (Doug Stinner)

"I agree that Skip's approach is more about evaluations needed by load rather than the evaluations needed by the system or market." (Dan Griffiths)

"The analytical approach proposed by Mr. Trimble is appropriate for individual end-users to use when assessing whether they should pursue individual DSR options that may be available to them. It goes further than Boonin's approach that focuses on the quantity change, also looking at the impact the customer's behavior may have on its retail electric bill." (joint statement Skip Trimble and Dave Boonin)

**Price Change Distribution Table (Dave Boonin's Model).** The Price Change Distribution Table (PCDT) method quantifies a DSR's impact on the direct cost of electricity that integrates the many pieces of this puzzle into a single answer. It provides DSR program developers with a tool by which they can focus on hours where DSR may have the greatest system benefits. The value of this method is that it measures a resource's benefits as both a resource (the traditional approach) and as a price hedge (a new approach) in a competitive market. The hedge benefit measures the impact DSR has on the price of electricity and all affected volumes.

The core of the PCDT is to focus on DSR driven price change and then on cost change rather than the traditional emphasis on hours of high prices (LMP) that may or may not have the same magnitude of benefits. The PCDT is supported by a group of tables that each start by looking at the distribution of the change in bid price caused by a particular increment or decrement on load based upon historical bid information. The price change distribution would be enhanced by additional information such as average load, amount of short-term resources used to meet load, LMP, impact on UCAP and ancillary services, etc. The model also relies on data that may not be generally available such as hourly MWh traded, and marginal prices of the next and last increments of load traded on the short-term markets. For more details, see Appendix B- "Quantifying DSR's Impact on the Cost of Electricity- Price Change Distribution Table Approach."

The PCDT created much debate and critique. Comments ranged from- the PCDT is a cutting-edge technique to it has little value in measuring DSR benefits. Most of the discussion on the PCDT focused on the "hedge benefit" component. Some of the comments follow.

"Both of these methodologies employ historical data, however, especially in light of the fact that market structures continue to evolve, historical data is probably not a good indicator of the future. These methodologies can incorporate forward estimates of data such as energy and capacity prices to evaluate DSR programs. However, any estimate of future benefits associated with DSR programs is subject to uncertainty." (Pa. Energy Association with concurrence from Ed Johnstonbaugh)

"I believe the "hedge" value specified in his [Dave Boonin's] methodology may be overstated. If the wholesale markets are efficient, once the market understands how and when the DSR programs are instituted, the value associated with the load reduction will diminish. If the market knows that when the LMP reaches $100/mw, then DSR participants will reduce load, the market will anticipate this reaction and as a result the LMP may not reach $100, or will only reach $100 at higher loads." (Doug Stinner)

"…generators might actually increase their prices in the non-DSR hours to make up lost revenue. A generator might require an average price of 3.5 cents per kwh and he can get that by bidding 3.0 cents most hours and benefit from high prices in a few hours or bid 3.2 cents and benefit less in fewer high price hours. Alternately the generator could bid higher for capacity. Bottom line is the DSR hedge benefit is very difficult to calculate." In addition, "…the hedge benefit is likely overstated. I don't believe generators will lower their bids in response to DSR but might increase bids if they are not collecting enough revenue. I recognize that the MMU will monitor this but SRMC does have some flexibility as to what is included and when looked at over all hours it might only be 1-2 mills/kwh that is needed." (Alan Cohn)

An opposite viewpoint was expressed in the following comments:

"Joe Bowring has found (see the State of the Market Report for 2003) that generators typically bid at short run marginal cost. So, they cannot bid differently (or at least not lower) when they know that DSR is operative. Specifically, they cannot run below SRMC so they will not bid below that point. In fact, there may be pressure on the lowest priced generators to bid above SRMC because, given active demand response, they will get less revenue in the hours when DSR is active even though the prices are (well?) above their SRMC. This is a matter for the MMU." "As for the use of forward markets, it is true that these are never exact in terms of the real-time price. However, day-ahead forward prices are very closely correlated with real-time. Longer term prices- monthly or greater- are often used in planning at every level because it is possible to hedge much of the uncertainty as to their final accuracy. So, inaccuracies are compensated for." (Dan Griffiths)

"…this flys in the face of both the laws (sic) of supply and demand and how pricing is done in the PJM market. Neither of these systems operates on a revenue sufficiency basis." "DSR makes energy cheaper by putting additional inframarginal bids into the supply curve. It has the same impact as adding energy bids to the less expensive part of the curve." "The claim that generators will bid above cost to recover expenses is irrespective of DSR. Generators that are currently short revenues have this incentive NOW. In fact, assuming the generator is not in a position to exercise market power, the only limit on their bids is the presence of lots of other sellers – of generation and DSR – in the market. That's the way it's supposed to be in a liquid market. If generators are in a position to exercise market power, I think the MMU can identify bids that are $1 to $2/mwh above cost. (Dan Griffiths)

"In short, DSR is just another resource. If DSR can be brought to bear at less than the bid price and displace the units bid at that price, the price on the system goes down. At different times, the bid price is more or less sensitive to changes in the market clearing condition (decrease in load or introduction of cheaper supply)…Focusing on when the market price is sensitive to resource change rather than only to when market price is high should give us all a better understanding of when DSR has value and how valuable it may be…" (Dave Boonin)

"PJM acknowledges that this benefit exists. The data exists at PJM. PJM is willing to cooperate. This is a benefit that state regulators need to know about if they are to make meaningful policies regarding DSR." (Dave Boonin)

"The approach for calculating DSR's benefits associated with the cost of electricity proposed by Mr. Boonin's model is appropriate for the Commission to use in performing any cost/benefit analysis it may do regarding DSR policy assessments. It captures the impact on the cost of electricity that comes from using less electricity (the quantity impact on cost commonly enjoyed by the participating customer) and on the electricity commonly enjoyed by all). For example, Boonin's methodology should allow the Commission to quantify the benefits associated with DSR that may be associated with metering requirements the Commission may wish to consider." (David Boonin and Skip Trimble)

"Both approaches are relatively straightforward and are based upon available market data. The Commission should take steps to have Mr. Boonin's methodology more fully developed so that the PUC can make the best policy decisions possible. The PUC should also support the development and use of an end-uses' methodology (Mr. Trimble's methodology) so that customers who are considering participating in a DSR program can make good decisions." (David Boonin and Skip Trimble)

**Discussion of Proposed Models.** Both of the above models appear to have merit in evaluating the cost-effectiveness of DSR programs. Various members of the Benefits sub-group noted what they felt were limitations of the models. Some of the comments suggested that because of the historical data limitations the models held little value to DSR policy analysis. Others suggested just the opposite.

Any model that attempts to model the "real world" or predict future benefits probably will be inaccurate. The question is to what degree. Most, if not all sub-group members, acknowledge that neither model will provide exact results, but many members seem to feel that they are still a critical resource for informed decisions and an aid for systematic policy analysis. The Commission staff feels that models can benefit policy analysis if some confidence level is incorporated into the model.

The Benefits sub-group does not recommend one model over the other, as each model serves a different purpose. The Commission must first determine the level of analysis that it desires before deciding what modeling it desires to employee, or they may choose to move forward with DSR without any in-depth cost-effectiveness analysis. However, this is not recommended. The sub-group's general finding is that the PCDT model appears suited for informed policy decisions from a more comprehensive perspective, and the "Simple Model" may be adequate to predict the benefits of individual DSR programs. If the Commission desires to utilize a quantitative model to analyze the cost-effectiveness of DSR programs, they should: 1) determine the level of detailed analysis that they desire, 2) determine the appropriateness and appropriate use of each of the above models, or another model, to provide that level of detail, 3) determine the availability and the cost to obtain the data necessary to run the model, and 4) determine the cost-effectiveness of using the model for policy analysis.

**Non-Quantifiable Benefits**

The non-quantifiable benefits committee of the Benefits Sub-group attempted to identify and classify non-quantifiable DSR benefits. Dan Griffiths and Kerry Campbell lead this effort with input from various sub-group members. The final product was a matrix of over forty non-quantifiable or partially quantifiable benefits. For more details, see Appendix C- Non-quantifiable Benefits Matrix. The matrix attempts to categorize the benefits into different areas for various stakeholders. The benefits are also noted as direct benefits or indirect benefits. Some of the benefits identified in Appendix C are associated with full deployment of automated metering systems with interval meter reading capability which may or may not be part of a DSR program.

The matrix is a first attempt at noting what may be non-quantifiable benefits. Dan Delurey, from Demand Response and Advanced Metering Coalition (DRAM) noted, "Another way to differentiate benefits is to look at them from the standpoint of who the beneficiary is. Key here is the fact there are more beneficiaries from demand response than simply the demand response provider and the participating customer. Benefits also may accrue to non-participating customers…or other parties in the electricity industry. There are also may be benefits to parties outside of the immediate electricity system (e.g. reliability) and even to society in general (e.g. environmental benefits)."

"Another factor is timing of the benefits, with some having short-term vs. long-term yields. This may also be considered from an investment perspective in terms of potential future benefits. For example, some demand response technology choices may provide different degrees of capability to capture future benefits."

"Finally, and certainly not least in importance, is [the] aspect of benefit quantification. Not all of the benefits of demand response can be easily quantified such that they lend themselves to easy inclusion in a business case evaluation. Yet these benefits are nevertheless real and may lend themselves to a regulatory analysis of demand response analogous to how other areas like energy efficiency and renewables have been treated in the past. Qualitative treatment may have to be considered."

Not all sub-group members agreed that all benefits in the matrix were appropriate. Bill Patterer from PECO offered specific comments on selected benefits that he either felt were redundant with another benefit or disagreed that it was a benefit.

The value of the non-quantifiable benefits committee's work is not so much if everyone agrees that all forty-some non-quantifiable benefits should be included, but that there are DSR benefits that are not quantifiable and should be recognized as potentially offering value. Dan Griffiths stated in, "PUC DSR Benefits Sub-Group- Analytical Classification of Benefits", "Everyone agrees that there are benefits to many DSR programs. However, there is not substantial consensus as to the magnitude of benefits, who benefits and how benefits can be measured…" The Benefits sub-group's one objective was to document that non-quantifiable DSR benefits do exist. The sub-group did not reach consensus on which ones they are.

**Summary**

The Benefits Sub-group attempted to identify both quantitative and non-quantitative DSR benefits. The quantitative committee examined two models that could be used for analysis of DSR programs. The PCDT model provides a more comprehensive method and is useful for DSR policy analysis. The "Simple Model" may not capture as many of the DSR benefits but could be used to assess the benefits of individual DSR programs. If the Commission wishes to use either model, a more detailed analysis should be conducted of each model including the availability and cost of data to run the model. If the Commission is interested in developing cost-effective DSR policy and programs, it should consider some type of quantitative policy analysis tool.

The non-quantitative committee generated a long list of DSR benefits that are not easily quantifiable. Not all members agreed that all non-quantifiable benefits were mutually exclusive or even constituted a benefit. The important point is that DSR programs may generate benefits that are not quantifiable and may benefit populations beyond the customer or the utility.

**APPENDIX A – “Valuation Process Proposal Pennsylvania Demand Side Response”**

# Valuation Process Proposal
# Pennsylvania Demand Side Response

## Forward

This methodology is a simple, replicable and an inferential approach to valuing the ever-dynamic DSR potential. It is based upon public and standardized market information (LMPs and published forward electricity price curves), utilizes basic mathematics and proven statistical inferences and provides standardized results whose meaning should be universal. It includes the physicality of the market (transmission congestion, operational changes, reliability and changing control area dynamics), market designs and market elements (supply/demand, fuel prices, PJM DSR designs, credit and interest costs) and regulatory changes. It is easy to perform, cost effective and auditable.

## The Process

The process includes four basic steps: LMP frequency analysis, statistical analysis of that information in context of DSR value, development of confidence level of that information and then projection of the value of the forward market.

### I. LMP Frequency Analysis

**Data:** PJM provided LMP data for a specific delivery point. There are close to 1700 different nodes in PJM and these reflect the specific volatility of each potential delivery point. They are offered as integrated hourly prices. Congestion, fuel costs, market events and near real time supply/demand events are here portrayed.
**Requirement:** The evaluator must identify a point where DSR makes economic sense for participation. This point can be economic, political, budgetary or based upon supply contracts.
**Process:** Two evaluations will take place. First a frequency analysis of the data broken into groupings of On-Peak, Off-Peak and RTC. This gives actual pricing information. Second is looking at a frequency evaluation of the difference between the economic point selected above and the prices again at On-Peak, Off-Peak and RTC. Value occurs only when positive. This is the "added value" of DSR participation.

### II. Statistical Analysis

**Data:** Frequency analyses (above).
**Requirement:** Define whether monthly, annual or seasonal data is required.
**Process:** Two evaluations will take place. First a complete frequency analysis of the data broken into On-Peak, Off-Peak and RTC. This gives actual pricing information. Second is looking at a frequency evaluation of the difference between the economic point selected above and the prices at On-Peak, Off-Peak and RTC. Value occurs only when positive. This is the "added value" of DSR participation. From these analyses, derive the mean and standard deviations which will provide the simple statistical process of developing confidence levels.

## III. Confidence Level

**Data:** The standard deviation and the mean developed above are the cornerstones of the confidence level calculation.
**Requirement:** The evaluator must identify a confidence level or several confidence levels. Perhaps, e.g. 75% and 90% levels which will give inferential probabilities of expected results.
**Process:** This is a simple mathematical process that incorporates confidence level, mean and standard deviation to give a range of expectations.

## IV. Value Projections

**Data:** Forward curves will be provided by independent sources in the market place (who now provide these indices for financial, trading and credit institutions). Whereas indices based upon each LMP node are not available, the forward curves can be accessed for general zones (in PJM) such as the PP&L zone. These numbers reveal the general market conditions going forward.
**Process:** The forward curve (average of the bid/ask points) will be compared to the mean price developed in step one. The relative change (plus or minus) will be multiplied by the range of values for On-peak, Off-peak and RTC. This is your value-added going forward and can be annual or monthly.

**APPENDIX B – "Quantifying DSR's Impact on the Cost of Electricity Price Change Distribution Table Approach"**

# Quantifying DSR's Impact on the Cost of Electricity
# Price Change Distribution Table Approach

**David Magnus Boonin, TBG Consulting**

**Overview - Price Change Distribution Table Approach**

The Price Change Distribution Table Approach (PCDT) is a new methodology to quantify a DSR's impact on the direct cost of electricity that integrates the many pieces of this puzzle into a single answer. It also provides DSR program developers with a tool by which they can focus on hours where DSR may have the greatest system benefits. The value of this methodology is that it measures a resource's benefits as both a resource (the traditional approach) and as a price hedge (a new approach) in a competitive market. The hedge benefit measures the impact DSR has on the price of electricity and all affected volumes (e.g., short-term resources used to provide load in the affected region).

The core of the PCDT is to focus on DSR driven price change and then on cost change rather than the traditional emphasis on hours with high prices (LMP) that may or may not have the same magnitude of benefits. The PCDT is supported by a group of tables that each start by looking at the distribution of the change in bid price (e.g., number of hours for each $0.50/ MW change in bid) caused by a particular increment or decrement of load based upon historical bid information (only historical information captures the volatility most often associated with DSR benefits). This price change distribution would be enhanced by additional information such as average load, amount of short-term resources used to meet load, LMP, impact on UCAP and ancillary services, etc. The tables should be very mechanical and easy to update relatively frequently (e.g., quarterly).

A hypothetical example is provided below. A template for a single table is shown at Attachment A.

PCDT was selected as the preferred methodology for assessing this benefit of DSR. Several other methodologies were considered and are summarized briefly in Table 1. The PCDT was an attempt to streamline the hourly bid data into a more user-friendly tool. Some of the other tools' basic approaches are integrated into the PCDT (e.g., Price Distribution and Forward Curves). Note: If the accuracy was determined to poor, ease of use was also considered poor.

**Table 1 – Comparison of Methodologies**

| Methodology | Accuracy | Ease to Assemble | Ease to Use |
|---|---|---|---|
| **PCDT** | Very Good | Fair | Good |
| **Hourly Bid Data:** Allows for superior hourly matching of benefits. No data loss to averages. Cumbersome database that provides little guidance. | Excellent | Fair | Fair |
| **Price Distribution:** Doesn't capture price changes, only price levels. Premise incorporated into PCDT. | Poor | Good | Poor |

| | | | |
|---|---|---|---|
| **Forward Curves:** Loses hourly details that drive DSR. Premise can be incorporated into PCDT through potential enhancement. | Poor | Good | Poor |
| **Production Cost:** Bids not cost drive today's markets prices. Antiquated methodology. | Poor | Fair | Poor |
| **Supply-Side Proxies:** A fair long-term proxy. Not tied to short-term markets. | Poor | Good | Poor |

Depending on the upfront flexibility and commitment that is desired to be engineered into the system, there should be no reason why a PCD table could not be customized to meet the explicit constraints of a particular DSR (e.g., a customized form driven by a set of queries and supported by a relational data base. Through this type of a methodology, the analyst could focus on virtually any zone or time period or range of increment or decrement by answering a few straightforward program design questions. This would decrease the ease of assembly and increase the ease of use.

**<u>What's Being Measured?</u>**

One of the many potential benefits of Demand-Side Resources (DSR) is the impact it has on the cost (i.e., price multiplied by quantity) of electricity. DSR can cause these changes because of two major features: DSR as an energy resource and DSR as a price hedge. The energy resource is the impact that DSR has on the supply-demand situation. It may be a pure reduction in load or shift in load. These changes may allow the system to avoid the need for providing electricity during periods when supply resources are expensive and may also reduce the systems needs for capacity and ancillary services.

The hedge impact is principally driven by the change in price(s) that this change in load causes. The principal change is the shift of the LMP. This can only be applied to the load that is provided by spot or near spot (unhedged) resources. For example, if the system requirements were all met through long-term fixed price contracts, there would be no hedge value of DSR as there would be no change in price (no change in the bid over the relevant range) caused and there would be no applicable (unhedged) quantity of load to apply the change. Conversely, if all demand were met by short-term (e.g., spot or day-ahead) purchases, the hedge impact would be the change in the bid price caused by the DSR multiplied by the entire applicable load. There can also be a hedge impact on UCAP and ancillary services if the DSR causes a change in the price of these components to the total cost of electricity.

In addition to the two major sources of the benefits (DSR as an energy resource and DSR as a price hedge), there are also some hybrid impacts associated with UCAP and Ancillary Services. The table below outlines what an ideal measure would capture.

**Table 2 – Ideal Components of DSR's Impact on the Cost of Electricity**

| Component | General Description | Thorny Issues |
|---|---|---|
| **Change in Load** | Multiply change in load by LMP for each hour DSR is to be deployed and sum. | • Shifts Vs Reductions<br>• 1600 zones<br>• Matching hours<br>• Avoiding averages |
| **Change in Price (LMP)** | Multiply change in LMP by applicable load for each hour DSR is to be deployed and sum. | • Steepness of bids<br>• 1600 zones<br>• Applicable load<br>• Matching hours<br>• Avoiding Averages |

| | | |
|---|---|---|
| **Change in UCAP** | Calculate both change caused by reduced UCAP requirement and reduced UCAP price. | • UCAP changes<br>• Matching hours<br>• Avoiding Averages |
| **Change in Ancillary Services** | Calculate both change caused by reduced services requirement and reduced services price. | • Ancillary Services changes<br>• Matching hours<br>• Avoiding Averages |

The table lists two recurring issues of matching hours and avoiding averages. Matching occurrences to the same hours is important so as not to overstate the benefits by claiming that two or more benefits occur during the same hour or group of hours without substantiation (e.g., there may be no impact on UCAP in certain hours where the change in the bid price is high). It is also important not to understate the impact of DSR by using averages or other measures that blur the very events to which DSR can be applied.

This document is not intended to provide all the answers to assessing the benefits associated with the cost of electricity from DSR. It should help focus the discussion and assure that important benefits (e.g., hedge benefits) do not go uncounted).

**Major Premise – Hedge Impact is Most Important**

The emphasis of this methodology is the hedge effect, the impact that DSR can have on LMP and on the total cost of electricity. Often the emphasis is has been focused on hours when the raw LMP is high. This methodology focuses first on the hours when achievable changes in load could have resulted in large changes in the LMP. It is intuitively believed (only further analysis will support or refute this claim) that there are hours where the absolute price is not relatively high, but that the potential change in price is significant. It is also believed that during periods of high prices, that the value of DSR is much greater when the potential to change the LMP is also high.

The following hypothetical example is provided to support these assumptions.

Base Case - High Price and High Change in Price: Assume that the LMP without DSR is $80/MW and that a 100 MW one-hour reduction in load would change the LMP (based upon the bids received) to $60/MW. Also assume that there is 1,200 MW of short-term purchases being made to meet load. The resource impact of DSR at this time is the avoided 100 MW multiplied by the avoided $80/MW or $8,000. The hedge impact of the DSR is the impact on LMP of $20/MW ($80-$60) multiplied by the affect load of 1,100 MW (1,200 MW less the 100 already counted) or $22,000. The total impact is $30,000 with about 73% associated with the change in price.

If the focus had been on only on hours with high prices and there was no hedge value (e.g., no change in the LMP over the relevant range) the benefits would have been much less (only $8,000).

If the change in LMP were still $20, but the starting price had been much lower (e.g., $60/MW), $22,000 in hedge benefits would still exist and the resource benefit would be reduced to $6,000 or to $28,000 in total.

This premise is driven by the belief that the amount of load impacted by the change in price will be much greater than the load actually changed during the hours that DSR is used. This is supported by the following reasons.

- DSR properly applied will focus on this type of hour to capture these benefits.
- DSR will allow the system to rely more on short-term resources and avoid the insurance premiums associated with long-term future contracts. (This benefit has not been quantified as of this time).

Note, that the methodology suggested herein is applicable even if the above premise is false. It is prudent to pursue this methodology given the enormous potential analytical upside that cannot be gained if the focus is mainly on the resource portion.

**Some Other Areas of Special Emphasis**

In addition to building a methodology that is designed to identify the potential number of hours when benefits can be greatest, the methodology proposed should have the capability to:

- Focus on benefits that accrue to a particular utility service territory. The PA PUC is considering whether to mandate its jurisdictional utilities to implement DSR. If the costs are to be borne within the utility's sphere (including its customers), the benefits should be disaggregated to show what is retained in the utility's sphere. Resource initiatives ranging from power plant productivity to DSR will impact the cost of electricity on the entire integrated resource system (e.g., PJM). These broader benefits should be quantified and policy discussions should be increased with PJM on how best to assign (capture) the benefits to the driving utility. Similarly, the benefits of a utility sponsored DSR may provide benefits to the providers of non-POLR energy users (a benefit that may or may not be captured directly by the end-user).
- Only the load met by short-term resources should be considered in quantifying the hedge benefits. Long-term contracts will not be affected and to fail to make this adjustment will overstate the value of DSR.
- The focus is of this methodology is on the actual change in the cost of meeting system requirements. This methodology does not consider changes such as the change in a particular customer's utility bill as that is more of an inter-class shift rather than a change in the total size of the pie.
- PCDT should also allow the analyst to consider future changes by applying information from the incremental and decremental bid tables and possibly by considering future curves.
- PCDT should allow DSR to be considered like any other resource. The value of a new base-load generating plant on the system is not just the incremental power it displaces (the old production cost based paradigm) but is also the value of lowering the overall price of electricity incurred by all.

**A Look at the Tables**

PCDT is based upon a family of tables. Each table would represent a different situation that would first look at the distribution of the change in price.

The situations would all start with a definitive increment or decrement of load. The table would track the impact on the market-clearing bid that the load change would cause (e.g. number of hours when a 50 MW reduction would lead to a $10 change in the price). Historical data would be used to create these base tables. A family of tables would be developed that would look at things such as:

- Different decrements and increments of load. (The appropriate load change levels need to be initially determined and the increments and decrements need not be symmetrical. Additionally the increments and decrements could be changed based upon the "territory" being considered).
- On peak and off peak (TOD)
- Seasons or months of the year
- Territories. It would not be practical to perform this analysis for all 1600 zones in PJM, however defining the territories along the lines of PJM, PJM east and west and utility service territories is probably sensible.

It is suggested that we start with the system as a whole (all hours for all of PJM and a significant load decrement) as a first cut. Additional tables (hundreds) could then be built. A table would then be built for each scenario that would provide the distribution in change in price associated with the load change and other chosen characteristics. As stated earlier, it is probably possible to develop the underlying data into a relational database so that customized tables could be easily created for individual DSR programs.

To allow this distribution information to be most useful, the following information should be captured for each of the groups of hours identified. These are the likely column headings (The rows will be the hours affected for each range of a price change).

- <u>Change in LMP</u>: The spot LMP is used, as it is the cleanest approach (free of all insurance premiums) and most applicable to DSR.
- <u>Average load</u>: Although averages are often dangerous, the small range of a change in price should make it a good second best measurement (this applies to other averages used below. Average load is one of the measurements that can be used to combine with change in price to determine the maximum potential benefit associated with the price change if all load were provided by short-term resources.
- <u>Average load provided by short-term resources</u>: This would probably include at least spot purchases and day-ahead purchase, the core of the ISO clearinghouse. When multiplied by the change in price it may provide a more sensible measurement of actual benefit than total load.
- <u>Average LMP</u>: In order to be able to calculate the resource value of the hours under consideration, it is important to capture the actual price as well as the change in price.
- <u>Maximum impact on UCAP requirement by the increment or decrement</u>: This would provide a partial basis for assessing the changing in UCAP. (Note that UCAP benefits may need to be lagged to the following UCAP year).
- <u>UCAP requirement</u>: For the hours in question, the total average UCAP requirement. This should be to UCAP for the relevant territory regardless of whether a change has occurred. This is necessary to calculate the UCAP benefit.
- <u>Average Change in UCAP price</u>: This should be market based (bid) historical data.
- <u>Average UCAP Price</u>: The average UCAP price over the period in question.
- <u>Ancillary Services</u>: Columns could be established for: Number of Hours within the Range Where Ancillary Services are Impacted. Ancillary Services Requirement, Average Ancillary Service Price Change and Average Ancillary Services Price. At this time, this maybe excessive fine-tuning.

- Total Benefit: For each row, calculations could be performed to indicate the most beneficial periods. This would allow the analyst to resort the data based upon some total benefit measurement. Other columns that show the subtotals for hedge, resource and UCAP benefits as well as an hourly average benefit would be useful.

**Sources of Information**

Most of this information should be available from PJM's hourly bid and LMP data. Load data is readily available as is the amount of short-term contracts, the core of the ISO market. UCAP data should also be available from PJM bid data. Ancillary Services may involve using OASIS data.

**Possible Enhancements**

It would probably be desirable and necessary to periodically update this family of tables. If the driver is actual historical data, it should be possible to have frequent updates of the data. If the process of establishing these tables requires a great deal of judgment, then the tables will need to be static. Again, with proper database management, it should be possible to allow PCD tables to be customized to meet the assessment needs of any particular DSR program.

Relying on historical data (e.g., past couple of years) does not reflect that there may be significant other changes occurring in the marketplace. Some of these are fairly easily modeled with the existing tables and data (e.g., additional load or resources), while others (e.g., expanding PJM, change in market rules, maturing market etc) are not easily captured by the PCDT as described thus far. This group of potential changes can be assumed to be captured by PJM's future curve. Future curves give little if any insight into the frequency or types of hours where DSR may be helpful, but it does provide insight about future price levels. This can be extremely useful if the DSR program in question has a long lead-time and or operational prospect. Creating some type of annual adjustment factor based upon future curves could be a significant enhancement to the PCDT.

**How to Apply the Tables**

Assume that there is a simple DSR program that needs to have its benefits quantified. Utility A wants to consider implementing a direct control DSR program on 50 MW of load. It can only control this load during 100 hrs during the summer.

With this information, the analyst would look at the 50 MW decrement table for the utility zone in question for the summer (Note: if more than one summer of data is used in the data based, this can be normalized by a percentage rather than hour distribution). See template at Attachment A.

The analyst could either start examining the number of hours impacted by the 50 MW decrement within particular LMP change ranges (Column B). A quick assessment of this column indicates that the 100-hour constraint is met at the $26.50 level. If all of this row were used, too many hours would be included. Only 5 of the 15 hours are needed, so in the final analysis, the benefits for this row would need to be accordingly prorated.

The calculation of the hedge benefit is the price change (Column A plus $0.25/MWh to reflect the average price over the range) multiplied by the number of hours (Column B) multiplied by the average level of short-term resources used meet the load during the hours in question (adjusted for the number of megawatts provided as the DSR).

The calculation of the resource benefit is the number of hours (Column B) multiplied by the number of megawatts considered by this decrement (50 MW) multiplied by the average LMP.

The UCAP benefit was calculated by multiplying the maximum impact on UCAP by the price of UCAP by 365 days to determine its resource benefit and adding to it the product of peak demand, the change in the price of UCAP and 365 days.

These are then added together to produce the total benefit (column L). The sum of the relevant range of rows of column L is the estimated value of the program for this period (one summer in this case).

The total benefit per hour is calculated by dividing the total benefit (Column L) by the number of hours on the row (Column B). It may be useful to sort by total benefit per hour before doing further analysis as the metric gives the best assessment of when the most valuable hours occur. In this case, it was assumed that the values in this column would be less than those listed.

The total benefit is derived by adding the total column until the number of hours that are applicable to this particular DSR program are used. If the DSR program were year round or off peak, a different PCD table would have been used to assess its benefit. If the DSR were unconstrained as to the number of hours, the benefit would be the sum of total benefits (all of Column L). If the program provided more than 50 MW in a resource, another table would be considered and or the results of two tables would need to be extrapolated.

In this hypothetical, most of the value comes from the hedge benefits (Column I). This is because the change in LMP is large and the load served by short-term resources is large. If this were not the case (e.g., the potential change in load had little or not impact on price or if all the load was provided by long-term resources - characteristics common to off-peak situations without a large amount of unexpected outages) then the main benefit would be the resource benefit.

If several resource changes were being considered, (e.g., four each of 50 MW), the analyst should look at each separately to see which has the best return and then layer them incrementally so that the first 50 MW in benefits are not counted four times.

**Strengths &Weaknesses**

Below are summarized some of PCDT's strengths and weaknesses are compared below.

| Table 3 - Strengths and Weaknesses of PCDT | | |
|---|---|---|
| **Issue** | **Strengths** | **Weaknesses** |
| **Estimates Benefits as Needed** | PCDT has the capability of capturing the benefits of a wide variety of DSR programs (and other resources), based upon historical information. | PCDT requires an enhancement to be able to quantify non-resource changes that may influence future LMP. Forward curves may be of assistance. |
| **Data** | PCDT is based upon actual historical data. Avoids issues of weather and other | The market is still developing and actual data may not be a reliable predictor of the |

| | | |
|---|---|---|
| **Source/Type** | normalization that may mute DSR benefits | future. May only be able to look at a few years of data and miss long-term whether patterns, etc. |
| **Analytical Adjustments** | Incremental and decremental load tables allow analyst o make adjustments. | Non load and resource changes not easily captured |
| **Congestion** | PCDT can look at any combination of zones. | PCDT not well suited to do analysis for every zone (1,600 and growing) individually |
| **Assessing Many Programs** | PCDT allows analysts to track the cumulative benefits of resources. | PCDT requires analyst to consider other resource changes on the system and adjust assessment as needed. |
| **Scope of Evaluation** | PCDT allows analyst to look at benefits on many different levels (PJM, utility, etc). | PCDT not designed to look at benefits to an individual or class of participating customers (not a bill analysis tool). |
| **After-the-Fact Evaluation** | PCDT is a tool to assess a potential program. | PCDT cannot be used determine the benefit actually achieved as much of the benefit may be absorbed by the marketplace in its assessment of risk. |

**Related Market Issues**

A problem in the PJM marketplace today is getting benefits and risks properly matched. When considering DSR benefits, the question of who is delivering these programs and assuming the risk must also be considered. This can have a major impact on POLR design.

DSR that is a one-on-one relationship between the end-user and a supplier have not worked. End-users have been hesitant to get involved, as there are too many unknowns about the potential benefits that are based on spot markets and how they may change. Suppliers are not able to capture enough of the hedge value and/or do not have deep enough balance sheets to assume the risk of future potential benefits. PJM has discussed monetizing the future value of DSR. In this way the participants would know in advance what level of return they would be reaping from participating in a DSR program and future changes to the demand/supply balance would not affect that return..

With the market making utilities increasingly more insulated from the responsibility of providing reliable, reasonably priced electricity, the issue of matching risks and benefits associated with utility provided DSR becomes more difficult. Utilities have the wherewithal to implement DSR. The question will be whether they have will be provided with the appropriate incentives to provide DSR that stabilizes prices and increases reliability and reasonable costs. If the utility has simple full-requirements contracts with third-party competitive suppliers and the end-users are charged based upon fixed POLR rates, then all the gains of DSR go to the suppliers and only indirectly to consumers if the benefits of DSR were assumed when the market set the price. The utility may not only receive any benefit from its sponsorship of DSR but may actually be penalized through reduced retail revenues. If utility sponsored DSR is to work, this issue must be addressed.

Attachment A - Template for Single PCDT Table

| | A | B | C | D | E | F | G | H | I | J | K | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **Appendix A - PCDT Template/Hypothetical** | | | | | | | | | | | |
| 2 | | | | | | | | | | | | |
| 3 | **Table Description: 50 MW Decrement; Utility Zone A; Summer** | | | | | | | | | | | |
| 4 | **A** | **B** | **C** | **D** | **E** | **F** | **G** | **H** | **I [=(A+0.25)* B*(D-50)]** | **J [=B*50*E]** | **K [=(F*G*365) +(H*C*365)]** | **[** |
| 5 | **Change in LMP Based on Decrement $/MWh** | **Number of Hours Impacted by Decrement** | **Average Total Load MW** | **Load Served by Short term Resources MW** | **Average LMP $/MWh** | **Maximum Impact on UCAP MW** | **UCAP Price $/MW/Day** | **UCAP Price Change Based on Decrement $/MW/Day** | **Hedge Benefit $** | **Resource Benefit $** | **UCAP Benefit $** | |
| 6 | | | | | | | | | | | | |
| 7 | **$30.50** | 5 | 8000 | 2500 | $80 | 40 | $25 | $0.25 | $376,688 | $20,000 | $1,095,000 | |
| 8 | **$30.00** | 15 | 7800 | 2500 | $78 | 0 | $40 | $0.00 | $1,111,688 | $58,500 | $0 | |
| 9 | **$29.50** | 10 | 7700 | 2400 | $76 | 0 | $40 | $0.00 | $699,125 | $38,000 | $0 | |
| 10 | **$29.00** | 10 | 7700 | 2200 | $72 | 0 | $35 | $0.00 | $628,875 | $36,000 | $0 | |
| 11 | **$28.50** | 10 | 7400 | 2000 | $75 | 0 | $20 | $0.00 | $560,625 | $37,500 | $0 | |
| 12 | **$28.00** | 15 | 7600 | 2200 | $70 | 0 | $35 | $0.00 | $911,063 | $52,500 | $0 | |
| 13 | **$27.50** | 15 | 6000 | 2400 | $60 | 0 | $10 | $0.00 | $978,188 | $45,000 | $0 | |
| 14 | **$27.00** | 15 | 7200 | 2000 | $72 | 0 | $10 | $0.00 | $797,063 | $54,000 | $0 | |
| 15 | **$26.50** | 15 | 7000 | 1700 | $70 | 0 | $10 | $0.00 | $662,063 | $52,500 | $0 | |
| 16 | | | | | | | | | | | | |
| 17 | * Values would continue until LMP change reached zero. Rows have been halted on this template as constraint on example DSR was set at 100 hours of application | | | | | | | | | | | |
| 18 | valuable hours have not been ignored, although this need not be the case. Resorting by Average Hourly Benefit (Column J) is generally recommended. | | | | | | | | | | | |
| 19 | * Values are hypothetical for example purposes only assuming only a single year's data used as basis. PCD tables would be based on actual historical data. | | | | | | | | | | | |
| 20 | * LMP Change represents floor of $0.50 range. Mid point used for analysis. No averages needed. | | | | | | | | | | | |
| 21 | * Benefit calculations based upon the average amount of short-term resources used to meet load. | | | | | | | | | | | |
| 22 | * UCAP benefits may need to be deferred (lagged) until the next UCAP year when perfroming net present value calculations. | | | | | | | | | | | |
| 23 | * Total benefit calculations provided for clarity. Also will make use easier. | | | | | | | | | | | |
| 24 | * To claculate a particular resource's benefit, it is necessary to sum the benefits over the appropriate number of rows. | | | | | | | | | | | |
| | * Ancillary Services not included for simplicity of presentation. | | | | | | | | | | | |

## APPENDIX C – Non-Quantifiable Benefits Matrix

# Primary Benefits

### Benefits Broadly Distributed, Not Just to Participants

| Benefit | Impact | Can the Impact be Easily Quantified or Not? | Critique | Response |
|---|---|---|---|---|
| Lower Wholesale Energy Prices | Lower Costs - LSEs and Customers | Yes | Quantifying broadly distributed retail level benefits is difficult | Prospectively, this is true. Wholesale price reductions can be calculated but LSEs do not always pass these through to customers. However, it can be calculated after the fact. |
| Increased Distribution System Reliability Due to Control of Peak Loads | Improved Security or Reliability | No | | |
| Increased Transmission System Reliability due to Control of Peak Loads | Improved Security or Reliability | No | | |
| Decreased ability of market participants to exercise market power | Lower Prices - Wholesale | No | | |
| Avoided Transmission System Capital and O&M Cost | Lower Costs - EDC | Yes | Planning cannot reflect this for optional programs or for mandatory response programs where the participant can leave the program | In fact, PJM is in the process of integrating DSR into the transmission planning process. This will explicitly reflect the costs and benefits of DSR as an alternative to transmission. |
| Avoided Distribution System Capital and O&M Cost | Lower Costs - EDC | Yes | Planning cannot reflect this for optional programs or for mandatory response programs where the participant can leave the program | After PJM has completed its integration of DSR into the transmission planning process, distribution planners should be able to adapt this methodology to calculate benefits to costs where DSR can substitute for construciton of distribution. |
| Economies of Scale Drive Advanced DSR Technology Use | All Customers Benefit from Technology Enhancement | No | This is not a benefit. | Economies of scale will reduce prices and technology advances will improve efficiency and capability. DSR participation will expand with the indirect benefits being those of any expansion of DSR. |

# Master List with Original Comments

| Benefit Number | Benefit - Draft 4/19/2004 | Benefits Category | Utilities | Competitive LSEs | Customers End Use | Government | Economic Activity | Health Care Providers | Quantifiable or Not | Comments |
|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Improved Dwelling Comfort | **Quality of Life** | | | D | | | | N | How is this a benefit? Most DSR programs require customers to shift usage from peak to off peak which results in decreased customer comfort? |
| 2. | Lower Wholesale Energy Prices | **Lower Costs - LSE** | D & I | D & I | | | | | Q | Quantifying the indirect benefit to all market participants is difficult proposition |
| 3. | Lower Wholesale Capacity Prices | **Lower Costs - LSE** | D & I | D & I | | | | | Q | Quantifying the indirect benefit all market participants is difficult proposition |
| 4. | Avoided Transmission System Capital and O&M Cost | **Lower Costs - EDC** | D & I | D & I | | | | | Q | From a system perspective, this benefits would not be quantifiable in most cases. A system planner can not count on DSR programs which include optional participation in curtailments. Even for mandatory curtailment programs, if the program can be discontinued at any time by customer, the benefit is difficult to quantify from a system design perspective. |
| 5. | Avoided Distribution System Capital and O&M Cost | **Lower Costs - EDC** | D & I | | D & I | | | | Q | Same as above. |
| 6. | Lower Retail Energy Prices | **Lower Costs - Customers** | D | D | D & I | D & I | | | Q | How are lower retail prices a benefit to utility or LSE? We have already accounted for this benefit in #3 and #4. Lower retail prices benefit consumer. |
| 7. | Increased Distribution System Reliability | **Improved Security or Reliability** | D | | D & I | | | | N | |
| 8. | Less Volatile Wholesale Energy Prices Make Long-term Contracts Feasible for Sellers and Buyers | **Lower Costs - LSE** | D | D | I | I | I | | N | Long term contracts are feasible today. Option pricing theory states that as volatility decreases, option prices will decrease as the option is less likely to finish ITM. Thus, decreasing the volatility of the wholesale markets will in effect reduce the hedging costs and therefore overall cost of long term contracts. This benefit has already been stated in #2., $3, #6. |
| 9. | Increased Transmission System Reliability due to Control of Peak Loads | **Improved Security or Reliability** | D | | I | | I | | N | |
| 10. | Transmission Systems Less Vulnerable to Catastrophic Outages | **Improved Security or Reliability** | D | | I | | | | N | This is essentially the same as #9. |
| 11. | Avoided Transmission Siting Costs | **Lower Costs - EDC** | D | | I | | I | | Q | Utilities (or ITC) would recover siting costs so eliminating this cost is not really a benefit. While theoretically quantifiable, practically it is unlikely that DSR program will have enough of an impact in enough time to avoid building transmission assets, if needed. Additionally, the transmission restraint may be caused by users outside the LSE territory. |
| 12. | Avoided Generation Siting Costs | **Lower Costs - Generators** | D | | | D | | | N | This is a GenCo benefit, not a utility (or EDC) benefit. Again, reduced siting costs would ultimately be seen as reduced wholesale costs and retail costs already captured in #2,#3, #6. |
| 13. | Lower Health System Costs from Reduced NOX, SO2, Hg, PM-10s and CO2 | **Health Benefits** | D | | D & I | I | I | I | Q | This should be non-quantifiable. If the DSR program is peak shifting, may actually increase emissions depending on what type of generation is on the margin peak vs. off peak. |

| Benefit Number | Benefit - Draft 4/19/2004 | Benefits Category | Utilities | Competitive LSEs | Customers End Use | Government | Economic Activity | Health Care Providers | Quantifiable or Not | Comments |
|---|---|---|---|---|---|---|---|---|---|---|
| 14. | Improved Dwelling Safety for Elderly, Health Impaired and Low-Income Due to Improved Reliability and to Being Able to Afford Necessary Heat, Cooling, Ect. Due to More Efficient Home Energy Use | **Improved Quality of Life** | | | D & I | I | | | N | This is the result of #6, #7. Not really an independent benefit. |
| 15. | Improved Public Health from Reduced NOX, SO2, Hg, PM-10s and CO2. | **Health Benefits** | D & I | | D & I | I | | I | Q | Same benefit as #13. See response to #13. |
| 16. | Advanced DSR Technology Use | **Technology Enhancement** | | | I | I | I | | N | How is this a benefit.? |
| 17. | Better Jobs | **Economic Benefits** | | | | I | I | | N | Is this a net benefit compared to jobs that are lost? |
| 18. | Work Force Diversification due to New and Varied Technologies | **Economic Benefits** | | | D & I | I | I | | N | How is this a direct benefit to end use customer? |
| 19. | Economies of Scale Drive Advanced DSR Technology Use | **Technology Enhancement** | | | | I | I | | N | |
| 20. | More Efficient Generation Construction due to Reduced Fuel Risk | **Lower Costs - Generators** | D & I | D & I | | | | | N | How does this benefit utility or LSE if they are not generation owners. Isn't the real benefit already stated in #2 and #3? |
| 21. | Reduced Fuel Extraction Impacts on Environment | **Environmental Benefits** | | | D & I | I | I | | Q | Please explain how this is quantifiable. Peak shifting technologies may not reduce total usage. |
| 22. | Reduced Fuel Transportation Impacts on Environment | **Environmental Benefits** | | | D & I | I | | | Q | Please explain how this is quantifiable. Peak shifting technologies may not reduce total usage. |
| 23. | Reduced Power Plant Waste Disposal Costs and Environmental Impacts | **Lower Costs - Generators** | D | | I | | | | N | If we are talking nuclear or coal typically baseload and probably not impacted by DSR. |
| 24. | Reduced Land Impacts from Avoided Generation Construction | **Environmental Benefits** | | | D & I | I | | | N | |
| 25. | Better Allocation of Water Resources to Other Economic Uses | **Economic Benefits** | | | I | I | I | | N | Many new peakers are air cooled. Benefit offset by increased pool, sprinkler and fire hydrant usage by DSR participants needing to cool off during curtailment periods. |
| 26. | Improved Quality and Economic Activity Related to Recreation - Less acid rain and Hg in fish | **Environmental Benefits** | | | D & I | I | I | | N | This is probably not the case if DSR offsets new peaker construction which are usually efficient gas plants. |
| 27 | Dynamic and long-term fuel diversity benefits | **Improved Security or Reliability** | D | D | I | D | I | | N | |
| 28 | Decreased ability of market participants to exercise market power | **Economic Benefits** | D | D | D & I | I | | | N | |
| 29 | Greater Customer Choice of Billing (regulated and market) | **Economic Benefits** | D | D | D | | | | N | |
| 30 | Higher levels of customer satisfaction | **Quality of Life** | D | D | D | | | | Q | |
| 31 | Less pressure on marginal fuels during critical periods (e.g. gas) | **Improved Security or Reliability** | D | D | I | | I | | Q | |
| 32 | Reduction in meter reading costs, direct and indirect | **Lower Costs - EDC** | D | I | I | | | | Q | |
| 33 | Theft Identification and management | **Lower Costs - EDC** | D | I | I | | | | Q | |
| 34 | More accurate mesurement and billing result in reduced administration and management costs | **Lower Costs - EDC** | D | D | D | | | | Q/N | |
| 35 | Quicker and more efficient outage detection and restoration | **Improved Security or Reliability** | D | D | D | | I | | Q | |
| 36 | Two-way communication between customer and utiility | **Technology Enhancement** | D | I | D | | | | N | |
| 37 | Direct control over customer customer end-use | **Lower Costs - Customers** | D | I | D | | | | Q | |

| Benefit Number | Benefit - Draft 4/19/2004 | Benefits Category | Utilities | Competitive LSEs | Customers | End Use | Government | Economic Activity | Health Care Providers | Quantifiable or Not | Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 38 | Remote control over customer end-uses by customer | **Lower Costs - Customers** | D | I | D | | | | | Q/N | |
| 39 | New informatin to customers about their bill and usage | **Lower Costs - Customers** | D | D | D | | | | | Q/N | |
| 40 | Increased ability of non-residential customers to monitor, manage and optimize business processes and operations | **Lower Costs - Customers** | D | I | D | | | | | N | |
| 41 | Faster and more accurate settlement transactions among UDCs, competitive providers and customers | **Technology Enhancement** | D | D | I | | | | | Q | |

# Economic

| Benefit Number | Benefit | Benefits Category | Utilities | Competitive LSEs | Customers | End Use | Government | Economic Activity | Health Care Providers | Quantifiable or Not | Quadrant | Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 6. | Lower Retail Energy Prices | Lower Costs - Customers | | D | D | D & I | D & I | | | Q | | |
| 16. | Advanced DSR Technology Use | Technology Enhancement | | | | I | I | I | | N | | |
| 17. | Better Jobs | Economic Benefits | | | | | I | I | | N | IV | |
| 18. | Work Force Diversification due to New and Varied Technologies | Economic Benefits | | | | D & I | I | I | | N | III & IV | |
| 19. | Economies of Scale Drive Advanced DSR Technology Use | Technology Enhancement | | | | | I | I | | N | | |
| 25. | Better Allocation of Water Resources to Other Economic Uses | Economic Benefits | | | | I | I | I | | N | IV | |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 28 | Decreased ability of market participants to exercise market power | Economic Benefits | D | D | D & I | I | | | N | | |
| 29 | Greater Customer Choice of Billing (regulated and market) | Economic Benefits | D | D | D | | | | N | | |
| 36 | Two-way communication between customer and utiility | Technology Enhancement | D | I | D | | | | N | | |
| 37 | Direct control over customer end-use | Lower Costs - Customers | D | I | D | | | | Q | | |
| 38 | Remote control over customer end-uses by customer | Lower Costs - Customers | D | I | D | | | | Q/N | | |
| 39 | New informatin to customers about their bill and usage | Lower Costs - Customers | D | D | D | | | | Q/N | | |
| 40 | Increased ability of non-residential customers to monitor, manage and optimize business processes and operations | Lower Costs - Customers | D | I | D | | | | N | | |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 41 | Faster and more accurate settlement transactions among UDCs, competitive providers and customers | Technology Enhancement | D | D | I | | | | Q | | | |

# Environmental, Health, Quality of Life

| Benefit Number | Benefit | Benefits Category | Utilities | Competitive LSEs | Customers End Use | Government | Economic Activity | Health Care Providers | Quantifiable or Not | Quadrant |
|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Improved Dwelling Comfort | Quality of Life | | | D | | | | N | |
| 13. | Lower Health System Costs from Reduced NOX, SO2, Hg, PM-10s and CO2 | Health Benefits | D | | D & I | I | I | I | Q | I & II |
| 14. | Improved Dwelling Safety for Elderly, Health Impaired and Low-Income Due to Improved Reliability and to Being Able to Afford Necessary Heat, Cooling, Ect. Due to More Efficient Home Energy Use | Improved Quality of Life | | | D & I | I | | | N | III & IV |
| 15. | Improved Public Health from Reduced NOX, SO2, Hg, PM-10s and CO2. | Health Benefits | D & I | | D & I | I | | I | Q | I & II |
| 21. | Reduced Fuel Extraction Impacts on Environment | Environmental Benefits | | | D & I | I | I | | Q | |
| 22. | Reduced Fuel Transportation Impacts on Environment | Environmental Benefits | | | D & I | I | | | Q | |
| 24. | Reduced Land Impacts from Avoided Generation Construction | Environmental Benefits | | | D & I | I | | | N | |
| 26. | Improved Quality and Economic Activity Related to Recreation - Less acid rain and Hg in fish | Environmental Benefits | | | D & I | I | I | | N | |
| 30 | Higher levels of customer satisfaction | Quality of Life | D | D | D | | | | Q | |

## Reliability

| Benefit Number | Benefit | Benefits Category | Utilities | Competitive LSEs | End Use Customers | Government | Economic Activity | Health Care Providers | Quantifiable or Not |
|---|---|---|---|---|---|---|---|---|---|
| 7. | Increased Distribution System Reliability | Improved Security or Reliability | D | | D & I | | | | N |
| 9. | Increased Transmission System Reliability due to Control of Peak Loads | Improved Security or Reliability | D | | I | | I | | N |
| 10. | Transmission Systems Less Vulnerable to Catastrophic Outages | Improved Security or Reliability | D | | I | | | | N |
| 27 | Dynamic and long-term fuel diversity benefits | Improved Security or Reliability | D | D | I | D | I | | N |
| 31 | Less pressure on marginal fuels during critical periods (e.g. gas) | Improved Security or Reliability | D | D | I | | I | | Q |
| 35 | Quicker and more efficient outage detection and restoration | Improved Security or Reliability | D | D | D | | I | | Q |

# Cost Reduction

| Benefit Number | Benefit | Benefits Category | Utilities | Competitive LSEs | End Use Customers | Government | Economic Activity | Health Care Providers | Quantifiable or Not |
|---|---|---|---|---|---|---|---|---|---|
| 2. | Lower Wholesale Energy Prices | Lower Costs - LSE | D & I | D & I | | | | | Q |
| 3. | Lower Wholesale Capacity Prices | Lower Costs - LSE | D & I | D & I | | | | | Q |
| 4. | Avoided Transmission System Capital and O&M Cost | Lower Costs - EDC | D & I | D & I | | | | | Q |
| 5. | Avoided Distribution System Capital and O&M Cost | Lower Costs - EDC | D & I | | D & I | | | | Q |
| 8. | Less Volatile Wholesale Energy Prices Make Long-term Contracts Feasible for Sellers and Buyers | Lower Costs - LSE | D | D | I | I | I | | N |
| 11. | Avoided Transmission Siting Costs | Lower Costs - EDC | D | | I | | I | | Q |
| 12. | Avoided Generation Siting Costs | Lower Costs - Generators | D | | | D | | | N |
| 20. | More Efficient Generation Construction due to Reduced Fuel Risk | Lower Costs - Generators | D & I | D & I | | | | | N |
| 23. | Reduced Power Plant Waste Disposal Costs and Environmental Impacts | Lower Costs - Generators | D | | I | | | | N |
| 32 | Reduction in meter reading costs, direct and indirect | Lower Costs - EDC | D | I | I | | | | Q |
| 33 | Theft Identification and management | Lower Costs - EDC | D | I | I | | | | Q |
| 34 | More accurate mesurement and billing result in reduced administration and management costs | Lower Costs - EDC | D | D | D | | | | Q/N |