-- DRAFT Request for Proposal (RFP) --

Assessing Supply-Side, Energy Efficiency and Demand Response Resources

Outline:

1.0 RFP Overview

The _Client_ is developing a planning approach that recognizes the uncertainties in long-term resource planning. The electricity market to be addressed includes To Be Filled in by Client. The proposals are due on Month, Day,Year.

Demand response resources (DRR) in the context of this assignment is defined as load response called for by others and price response managed by end-use customers. Load response includes direct load control of equipment (air conditioners, hot water heaters, or any other equipment that can be isolated), partial load reductions that can be "called" by a product[1] administrator, and even complete load interruption.[2] Entities that may call for load response include Independent System Operators (ISOs), load serving entities (LSEs), utility distribution companies, and independent load aggregators. Price response includes real-time pricing, dynamic pricing, critical peak pricing, time-of-use rates, and demand bidding or buyback programs.[3]

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[1] The term DRR product is used in the same context as a DRR program. It represents a contract between an end-user and a product or program administrator that allows for load to be reduced under certain conditions. Usually, these conditions are associated with high prices for electricity and/or conditions that threaten the reliability of the system.

[2] A complete interruption may be associated with facilities that have their own on-site generation that they can use to meet all of their needs or at least their essential needs.

[3] This definition is the same as that included in a recent International Energy Agency report on DRR Valuation: Violette, D. R. Freeman, and C. Neil; "DRR Valuation and Market Analyses: Assessing the DRR Benefits and Costs – Volumes I and II;" prepared for the International Energy Agency Demand Side Programme; Task XIII: Demand Response Resources, January 6, 2006. This definition also parallels that developed by the Peak Load Management Alliance (PLMA) and documented in "Demand Response: Design Principles for Creating Customer and Market Value" prepared by the Peak Load Management Alliance, November 2002, and available at www.peaklma.com.

The approach is to use a forward looking resource planning framework to assess the value of DRR by reducing market prices of electricity and reducing risks associated with low-probability / extreme events that may occur only every 4 to 6 years, but are very costly to the electric system and customers. One method for approaching this issue is presented in Section 3.0 Work Elements of this RFP, but respondents can propose alternative methods.

[Here is something you might want to try, i.e., a stage one analysis, or you can delete the next few lines.]

The assignment process is expected to include:

1. A best and finals process where qualified bidders meet in person or via tele-conference with the ___________ project management team.
2. The award of from 1 to 3 scoping contracts at $15,000 (or you can use $10,000) each to produce a “final the scope of work report” for this effort based on the proposals submitted in response to this RFP, with the ability to adjust pricing if needed. Note – In this proposal it is expected that an initial estimate for the full effort will be provided.
3. The selection of 1 of the 3 final scope of work projects for full funding.
4. The delivery of the products as outlined in the accepted final scope of work report.

It is hoped that any proposed approach can take advantage of existing models and methods for resource planning, and adapt these tools to address system costs, uncertainty and risk management in developing future resource plans that include DRR.

2.0 Background and RFP Objectives

There is wide consensus that an efficient electricity market requires the appropriate interaction of supply and demand. Without adequate capabilities for the demand response, the electric market can become price inelastic. A high level of price elasticity combined with a steeply upward supply curve for electricity can result in price spikes and a high level of price volatility. In addition, barriers may exist to implementing appropriate levels of demand response resources (DRR).

2.1 Barriers and Benefits of DRR

Barriers to demand response are inherent in electric markets that have a history of regulated retail pricing, and which have been restructured – this has bifurcated the benefits of demand response. This bifurcation of benefits is an important issue. Demand response has the potential to provide benefits to commodity providers, reliability organizations, transmission companies, distribution companies, and electric end-users. However, it is difficult for a provider of DRR products and services to aggregate the market-wide benefits such that an efficient amount of DRR will be provided into the market.

The market-wide benefits of demand response include:

- Lower electricity prices;
- Reduced price volatility;

- Increased efficiency in one of the most capital intensive industries;
- Risk management, i.e., a physical hedge against extreme system events that are difficult to incorporate in planning and valuation frameworks;
- Increased customer choice and customer risk management opportunities;
- Possible environmental benefits; and
- Market power mitigation.

In addition to these market-wide benefits, there are a number of private entity benefits that include reduced capital, operation, and maintenance expenses for transmission and distribution systems. These benefits accrue to the owners of these systems. There is also the potential for benefits to accrue to aggregators of demand response resources for sales to commodity providers or reliability organizations.

DRR benefits do not come without associated costs. As with any product or service, DRR requires marketing, start-up capital, and ongoing operational costs in terms of both servicing the product and paying participants for their demand responsiveness. This latter cost is important in that a vital component of customer value is now realized, i.e., those customers that can vary their demand for electricity from peak periods to off-peak periods are now provided with a financial incentive to take these actions. This creates an important value proposition in the markets – customers can now benefit from shifting energy usage from high cost periods to lower cost periods. This type of price response is necessary for an efficient market. Simply stated an industry can only be viewed as efficient if it appropriately prices what is scarce, i.e., on-peak electricity use; and, if incentives to conserve scarce resources are present in the market.

In addition, energy management equipment providers are now provided with an incentive to innovate and develop technology that will increasingly assist customers in shifting electricity use since there is now value associated with making such a shift, i.e., the equipment vendors now have a value proposition they can pitch to customers.

Potential reductions in market prices are a major motivation for demand response valuation and investment. A small percentage of responsive loads can significantly mitigate peak prices. Taking one example from U.S. markets, one reliability region indicated a 2% reduction in 2001 summer peak demand would have reduced the market clearing price from $400 to $175 per MWh, or by about 56%.[4]

Demand response exerts both short term and long term forces on a regional market. DRR acts to lower demand and its corresponding supply cost, thereby reducing the market clearing price, as illustrated in Figure 1.

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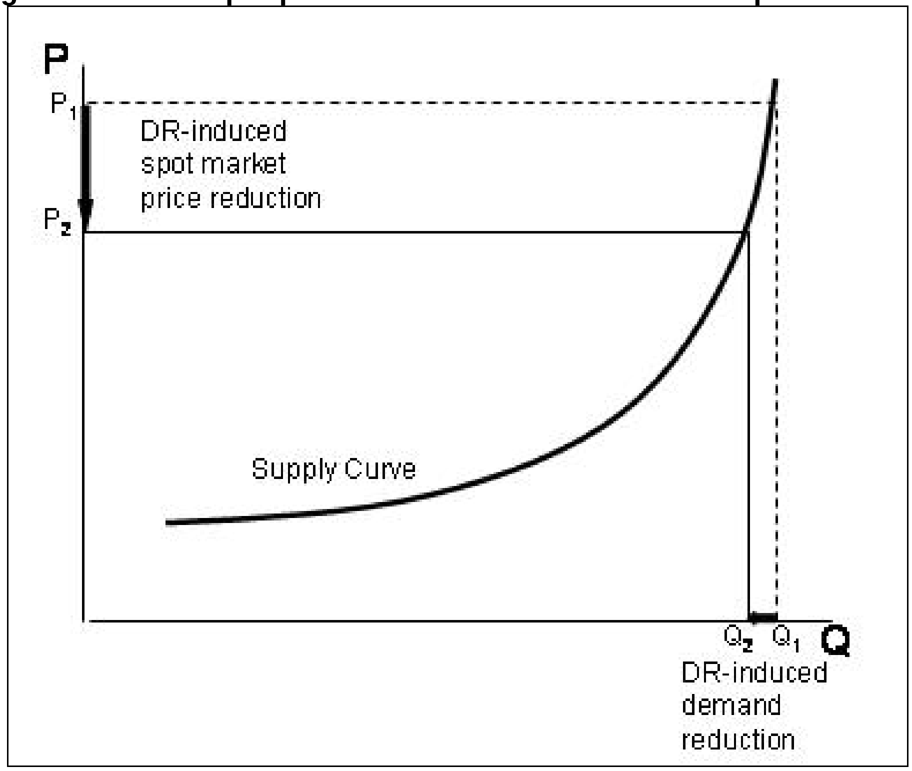
[4] For example, the ISO New England (encompassing the states of Massachusetts, Connecticut, Maine, Vermont, New Hampshire and Rhode Island) demonstrated that a 2% reduction in 2001 summer peak demand would have reduced the clearing price from $400 to $175 per MWh, or by about 56%. See: Bob Burke, Independent System Operator of New England, Remarks at the PLMA Spring Meeting on April 25, 2002. PLMA May Newsletter

Figure 1: Market spot price reductions from demand responsive load.



Both the long term value of DRR as well as the above static short-term value need to be considered. In the above short term example, the price reductions received as benefits by customers may be viewed as a cost by the suppliers that would have provided the electricity as these price reductions may result in revenue losses for suppliers. However, if DRR is viewed as a long-term commitment and DR forces can be expected by market participants for years into the future, then the supply side will take this into account. As a result, long-term equilibria can be reached where the impacts of DR on extreme market events are factored into decisions made by market actors. The end result can be a more efficient market with the appropriate balance between more capital intensive generators as an emergency resource complemented by DR. This should lead to an overall increase in capacity factors among generators if fewer units are built solely designed to operate for only a few hours per year. DRR may help reduce the requirements for long-term capacity expansion, in particular for peaking units.

2.2 Assessing the Impact and Value of DRR

This RFP is meant to examine the impacts and value of different types of DRR products on electricity market prices, the volatility of electricity prices, and management of price and quantity risks through the use of DRR. A number of approaches have been used to evaluate the benefits of developing products and programs that would allow for the demand for electricity to be more responsive to price or to events that reflect system reliability issues. The most common have used extensions of the standard practice tests that have been utilized to evaluate energy efficiency programs. These tests have been derived from the California Standard Practice Manual tests which have been applied by many entities, including applications in Australia.[5] Typically include the Total Resource Cost (TRC) test, the Participant Test, and the Ratepayer Impact Measure (RIM) test. These tests tend to be static in nature, do not incorporate risk management aspects of DRR, and are linked to the supply-side by the use of a estimate of avoided costs, usually represent a single resource (e.g., a combustion turbine).

The objective of this assignment is to try and move beyond the application of static benefit-cost tests of DRR and incorporate those factors of DRR that provide important market benefits. This is meant to be accomplished by comparing DRR and supply-side resources in an even manner. The need for, type and amount of supply-side resources required in a forward looking resource adequacy plan typically uses a forward-looking resource planning model. DRR has typically been examined outside of this planning context as a side calculation based on proxy avoided costs. One goal of this assignment is to directly introduce DRR into resource planning allowing it to compete with supply-side alternatives. This task poses challenges, but several recent efforts in the U.S. have taken this approach.[6]

There is also no getting around the tough questions that demand response products pose for overall resource planning and for the development of efficient electricity markets. The factors that influence electricity markets are dynamic, and a dynamic process is needed to assess their contribution to the overall robustness of the market. This implies that a planning process that directly addresses difficult issues such as uncertainty, a time horizon that is long enough to include low-probability, high-consequence events, and an electricity market that encompasses demand response resources as well as supply-side technologies, is needed to assess impacts on overall system costs, system reliability, and risks associated with extreme events. The utility industry has become expert at applying the types of models needed to address these questions for both costs related to generation and costs related to the transmission and distribution (T&D) systems. These modeling efforts will be needed to fully value DRR. A plan for incorporating uncertainty in both generation and T&D capital budgeting, and also in developing budgets for annual operating and maintenance (O&M) costs, is needed. In some cases, utilities are beginning to examine these issues using appropriate tools; in other instances past procedures that do not account for the increasingly dynamic nature of electricity markets are still being used.

The use standard practice tests such as the TRC test, and event reliability assessments will become more valuable and useful when an overall construct of avoided capital costs (generation and T&D) as well as avoided O&M costs is developed from a resource planning perspective. Static analyses of specific situations are best addressed once a comprehensive framework has been developed. The benchmark approaches and standard practice tests likely will continue to be used in the near term and these are useful as "proof-of-concept" analyses, and to justify the startup of selected

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[5] One such study is: *"Assessment of Demand Management and Metering Strategy Options,"* produced for The Essential Services Commission of South Australia by Charles River Associates, August 2004.

[6] Violette, D. R. Freeman, and C. Neil; "DRR Valuation and Market Analyses: Assessing the DRR Benefits and Costs – Volumes I and II;" prepared for the International Energy Agency Demand Side Programme; Task XIII: Demand Response Resources, January 6, 2006. A similar approach is taken in the Northwest Power and Conservation Council (NPCC) 5th Power Plan. See 5th Plan Volume 2 - Chapter 7 and Volume 3 – Section H at http://www.nwcouncil.org/energy/powerplan/plan/Default.htm.

DRR product development. But questions about how much DRR is enough, and the dynamics inherent in the timing of investment decisions, will likely need the development of a resource adequacy assessment for an electricity market. This assessment likely will have resource planning constructs for both generation and T&D.

2.3 Overall Assignment Objectives

This assignment has 5 over arching objectives:

1. **Assess the change in net system costs of a resource plan due to the inclusion of DRR.** This would typically be done by first developing a base case resource plan incorporating current status of resources such as energy efficiency and renewables. The second step would be the development of a resource plan that includes several different types of DRR, The final step would be the estimation of net benefits (or costs) of DRR by taking the difference in net system costs between the resource plan with DRR and the plan without DRR.

2. **Based on the change in net system costs over a planning period, estimate the overall reduction in market prices.** Note, this may be as simple as taking the difference in marginal costs for different periods between the without-DRR and with-DRR scenarios for selected months, average days and peak days on the system. If a bidder wants to propose an alternative method for translating marginal production costs into market prices, that approach can be evaluated.

3. **Assess the relative impact of selected types of DRR.** One challenge in the assessment of DRR is that it encompasses so many different types of products. This assignment is expected to address at least three DRR products:
    a. A callable DRR product with two to three hour notice given to participating customers. This is expected to be represented as a resource.
    b. A direct load control program where a reduction in load can be achieved in less than 4 minutes. This is expected to be represented as a resource.
    c. A price responsive load program – either a time-of-use (TOU) rates program with critical peak pricing (CPP) or a real-time pricing program. These may be represented through changes in the demands that must be met by the resource plan.

    To the extent the bidder believes that their approach can address additional DRR products, this will be taken into account. These additional DRR products might include: *1*.) day-ahead pricing, i.e., reservation pricing for loads where if the price the next day exceeds a given number, then a set load curtailment is called; or, *2*) both TOU-CPP and RTP can be addressed in separate DRR resource planning runs.

4. **<u>Assess the risk management benefits of DRR</u>**. Produce an assessment of the change in risks to the costs of providing electricity by including DRR. As discussed in Section 3.0 Work Elements, this is likely to require a Monte Carlo analysis that will incorporate uncertainty around key inputs expected to have a large impact on electricity costs. These are likely to include uncertainty around the costs of fuel inputs (coal, oil, and gas), demand (monthly energy and daily peak demands), and system operations (outages at major plants and

transmission lines). These are expected to be presented in terms of Value at Risk (VAR) metrics, such as VAR_{90} which shows the average net system costs averaged across the 10% worst cases in the Monte Carlo analysis. These have a probability of occurrence of once in ten years. VAR_{95} should also be presented.

5. **Assess the change in expected reliability**. This can be done by looking at changes in loss of load probability (LOLP) holding a reserve margin constant, or by holding LOLP constant and assessing the change in reserve margin that maintains that same LOLP.

It is expected that the final product would address each of these five objectives. The next section presents the work elements that are likely to be required by this engagement; however, alternative approaches can be considers.

3.0 Work Elements

This section suggests the work elements believed to be needed for this analysis. Alternate methods and work elements can be proposed if they – 1) reduce the cost of the work effort while maintaining work quality; and/or 2.) increase the robustness of the results produced by the alternative method. Some from of chronological model is expected, but the full hourly detail may not be needed. For example, there may be no need to examine every hour during periods where peak demands are not likely to occur; but, full hourly resolution may be provided during months in which system peaks are most likely to occur. Compromises in model detail are left to the bidder to develop in their proposal.

A summary of the work elements that are likely to be necessary for this effort include:

ELEMENT 1. Base Case Calibration -- represent the current resource mix in the market by simulating the dispatch of existing supply-side and demand-side resources to meet electricity demands on an hourly, daily and weekly basis for the two most recent historical years on which data are available.

ELEMENT 2. Assessment of Future Non-DRR Resource Options – Develop a base case set of options to meet future electricity needs. These options should be defined in terms of operations, availability, fixed and operating costs, as well as environmental emissions. The ability to purchase power and the intertie capability with neighboring regions should also be addressed as a resource option. Since the focus in on the valuation of DRR, some aggregation of supply-side options may be possible. These resource options should include:

1. A base case range of supply-side options including conventional fossil technologies as well as clean energy technologies and cogeneration/embedded generation.
2. Base case assumptions about energy efficiency as reflected in the energy and peak demands in each planning period. *[Note, this effort is not focused on energy efficiency, but energy efficiency and DRR both impact peak demand and, if possible, a base case efficiency option along with an aggressive efficiency option would be useful to run as alternative non-DRR base case comparison points.]*

<u>Element 3</u>. Assessment of DRR resource options. This would include the development of the three DRR options listed in Section 2.0 Assignment Objectives, and possibly additional DRR options as deemed appropriate by the bidder.

<u>Element 4</u>. Assess and Dimension Uncertainty – This requires the assessment of uncertainty around key parameters that are expected to have potentially large impacts on the system costs of meeting expected load requirements. This will involve"

Step 1. Determine pivot factors that are expected to have a significant influence on the costs of electricity. These are likely to include the cost of fuel inputs (coal, oil and gas), demand (monthly energy and peak days), system factors such as forced plant outages and transmission delivery interruptions, and environmental compliance costs, e.g., a carbon tax *[Note – the carbon tax may be uncertain as to when it begins and the magnitude of the tax or offset credits]*.

Step 2. Assess uncertainty around these factors and express that uncertainty via probability distributions.

Step 3. Draw a set of discrete future scenarios using the probabilities running through the planning period to adequately represent uncertainty in the system.

Step 4. The positive (or negative) correlations across the pivot factors should be identified as should the positive (or negative) correlations across years, i.e., if the forecast for August energy demand is above the mean for one year, how likely is it to be above the mean in the following year?

Step 5. Combine the probability distributions into a joint probability surface that can be used to draw a discrete set of futures with each future associated with a given probability.

Step 6. Determine the appropriate number of futures to assess through a Monte Carlo draw. It is expected that 100 futures will be needed to address the range of uncertainty in the planning framework. *[Note -- different approaches for drawing the scenarios can be used such as the latin hyper cube sampling]*.

Step 7. Make the recommended number of draws and develop the data sets for each "future" for the resource planning model runs.

<u>Element 5</u>. Production Model Runs without DRR – A resource planning model based on either optimization or comparison of production costs would be run for the selected set of futures drawn from the moRun each scenario through a resource planning model, providing a set of planning system outputs for an initial base case resource plan focused on the base case supply-side resources or non-DRR resources.

<u>Element 6</u>. Repeat the resource planning runs with the DRR resources. Net system benefits would be calculated by comparing the net present value of net system costs without DRR [the base case(s)]. Two different runs are expected – one that includes only the reliability resource DRR products (callable DRR) and a second that includes all DRR including the price responsive DRR product (TOU-CPP and/or RTP). using different combinations of resources with some runs focused on different EE and DR resource combinations to assess how they impact incremental system costs (e.g., the costs of meeting increment electricity needs) and the impact they have on risk. The output of these option resource plans should look at standard risk metrics as well as impacts on the net present value of system costs. [Note: If nodal pricing is used in the region, the impact on a subset of specific nodes should be included.]

<u>Element 7</u>. These results should be produced by the output of the resource planning model runs contained in Element 5. Based on the results of the base case without DRR and the with DRR production resource planning model results, the following should be reported:

1. The expect change in net systems costs (mean value) for different DRR scenarios.
2. Changes in the marginal cost of electricity between non-DRR and DRR model runs on annual peak days as well as system stress days when plant outages or transmission delivery constraints occur.
3. Changes in the volatility of marginal costs and/or estimates of market prices between non-DRR and DRR scenarios *[Note – Several different metrics can and should be used, e.g., the variance of the marginal costs across hours in the summer, or a metric that looks at the highest MC in each day]*.
4. General reporting of results that might include but not be limited to the number of years in which the DRR scenarios have higher costs than the non-DRR scenarios *[Note – DRR may not be used in all years, just as reserve requirements are not needed in all years]* and other standard reports such as generation by fuel type (coal, oil and gas) by month, and the normal suite of resource planning reports.
5. The impact of DRR on System Cost Risks in terms of the change in VAR_{90} and VAR_{95} between the non-DRR and DRR scenarios.
6. The impact on reliability in terms of the change in loss of load probability (LOLP) between the non-DRR and DRR scenarios holding reserve margins constant and/or the change and cost savings due to reserve margins that maintain a given LOLP level.

As the project progresses, draft outlines of the final report will be developed for review by the assignment project manager. Reporting details will be finalized in these reviews during the course of the assignment.

4.0 RFP Responses

Section 3.0 above discussed the suggested work elements. This section discusses what should be addressed by the bidder in the proposal. Issues to be addressed in the response include:

1. How you would go about developing the "final scope of work" report for this assignment as a stage 1 analysis. One to three contractors may be selected to develop a "final scope of work report" at a cost of $15,000. Based on that final scope of work report, one contractor would be selected to move forward with the analysis.
2. Describe your initial analysis framework and approach to the work elements identified in Section 3.0 above, i.e., the attributes of the resource planning framework and pros/cons of different methods of simplifying the assignment.
3. An initial list of factors contributing the uncertainty in the electric system in terms of cost and reliability, and how they would be considered.
4. Explain how the uncertainty would be incorporated into the resource planning modeling effort (e.g., Monte Carlo methods).
5. Address how uncertainty in resource performance (e.g., forced and unforced outages at generating units, derating of DRR resources if appropriate, and import/export uncertainties) would be addressed in developing the resource plans.

6. Demonstrate approaches for addressing market uncertainties such as uncertainties in the demand for electricity, fossil fuel costs, and the costs of raw materials, cost of a carbon tax (which could impact the cost of construction for certain supply-side resources options).
7. Discuss if the value of flexibility would be addressed in your approach.

In developing a response to this RFP, please develop a base case proposal that would meet the objectives using a “basic approach” with existing tools and methods to the greatest extent; then, identify research add-ons that could be explored at an additional cost.

In your response, please discuss:

1. What you see as the project challenges and critical success factors for this assignment.
2. If you plan to use any specific models or tools, please identify them and outline their capabilities.
3. Your familiarity with the costs and performance of alternative resource options/technologies including conventional supply-side options, as well as EE and DRR options.
4. Please discuss the advantages of your proposed approach in addressing key resource planning questions.
5. Provide a summary of your experience in resource planning and projects relevant to this assignment.

5.0 Evaluation Criteria

The evaluation criteria to be used for selecting a contractor are:

1. Approaches and tools to be used, along with a task plan for the assignment -- (25%)
2. Value of proposed additional studies -- (10%)
3. Experience of the project team with the regional energy market -- (20%)
4. Experience of the project team with resource planning and similar assignments -- (20%)
5. Cost of the assignment (both the basic approach and the add-on options) -- (25%)

6.0 Submission of Proposals

Proposals must be received by _________________. Proposals should be sent to:
Name
Address