STAC WORKING GROUP

ENABLING UTILITY FACILITATED/ CUSTOMER OWNED DER

BUSINESS STRUCTURES AND REGULATORY CHANGES THAT WILL FACILITATE WIDESPREAD, PROFITABLE DER INSTALLATIONS
a.k.a. Customer Owned Group

October 6, 2006 Discussion Draft

Mission: To develop one or more skeleton business model(s) that have the potential to increase the penetration of cost-effective DER at customer sites while providing business opportunities for multiple entities (customers, equipment suppliers, DER providers, utilities, etc.). This will be accomplished by removing barriers to the capture of the multiple value streams that DER can provide in various markets and locations. We will make recommendations for changing state utility regulatory practices and methods so that all parties can receive appropriate incentives to facilitate these business models.

Hypotheses:

1. Certain DER installations will provide a positive benefit/cost ratio.
2. Given current conditions, certain customers are adopting DER where its value exceeds its costs (based on internal value/discount rate determinations).
3. While some DER values can be captured, others can not currently be monetized.
4. Given current conditions, certain customers are not adopting DER where its value exceeds its costs because the value can not be easily monetized or captured.
5. Distribution utilities are in a key position to create DER installation barriers or to encourage the adoption of DER by their customers given the right regulatory signals.
6. Distribution utilities are in a key position to monetize local grid benefits.
7. Distribution utilities will be more motivated to encourage cost effective DER if some of the benefits accrue to their shareholders.
8. In seeking a win-win model, the goal should be to ensure that all stakeholder groups have the opportunity to realize benefits from DER.
9. Given the right incentives and a possible redistribution of value, DER businesses can grow over time, customers will have DER as a viable energy choice, utilities can develop a significant new DER profit center and non-participants will experience benefits.

Goals of Working Group:

1. Determine the types of customer sited applications and approaches that are most likely to meet a positive benefit/cost test.
2. Develop a value chain(s) for selected applications (e.g. wholesale energy and capacity value, customer reliability, local grid benefits, environmental, etc.)
3. Customize the value chain(s) to recognize differences in market structures (e.g. quasi- integrated (California) and disaggregated (Massachusetts)).

4. Construct a narrative business model that describes the potential role of each value chain participant (e.g. customer, equipment supplier, DER provider, utility, etc.)
5. For each narrative business model, describe the regulatory and public policy changes that would be needed to remove barriers to the participation of any value chain participant (e.g. lowering excessive interconnection fees, removing the utility's rate connection between sales and revenue).
6. For each narrative business model, describe the regulatory and public policy changes that would be needed to provide appropriate incentives for all value chain participants to install cost effective DER- including DER installed to meet larger state or national policy goals (where government is attempting to place a dollar value on non-monetized values).

Deliverables of Working Group:

1. Outputs from the E3 model for selected DER applications, showing costs and benefits. A list of potential values that are currently non-monetized will be included.
2. For each of the modeled applications, a value chain that shows one or more ways in which various entities can capture value. Where necessary, the value chain will be customized to show how value could be captured in an integrated market and in a market where wholesale has been split from retail.
3. At least one narrative business model with its accompanying rate/regulatory structure will be developed and presented at the January workshop. This narrative will focus on one or more of the modeled applications and will include a presentation of modeling results that show the aggregate impact of a large penetration of DER using this business model structure.

Time-Frame: Our group will deliver a work product for use at a second STAC workshop to be held in January 2007.

SUMMARY OF CUSTOMER OWNED WORKING GROUP CALL OF OCTOBER 26

The second conference call of the "Enabling Utility Facilitated/ Customer Owned DER" Working Group was held from 1-2 pm eastern time on October 26, 2006.
The purpose of the call was to review the revised Working Group Mission Statement, Goals, Deliverables and Timeline

CALL RESULTS

1. The revised "Mission Statement, Goals, Deliverables and Timeline" document for the Working Group was approved.
2. The initial applications to be run through the E3 Calculator Tool were discussed. The consensus of the group was to first concentrate on a CHP application and secondly a combined energy efficiency/ distributed solar PV application at a small to mid-size commercial building.
3. John Morrisette reviewed the Connecticut DER incentive program. There was interest expressed in further exploration of the program.
4. Potential utility incentives to customers who install DER in congested areas of the grid were encouraged by some. Utility representatives on the call explained that there were limited situations where customer DER could enable utility construction deferment. Tim Roughan explained the National Grid experience in this area over the last few years. Bob Bjorge urged that the perspective of the pilot project be expanded from an examination of circuit by circuit deferment opportunities to a larger view. This wider area view would examine the value of DER in maximizing the asset utilization of grid resources, thereby reducing the longer term need for system wide capital expenditures. Members on the call agreed that the distribution utility was in a unique position to direct the DER installations to the areas where the most grid value could be extracted.
5. Suggestions of other potential areas where utilities could bring value to the DER value chain included the following:
    - Managing customer participation in ISO programs, including scheduling
    - Offering interconnection services
    - Managing and hedging gas supplies for customers
    - Marketing, customer awareness and education
6. The next call agenda will include reviewing a value chain for each of the prioritized applications that shows the role of the customer, DER vendors/developers, the distribution utility and the regulatory authorities.
7. The schedule for future calls will be as follows:

- *November 30, 2006*
    - Review draft narrative business model(s) (based on revised value chain) with the accompanying rate/regulatory structure(s).
- *December 14, 2006*
    - Discuss revised narrative business models.
    - Report from utility representatives concerning their organizational response to initial business models.

SUMMARY OF CUSTOMER OWNED WORKING GROUP CALL OF NOVEMBER 9

The second conference call of the "Enabling Utility Facilitated/ Customer Owned DER" Working Group was held from 1-2 pm eastern time on November 9, 2006.
The purpose of the call was to review the Connecticut DER Incentive Program and discuss its applicability to potential pilots in Massachusetts and California.

CALL RESULTS

1. John Morrissette discussed the Connecticut DER Incentive program that provides both customer incentives and incentives to utilities in the form of $/Kw. payments for base load and emergency generation located at customer premises. Major program elements are summarized in the attachment. The following is a summary of questions and answers regarding additional program elements:

   - FMCC CHARGES

   The program is funded through ratepayer funds that are now being collected on customer bills in the form of Federally Mandated Congestion charges (FMCC). According to the DPUC web site, "The federally mandated congestion charges are attributable to congestion on the transmission system, particularly in the southwestern third of the state. This congestion limits the ability of the utilities to import power from other parts of Connecticut and other regions. To maintain system reliability in the face of this congestion, older, less efficient power plants in southwestern Connecticut need to run even though their costs of production exceed what their owners can earn by selling the power on the wholesale market. A large part of the congestion charge revenue goes to these plant owners for "reliability-must run" payments, to cover the difference between their operating costs and the market price." The Connecticut DPUC has authorized the incentive payments for DER installations to be made from this fund with the idea that distributed generation located in congested grid areas, especially Southwest Connecticut, will eventually result in a reduction in mandatory payments to the inefficient, must-run generating plants that are the current recipients of ratepayer funded FMCCs.

   For example, on a typical Connecticut Light and Power residential bill, the total per kilowatt charge is approximately $.1583. Of that, about $.0066 is allocated to the FMCC generation charges and $.0188 toward FMCC distribution charges. In total, FMCC charges represent about 16% of the kwh. charge on CL&P residential bills.

   - GAS REBATES

   John estimated that the customer rebate on the local natural gas delivery rate represents approximately one-third of an average customer total gas rate (the other two-thirds being commodity charges).

- SUBSIDIZED LOANS

In addition to the $/kw. incentives, customers may apply for low interest loans provided by participating banks. The loan subsidy (the difference between the 4% program rate and market rates) is paid by the utilities to the banks. The utilities then can file for repayment of the loan subsidy as well as their administrative expenses. To date, John noted that there was limited adoption of the loan program, although rising market interest rates may change that situation.

- STANDBY RATES AND BACKUP CHARGES

The DPUC ordered that standby tariffs for Connecticut utilities be eliminated. This was based on the DPUC determination that the initial cost rationale for those rates was based on generation related costs incurred by the distribution utilities. Now that they are no longer responsible for generation, the cost rationale for the rates has been eliminated. Demand charges as incurred by customers in every billing month are collected from each customer but the ratcheted component (based on previously established peak demand) of any demand charges are not billed to the customer. The utility is allowed to track these uncollected ratcheted demand charges and apply for reimbursement of the charges from the FMCC pool.

- PERFORMANCE GUARANTEES

Customers are required to post a five year performance bond to ensure that their project operates during designated operating hours. Designated hours are during the months of January, February and June through September. Projects are required to be operational from noon to eight p.m. with a minimum 85% capacity factor. The surety bond must be posted for 50% of the incentive amount received by the customer.

- RENEWABLE ENERGY CREDITS

CHP systems are eligible to receive Class III RECs in Connecticut.

- EXCESS GENERATION

CHP projects producing electricity for export are paid hourly LMPs with the utility retaining all capacity credits from the project (Rate 980). Emergency generators are required to participate in the NEISO load response program. Customers retain all energy and capacity payments under the ISO programs.

- RESULTS TO DATE

Approximately 30 projects representing 65 MW of capacity have been installed to date. Incentives of $8.5 million have been paid to customers and $4.5 million to utilities to date.

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