



COMMONWEALTH OF MASSACHUSETTS  
 DEPARTMENT OF  
 TELECOMMUNICATIONS AND ENERGY

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Investigation by the Department of  
 Telecommunications and Energy on its  
 own Motion into Distributed Generation

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D.T.E. 02-38-C

**Distributed Energy Planning Workshop Update**

**Submitted on December 22, 2006**

This update is based on three workshops which were held this fall to address the “Challenges for Distributed Energy Planning.” The issues to be addressed by these workshops were listed in Section 4.4 of the 2006 Report, and the Workshops discussed many of those issues, including potential roles of DG in distribution company planning. The discussions in the three workshops are summarized in **Attachment A**, including a list of attendees.

The workshop participants initiated development of a document to be entitled “Guidance Document for Customer-Owned Distributed Generation Applications.” The proposed Table of Contents for this document is presented in **Attachment B**. A draft of Chapter 1 is included, which addresses the background and objective of the document. **Attachment C** includes a draft of one other section of this Guidance Document (Section 3.3.1), addressing one particular solution to one of the three challenges.

A Technical Challenge Matrix is presented in **Attachment D**; this is the matrix originally suggested in the Report of the Distribution Planning Work Group on DG and Distribution Deferral (Attachment H of the 2006 Report). Its content to date was developed during the three workshops, and has provided the structure of key portions of the proposed Guidance Document.

Electronic versions of this Report, its Attachments and the related information gathered to date can be found at:

[www.masstech.org/dg/2006-12-13\\_Workshop.htm](http://www.masstech.org/dg/2006-12-13_Workshop.htm)

and detailed information regarding all the DG collaboration work to date is available at:

[www.masstech.org/policy/dgcollab](http://www.masstech.org/policy/dgcollab).

Questions regarding DG collaboration in general and this report in particular may be directed to Francis Cummings at 508-870-0312, Extension 1-270, or via email at [cummings@masstech.org](mailto:cummings@masstech.org).

Sincerely,

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## Distributed Energy Planning Workshops

### Meeting Notes: September 27, 2006 Technical Workshop

The first Distributed Energy Planning Workshop convened on September 27 at the Massachusetts Technology Collaborative (MTC) in Westborough. Fran Cummings served as the facilitator, with 17 additional participants. The agenda for the Workshop was posted on the MTC website at:

[http://www.masstech.org/dg/2006\\_Sept-27\\_Workshop.htm](http://www.masstech.org/dg/2006_Sept-27_Workshop.htm)

### Summary

Two presentations were made, by Fitchburg Gas & Electric and by NSTAR, including diagrams describing the challenges and some of the ways in which they differ according to the different types of circuits in Massachusetts. These presentations can be found at the web page above and at the following links:

- [Recloser-based Feeder Configuration](http://www.masstech.org/renewableenergy/public_policy/DG/resources/2006-09-27_Krell_Technical-Challenges-Part-1.ppt)  
([http://www.masstech.org/renewableenergy/public\\_policy/DG/resources/2006-09-27\\_Krell\\_Technical-Challenges-Part-1.ppt](http://www.masstech.org/renewableenergy/public_policy/DG/resources/2006-09-27_Krell_Technical-Challenges-Part-1.ppt))
- [Automated Switching Configuration](http://www.masstech.org/renewableenergy/public_policy/DG/resources/2006-09-27_Automated-Switching.ppt)  
([http://www.masstech.org/renewableenergy/public\\_policy/DG/resources/2006-09-27\\_Automated-Switching.ppt](http://www.masstech.org/renewableenergy/public_policy/DG/resources/2006-09-27_Automated-Switching.ppt)).

These and other challenges to integrating DG were discussed, and several solutions were also discussed, and these points were incorporated into the “Matrix of Challenges and Solutions” during the workshop as they were addressed. The revised Matrix was posted after the meeting on the workshop’s web page (above). The general consensus was that solutions can be found (some involving new equipment not yet in general use) but that some could potentially be expensive. Some challenges and solutions were identified as relatively more challenging, including issues associated with lightning arrestors. A series of next steps were identified to get additional information on solutions and their costs.

### Discussion Points

1. Most participants took a positive approach recognizing that the issues addressed by the Workshop were significant from multiple perspectives:
  - there will be an eventual proliferation of DG, so let’s anticipate issues of applicability and cost as the architecture changes, and

- let's also test the use of DG (and DR) where it can (a) postpone upgrades at lower cost and equivalent reliability or (b) reduce the frequency or duration of outages.
2. Several participants have been involved in the national discussions of a "modern grid" or "intelligent grid." There was general consensus that (a) this will not suddenly replace the existing grid, (b) it will not render obsolete the solutions we consider today, and (c) the communication and control designs that would accommodate DG on most circuits today will likely be found in future configurations. Therefore what we learn in solving technical problems on typical circuits today will continue to be valuable as the grid evolves.
  3. It was noted that there are likely to be significant costs to accommodate widespread DG on distribution systems. It was also noted that before long the upgrade of aging systems will not be "incremental" on many circuits, and including DG in modernization will become more cost-effective. Moreover, the demand-side drivers of security, reliability, power quality, and environmental stewardship will increasingly call for solutions, and add to the rationale for them.
  4. Faults (and the associated trips of on-line equipment) are more probable during peak hours, and create voltage sags on adjacent circuits several times per year. Both are increasingly expensive as customers' equipment becomes more sophisticated and essential to their operations. DG units are not currently configured to support the system and are often as sensitive as computers in disconnecting due to such disturbances. Confidence in DG protection system changes and improvement in reclosing capabilities to within 10 cycles or less may be necessary.
  5. Today automatic power restoration ranges from cycles to multiple minutes and can at times be even slower. Recloser + breaker + relay delay can exceed 2 minutes. IEEE 1547 requires that DG units remain off line 5 minutes (This was probably driven more by customers and manufacturers, who don't want to get hammered twice, than by utilities.) Typical re-sync capabilities of DG vary from a few seconds (inverters) to a minute (inductive) to several minutes (some synchronous). Issues were also identified concerning the impact of alternate sources on recloser operation. Many circuit are designed with reclosers that can only sense faults in one direct based on a single source location. DG units can confuse operation of protection systems for circuits with these type configurations.
  6. "Smart" reclosers, recloser controls, and other devices coming on the market monitor current and allow fast reclosing based on fault clearance instead of time delay. This will increase the probability of successful re-closing and increase the probability of DG ride-through, but will not eliminate all problems of power quality at the load. They also can be configured to adapt to changes in source and fault locations to insure proper operation when DG is on a circuit.
  7. There are several technical problems with grounding and over-voltage when two-way power is introduced, having to do with delta vs. Y transformers, lightning arrestors, and three-phase vs. single-phase connections. There are also problems of locating faults with non-directional equipment, and dispatching VAR support. These problems get worse as DG proliferates. Solutions involving widespread change-out of relays, transformer and wiring changes, limiting DG

sufficiently to avoid large voltage impositions, isolation transformers, etc. were discussed. Each solution raises other problems. Ultimately “smarter” sensing, communication, and control devices will be needed. The capabilities and cost of such devices will be investigated, along with ISO requirements and DG design issues.

8. Dispatchability of DG was discussed briefly. The capability to dispatch DG is not likely to be controversial (some systems have this built-in), but the criteria and control of dispatching were beyond the scope of this workshop. Load shedding is another distributed resource that is imperfectly dispatched today, generally not operated and maintained by the utility, hard to recruit and retain, and therefore not dependable in distribution planning. The December workshop should visit this issue again.
9. If DG exports power above its own load, it must be treated as a system resource, so the same quality and standards must be applied to its interconnection as to other resources.
10. The “Resource Type” Table associated with the Matrix might be expanded to include customer-sited vs. stand-alone but load-associated units.

### Next Steps

- For the next meeting, one feeder and substation will be selected for each distribution company or for each of the most common circuit configurations, and the technical solutions discussed to date (see revised Matrix) will be identified or designed for that particular distribution area in order to accommodate a substantial quantity of DG and/or to rely on the DG as a distribution resource. (Note: on Nov. 7, after these notes were first distributed, utility participants “recommended removing this item from the notes of the meeting,” indicated that they didn’t recall this discussion.)
  - The group noted that the challenges become greater as DG penetration on circuits becomes more significant as a percentage of the circuit loading. The current Tariff essentially calls for limiting the penetration to 7 ½ % of peak circuit load to avoid the types of problems discussed. The level of DG penetration for this analysis was discussed and a general agreement was reached to start with an assumption for a circuit with up to 50% DG, count the change-outs or other requirements, and compute the cost.
  - It was agreed to capitalize on studies already done by identifying one or more actual circuits that had recently had system modification studies performed and approved for particular DG interconnections, as a basis for adding hypothetical additional DG such that the combined output is increased up to 50% of peak circuit load, in order to then review the technical aspects of potential problems, to mitigate them through some of the possible solutions in the Matrix, and to develop cost estimates.
  - Utilities indicated that they would meet jointly to plan these next steps. They also expressed some concerns, including that their staff resources

are tied up in getting ready for next summer; and that such cost estimates can be abused.

- Utility participants will review past cost data accommodating DG on the order of 7 ½% of load.
- Utility participants will invite manufacturers to the next Workshop to provide additional information to help address the remaining issues, including cost, including:
  - GE
  - ABB
  - Siemens PTI (<http://www.pti-us.com/>)
  - S&C Electric Company (<http://www.sandc.com/products/icips.asp>), and
  - metering and SCADA providers.
- The next two Workshops will be held on:
  - November 15, 2006 (Technical Workshop 2) at WMECO, 55 Russell Street (RT 9), Hadley, MA 01035
  - December 13, 2006 (Economic/Policy Workshop).



## **Distributed Energy Planning Workshops**

### **Meeting Notes: November 15, 2006 Technical Workshop**

The second Distributed Energy Planning Workshop convened on November 15 at Western Massachusetts Electric Company, in Hadley, MA. Fran Cummings from MTC served as the facilitator, with 22 additional participants. The agenda and materials for the Workshop, including the revised Technical Challenge Matrix (“Matrix”), are posted on the MTC website at:

[http://www.masstech.org/dg/2006-11-15\\_Workshop.htm](http://www.masstech.org/dg/2006-11-15_Workshop.htm)

The following meeting notes are structured around the Agenda, which had been posted in advance.

#### **Welcome and Introductions** (9:00 – 9:30)

During the introduction of participants, Fran welcomed Johan Enslin and Khoi Vu from KEMA, Inc. and Jim Bing from New Energy Option, Inc., consultants recently engaged by MTC through a competitive RFP, who will provide support to this series of Workshops, beginning at this Workshop, including drafting portions of the Report to be submitted to the DTE on December 31, 2006.

In response to the Agenda item “Identify any new materials since last Workshop,” the utility participants indicated that they had assembled data on system modification costs, which they presented later in the day, but that no particular circuits had been identified or studied and no other information had been assembled for this Workshop. Also, Charlie Cyr offered a patent submitted by Chevron on Jan. 11, 2002 for an “Uninterruptible Power Generation System,” which featured a Static Disconnect Switch.

#### **Review Results of Workshop 1 on September 27** (9:30 – 10:00)

The following results of the first Workshop were reviewed:

- Technical Challenge Matrix, and
- Distribution Circuit Configurations.

#### **Challenge: DG Behavior on Distribution Circuits** (10:00 – 12:00)

The workshop turned to the Challenge entitled “DG Behavior on Distribution Circuits” and began by reviewing the list of solutions that were developed during Workshop 1 to address the “Specific Challenge” in Column C of the first row of the Matrix: “1.1.1, Ability for DG units to remain on line following a momentary interruption of the circuit it is supplied from....” That list was as follows:

- A. Customer load isolation with generator ride through
- B. Customer load interruption with generator trip
- C. High speed resynchronization or dispatch based DG reconnection
- D. Customer based energy storage device
- E. Utility based energy storage device or dispatch of emergency units
- F. Utility dispatched demand reduction program response

G. Employ more advanced communication systems to coordinate reconnection of DG units.

It was agreed to begin the discussion with the first solution “A. Customer load isolation with generator ride through.”

It was determined that, because this Solution was implemented primarily on the customer’s side of the meter and its implementation would not differ significantly depending on circuit characteristics, this Solution could be discussed in detail without selecting any actual circuit, or any one of the four generic circuit configurations discussed at Workshop 1 and listed in the Matrix (in the sheet named “Circuit Configurations”):

- Fused Circuit Configuration
- Recloser Circuit Configuration
- Auto Transfer Circuit Configuration
- Auto Sectionalizing Circuit Configuration.

The CHP facility at NECCO in Revere was mentioned because its circuit has experienced significant disturbances of the kind addressed by this “Challenge,” and the CHP facility has responded by implementing a ride-through capability for the 6 MW CHP and the entire manufacturing facility. This facility was therefore identified as one case example of “Solution A.”

For the selected Solution A, the Workshop then took up the Agenda items “Identify equipment and discuss costs” and “Scope out additional investigations needed to confirm cost estimates.”

An EPRI White Paper from 2001 was used as a reference throughout the discussion: Integrating Distributed Resources into Electric Utility Distribution System, which had been obtained from EPRI only the day before the Workshop. This report addressed issues that had been brought up in Workshop 1 and revisited at this workshop. It is now posted at:

[http://www.masstech.org/renewableenergy/public\\_policy/DG/resources/2001-12\\_EPRI\\_Integrating-Distributed-Resources\\_1004061.PDF](http://www.masstech.org/renewableenergy/public_policy/DG/resources/2001-12_EPRI_Integrating-Distributed-Resources_1004061.PDF)

Other reference materials included products/solutions from SEL, Chevron, etc. New materials will continue to be collected and made available to all participants. Particularly, documents or reports related to experiences by other US utilities will be the focus.

A brainstorming exercise was undertaken to identify potential costs for Solution A, “Customer load isolation with generator ride through:”

- It was noted that utilities may incur ongoing costs such as coordination of settings with DG owners in the event of changes in the utility circuit to which it is connected.
- Tim passed on a comment from Northern Power to the effect that, for a CHP project in the multi-MW size range, with a typical installed cost in the range of \$2000-2700/kw of generation capacity, there might be an incremental cost of 10-30% to add critical load support to meet customer needs. However, costs were not broken down to identify the incremental cost of adding the ride-through capability on top of critical load support capability.
- Alan indicated that in his experience a 15% adder might be required for ride-through capability, over a base of \$2,000/kW for a synchronous machine.
- It was indicated that if customer re-wiring or “load reconfiguration” is required in order to separate a customer circuit (so it could then be isolated with the DG to achieve the ride-through capability), the cost of such reconfiguration could account for a substantial portion of the cost figures under discussion. It was also noted that

this cost might not be required if an appropriate circuit already exists, or for a new construction situation.

- Customer benefits were discussed, including the observation that the incremental cost for Solution A might be zero for customers whose DG designs already include critical load support and/or ride-through capability to meet their own needs, which may often be the case for customers with critical loads and high requirements for reliability and power quality. It was noted that this market segment should be looked into further and could be treated differently in any Guidelines to be developed.
- Costs of \$120-150/kw were cited for inverters with ¼-cycle disconnect capability.
- It was noted that auto re-synchronization would be needed for utility support, and possible costs were discussed.
- Monitoring and “physical assurance” would be required as part of Solution A, and communication costs for utility coordination (needed for utility support) might be \$5,000 per site.

As indicated above, much of the discussion was focused on identifying what was incrementally needed for support of utility systems in addition to typical customer interconnection equipment costs. Some typical or potential cost elements are included in column H of the Matrix entitled “Detailed Solution Estimates for DG Support of Utility System,” based on the discussion to date. The matrix was updated after the Workshop and is available on the MTC website for the Workshop, and at:

[http://www.masstech.org/renewableenergy/public\\_policy/DG/resources/2006-11-15\\_Matrix\\_Workshop-2.xls](http://www.masstech.org/renewableenergy/public_policy/DG/resources/2006-11-15_Matrix_Workshop-2.xls)

### **European Experience with DG Integration, led by Johan Enslin, KEMA** (Lunch)

The European experience was presented by KEMA, using DG integration issues in the Netherlands as an example. While the European environment is different from that of the US (governmental subsidies, load nature, distribution networks,...) most technical issues, such as bidirectional flow, protection, power quality issues, voltage regulation, etc., are relevant to Massachusetts. KEMA helped Dutch and UK utilities and regulators to develop technical planning guidelines for DG integration. Workshop participants agreed that such materials would be an important reference for this project.

### **Challenge: Utility System Design Changes** (1:30 – 2:45)

The workshop turned to the Challenge entitled “Utility System Design Changes.” The first “Concern” (column B) was “2.1 Distribution circuits and their protection systems are largely designed to be operated radially out from a single electrical source,” and the first “Specific Challenge” (column C) was:

“2.1.1 Protection system modifications necessary for addition of a single DG unit. Of particular concern was the impact on lightning arrestors and single phase customers when connected DG is significant with respect to loads (i.e. effective grounding issues).”

Two Potential Solutions had been identified during Workshop 1:

- A. Limit generation on circuit to a small percentage of circuit load.
- B. Modified DG connection and/or addition of effective grounding for units may mitigate concern.

For this Solution A, it was noted that the EPRI paper suggested 15% of circuit peak load as a general limit, for acceptance under a fast track process, based on installations that passed all other interconnection related screens.

Most of the discussion addressed the potential for multiple DG units, which was addressed by the second “Specific Challenge” (column C):

“2.1.2 Protection system modifications necessary for addition of multiple DG units on a single circuit. Of concern was the protection system devices that are non-directional in nature that serve to interrupt or indicate location of faults. Higher fault current levels also present concerns.”

The following Potential Solutions had been identified during Workshop 1:

- A. Limit generation on circuit to below acceptable fault current contribution levels.
- B. Upgrade and replacement of protection system equipment to allow for reverse power flow operation including communication systems upgrades as needed.
- C. Introduction of current limiting device to mitigate contribution to area fault duty.

For Solution A above, one suggestion was for use of a "Flex Phase" device which is designed to mitigate fault duty contribution of a generating source where short circuit constraints exist on a system. The discussion referenced the material from Northern Power concerning its “FlexPhase™ power converter system” and about its approach to Critical Load Support (CLS) Applications<sup>1</sup> (from its website <http://www.northernpower.com>) that had been posted on the Workshop page. It was suggested that the high level cost estimate for such a device may be in the range of \$100,000, and it was noted that there are a number of products in the marketplace with some of these capabilities.

The utility members shared some example projects related to cost of system modifications in order to accommodate DG sites.<sup>2</sup> In the examples given by National Grid and WMECO the unit cost of inter connection ranged from approximately \$12,000/MW for 2.7MW hydro installation to a high of \$177,500/MW for an 800kW landfill gas installation. It should also be noted that the cost numbers for these installations do not include any cost that may be incurred from other utilities such as cable or phone service.

Some Workshop participants emphasized that, while there are potential additional costs for all solutions that are associated with utility system or customer equipment modifications due to DG interconnections, these costs are difficult to estimate in general without defining a specific location and type of installation. During the course of the discussions it was noted several times the engineering requirements for interconnection and for distribution system support will vary from site to site, and from one proposed system to another proposed system.

In the discussions surrounding the costs of technical solutions it was also observed that discrete components are only part of the cost of each interconnection solution. The components are part of a system and if the system infrastructure is not already in place the total costs can be much larger than the component costs. Most of the current infrastructure is older electromechanical equipment which, while reliable, is generally not configurable. The issue of communications based systems was discussed, noting its virtues and its costs. It was noted that old equipment can be replaced with modern components over time, although this is not sufficient because for

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<sup>1</sup> [http://www.masstech.org/renewableenergy/public\\_policy/DG/resources/2006\\_Northern-Power\\_FlexPhase-1-1\\_CLS.pdf](http://www.masstech.org/renewableenergy/public_policy/DG/resources/2006_Northern-Power_FlexPhase-1-1_CLS.pdf)

<sup>2</sup> The spreadsheet with this information will be posted on the Workshop web page:  
[http://www.masstech.org/dg/2006-12-13\\_Workshop.htm](http://www.masstech.org/dg/2006-12-13_Workshop.htm)

the new equipment to operate it requires a whole new architecture. This is a “systems” challenge, not a component problem.

The utility attendees offered to develop an equipment list necessary for utility support for typical installations and to collect data for component equipment costs. The consultants may then be able develop some examples or ranges of system costs based on those data.

**Agree on Tasks & Deliverables for Next Workshop, Other Next Steps** (2:45 – 3:30)

There was general agreement to develop (to the extent that time is available before the December 31 Report to the DTE) a set of technical guidelines, design change guidelines, standards or best practices, which could be called Design Guidelines for DG Integration and could be incorporated into utility planning documents as discussed earlier during the meeting. This should include key case studies and examples of costs for integration. This could include a toolbox of approaches, which could be varied based on categories of DG (e.g., different solutions tailored for synchronous vs. inverter-based DG). [See additional ideas about the guidelines in the earlier discussion.]

The following was added to the Matrix in a new column “DG Workshop Proposed Actions:”

The option of developing a planning guide document that would aid planning and protection system engineers in addressing and mitigating the potential problems identified in this matrix was discussed. The document would also help customers by listing the types of issues that are encountered when considering interconnection of a generator which could also provide utility support. The design options in terms of equipment requirements and their related costs would also be identified. This document would be based on existing documents as much as possible and could rely extensively on a document that KEMA developed for the Dutch utility.

Additional briefing on guidelines developed elsewhere and discussion of potential guidelines for Massachusetts will likely take place during the conference call scheduled for Tuesday, Nov. 21, from 1:00 pm through 3:00 pm.

There was an active discussion of the role of economic analysis, and how to address several of the steps listed in the 2006 Report, such as:

- 5) Design Cost Analysis, and
- 6) Economic and Market Calculations (including “review [of] Navigant’s economic analysis with the revised inputs...”).

It was noted that the guidelines would include “a process to get” economic numbers, at the point when real numbers are needed. Several participants argued that a focus on economics is “not the right path” at this point, or that we could not or should not try to put particular dollar numbers in the report on these workshops, for reasons [listed elsewhere?], such as high degree of variability and site-specificity. The question was raised whether the report should include ranges or examples of cost per component or cost per site, where appropriate, instead of cost per circuit or per kW. Some consensus seemed to be emerging that examples of costs could be included, based on one or more cases and with reference to processes or procedures to be developed for the guidelines, as long as the Report emphasizes that they are only illustrative and acknowledges sources of variability. It was noted that the EPRI “win-win” project may be the right forum for discussion of economic issues. It was stated that if it is decided to change the approach or the deliverable of the Workshops from those presented in the 2006 Report, it would be important to explain the rationale to the DTE and other stakeholders. It was also observed that the Workshop report will not necessarily reflect the views of parties that are not

participating in the Workshop process. The question was also raised, if the Navigant economic analysis were not revisited, what the participants would indicate about the validity of the Navigant conclusions based on the technical work to date.

Attendees felt that we can “get this done” – developing the role of DG for distribution company planning – without first trying to get “final, conclusive” economic estimates of costs and benefits. A general approach was discussed that would involve a “shift from where we started.” The discussion included the following elements:

- DG may be a “distribution resource” in “isolated cases”
- “we can find instances” where DG is a viable solution
- DG growth will depend mostly on “other drivers” than distribution deferral
- PV and other DG “has benefits, though not necessarily always for distribution”
- An “uptick” in DG should be expected, partly due to FCM, increasing the need to clarify the utility role
- Planners can focus now on “how to accommodate” and integrate DG in order to “realize benefits down the road”
- DG is a “resource we can take advantage of which has future value to distribution.”

The above elements involve 2 potential roles, that could be pursued in parallel:

1. Leverage future value of customer DG: when DG “shows up” as a result of non-utility market and policy drivers, respond to that DG in such a way as to anticipate ways to take advantage of it, by “realizing” the greatest possible future benefits for the distribution system (e.g., by encouraging ride-through) and/or to best managing potential future costs to accommodate that DG (e.g., by anticipating system design changes that may be needed for future DG), and
2. Seek locations to use DG as a distribution deferral resource: when possible opportunities to defer circuit upgrades or other distribution investments arise, assess possible DG alternatives to traditional solutions and, where feasible, seek ways to encourage DG and other DER in those particular locations.

The “guidelines” document would identify methods and factors for utilities to consider as they implement both of these roles or strategies. There was a general feeling that the emphasis should be on the first of these roles.

Attendees suggested that a draft document be prepared before the December 13 Workshop (by MTC’s consultants). Alternative structures were suggested, either following the steps and points listed in the 2006 Report, or organized around the potential contents of the guidelines planning document, or following the structure of the Technical Challenge Matrix as it has been elaborated during the Workshops. It was also noted that the report should outline the “major issues” and identify existing references. It was noted that additional stakeholders are expected at the December 13 “Policy Workshop,” which will also be summarized in the December Report. It was emphasized that while some such outlining and writing should be initiated, significant work remains to assemble additional substantive information, as discussed elsewhere, including:

- Utility representatives will get together and come up with cost sheet(s) based on past purchases. (Note: on Dec. 4, after these notes had been distributed, one utility participant emailed the following “understanding of the utility commitment: As part of the November 15th workshop we discussed the challenge ‘Utility System Design Changes.’ This specific section of the technical challenge matrix relates to the Control & Protection equipment and communication system changes to support the installation of distributed

generation within the distribution system. The primary concern is the existing protection systems are non-directional. The installation of multiple distribution generation units could trigger substantial modifications to this protective system. The utilities committed to identify the type of protective and communications equipment that would require replacement and provide a ‘ballpark’ cost estimate.”)

- Charlie Salamone will update the Matrix with changes suggested.
- Alan Dickens will provide some info about Co-Energy America projects (e.g., costs for “Solution A” ride-through).
- Charlie Cyr will circulate info about directional devices from Cooper.
- Participants are encouraged to review the EPRI Report which Charlie referenced during the meeting: Integrating Distributed Resources into Electric Utility Distribution Systems (December 2001).
- Other key EPRI reports will be sought.
- A technical conference call was scheduled in the next week to hear a briefing from KEMA on the guidelines that were cited earlier, to discuss the nature of guidelines to be developed for Massachusetts, to review the Meeting Summary to be distributed before then, and to discuss any other next steps:  
Tuesday, Nov. 21, from 1:00 pm through 3:00 pm.
- All stakeholders are encouraged to submit comments, questions and new information as soon as possible to Fran at [cummings@masstech.org](mailto:cummings@masstech.org), to be posted as appropriate on the web page for the December 13 Workshop:  
[http://www.masstech.org/dg/2006-12-13\\_Workshop.htm](http://www.masstech.org/dg/2006-12-13_Workshop.htm)
- MTC consultants will prepare drafts and materials for the next Workshop.

Two dates were also identified for additional conference calls to prepare for the December 13 “Policy Workshop”:

- Monday, Dec. 4, from 2:30 pm through 4:30 pm
- Friday, Dec. 8, from 2:30 pm through 4:30 pm.

The Workshop was adjourned at 3:30 pm.

**Attendees (for either of the first 2 Workshops)**

David	Thimsen	EPRI	(651) 766-8826	dthimsen@epri.com
Gerry	Bingham	Massachusetts Division of Energy Resources	(617) 727-4732 x40178	gerry.bingham@state.ma.us
John	Bzura	National Grid USA Service Company	(508) 421-7642	JOHN.BZURA@us.ngrid.com
Tim	Roughan	National Grid USA Service Company	(508) 421-7510	timothy.roughan@us.ngrid.com
Frank	Barys	National Grid USA Service Company	(508) 421-7614	francis.barys@us.ngrid.com
Janette	Sandberg	NSTAR Electric & Gas Corporation	(781) 441-8739	janette_sandberg@nstaronline.com
Richard	Zbikowski	NSTAR Electric & Gas Corporation	(781) 441-8335	richard_Zbikowski@nstaronline.com
Rudy	Stegemoeller	Plug Power, Inc.	(518) 283-0933	rudysteg@capital.net
Beka	Kosanovic	UMass Center for Energy Efficiency & Renewable Energy	(413) 545-0684	kosanovic@ecs.umass.edu
Paul	Krell	Unitil	(603) 773-6463	krell@unitil.com
Charles	Cyr	Waldron Engineering and Construction	(603) 772-7153 x108	ccyr@waldron.com
Cynthia	Janke	Western Massachusetts Electric Company	(413) 585-1750	jankecj@nu.com
Daniel	Butterfield	NSTAR Electric & Gas Corporation	(781) 441-8627	Daniel_Butterfield@nstaronline.com
Bruce	Renz	Renz Consulting	(614) 804-4840	bruce@amperion.com
Alan	Dickens	Co-Energy America, Inc.	(603) 772-4533	adickens@coenergyamerica.com
Dave	Doucette	Energy Program Consulting	(508) 655-4540	dpdoucette@comcast.net
Pentti	Aalto	PJA E	(603) 485-2559	pjaesd@comcast.net
Stephen	Cowell	SEBANE (Conservation Services Group)	(508) 836-9500	steve.cowell@csgrp.com
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## **Distributed Energy Planning Workshops**

### **Meeting Notes: December 13, 2006 - Policy Workshop 3**

The third Distributed Energy Planning Workshop convened on December 13 at MTC Headquarters in Westborough, MA. Fran Cummings from MTC served as the facilitator, with 18 additional participants on site and 8 by teleconference/webinar. A listing of participants for all Workshops appears at the end of these minutes. The agenda and materials for the Workshop, including the revised Guidance Document, are posted on the MTC website at:

[http://www.masstech.org/dg/2006-12-13\\_Workshop.htm](http://www.masstech.org/dg/2006-12-13_Workshop.htm)

The following meeting notes are structured around the Agenda, which had been posted in advance at the above link. References to Attachments refer to the Attachments to the December 31, 2006 report to the Department of Telecommunications and Energy (DTE) entitled "Update on Distributed Energy Planning Workshops."

#### **Welcome and Introductions** (9:00 – 9:20 AM)

Fran began the meeting by reviewing the schedule for completing a report to the DTE prior to the end of the year. The Working Group discussed the question of whether MTC or the Distribution Planning Work Group (DPWG) is submitting the report. The WG is facing a tight schedule for review and acceptance of report by the WG for delivery before December 31. There is limited availability of WG members in this time frame.

#### **Review Results of Workshops 1 and 2 on September 27 and November 15** (9:20 – 10:00 AM)

Charlie Salamone discussed results from prior workshops. The presentation discussed the Matrix of Challenges and Solutions (Attachment D of final submission), which has been expanded into the Guidance Document (extracts in Attachments B and C). The presentation is available at:

<http://www.masstech.org/dg/DGRoles.ppt>

Charlie then presented and expanded on the two roles of DG in distribution planning – the technical, economic, and legal challenges for each. Most workshop participants indicated that DG installed by utilities is not permitted in MA. They felt that giving incentives to customers is possible but unlikely to work. DG does occur for customer-driven reasons. They questioned how can we take advantage if it does occur. They expressed the view that the key is managing the cost.

#### **Role #1: Leverage Future Value of Customer DG**

Questions discussed with respect to Role 1 included the following: If DG occurs in response to generation market and /or policy drivers, is there a way, with some incremental modifications or layers, to take advantage of the DG later? For example, is there optional low-cost customer equipment or design configuration that would facilitate and support the reliable operation of DG within the utility distribution system? Is there utility equipment or design that would facilitate the reliable operation of widespread DG within the distribution system? Due to reliability and

operation requirements, customers will generally not be receptive to disconnection by the utility when they lose their internal generation. We must clarify how the customer takes first steps without making this commitment. The decision and the cost would be the customer's. The technical approach might be for the customer to island off or shed load. Will the customer elect to do this?

The utility would need to upgrade to accommodate the future operating arrangement. Charlie presented a screening process for identifying sites. Utilities would perform this task as part of their initial planning process. Light industrial loads were described as not offering an opportunity.

During the discussion of Role 1, it was noted that presenting a cost-benefit analysis to justify installing even a basic recloser rather than fuses is already a significant challenge. Any substantial increase in cost would make this assessment even more difficult. When installing a recloser, choosing a more elaborate and DG-friendly bidirectional flow tolerant controller with communications adds a 50% cost premium over a basic unit with hydraulic operator and controller designed for one power flow direction. How do we show benefits that give confidence that the additional investment will be utilized and bring adequate returns? Overall, when upgrades are due to happen, can the utility make DG friendly decisions?

It was also noted that the incremental cost of DG friendly equipment may be lower when and if decisions are made for grid modernization, through which many systems would be highly DG friendly in their base case configuration. Utilities continue to evaluate new system configurations and modern equipment, some of which could be part of a redesign of the distribution system (i.e., Modern Grid Initiative). But they have seen significantly increased cost to make the transition. The Modern Grid approach takes the utility to more sophisticated operations but with higher costs for planning, design, procurement and installation of the distribution system. It was suggested that existing rates do not support the Modern Grid approach, which will cost more than today's distribution systems. Right now the high overall energy costs make it difficult to look at raising rates to fund the distribution companies' Modern Grid approaches that may be more supportive of customer DG. A clear picture of challenges and possible approaches might help utilities and regulators in deciding on rate cases where the fundamental approach to DG is at stake. Utilities are interested in trying pilot installations in conjunction with MTC (e.g., congestion relief pilots).

Contractual issues between utilities and customers relating to DG have not been included in study to date but will have to be addressed, through EPRI and other projects.

### Role #2: Seeking Locations to Use DG as Distribution Deferral Resources

This is the role at the core of the earlier Navigant study covered in the June 2006 DPWG report, in which the utility would identify circuits where planned capacity upgrades might be deferred through customer DG, and would promote use of DG there. It was observed that the following was stated on Page 36 of the June 2006 DPWG Report: "Based on the conclusions in the Navigant Economic Analysis, DG appears to provide some positive benefits in deferral of distribution investment, but only within narrow windows of opportunity, based on specific timeframes, need dates and specific feeder lines, and only when DG is combined in a package of resources that includes energy efficiency and demand response measures. Thus, the deferral value results, on their own, summarized in the Navigant Report, do not provide support for widespread deployment of DG."

It was noted that an essential part of Role 2 would be development of a straightforward analytical screening process (e.g., annual) that would increase the efficiency of actively

pursuing DG as a solution for deferral. The utilities expressed concern that significant resources would be needed to identify the few viable instances where DG would defer upgrades to distribution infrastructure. They repeated their concern over the lack of experience with operational issues regarding implementing DG within the distribution system and suggested that at this time the primary effort should be on the implementation of pilots which would be needed to show practical issues and solutions.

In conclusion, the DPWG felt that Role 2 has limited opportunities, and faces economic and practical challenges to operate successfully. By contrast, Role 1 deserves more attention and work - there will be many more customer-driven DG installations, and thus more possibilities for utility planning benefit.

**Guide Document, December 11 Draft, and Related Discussions** (10:00 – 11:00 AM)

The KEMA document, titled at that time “Planning Guidelines for Customer Owned Distributed Generation”, has technical content not planned for detail review at the Workshop – some of this had been done in preceding teleconferences. See The basis for discussion at the Workshop was the December 11 draft:

<http://www.masstech.org/dg/2006-12-11-DRAFT-Planning-Guide-KEMA.doc>

Eric Udren of KEMA characterized the guide as a work in progress - it will not be complete prior to submittal to the DTE at the end of the year, and is proposed for completion in 2007. The stakeholders confirmed that the guide provides the type of information that would be useful to support customer DG applications. The document would support both utilities and customers working in a relationship under Role 1 discussed above. The presentation discussed the DG penetration issues, including examples of when high penetration of DG could provoke problems - there are thresholds beyond which there could be significant system-wide response issues. The discussion cited a GE study on DG high-penetration system impacts that suggests that DG could help or hurt system response to disturbances, depending on specific DG response characteristics. IEEE 1547 rules, required by existing tariffs, were not created with recognition of these response issues. A penetration level of 15% - 20% has been considered as a threshold at the distribution circuit level, but at the system level smaller penetrations could impact performance during disturbances. The utility group suggested that this issue be highlighted in the report.

The presentation continued on the layout of the planning guide, including how the Matrix of Challenges and Solutions has been mapped into the Guidelines. The concept of adding example cases, with diagrams and explanations, for each of the problems discussed in the report was presented and accepted by the group. The draft presents a number of factors that could be used as part of a flow chart that would provide a means to review or screen installations for possible problems and solutions. It was noted that the Modern Grid approach could be included as part of the control & monitoring section, and that this includes communications for DG maintenance as described in draft IEEE 1547-3. Participants felt that system loss issues, which have proven difficult to analyze in the past, should be omitted here and dealt with in economic analysis later, if at all. It was suggested that NPCC guidelines should be analyzed and incorporated where appropriate.

It was requested that Guidelines should include a previously-discussed CHP example cited on Page 2 of the November 15 Workshop 2 minutes.

There was some discussion concerning wind projects - large wind farms are connected at distribution as well as transmission level. Smaller wind farms below the ISO involvement size level of 5 MW are not necessarily studied for impact upon the transmission system. It was

requested that the guidelines explain this distinction, and focus on handling these smaller installations.

The group felt that the title suggests that the document is a comprehensive overall guide, although it is intended to be a toolbox for use by utilities and customers in identifying and addressing potential problems. A change of title was requested, and handled in the breakout discussions described below. The revised title is "Guidance Document for Customer-Owned Distributed Generation Applications."

#### Photovoltaic (PV) hybrid ridedthrough solution discussion

Jim Bing of New Energy Options presented a PV discussion referencing the diagrams in the section of the Guidelines that was then numbered 6.5, Special Issues for Solar Photovoltaic (PV) DG. The discussion began with a review of the voltage and frequency limits for response of PV to the utility circuit. The presentation also reviewed a variety of typical PV installations and interconnections, some of which included energy storage and local load control options. PV systems are highly configurable, originating with free-standing (off-grid) applications. The simplest Scenario 1 connection with no storage or load shedding comprises 80% of installations. The fault scenario discussion noted that all units must be IEEE 1547 compliant; UL testing standard 1741 has been harmonized with 1547. These systems all wait 5 minutes after the system is restored before reconnecting to the grid, and Distribution Company inspectors check for this behavior, even though IEEE 1547 allows for shorter adjustable delay. Energy storage options include a Beacon Power flywheel system, and a 1 MW battery storage system from SAFT.

#### EPRI Work on DG Applications

Dan Rastler and Bill Steely presented several of their EPRI DG initiatives by telephone. EPRI is working on technical assessment and characterization of cost, performance, and emissions of technologies they identify. How do these technologies interact on the grid? EPRI is working specifically on:

- Radio DG communications.
- Software tool (which may become publicly available) for screening radial interconnections.
- DG on spot and grid networks – a tougher problem than radial circuits.
- Impact of penetration level.
- Best practices on the utility side for using DG to support planning and operations with focus on high concentrations of PV. It is possible that EPRI will publicly share key results.
- Software tool – when to use DG to defer capital upgrade investment.
- How the utility monetizes the benefit of customer DG.
- Assessment of near-term benefits of communications.
- Finding demonstrations and applications – peak shaving, premium power, and energy storage. Do they meet availability and greenhouse gas emissions requirements?
- Opportunity fuels – natural gas, biomass, and biodiesel. How to serve emissions and other constraints in an urban area.
- Market integration – how to work through DG regulatory variations among the states.
- Business case and business models - how can customer owned and operated equipment be monetized and related back to the utility?
- Working with DUIT on testing inverters.

EPRI has looked at the MTC Guidelines draft, and sees it as ambitious, and needing to be actionable. They suggested adding more on PV, as well as including application related sections from both the customer and utility sides. EPRI offered send comments and wants to engage in the document development process. (EPRI did send more detailed comments after the Workshop).

## **Breakout Sessions** (11:00 AM – 12:30 PM)

### Technical Session

The technical group discussed the current state of the guide and noted that it serves as a review of solution strategies at this stage, with appropriate level of detail. Following up the earlier morning discussion of how the title needs revision, the Guidelines were renamed as “Guidance Document for Customer Owned Distributed Generation Applications”.

Utility markups are to be received for Section 1.2. Section 1.4 is to be revised to address high penetration DG impacts on higher level systems - at least identify the potential problems without necessarily suggesting solutions. It can point out that control and protection systems may need to change to address future concerns with penetration. In the original Section 1.5, DG as impacted by the document may not begin to appear until 2009, if not later. It was suggested that the document explain that ISO reviews are required for units greater than 5 MW, even though 5 MW is below the IEEE 1547 10 MW limit. One utility is processing a 15 MW distribution application of wind generation, but this will have ISO review. Most DG installations are under 1 MW. NPCC input is to be incorporated.

Underfrequency generator tripping needs attention. The Guidance Document needs a Section 3.1.4 – what does IEEE 1547 tells you, plus regional procedures. Large generating units are to remain on line during frequency excursions. IEEE 1547 says small units *can* do it, but are small units actually being set for compliance with the regional Under Frequency Load Shedding (UFLS) schemes? Utility participants suspected this may not be closely tracked.

In Section 4 operational issues have been added to the title and content. The group discussed switching and green-stripe tagging issues that could call for units to trip quickly and remain off line rather than staying on line. The field repair crews validate that the circuit is dead, ground the circuit conductors, and work with gloves. NESC requirements have not been addressed. What are the *incremental* risks in the operations of the distribution system when the DG is considered as an integrated resource supporting the increased customer load on a circuit?

### Economic Session

Mike Stocki of UMass made a presentation about potential DG adoption scenarios and a sensitivity comparison with Navigant results for customer-owned DG. Fran Cummings of MTC also presented elements of a potential framework for DG cost-effectiveness, including deferral and other benefits, and including incremental costs to make DG a potential distribution resource.

## **Other Outstanding Issues from 2006 Report** (1:00 – 2:30 pm)

### Role of Non-Dispatchable PV in Distribution Planning

Jim Bing made a presentation on Non-Dispatchable PV:

<http://www.masstech.org/dg/MTC DG12-13Workshop-1061212.ppt>

This included discussion of the capacity value of PV plants. Jim's presentation referred to the following paper prepared by D. S. Shugar of PG&E in 1990, "PV in the Utility Distribution System: The Evaluation of System and Distributed Benefits," which is posted at:

[http://www.masstech.org/renewableenergy/public\\_policy/DG/resources/1990-05-22-PVBenefits-DShugar-PG-E.pdf](http://www.masstech.org/renewableenergy/public_policy/DG/resources/1990-05-22-PVBenefits-DShugar-PG-E.pdf).

The group noted that, while PV may not contribute fully to peak load reduction, it may provide for lower pre-contingency loading that increases available capacity under contingency conditions. The discussion also included the meteorological data bases used by PV installers for planning.

The discussion turned to the impact of PV and the two utility roles discussed above. The group observed that Role 1 (in which the utility tries to utilize benefits of DG that the customer chooses to connect) is more practical to learn about and handle now. As utilities connect PV now, the question is what to do to take advantage of it. Utilities asked how they can actually get the benefit. It was noted that there is international experience with the use of DG as a tool for distribution planning.

One participant proposed that DG should be able to connect without particular utility response to the one installation – rather, take advantage of the statistical behavior of a population of units. This would be related to how the utility reacts to customers who buy and use air conditioners – the customers don't plan this with the utility. This approach assumes there are a relatively large number of DG units operating on a circuit. Today only a limited number of DG units are installed on any specific circuit.

#### Discussion of EPRI STAC Project

Gerry Bingham of MA-DOER provided an overview of the current effort by the EPRI State Technologies Advancement Collaborative (STAC) group. In earlier phases of the program, an experimental project had a tough time finding customers who agree to physical assurance. They were also not seeing major benefits from deferring line upgrades. DG can have a business disincentive for utility – lost revenue – so how do we make a business case? He noted that they committed to review and develop new business models for DG integration, focusing on the bottom line for each stakeholder. The EPRI STAC group is looking for the right business models for a January California Workshop. One next step will be discussions with utility participants to see if any would be interested in pilot testing the proposed business models. At the end of the EPRI effort will be a review of the pilots that are selected for implementation. The DPWG is interested in stakeholder briefing and opportunity for input later. EPRI is planning a promotional presentation at the end of the project.

#### The Modern Grid Initiative

Bruce Renz made a presentation on this Initiative, which is posted at:

[http://www.masstech.org/renewableenergy/public\\_policy/DG/resources/2006-12-09-Renz-DFT-Modern-Grid.pdf](http://www.masstech.org/renewableenergy/public_policy/DG/resources/2006-12-09-Renz-DFT-Modern-Grid.pdf).

One comment was that the Modern Grid Initiative is working at a high level (20,000 feet), as compared to the DPWG application detail focus (1,000 feet). For overall background see <http://www.moderngrid.org>. There is a white paper expounding on characteristics stated on Slide 4. IntelliGrid talks about replacing meter with consumer portal.

Within the Morgantown project, Phase 2 (planned for 2008) will be a demonstration of dynamic islanding with DER. The project also includes grid-friendly appliances that sense voltage and frequency.

There was a discussion of ways for the DPWG to stay connected with these and other projects.. Bruce suggested reviewing the San Diego Smart Grid Study, summarized in the following presentation:

[www.masstech.org/renewableenergy/public\\_policy/DG/resources/2006-11-16-SanDiego-ModernGrid-Anders-EPIC.pdf](http://www.masstech.org/renewableenergy/public_policy/DG/resources/2006-11-16-SanDiego-ModernGrid-Anders-EPIC.pdf)

#### RPI Renewable Energy Test-Bed

Nag Patibandla of the RPI Center for Future Energy Systems introduced the “renewable energy test-bed” for which it has received a state grant and summarized RPI renewable energy efforts.

#### **Discussion on How to Proceed with Report and Supporting Documents** (2:30 – 5 PM)

The stakeholders reviewed a detailed outline for a comprehensive report, posted at:

<http://www.masstech.org/dg/2006-12-11-DRAFT-Outline-Workshop-Report.doc>

As discussed during the introduction, the submission would have to be appropriate considering the short available time before the committed December 31 delivery date. Also, it was noted that DTE has not yet reacted officially to the prior June 2006 report, and the WG felt the need to propose a logical basis for any continuing work.

The Utility group felt that the Guidance Document was needed and useful, but that there are issues in the draft Report that they are not yet comfortable with. Users are concerned about what reviewers will perceive as the intent of the report if it is not fully developed prior to filing. They felt that the additional work needed would not be feasible prior to the end of the year.

The group noted that the formal DG Collaborative process was completed in June 2006. The group agreed that the more recently raised issues must inevitably be dealt with, and continuing the effort should help all stakeholders prepare for this use of DG. The utilities felt that as long as they can confront these issues without being forced to follow specific uneconomic or technically unfeasible approaches, they are supportive of continuing with development of the Guidance Document. They discussed how the two roles for utilities are interesting and worth developing, but creating the Guidance Document is seen as a precondition to understand the issues that must be addressed for each role. They stated a commitment to making the effort to develop the Guidance Document as quickly as is practical. They see Report Outline Section 4 on the two utility roles as fine in concept, but wording needs work before utilities would be comfortable with the message. They asked about what is the customer experience for each utility role? A number of factors on the two roles, ranging from resource issues to customer contract requirements, would need to be explained. Some participants thought that Role 1 may have more impact on transmission and forward capacity than on the distribution system. Others asked if there is a need for a contractual arrangement to implement Role 1.

The Workshop group agreed that the economic analysis work (Section 5) is not ready for use.

There was discussion about how to see value in proceeding further. To date the group has been resource deficient for completing the document. The primary question seems to be: “What is

the recommendation of the Working Group?" If the group agrees that a program for deferring line upgrades would yield only targeted and limited results (if any), why not say that in the report now instead of continuing to state that it's "inconclusive." We could then agree to concentrate on roles for DG in a context broader than just deferring upgrades; by seeking to quantify (and compensate) benefits wherever it is installed instead of asking where DG can replace wires. The utilities were concerned that the effort was directed at forcing the utility to include DG as a utility deferral solution, even though the implementation steps cannot be carried out today. Also, there is not enough DG, or financial incentive to pursue such an approach. The importance of incorporating this work into anticipated attention from the next administration was highlighted. It was stated that in going forward, DTE will need to know what utilities are willing to do on their own, versus what might be mandated.

There was some discussion on the reluctance of customers to forego having a distribution supply backup even if they had their own DG resource. Perhaps the issue of customer need for utility backup at times of DG outage should be treated separately from the ability to configure DG as a distribution resource. On a related reliability topic - if DG does not perform properly, utilities are concerned about who should not be responsible for the negative service quality impact. It may be appropriate to ask EPRI to look at contractual responsibility issues.

The group requested that underfrequency load shedding (UFLS) be considered in the Guidance Document and in future tariffs.

Bruce Renz explained the priorities in the California Loading Order for handling supply deficiency:

- a) Improve efficiency
- b) Use renewables. By 2010, CA would like to go from 5% to 20% renewables (but very unrealistic).
- c) Use demand response.
- d) Central generation with clean technologies (no coal).
- f) Future – plug-in hybrid vehicles as fuel-cell generators.

A comment was made that regulators need to think more broadly and "loosen handcuffs" on utilities. California is still vertically integrated. In MA, generation is separated and distribution companies are wire companies only. This complicates the establishment of the utility roles.

At prior Workshops the utilities had agreed to provide lists of equipment needed for DG utilization with costs. The utilities stated that they have been attempting to identify incremental costs but were having difficulties extracting this data from their records. It was suggested that KEMA might help with data it would access independently from other sources. A few case studies could identify the costs of with DG use. Utilities wanted examples of straightforward versus complex cases. The goal is to guide customers who never did this before. The group heard about how customers want transparency to predict costs before they apply new equipment for PV applications.

The discussion moved to consideration of whether MTC should continue to fund work by KEMA to complete the Guidance Document. Utilities favored continuing development in early 2007. The Document would not be filed with the DTE. Instead, note would be submitted that such an effort is in progress and seeking feedback. KEMA suggested two more workshops (perhaps in February and March) to get stakeholder participation in development of the guide by April. The authors were asked to seek EPRI feedback on the Guidance Document.

The WG returned to the key question of what type of report should be filed with the DTE at the end of December. It was noted that the report will just be informational; telling the DTE what has been accomplished. The report or cover letter is to be based on Statement 2 now appearing at the beginning of the Report Outline. Attachments are to be the Guidance Document table of contents (TOC) with draft of Chapter 1; and the Matrix of Challenges and Solutions from earlier workshops. A heading showing the addition of material on examples of how CHP projects have demonstrated a capability for ride-through is to be added to the TOC for the Guidance Document. An example from Section 3.3.1 of the Guidance Document is also to be included as an attachment. .

Comments were made that the DPWG must address the related business issues, not just technical issues. It must invest time and money going forward to look at this. The Working Group members felt that the DPWG should also continue to exist as a forum as the economic, regulatory and technical situation for DG evolves.

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# Attachment B

(Attachment to [Dec. 31, 2006 Report to the Department of Telecommunications & Energy](#))

## Guidance Document for Customer Owned Distributed Generation Applications: *Draft Outline*

Submitted to:  
Massachusetts Technology Collaborative



Prepared by:  
**KEMA Consulting, Inc., with inserts from other team members**

Based on:  
Distributed Energy Planning Workshops, Fall 2006

*These Workshops were commissioned by the Massachusetts DG Collaborative in its [2006 Report to the Department of Telecommunications & Energy](#).*

*Further information at:*  
[www.masstech.org/dg/2006-12-13\\_Workshop.htm](http://www.masstech.org/dg/2006-12-13_Workshop.htm).

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# Table of Contents

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<b>1. Introduction.....</b>	<b>1-1</b>
1.1 Preface .....	1-1
1.2 Background.....	1-1
1.3 Objective of the Guidance Document.....	1-2
1.4 Challenges and Solutions.....	1-3
1.5 Time Frame of Implementation.....	1-3
1.6 Relationship to Other Standards .....	1-4
1.7 Two Potential Role(s) for DG in Distribution Company Planning.....	1-4
1.7.1 Role #1: Leverage future value of customer DG.....	1-5
1.7.2 Role # 2: Seek locations to use DG as distribution deferral resources .....	1-6
<b>2. Existing Standards Summary .....</b>	<b>2-8</b>
2.1 IEEE 1547-2003 .....	2-8
2.2 Companion Standards to IEEE 1547-2003.....	2-9
2.2.1 IEEE 1547.1 (Draft) .....	2-10
2.2.2 IEEE 1547.2 (Draft) .....	2-10
2.2.3 IEEE P1547.3 (Draft) .....	2-10
2.2.4 IEEE P1547.4 (Draft) .....	2-10
2.2.5 IEEE P1547.5 (Draft) .....	2-10
2.2.6 IEEE P1547.6 (Draft) .....	2-10
2.3 FERC Large Generator Interconnection Requirements, Appendix G, Interconnection Requirements for a Wind Generating Plant .....	2-11
<b>3. Challenges and Solutions: DG Behavior on the Distribution System.....</b>	<b>3-13</b>
3.1 Ability of DG Units to Remain On Line during Disturbance.....	3-13
3.1.1 Ability for DG unit to remain on line following a momentary interruption of the circuit it is supplied from.....	3-13
3.1.2 Ability for DG units to remain on line following a disturbance on a nearby system element resulting in voltage and/or current excursions .....	3-13
3.1.3 Ability for DG units to remain on line following an auto-transfer switch operation.....	3-13
3.1.4 Ability for DG units to ride through frequency excursions of the utility system .....	3-13
3.2 Ability for DG Units to Provide Capacity, Voltage and Reactive Support for the Distribution System.....	3-14
3.2.1 Ability for DG units to maintain voltages during and following a disturbance.....	3-14
3.3 Solutions for Keeping DG Units On Line, Supplying Capacity and Reactive Support for the Distribution System .....	3-16
3.3.1 Customer load isolation with generator ride through .....	3-16
3.3.2 Customer load interruption with generator trip .....	3-22
3.3.3 High speed resynchronization or dispatch based DG reconnection.....	3-22
3.3.4 Customer based energy storage device.....	3-22
3.3.5 Utility based energy storage device or dispatch of emergency units.....	3-23
3.3.6 Utility dispatched demand reduction program response.....	3-23
3.3.7 Employ more advanced communication systems to coordinate reconnection of DG units .....	3-24
3.4 Guidelines to Address Operating Challenges during DG Interconnection.....	3-24

---

# Table of Contents

---

<b>4.</b>	<b>Challenges and Solutions: DG Impact on Utility System Design and Operation.....</b>	<b>4-25</b>
4.1	Challenges for DG Impact on Utility System Design and Operation.....	4-25
4.1.1	DG impact on safety of utility maintenance crews (new) .....	4-25
4.1.2	DG and distribution circuit grounding.....	4-25
4.1.3	DG impact on relays and protective devices .....	4-25
4.1.4	Protection system modifications necessary for addition of multiple DG units exporting power to a substation. ....	4-26
4.1.5	Protection system modifications needed for circuits configured for loop supply and/or auto transfer switch operation when one or more DG units are on any of the associated circuits. ....	4-26
4.1.6	Voltage and VAR regulation equipment modifications necessary for addition of multiple DG units with intermittent operation on the system.....	4-26
4.1.7	Special problems with large penetration of DG.....	4-26
4.2	Solutions for Controlling Impact of DG on Utility System.....	4-27
4.2.1	Limit generation on circuit to a small percentage of circuit load. ....	4-27
4.2.2	Limit generation on circuit to below acceptable fault current contribution levels ...	4-27
4.2.3	Modified DG connection and/or addition of effective grounding for units.....	4-27
4.2.4	Upgrade and replacement of protection system equipment to allow for reverse power flow operation including communication systems upgrades as needed. ....	4-27
4.2.5	Introduction of current limiting device to mitigate contribution to area fault duty. ....	4-27
<b>5.</b>	<b>Challenges and Solutions: DER Monitoring and Control.....</b>	<b>5-29</b>
5.1.1	DG Unit Availability (Reformat here for consistent appearance) .....	5-29
5.1.2	Real Time Monitoring of DG Units.....	5-29
5.1.3	Real Time Control of DG Units.....	5-29
5.1.4	Communications Alternatives for DG Control and Monitoring .....	5-32
<b>6.</b>	<b>Typical Equipment Upgrades .....</b>	<b>6-33</b>
6.1	Utility-customer interconnections .....	6-33
6.2	Operating conditions.....	6-33
6.3	Analysis for Optimized DG Location.....	6-33
6.3.1	Evaluating Benefits of Loss Reduction from DG.....	6-34
6.3.2	Planning Process to Prioritize Locations or Opportunities .....	6-34
6.4	Special Issues for Combined Heat and Power (CHP) DG.....	6-34
6.5	Special Issues for Solar Photovoltaic (PV) DG .....	6-34
6.6	Special Issues for Wind DG .....	6-34
<b>7.</b>	<b>Wide Area System Impact of Significant DG Penetration .....</b>	<b>7-36</b>

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# Table of Contents

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**List of Exhibits:**

Figure 2-1 – Voltage disturbance ride-through capability for DG less than 10 MVA, from IEEE 1547-2003 Table 1 .....2-9

Figure 2-2 – Voltage disturbance ride-through capability for wind generators greater than 10 MVA, from FERC LGIA Appendix G .....2-11

Figure 3-1 Customer Supply Connections for Load Isolation with Ride-Through.....3-17

# 1. Introduction

## 1.1 Preface

The present outline is not the complete Guidance Document. It presents a framework, based on Working Group assessment of needs and challenges. The Working Group proposes technical and operational investigations in 2007 to complete the Guidance Document outlined here. Economic evaluation is to be included in a separate (future) document, *Cost Effectiveness of Distributed Energy Solutions*.

## 1.2 Background

The Massachusetts DG Collaborative has developed uniform distributed generation (DG) interconnection standards that have been incorporated into the Model Interconnection Tariff that has been approved in D.T.E. 02-38.<sup>1</sup> The Distribution Planning Work Group (DPWG), formed by the DG Collaborative, has been working since 2004 to respond to certain requests from the Massachusetts Department of Telecommunications and Energy concerning “the role of DG in Distribution Company planning.” Accordingly, it has been considering a number of technical challenges that must be overcome to improve the opportunity for the expansion of customer-owned DG on the distribution system. The development process is described in the report to which this Guide is attached. In June of 2006, the Massachusetts DG Collaborative submitted its report D.T.E. 02-38 C in response to questions from D.T.E. on several topics including the role of DG in planning. This Guidance Document framework was developed in the course of continuing work by the DPWG after that submission, into 2007.

The DPWG has created this Guidance document to explain potential challenges and solutions for distributed generation installations that serve the generation owner, particularly in the event of widespread and substantial adoption of such DG. Beyond this, the WG also is looking at how the DG can impact distribution capacity planning needs. The concept is that DG installations might eventually help the utility to defer capital investments for system upgrades. For example, finding a way to use DG peak-shaving potential to expand the peak capacity of a distribution circuit might defer capital investment in capacity that is infrequently used.<sup>2</sup>

To achieve this goal, customer owned generation must serve as a dependable resource to reduce net demand by the cogenerating customer, or to reduce generation capacity peak demands. Identifying how to make the DG a dependable resource is a complex problem that is situation dependent. Utility-side variables include voltage level, circuit configuration, protection system design, and specific utility circuit

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<sup>1</sup> D.T.E. 02-38-C, Investigation by the Department of Telecommunications and Energy on its own motion into Distributed Generation, December 27, 2005; see:

[www.masstech.org/renewableenergy/public\\_policy/DG/resources/02-38-C\\_DTE-order.pdf](http://www.masstech.org/renewableenergy/public_policy/DG/resources/02-38-C_DTE-order.pdf)

<sup>2</sup> This Guide document addresses technical Challenges and Solutions, including some information related to their costs and benefits, but economic, financial and rate analysis and issues are beyond the scope of this document.

capital improvement to be deferred through addition of the DG. Customer-side variables are generation type, interconnection design, customer protection systems, and customer load mix. These all combine to play roles in practicality and cost of utilizing customer generation as a utility system resource. The DPWG believes that attempting to present a specific set of cases and requirements cannot cover all situations due to the large number of variables. By contrast, this Guidance Document format provides a toolbox for utilities and their cogenerating customers to use in developing their own site-specific solution that addresses the potential operating concerns for a proposed installation, whether or not it is intended to serve as a resource to the utility system.

This Guidance Document also serves both utilities and customers in earlier planning or facility design phases, leading to a layered design. The layers comprise early choices of design approach that may be low in cost, yet lay the groundwork for utility-supporting DG at a later time. Sections of the Guidance below show practical techniques for adding incremental design features at the DG site, citing relevant standards where appropriate.

Finally, the Guidance Document should help equipment suppliers identify opportunities to build business by creating solutions for unmet needs, or for requirements met only with difficulty and expense that inhibits penetration of DG support.

### **1.3 Objective of the Guidance Document**

This document provides guidance to:

- Distribution Company (“utility”) planners,
- Distribution protection engineers, and
- Customers that own generation or are considering DG installations of less than 5 MVA.

It identifies salient issues and concerns, possible solutions, and typical equipment upgrades associated with running customer owned generation that is compatible with the connected utility distribution system. It also shows how the DG can operate in support of the electric distribution system itself, or in support of utility generating capacity. While the guide cannot address all possible issues, it suggests areas where development by participants or equipment suppliers could solve technical or operating issues that may arise in particular situations. The Guidance Document distinguishes between issues that are addressed with available solutions, versus those that are unresolved. Of the latter, it attempts to identify those for which a possible solution strategy can be attempted, versus those for which creative problem solving is still needed at the time of writing.

Points in the Document could be factored into design of customer and utility installations where installation or utility use of DG is not immediately planned, but may occur in the future. Even if the largest investments are not being made, designs can specifically accommodate future upgrading –

designing with the needed supporting layers as described in the Background above. At the time of initial construction, the cost of adapting the design for easy future upgrading by adding these design layers may be low. By contrast, modifying the electrical supply interface later may be expensive and operationally difficult. Such a layered approach could create a cost-effective path to customer DG benefits, as well as increased utility support by DG over time.

This Guidance Document does not discuss all of the contractual, operational and legal issues that may be associated with operation of customer-owned DG in a role of supporting the utility distribution circuit or reducing peak demand. However, the existence of these physical assurance requirements may impact some of the technical points in the guidance. More specifics on these issues are addressed in other documents developed by MTC to advance the deployment of utility-supporting DG.

## **1.4 Challenges and Solutions**

Three chapters as listed below by number address the Challenges and Solutions that have been identified as part of the DG Collaborative effort and are based on the three primary areas of concern identified in the 2006 DG Collaborative Report to the Massachusetts DTE:

- 3) DG Behavior on Distribution Systems.
- 4) Utility System Design Changes.
- 5) DER Monitoring and Control.

In addition, the DPWG has added sections proposed in more recent work:

- 6) Typical Equipment Upgrades
- 7) Wide Area System Impact of Significant DG Penetration

## **1.5 Time Frame of Implementation**

In national experience to date, DG penetration has been gradual, not even keeping up with the rate of efficiency gains. In California, at time of writing, DG is only 2% to 3% of load. A set of accelerated DG installation policies would be needed to achieve a base of 600MW to 1.2 GW, 5% to 10%. The Guidance Document and related documents are expected to be absorbed by customers and utilities, and first applied, during the 1 to 2 year period following publication. Significant installation levels influenced by these guidelines could appear in the time frame of 2009 – 2016.

## **1.6 Relationship to Other Standards**

Utilities and DG owners are already connecting according to the requirements of the Massachusetts Interconnection Tariff as approved in D.T.E. 02-38 and the separate Massachusetts Interconnection Standards and Qualifying Facility (QF) Standards. These specify adherence to the requirements of IEEE 1547-2003, discussed in Chapter 2 and throughout the Guidelines. Chapter 2 summarizes the key requirements in this standard and its companion standard documents. DG and interfacing equipment manufacturers design for conformance as well. Note that utilities may also apply other standards for customers with DG, such as compliance with a regional underfrequency load shedding (UFLS) scheme.

Also described in Chapter 2 are key requirements from FERC Large Generator Interfacing Requirements Appendix G for wind generating plants larger than 10 MVA. Conformance to these requirements is not required for smaller sizes or other types of DG, but nonetheless they point to requirements for any DG that is to serve as a reliable resource for the utility. This makes them useful to discuss in this Guidance Document. We note that these large wind generator requirements are not compatible with those of IEEE 1547. This inconsistency with IEEE 1547 is not officially resolved at the time of writing.

Whether or not the installation is proposed for reliable and planned utility support, it must still comply with IEEE 1547-2003. However, the utility capacity support role of the installation may be compromised in some cases. In the chapters below, requirements with apparent conflicts are clearly identified. This flags these points for special attention by designers, and the identified conflicts should be considered by IEEE SCC 21 in future revisions of IEEE 1547. For example, the FERC requirements just cited might be rationalized with IEEE 1547 requirements for DG response to voltage sags.

In planning a new DG installation, the customer and utility must identify clearly at the outset whether or not the DG is to serve as a reliable utility resource that is suitable for consideration in utility capacity planning. The choice is driven by economic or operating incentives for each party that is addressed in the separate document “Cost Effectiveness of Solutions”, under development separately from this Guidance Document.

## **1.7 Two Potential Role(s) for DG in Distribution Company Planning**

The DPWG considered at length how DG could be developed on the distribution system along with the ways DG could be used to support the system. The Working Group envisioned a number of ways that DG might occur on the system beginning with targeted, utility directed development and then expanding out to include enlisting DG that has been installed by customers for other reasons. On this basis two different roles were identified by the Working Group for DG in Distribution Company planning. The former case, called Role #2 in the following, has been the focal point of evaluations for many of the DG Collaborative discussions and is reasonably well understood in its application. The latter case, called Role #1, has emerged from current workshop discussions as an alternative approach that is more opportunistic in

nature but less certain in terms of the potential benefits to the distribution system. This approach is currently not as well defined and will require additional review and development before being considered practical or viable. This role does offer utilities the advantage of capitalizing on customer DG at potentially lower implementation costs but also introduces uncertainty with respect to the future use and future obligations of both customers and utilities. In many respects the equipment characteristics for implementing this role would run parallel to those associated with the Modern Grid initiative promoting an equipment upgrade path for utilities that works toward improving the flexibility and adaptability of current distribution systems. On a technical basis both DG roles in utility planning are viable but are different in terms of implementation strategies. The roles are summarized here, primarily from a technical perspective, to illustrate some of the opportunities that each may provide and explain how this Guidance Document may be used to support their application.

### **1.7.1 Role #1: Leverage future value of customer DG**

In this role for DG,<sup>3</sup> when DG “shows up” as a result of non-utility market and policy drivers, the Distribution Company would respond to that DG in such a way as:

- to take advantage of it, by realizing the greatest possible future benefits for the distribution system, and
- to best manage potential future costs to accommodate that DG.

Including “utility friendly” equipment on new DG units at time of installation that considers distribution system support and would be difficult or expensive to retrofit at a future date could allow for greater use of customer installed DG resources. Inclusion of voltage regulation, synchronizing, protection features and other equipment enhancements when a new unit is being installed could avoid significant DG equipment replacement costs when the utility needs capacity on its system. In this approach, taking advantage of this resource, when it’s available, would more likely be a lower cost option than other upgrade alternatives.

In this role, utilities could also consider using “DG friendly” equipment when upgrading their facilities that do not currently support use of DG units but may be good candidates for DG additions in the future. Use of relays and recloser controls can deal with reversed power flow, relays that can vary operating characteristics according to the affects of connected DG, more flexible protection equipment, and more intelligent voltage control equipment that can function with DG resources or be upgraded at minimal cost to work with DG resources will also help make use of future DG additions as a system resource less costly and more viable.

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<sup>3</sup> This Role was first enunciated in the November 15, 2006 Workshop; see meeting notes.

This process could use a screening approach to identify those areas where DG resources either might occur or where such resources could have future benefit if they were to be developed. This might consider locations where renewable resources such as wind or PV might occur in larger amounts. Areas where future growth is not easily accommodated and the customer base is likely to adopt DG could also be considered. The process could also exclude areas where significant DG is likely not to occur such as solely residential areas, or segments of the system that are difficult to configure for DG connections such as large low voltage network systems. The result would be identification of segments of the utility system that are candidates for DG-friendly upgrades if and when upgrades are determined to be needed.

Beyond the purely technical issues associated with making customer DG a viable utility resource, (which is an objective of this DG Guidance Document) economic and procedural considerations would need to be resolved. Some additional expenditure would need to occur during installation without any certainty of a future value and customers would have to have some obligation to provide support when requested at a future date.

### **1.7.2 Role # 2: Seek locations to use DG as distribution deferral resources**

Application of this role would be focused on times at which:

- particular circuit upgrades or other distribution investments have been identified and the costs have been determined (that is, within the next 5 years or so), and
- a screening process can identify possible distributed energy alternatives that could economically defer those investments.

This is the “role for DG in planning” that Navigant analyzed in January 2006 for the Distribution Planning Work Group,<sup>4</sup> and which is now widely understood to be relatively limited in its applicability and it benefits -- it is short-term and single-circuit in its application.

Actively seeking DER as an alternative to distribution upgrades has been shown to be potentially viable under the correct, though limited, set of conditions. When these conditions are right, use of distributed energy resources as an alternative to traditional upgrades can make economic sense for the utility as well as other stakeholders. Effective screening procedures need to be in place to allow for consideration of DER solutions only when they are technically and economically viable. The set of issues to consider in the screening process include technical matters concerning the distribution system equipment characteristics (as well as the matters included in the DG planning guide), capacity requirements in terms of amount, duration, triggering event and future growth as well as customer base considerations with respect to penetration and adoption rate characteristics.

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<sup>4</sup> See [DG and Distribution Planning: An Economic Analysis for the DG Collaborative, by Navigant Consulting, Inc.](#), January 2006, Attachment G of [2006 Report](#).

The primary concern here would be the extensive efforts necessary to determine if and when a DER solution is viable. This could involve significant utility time and energy to process data and conduct studies for what may prove to be a highly limited set of opportunities. Screens that are easy to assess and effective at identifying viable scenarios are a critical part of this approach.

# Attachment C

(Attachment to [Dec. 31, 2006 Report to the Department of Telecommunications & Energy](#))

## Guidance Document for Customer Owned Distributed Generation Applications: *Section 3.3.1 only*

Submitted to:  
Massachusetts Technology Collaborative



Prepared by:  
**KEMA Consulting, Inc., with inserts from other team members**

Based on:  
Distributed Energy Planning Workshops, Fall 2006

*These Workshops were commissioned by  
the Massachusetts DG Collaborative in its  
[2006 Report to the Department of Telecommunications & Energy.](#)*

*Further information at:  
[www.masstech.org/dg/2006-12-13\\_Workshop.htm](http://www.masstech.org/dg/2006-12-13_Workshop.htm).*

## ***Attachment C to December 31, 2006 Report***

# **Extract from Draft Chapter 3,**

## ***Challenges and Solutions: DG Behavior on the Distribution System***

*The following is draft material, to be organized into specific guidance for customers, utilities, and others. As indicated below, the application scenario, distribution system facts, and relevant standards extracts are to be organized as a flowchart- or checklist-based screening process.*

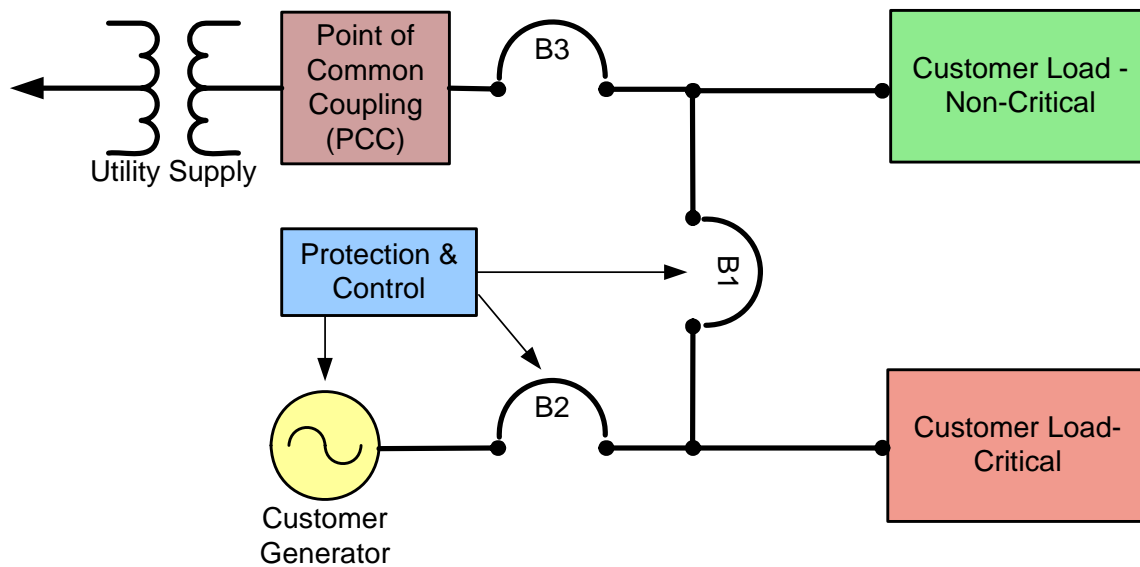
### **3.3 Solutions for Keeping DG Units On Line, Supplying Capacity and Reactive Support for the Distribution System**

#### **3.3.1 Customer load isolation with generator ride through**

High-level goals:

- 1) To ride through system fault external to connected utility feeder, as long as fault is cleared and system recovers. The sequence of voltage changes for this situation is described in Section 3.1.1.
- 2) To ride through recoverable routine sags, swells, and interruptions on the feeder. Causes are described in Sections 3.1.2 and 3.1.3.
- 3) To disconnect from the utility system for fault on connected feeder, or for remote disconnection (islanding) of feeder for any reason.
- 4) To properly supply local load during the utility outage.
- 5) To detect legitimate restoration of utility supply (distinguished from any other DG unintentionally backfeeding the island, if that risk exists).
- 6) To resynchronize with utility feeder as soon as stable supply is confirmed.

*Proposal:* Organize the following, and other application data research, into a screening process (flow chart or check list) for achieving a successful application for customer load isolation with generator ride-through.



**Figure 3-1 Customer Supply Connections for Load Isolation with Ride-Through**

The connection of Figure 3-1 assumes that the total customer load exceeds the customer generating capacity. If the customer generating capacity approaches the total connected load, the load may not need to be separated into critical and non-critical blocks.

The local generator can operate from any reliable energy source, such as surplus process heat in a combined heat and power (CHP) installation. Renewable energy sources such as solar photovoltaic (PV) or wind require local storage as explained in 3.3.4 below.

Breakers B1 and B2 have shunt trip and closing control for flexibility in switching operating modes of the connection. Breaker B3 does not need to have this functionality for the purposes described here.

Operating states:

- 1) Normal operation: All breakers are closed. Customer generator and utility supply operate in parallel to supply all loads. If customer generating capacity approaches typical customer load levels, the protection and control (P&C) function may need to regulate generator output to avoid power flow through the point of common coupling (PCC) back into the utility system, or to regulate the amount of backfeed that is permitted. The level of acceptable backfeed, if any, must be allowed under tariff rules, and also be defined in the interconnection agreement between the utility and the customer.
- 2) Fault on utility circuit that supplies customer: The utility supply trips at the substation or intervening recloser; or an intervening lateral fuse blows. The protection and control (P&C) function at the customer site detects islanding by current flow

direction, voltage, frequency change, or receipt of a direct utility control message, and trips circuit breaker B1. The customer generator and critical load ride through the outage. Non-critical load is left tied to the dead utility circuit.

- 3) Successful reclosing of the utility circuit, or repair of fuse: The customer P&C detects the sustained re-energization of the utility supply and non-critical load, showing that the fault or outage is over. P&C closes breaker B1 with synchronism and voltage match checking. For larger customer generators or for inverter-based DG, the P&C may include an automatic synchronizer function that adjusts generator frequency and voltage to bring it into synchronism with the utility supply before closing B1. Normal operation resumes.
- 4) Utility system voltage sag or swell: The customer P&C should keep the customer generator and all load connected as long as possible, consistent with requirements of IEEE 1547-2003 (or other standards to be cited or proposed response that is different from IEEE 1547). Early disconnection by an ensemble of many cogenerating customers around the utility system could adversely impact the ability of the utility system to recover from the voltage disturbance. If the customer P&C function decides that the utility connection must be opened due to the voltage disturbance, breaker B1 is tripped as in fault scenario (2). Restoration is then carried out as in scenario (3) just above.
- 5) Generator failure or maintenance:<sup>5</sup> Trip breaker B2 to isolate the distributed generator. Breaker B1 remains closed, so that critical loads are supplied from the utility circuit. In this mode, critical loads will be deenergized if the utility supply suffers a fault or outage. If the process outage is unacceptable, the customer must consider the need for multiple redundant generators and more switching for flexibility; or for uninterruptable power supplies for selected loads.

Breaker B3 is included for utility supply isolation, for maintenance and safety purposes, and to clear rare bus faults in customer switchgear. It has no normal operational function.

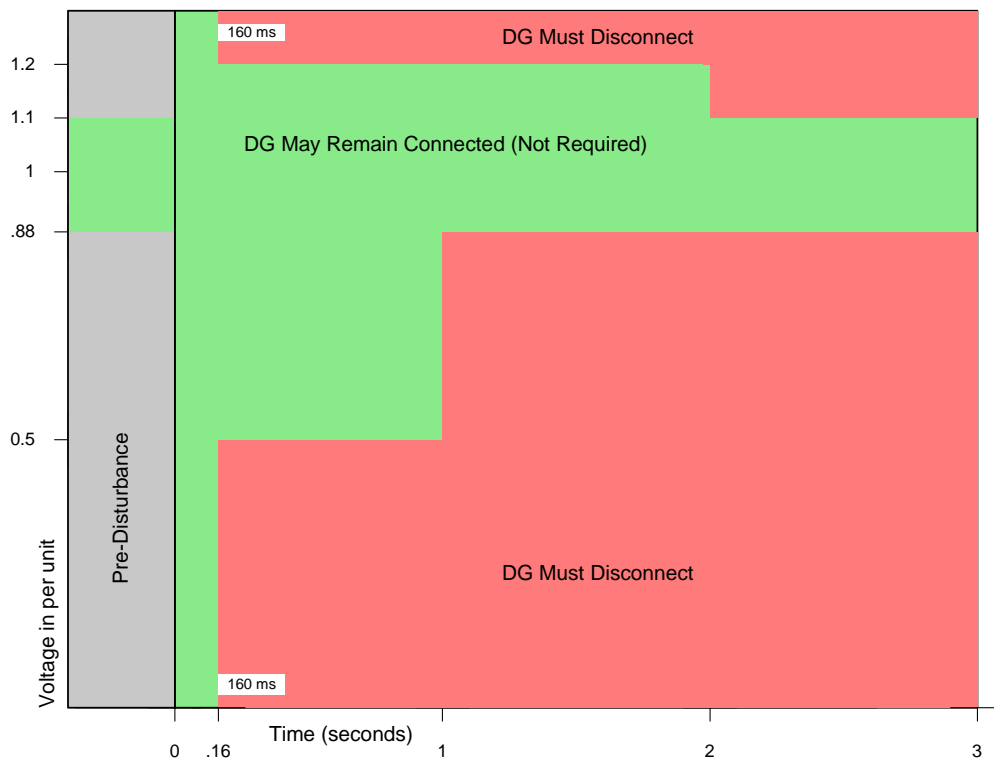
Requirements from IEEE 1547-2003:

- 1) IEEE 1547 applies to DG less than 10 MVA.

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<sup>5</sup> For a DG unit which has been committed to serve as a firm distribution resource, this section 3.3.1 does not address the additional functionality of providing physical assurance for the distribution utility. This means that, in the event of a DG outage at a time when the utility circuit is heavily loaded, the net load of the host customer at the electric power revenue meter or at the Point of Common Coupling (PCC) is to be limited to the level specified in the tariff or distribution resource agreement between the utility and the host customer.

- 2) For following requirements (2) through (6), customer load can remain connected to customer DG. The Standard focuses on disconnecting of utility circuit (area electric power system, area EPS) from the customer circuit having DG (local EPS). Customer loads that remain connected to DG within the local EPS create no conflict.
- 3) DG must not close onto dead utility circuit.
- 4) DG must detect that it is feeding islanded utility circuit, and disconnect within 2 s. (Intentional islanded operation is addressed in draft 1547.6.).
- 5) DG must disconnect from the utility circuit for faults on the circuit, prior to reclosure. No minimum dead time for circuit is stated. However, note in (6) below that a fault-induced voltage dip requires disconnection within 160 ms (10 cycles). A high-impedance fault may not produce this required voltage dip – for utilities to consider when applying special new high-impedance fault detection relays at the utility substation. Sequential tripping (relay trips circuit, followed by DR trip on islanding) is acceptable outcome for this scenario.
- 6) Voltage dip ride-through - allowed connection times for voltage excursions are shown in the following figure. For DG of 30 kW and above, the settings for voltage and time thresholds must be field adjustable. Footnote 7 in Standard implies latitude for changing these settings to meet site or other technical requirements.



- 7) DG must disconnect from utility circuit for frequency excursions below 59.3 Hz or above 60.5 Hz within 160 ms. For DG > 30 kW, frequency and time setpoints are required for range of 59.8 to 57.0, presumably for setting coordination with region UFLS scheme.
- 8) When utility circuit voltage recovers to Range B per ANSI C84.1 and between 59.3 and 60.5 Hz, the DG can reconnect. Note: IEEE 1547 does not require any time delay before reconnecting. It only requires that the DR have either an adjustable or fixed 5 minute *timer* for reconnection. No minimum acceptable time delay adjustment is stated. Synchronizing accuracy requirements are given in Table 5.
- 9) An application issue not directly addressed in IEEE 1547 – Measurements and settings in the DG switching control system should insure that, with multiple DG owners on a utility circuit, they all disconnect. An approach is to determine that the voltages on the islanded utility circuit caused by any specific DG that fails to disconnect cannot reach a magnitude where resynchronization and closing of other DG on the utility circuit may occur.

Distributed Generation Coordinating Group - Technical Steering Group (UK), *Technical Guide to the Connexion of Generation to the Distribution Network*, K/EL/00318/REP - URN 03/1631, February 2004<sup>6</sup>:

- 1) Fault ride-through must be implemented early in DG implementation in order to avoid limits on penetration later.
- 2) Fault ride-through may be difficult to coordinate with undervoltage protection when there are many generators at the same voltage and vicinity.

EPRI White Paper, *Integrating Distributed Resources into Electric Utility Distribution Systems*, Document 1004061, December 2001<sup>7</sup>:

- 1) Watch for ferroresonance and grounding issues when utility disconnects.
- 2) Voltage dip detection of faults implied in IEEE 1547 may not be adequate to insure DG trip, especially with DG-local load balance and/or with inverter DG. Alternative fault detection methods listed on pages 4-47 to 48.
- 3) DR can be certified for anti-islanding detection type test per UL 1741 or IEEE 929.
- 4) DG must not attempt to regulate voltage or power factor at point of supply during normal operation, according to 1547. But if the DG and local load disconnect, the local load must be maintained within voltage and frequency limits.
- 5) With some configurations (perhaps with many DG customers), stability can be a problem. Not much offered here for solutions or approaches.

*Additional references to be cited and integrated in future drafts.*

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<sup>6</sup> See [http://www.masstech.org/renewableenergy/public\\_policy/DG/resources/2004-02-11\\_FES\\_DG-Connection\\_00318\\_v040211.pdf](http://www.masstech.org/renewableenergy/public_policy/DG/resources/2004-02-11_FES_DG-Connection_00318_v040211.pdf) and the referenced Distribution Code of Great Britain (2006), [http://www.masstech.org/renewableenergy/public\\_policy/DG/resources/2006-11\\_UK\\_Distribution-Code\\_8.pdf](http://www.masstech.org/renewableenergy/public_policy/DG/resources/2006-11_UK_Distribution-Code_8.pdf)

<sup>7</sup> See [http://www.masstech.org/renewableenergy/public\\_policy/DG/resources/2001-12\\_EPRI\\_Integrating-Distributed-Resources\\_1004061.PDF](http://www.masstech.org/renewableenergy/public_policy/DG/resources/2001-12_EPRI_Integrating-Distributed-Resources_1004061.PDF)

**TECHNICAL CHALLENGE MATRIX**  
**Issues and Concerns**  
**Revised Draft Based on 11-15-06 Workshop Discussion**

DER Challenges	Issue or Concern	Specific Challenge to Resolve	Potential Solutions	Detailed Solution Estimates for DG Support of Utility System	DG Workshop Proposed Actions
1. DG Behavior on Distribution Systems	1.1 Resiliency of DG units to remain on line during disturbances	1.1.1 Ability for DG units to remain on line following a momentary interruption of the circuit it is supplied from. Examples include recloser operations involving up to 4 interruptions lasting from 1 to 45 seconds. Other devices include automatic sectionalizing units (ASU) and vacuum fault interrupters.	A. Customer load isolation with generator ride through B. Customer load interruption with generator trip C. High speed resynchronization or dispatch based DG reconnection D. Customer based energy storage device E. Utility based energy storage device (i.e. flywheel, battery, etc.) or dispatch of emergency units F. Utility dispatched demand reduction program response G. Employ more advanced communication systems to coordinate reconnection of DG units	In general there are potential additional costs for all solutions that are associated with utility system or customer equipment modifications due to DG interconnections that are difficult to define absent knowledge of the specific location and installation. Solution A. Typical Isolation Equipment Costs: 10-30% incremental cost including: \$2000-2700/kw gen capacity (\$120-150/kw for inverters) 15% adder for customer load reconfig. \$2000/kw for auto re-synch. (needed for utility support) \$5,000 Communication costs for utility coordination (needed for utility support)	The option of developing a planning guide document that would aid planning and protection system engineers in addressing and mitigating the potential problems identified in this matrix was discussed. The document would also help customers by listing the types of issues that are encountered when considering interconnection of a generator which could also provide utility support. The design options in terms of equipment requirements and their related costs would also be identified. This document would be based on existing documents as much as possible and could rely extensively on a document that KEMA developed for the Dutch utility. [Note: The utility group offered to develop an equipment list necessary for utility support for typical installations that included component equipment costs]
1. DG Behavior on Distribution Systems	1.1 Resiliency of DG units to remain on line during disturbances	1.1.2 Ability for DG units to remain on line following a disturbance on a near by system element resulting in voltage and/or current excursions.	A. High speed resynchronization or dispatch of DG for reconnection B. Customer based energy storage device C. Utility based energy storage device or dispatch of emergency units	These solutions may be addressed in the planning guide document.	
1. DG Behavior on Distribution Systems	1.1 Resiliency of DG units to remain on line during disturbances	1.1.3 Ability for DG units to remain on line following an auto-transfer switch operation transferring a customer connection from one distribution supply to an alternate supply.	A. High speed resynchronization or dispatch of DG for reconnection B. Customer based energy storage device C. Utility based energy storage device or dispatch of emergency units	These solutions may be addressed in the planning guide document.	
1. DG Behavior on Distribution Systems	1.2 Ability for DG units to provide capacity, voltage and reactive support for the distribution system.	1.2.1 Ability for DG units to maintain voltages during and following a disturbance. Ability for DG units to support loads when utilities need capacity. (Renewable resources may be included based on statistical contribution data)	A. High speed resynchronization or dispatch of DG for reconnection B. Customer based energy storage device C. Utility based energy storage device or dispatch of emergency units	These solutions may be addressed in the planning guide document.	
2. Utility System Design Changes	2.1 Distribution circuits and their protection systems are largely designed to be operated radially out from a single electrical source	2.1.1 Protection system modifications necessary for addition of a single DG unit. Of particular concern was the impact on lightning arrestors and single phase customers when connected DG is significant with respect to loads (I.e. effective grounding issues).	A. Limit generation on circuit to a small percentage of circuit load B. Modified DG connection and/or addition of effective grounding for units may mitigate concern	A. EPRI paper suggests 15% of circuit peak load aggregate as a general limit. It was recognized that this is based on installations that passed all other interconnection related screens for acceptance under a fast track process.	
2. Utility System Design Changes	2.1 Distribution circuits and their protection systems are largely designed to be operated radially out from a single electrical source	2.1.2 Protection system modifications necessary for addition of multiple DG units on a single circuit. Of concern was the protection system devices that are non-directional in nature that serve to interrupt or indicate location of faults. Higher fault current levels also present concerns.	A. Limit generation on circuit to below acceptable fault current contribution levels B. Upgrade and replacement of protection system equipment to allow for reverse power flow operation including communication systems upgrades as needed. C. Introduction of current limiting device to mitigate contribution to area fault duty.	A. On suggestion was for use of a "Flex Phase" device which is designed to mitigate fault duty contribution of a generating source where short circuit constraints exist on a system. The high level cost estimate for such a device was in the range of \$100,000.	
2. Utility System Design Changes	2.1 Distribution circuits and their protection systems are largely designed to be operated radially out from a single electrical source	2.1.3 Protection system modifications necessary for addition of multiple DG units exporting power to a substation.	A. Upgrade and replacement of protection system equipment to allow for reverse power flow operation.	These solutions may be addressed in the planning guide document.	

Attachment D to December 31, 2006 Report

DER Challenges	Issue or Concern	Specific Challenge to Resolve	Potential Solutions	Detailed Solution Estimates for DG Support of Utility System	DG Workshop Proposed Actions
2. Utility System Design Changes	2.1 Distribution circuits and their protection systems are largely designed to be operated radially out from a single electrical source	2.1.4 Protection system modifications needed for circuits configured for loop supply and/or auto transfer switch operation when one or more DG units are on any of the associated circuits.	A. Upgrade and replacement of protection system equipment to allow for reverse power flow operation.	These solutions may be addressed in the planning guide document.	
2. Utility System Design Changes	2.1 Distribution circuits and their protection systems are largely designed to be operated radially out from a single electrical source	2.1.5 Equipment modifications necessary for addition of multiple DG units exporting power to the substation.	A. Upgrade and replacement of protection system equipment to allow for reverse power flow operation.	These solutions may be addressed in the planning guide document.	
2. Utility System Design Changes	2.1 Distribution circuits and their protection systems are largely designed to be operated radially out from a single electrical source	2.1.6 Voltage and VAR regulation equipment modifications necessary for addition of multiple DG units with intermittent operation on the system.	A. Modify capacitor and/or voltage regulator control equipment to allow for coordination with DG units	These solutions may be addressed in the planning guide document.	
3. DER Monitoring and Control	3.1 DG unit availability	3.1.1 Necessary reliability, availability and capacity characteristics of DG units during extreme weather conditions when providing support for the distribution system.			
3. DER Monitoring and Control	3.1 DG unit availability	3.1.2 Comparability requirements for DG units to support the distribution system during outages in a manner consistent with other distribution system elements.			
3. DER Monitoring and Control	3.2 Real time monitoring of DG units.	3.2.1 Terminal equipment and communication alternatives for providing status information and power flow quantities (i.e kw, kvar & voltage) for DG units on the system.			
3. DER Monitoring and Control	3.2 Real time monitoring of DG units.	3.2.2 Alternatives for aggregating DG information for units supporting an area.			
3. DER Monitoring and Control	3.3 Real time control of DG units.	3.3.1 Alternatives for providing direct or indirect dispatch control of DG units.			
3. DER Monitoring and Control	3.4 Real time control of DG units.	3.4.1 Alternatives for providing ISO-NE direct or indirect dispatch control of DG units.			

Attachment D to December 31, 2006 Report

Challenge/ Circuit Type	1.1.1	1.1.2	1.1.3	1.2.1	2.1.1	2.1.2	2.1.3	2.1.4	2.1.5	2.1.6
	Circuit remains out until manually reconnect ed.									
Fused Circuit Configuration	G	A,B,C,D,E	A,B,C,D,E	A,B,C,D,E	A,B	A,B	A,B	A,B	A,B	A,B
Recloser Circuit Configuration	A,B,C,D,E	A,B,C,D,E	A,B,C,D,E	A,B,C,D,E	A,B	A,B	A,B	A,B	A,B	A,B
Auto Transfer Circuit Configuration	A,B,C,D,E	A,B,C,D,E	A,B,C,D,E	A,B,C,D,E	A,B	A,B	A,B	A,B	A,B	A,B
Auto Sectionalizing Circuit Configuration	A,B,C,D,E	A,B,C,D,E	A,B,C,D,E	A,B,C,D,E	A,B	A,B	A,B	A,B	A,B	A,B

Attachment D to December 31, 2006 Report

Resource Type Table							
Unit Output / Unit Type	Small <100 KW	Medium <500 KW	Large <5000 KW	Standalone Generator	Output Less than Load	Output Greater than Load	Intermittent
	It was concluded that size relative to customer load and circuit load was the most critical issue due to protection system and equipment ratings concerns.			This type of interconnection would not be applicable to customer load isolation schemes.			
Inverter Based				This type of resource has the ability to ride through disturbances and reconnect based on the control equipment settings.	This type of resource has the ability to ride through disturbances and reconnect based on the control equipment settings.	This type of resource has the ability to ride through disturbances and reconnect based on the control equipment settings.	This type of resource has the ability to ride through disturbances and reconnect based on the control equipment settings.
Synchronous Generator				Equipment additions/modifications and interconnection design reviews are necessary to meet requirements for providing system support.	Customer connection designs that allow for critical loads to be isolated with generation are needed for this type insatllation.	Equipment additions/modifications and interconnection design reviews are necessary to meet requirements for providing system support	Equipment additions/modifications and interconnection design reviews are necessary to meet requirements for providing system support
Induction Generator				Appropriate generator design in conjunction with the above note for synchronous units are needed.	Appropriate generator design in conjunction with the above note for synchronous units are needed.	Appropriate generator design in conjunction with the above note for synchronous units are needed.	Appropriate generator design in conjunction with the above note for synchronous units are needed.

[Challenge Matrix!A1](#)  
[Circuit Configurations!A1](#)