Effects of Rural Electrification on Distributed Generation Siting and Interconnection in Massachusetts

Prepared for:

Massachusetts Department of Energy Resources

Prepared by:

Peregrine Energy Group, Inc. and

Richard C. Gross, P.E., Inc.

April 16, 2013

Disclaimer

This report was prepared for the Massachusetts Department of Energy Resources (DOER). Technical research and interviews with electric utilities and renewable distributed generation developers were carried out by technical consultants Peregrine Energy Group, Inc. and Richard C. Gross, P.E., Inc. Funding was provided to the consultants under RFQQ-ENE-2013-012 issued by the DOER. The findings and recommendations are those of the technical consultants and do not represent the official views of the DOER.

This report is commissioned by the DOER as part of its mandate to promote policies and programs that ensure that Massachusetts' citizens have access to adequate, diverse energy supplies that are available at reasonable cost and with minimal impact on the environment. Funding for this report was provided by DOER from Alternative Compliance Payments collected per 225 CMR 14.00, promulgated pursuant to M.G.L. c. 25A, § 11F.

Table of Contents

Acknowledgements

The authors thank the following utility company representatives for their time and assistance with this study: Vishal Ahirrao, Kevin Kelly, Timothy Roughan, and John Teixeira of National Grid; Amin Jessa and Robert Andrew of NSTAR; John Bonazoli of Unitil Service Corporation; and David Wrona, Cynthia Janke, and Mark Gilmore of Western Massachusetts Electric Company.

We are also grateful to the following individuals who discussed their distributed generation projects with us: Leonard Roberts of Roberts Brothers Lumber Company, Inc., Louis Aragi of Pine Island Farm, and Conrad Geyser of Cotuit Solar, LLC.

Lastly, we thank Gerald Palano of the Massachusetts Department of Agricultural Resources and Robert Rizzo, Gerry Bingham, and Dwayne Breger of the Massachusetts Department of Energy Resources for their input and direction.

1.0 Executive Summary

Massachusetts Department of Energy Resources (DOER) engaged Peregrine Energy Group, Inc. with Richard C. Gross, P.E., Inc. (together "Peregrine") in November 2012 to gather information for DOER's use on how patterns of rural electrification affect the siting and interconnection of distributed generation ("DG") projects. DOER has defined distributed generation, for purposes of this study, as development of larger scale (greater than 30 kW, up to several MW) distributed clean energy resources (solar PV, wind, combined heat and power, etc.) that operate in parallel with the electric utility distribution system. DOER hypothesized in RFQQ-ENE-2013-012 that such development "requires upgrades to electrical distribution lines for interconnection to the utility grid, including access to three phase power lines and other means to smooth out voltages from intermittent resources." And further that, "the lack of three phase power lines and other interconnection challenges has restricted distributed generation in these areas."

Research and analysis carried out by Peregrine over a three-month period included interviews with the four investor-owned electric distribution utilities active in Massachusetts, discussions with successful and would-be distributed generation developers, conversations with State agencies, and literature searches.

Peregrine found that

- The share of overhead single-phase circuits in distribution systems of investor owned utilities varies from 45% to 65%, measured in circuit-feet.
- Converting circuits from single-phase to three-phase can result in higher interconnection costs than can be absorbed by a would-be generator.
- There have been few requests for such conversions to date in Massachusetts
- It appears that, despite the preponderance of single-phase distribution, particularly in rural areas where there is more open land, DG developers have been mostly able to select locations that already have three-phase overhead distribution.
- Property owners served by single-phase distribution who seek to develop distributed generation to supply or support existing operations may choose to forego installing on-site DG because they cannot avoid incurring the cost of distribution system conversions and upgrades.
- Utilities are able to accommodate interconnection requests by distributed generators as long as these interconnections do not adversely affect power quality.
- The effect of distributed generation on power quality can be greater on rural distribution circuits since these circuits are typically remote from the core of the interconnected generation and transmission system and therefore "less stiff."
- Utilities require interconnecting generators to incorporate a variety of devices and equipment to protect power quality and are inclined to rely on proven approaches rather than emerging technology for this purpose.
- That said, increasingly on a pilot basis, utilities are looking at the effectiveness of emerging technologies to address power quality concerns associated with DG.

2.0 Introduction

This report has been prepared in response to the Commonwealth of Massachusetts Department of Energy Resources (”DOER”) RFQQ-ENE-2013-012 – *Rural Electrification Upgrades for Renewable Energy Economic Development* to assist DOER to expand its understanding of technical barriers to and options for interconnecting distributed generation (“DG”), including solar photovoltaic systems, wind turbine generators, and combined heat and power (“CHP”), to electrical distribution circuits in rural Massachusetts.

This report addresses the:

- Extent of single-phase power distribution in rural areas of Massachusetts and any constraints this distribution service places on distributed generation project development,
- Benefits that three-phase power may create beyond support of DG projects,
- Challenges associated with interconnecting DG to electrical distribution circuits in rural Massachusetts, and
- Costs associated with distribution service upgrades and other interconnection technologies.

2.1 Methodology

The research conducted for this report was a combination of interviews with representatives of Massachusetts investor owned utilities, discussions with developers of distributed generation projects, review of interconnection impact studies prepared in response to applications for interconnection for distributed generation, and additional investigation of publicly available information sources. It also has drawn from the authors’ prior and ongoing professional involvement in power project development.

2.2 Report Structure

Research results are organized into four major Sections:

- 3.0 Single-phase and three-phase distribution in rural Massachusetts
- 4.0 System-wide benefits from distribution system upgrades
- 5.0 Effects of the rural electric distribution configuration on renewable DG
- 6.0 Costs for circuit upgrades and other interconnection technologies
- 7.0 Conclusions and Areas for Further Consideration.

3.0 Single-phase and three-phase distribution in rural Massachusetts

The approved Distributed Generation interconnection tariff in MA ("the tariff" or "the DG tariff") stipulates that single-phase distributed generation projects rated less than 10 kW may be eligible for a Simplified interconnection application process in Massachusetts. Smaller scale (e.g. 25 kW or less) distributed generator projects also may be interconnected to single-phase distribution circuits. All other projects located on single-phase service that are seeking to interconnect must follow the Expedited or Standard Review tracks in the tariff.

For projects that follow the Expedited process and pass the associated screens, interconnection can occur quickly. Those projects that are not eligible for the Expedited process continue into the Standard process which requires a System Impact Study to identify the technical requirements of the electrical interconnection facilities for the project and, if necessary, utility system upgrades that are necessary to accommodate the interconnection and operation of the project. For projects requiring substantial utility system upgrades for interconnection service, the electric utility may need to perform an additional phase of engineering analysis referred to as a Detailed Study.

The rationale for this standard in the tariff is to allow for simplified or expedited interconnection for those distributed generation projects that will likely have minimal impact on other customers on the distribution circuit in question, and to acknowledge that larger projects 25 kW or greater may have impacts on the system or on other customers they share circuits with which require more detailed planning and specific mitigation strategies. The operation of a distributed generation project is not permitted to have an adverse impact on the voltage, power quality, or reliability of any other electric utility customers served by the utility electricity distribution system.

Electrical circuits are commonly described as "single-phase" or "three-phase", reflecting the number of energized conductors they have.

- A three-phase distribution circuit consists of three energized conductors that are insulated from ground. Larger scale (greater than 30 kW, up to several MW) distributed renewable energy resources need to be interconnected to a three-phase distribution circuit. On an overhead distribution circuit, the energized conductors may be either bare (i.e. non-insulated) or partially insulated (also referred to as covered or tree wire) conductors that are supported by insulators attached to utility pole cross-arms (referred to as "open wire" construction) or partially insulated conductors that are arranged in spacer brackets and supported by a messenger wire (referred to as "spacer cable" construction). Three-phase circuits generally employ larger and taller poles than single-phase circuits as required by utility-specific safety codes.
- A single-phase electrical distribution circuit is typically a lateral tap from a three-phase distribution circuit. A single-phase distribution circuit typically consists of one energized

conductor that is insulated from ground and one conductor that is intentionally grounded. In some cases (e.g. effectively-ungrounded and delta distribution systems), a single phase distribution circuit requires two energized conductors.

Electric utilities construct three-phase circuitry as the primary means of supplying electricity from the central-station type generators through the high voltage transmission system, and to the distribution substations that convert the high voltage circuits to the distribution-voltage level circuits that supply their distribution customers. The distribution circuits typically emanate from the distribution substations as three-phase circuits. Lateral taps from the three-phase sections of the circuits are made as necessary (e.g. to supply customers on side streets) and may be either three-phase taps, two-phase taps, or single-phase taps, depending on the electrical load concentration and types of load. Unless there is a need to provide three phase service to one or more customers, single-phase laterals are the most economical design to serve single-phase distribution customers. In addition, single-phase laterals are less visible and require less tree trimming than three-phase overhead circuits.

3.1 Extent of single-phase distribution

Rural parts of Massachusetts include mountainous areas with larger tracts of land that could support wind projects, abandoned farmland that is suitable for ground-mounted solar electric development, and locations with nearby biomass waste or sustainable production that could fuel CHP projects. Single-phase distribution lines are common and widespread in rural areas that might be good locations for expanding renewable distributed generation. Since a premise of this investigation is that all investor-owned electric utility customers should have equal opportunity to self-generate from clean energy resources, it is important to recognize what issues that this widespread single-phase distribution in rural Massachusetts may pose to customers seeking to install distributed generation.

Discussions were undertaken for this report with staff of the four Massachusetts investor-owned electric utility companies. Peregrine met with, National Grid, NSTAR, Western Massachusetts Electric Company, and Unitil to discuss policies and practices with respect to distribution circuit configuration, the conversion of circuits from single-phase to three-phase construction, and the system impacts and mitigation techniques associated with the interconnection of distributed generators.

From these interviews and additional independent research, the consultants have gathered the following information and derived the following conclusions.

The amount of single-phase overhead distribution circuitry, as a percentage of the total overhead distribution circuitry on the investor owned utility distribution systems varies from 45% to 65%. National Grid ("NGrid") estimates that 60% of their overhead electrical distribution system in their Massachusetts service territory is single-phase. Unitil estimates that 65% of their overhead electrical distribution system in Massachusetts is single-phase. WMECo's overhead distribution system is 62% single-phase, which is similar to the NGrid and Unitil distribution systems. In contrast to the other utilities surveyed, only 45% of NSTAR's overhead electrical distribution system is single-phase.

NSTAR provided the following additional detailed information on its distribution network.

- There are approximately 8,000 circuit-miles of overhead distribution circuitry in the NSTAR service territory. This includes circuits operating at nominal phase-to-phase voltages of 22.8 kV, 13.8 kV, 13.2 kV, 8.32 kV, and 4.16 kV. Within Route 128, there is a significant amount of underground distribution.
- The NSTAR distribution system has approximately 2,000 automated and/or remote-controlled distribution switching devices which are used to isolate faulted sections of the distribution system, re-configure the distribution circuits as necessary to restore power to non-faulted sections of the distribution system after outages, and automatically transfer loads between normal and alternate sources. The switching devices include circuit reclosers, sectionalizers, and motor-operated disconnect switches.
- NSTAR representatives observed that when there is demand for new distribution circuitry, NSTAR will build it. That said, in some rural areas, there is limited NSTAR distribution infrastructure because NSTAR never had any reason (e.g. to serve large customer loads) to develop this infrastructure.

There is significant town-to-town variation across Massachusetts in the mix of single-phase and three-phase distribution. NSTAR and WMECo each prepared and shared a detailed summary of the total quantity of single-phase and three-phase overhead distribution circuitry in each town and city in their respective service territories.[1] These summaries included the phase-to-phase operating voltage of the three phase sections. The NSTAR and WMECo summaries are included with this report as Appendix 1 (NSTAR) and Appendix 2 (WMECo). Consistent with NSTAR's observation about limiting investment in distribution infrastructure where there is little need or demand, the detailed town-by-town summaries show that communities with low population densities generally have a greater ratio of single-phase to three-phase distribution circuitry. While National Grid and Unitil did not provide a similar level of data, National Grid told the authors that approximately 60% of their overhead distribution system in Massachusetts is single-phase overhead construction. The percentage for Unitil is 65%.

3.2 Conversion of single-phase circuits to three-phase

The electric utility will convert single-phase or two-phase sections of their distribution circuits to three-phase construction as required, either due to increased load levels, to balance the amount of load supplied by each phase of the three phase circuit, to create a three-phase field tie to an adjacent distribution circuit for better operational flexibility and improved reliability, or to provide three-phase service in response to a customer request. Converting a section of the distribution circuit from single-phase construction to three-phase construction is only done if

---

[1] National Grid and Unitil chose to prove aggregate estimates.

such change is deemed necessary by utility-specific system planning parameters because it increases the utility's construction, maintenance, and repair expenses.[2] As the amount of circuitry on the distribution system increases, likewise does the exposure to potential disruption and the amount of infrastructure that the utility must maintain and ultimately replace at some point in time.

Upgrading the entire distribution system to three-phase would be cost prohibitive and provide minimal electrical service advantages to existing single-phase customers. In addition, three-phase circuitry, with larger poles and multiple wires, has a greater visual impact than single-phase circuitry. Further, protecting this bigger infrastructure from storm damage requires clearing and trimming more trees, which may be objectionable to area residents.

Utilities report that there have been few situations where project developers have requested conversion of single-phase distribution to three-phase. Distributed generation developers appear to match their generation projects to existing service configurations and voltage. The majority of interconnection applications received by the utilities for DG projects 25 kW or larger are for projects with adjacent or nearby three-phase distribution service.

The outcome of interconnection applications for larger projects (i.e. 25 kW or larger) in single-phase service areas as received over the past several years by the four (4) investor-owned electric utility companies in Massachusetts is as follows:

- National Grid has interconnected six (6) three-phase distributed generation projects, each with a generation capacity of less than 500 kW, which required the conversion of the original single-phase distribution circuit to three-phase construction in order to accommodate the interconnection of the project. The additional cost for the conversion required for each of these projects did not deter the projects from being constructed.
- NSTAR has not had any distributed generation projects that required the conversion of a single-phase section of their distribution system to three-phase construction solely for the purpose of interconnecting a distributed generator.
- WMECo has received a few interconnection requests for three-phase distributed generators at locations serviced by single-phase distribution circuits; however, of those projects, only one project has proceeded to commercial operation and required the conversion of the single-phase circuit to three-phase construction. Some of these projects are still active and in the earlier stages of the interconnection process.
- Unitil reported one Massachusetts project application for a three-phase project in a single-phase service area.

It appears that in screening potential DG project sites, despite the preponderance of single-phase distribution circuits, developers of distributed generation that require three-phase interconnection service are mostly able to select locations that already have three-phase overhead distribution. This allows them to avoid the cost for converting single-phase circuits to three-phase.

[2] Each utility's System Planning Filings are available at the MA-DPU File Room website.

On the other hand, for a would-be distributed generation developer who already owns property in an area served by these widespread single-phase circuits, being on a single-phase circuit will likely result in additional interconnection costs which could be a financial barrier to installing a project larger than 25 kW. Property owners that seek to develop distributed generation to supply or support existing farm or sawmill operations may not be able to build the larger projects that they need. The cost of distribution system conversion to three-phase that an otherwise economical, larger DG project would need to carry could be quite high, limiting such clean energy DG projects to less than 25 kW. It should be noted that would-be developers of some larger distribution projects also can be thwarted by other factors beyond their immediate control such as local zoning requirements, abutter concerns, and higher than anticipated equipment purchase and installation costs.

4.0 System-wide benefits from distribution upgrades

Utilities will upgrade their electric distribution systems to improve reliability, serve new customer loads, and to provide interconnection service to distributed generation customers. There are benefits associated with distribution system upgrades (e.g., conversion of single-phase construction to three-phase construction) that accrue to affected utility retail customers in the area, future interconnecting distributed generators, and the utility company itself. These benefits include:

- Making it easier for additional, future distributed generation projects to interconnect on the upgraded circuit,[3]
- In some cases, newer distribution system infrastructure that is built to current construction standards will improve reliability.
- Using the opportunity of an upgrade to employ current distribution circuit construction methods that are more resilient in storm conditions than former construction methods (i.e. replacing bare wire with covered wire or reduced span lengths), resulting in greater circuit reliability,
- Power quality improvements, such as improved voltage regulation to other electric loads on the circuit,
- Economic opportunities to retail customers for new business creation and business expansion by allowing installation of more powerful three-phase electrical machines, construction of new facilities, and opening of businesses that require more electric load than could be supplied by a single-phase circuit, and

In addition, when the distribution upgrade includes the installation of more automated power system communication and control devices, it can improve the overall power quality on a distribution circuit and mitigate the effects of system disturbances that aren't related to the operation of the distributed generator (e.g. abrupt voltage changes due to faults and load rejection at other points within the distribution system).

[3] Recognizing that an upgrade to three-phase service may enable the utility to accommodate up to 67% of the minimum load on the circuit without study.

5.0 Effects of electric distribution configuration on DG

5.1 Attributes of single- and three-phase distribution circuits and their effects on DG interconnection

The necessity for three-phase distribution circuitry for the interconnection of distributed generation is a function of the generator/inverter capacity and its configuration. Generators and inverters that are larger than approximately 30 kW will generally be three-phase devices requiring a three-phase circuit for their interconnection and operation. And as noted in the prior section, it appears that most large, stand-alone, virtual net-metered projects are being sited where three-phase interconnection is already available.

Smaller distributed generator projects such as residential PV projects are often matched to the single-phase distribution service typical of residential customers and sized for on-site use. NSTAR provided the summary table below that shows the interconnection applications received for distributed generation projects rated 25 kW or less and presumed to be single-phase. Of these projects, NSTAR has not converted a single-phase section of their distribution system to three-phase solely for the purpose of interconnection.

Interconnection Requests by Customer Type (number of applications)

	Residential	Commercial	Municipal	Industrial	Total
Expedited/Standard	106	60	19	0	185
Simplified	2,825	324	20	3	3,172
Total	2,931	384	39	3	3,357
	87%	11%	1%	0%	

An electric utility distribution system in a rural area will often evolve from its original construction and operation at a lower distribution system voltage that served a relatively small number of light loads. As loads increase in the area, parts of the distribution system may need to be upgraded to operate at a higher voltage in order to meet the increased load levels.

In rural areas, long single-phase taps often have been left operating at their original, lower operating voltage from the time of initial electrification, resulting in these rural customers being served by older distribution circuitry. These taps that are still operating at low operating voltages are supplied via a step-down transformer bank from the rest of the distribution circuit that has been upgraded to a higher operating voltage. This approach avoids the expense of line upgrades: replacing the older poles and distribution transformers, replacing small conductor sizes that may not meet current standards (though they did meet the National Electrical Safety Code ("NESC") and company-specific standards at the time of their original construction), and re-insulating the long single-phase laterals to operate at the higher voltage.

In some cases, reliability will be improved by newer distribution infrastructure that is built to current construction standards. Often, however, the older, lower voltage circuits continue to provide adequate service to customers that are supplied by these circuits, and utilities have seen no reason to upgrade the circuits because load levels have not substantially increased. One of the electric utilities interviewed for this report stated that most, if not all, older conductors on its distribution system do meet the current NESC criteria.

It is not unusual for the size of the conductor and its associated current-carrying capacity in rural areas to be smaller towards the end of the distribution circuit, even on the three phase sections. The result is that interconnection of a three-phase distributed generator in a rural area serviced by only a single-phase circuit could require more new construction, the replacement of all the distribution transformers along the single phase circuit (if a voltage conversion is required), and also additional upstream upgrades to meet distribution utility requirements.

The conditions and characteristics of distribution circuits, particularly as they are in rural regions, may be less supportive of clean energy project interconnection. Interconnecting distributed generators to long rural circuits may require more upgrades to avoid impacting other customers with voltage fluctuations. Rural areas with limited numbers of customers on distribution circuits typically do not require upgrades to provide adequate service to existing customers. Such circuits are likely to remain in service in their original configuration.

Where the original infrastructure is approaching the end of its useful service life, some original elements may have slowly deteriorated. In addition, since tree trimming is typically done in multi-year cycles (to maintain reasonable distribution system operating costs), some towns and customers will be resistant to tree trimming activity when the time comes. Such conditions could result in more frequent customer outages and a longer average duration of each outage on some rural distribution circuits, compared to the utility average reliability figures.

For retail customers on these circuits, frequent line problems and outages create inconvenience. For capital-intensive renewable energy projects, such conditions can result in reduced net capacity factors, higher extended costs for each kWh generated, and problematic project economics.

5.2 Technical challenges of interconnecting DG with rural distribution

As field experience with the particular attributes of renewable distributed generation grows in rural settings, interconnection technology is evolving. This evolution not only addresses the particular technical challenges that siting in rural locations create, but also the general issues associated with interconnection on distribution circuits, be they single-phase or three-phase (e.g. evolving electric utility requirements for protective relaying systems, communications between the utility and the distributed generator, remote utility control of the circuit breaker that interconnects the distributed generator to the utility distribution circuit).

This report section describes and evaluates interconnection technology options (commercially available and emerging) that address the interconnection challenges of distributed generation on rural distribution lines, including effects of DG on power quality.

Power quality can be affected by the intermittent and changing output of the distributed generator, causing voltage fluctuations ("voltage flicker") for retail customers. It can also be affected by a sudden shutdown of distributed generation that may occur, for example, as a result of a fault within the DG interconnection facilities. These power quality issues can not be corrected quickly enough by typical electric utility voltage regulation equipment (e.g. voltage regulators and switched capacitor banks), but can be corrected by more sophisticated power system devices such as Static Var Compensators ("SVC") and Static Synchronous Compensators ("STATCOM") devices, described in more detail below.

The effect of distributed generation on power quality can be greater on rural distribution circuits since these circuits are typically remote from the core of the interconnected generation and transmission system and therefore "less stiff." This can be quantified by the maximum amount of current that will result from a short circuit at the point of interconnection, where low short circuit current levels indicate a less-stiff point in the distribution system.

Voltage along less stiff rural distribution circuits may fluctuate more noticeably with fluctuations of distributed generator output, particularly where the distributed generation is an intermittent source. Lower load density and load levels on rural distribution circuits and substations can further exacerbate these system impacts.

In rural areas that are remote from the distribution substation, the distribution circuit may be constructed with smaller wire sizes or supplied through a step-down transformer that could further limit the amount of load or distributed generation that could be interconnected without triggering distribution system upgrades.

Typical electric utility practices for regulating the voltage on distribution circuits include installing voltage regulators and switched/fixed capacitor banks.

- A voltage regulator is a type of transformer that automatically changes the ratio between its input and output voltages by mechanically switching between tap points along the transformer windings. The switching takes place in response to a sustained change in the circuit voltage level, typically 30 to 90 seconds, to minimize switching operations.
- Capacitor banks are devices that are installed along distribution circuits to compensate for the magnetizing current associated with motor loads and the inductive component of the distribution circuit impedance. This effectively reduces the loading and impedance of the distribution circuit, which in turn reduces the voltage drop along the circuit. Capacitor banks may be switched on and off by time-controls or in response to sustained changes in circuit loading or voltage level.

But intermittent distributed generator output also can cause excessive switching operations of voltage regulation equipment, especially voltage regulators, which can lead to accelerated maintenance and replacement cycles.

Further, as noted above, fluctuations of distributed generator output can cause voltage variations on the distribution circuit that are noticeable to other customers (e.g. intermittent dimming of lights or "voltage flicker"). In addition, higher distributed generator output during low load conditions on the distribution circuit can cause elevated circuit voltages.

5.3 Strategies to mitigate effects of DG on power quality

Electric utility companies in Massachusetts are required to maintain the power quality and service reliability of their electrical distribution systems. Maintaining power quality is one of the major issues that utilities focus on in evaluating the impacts of interconnecting new DG. Distributed generation customers are also required to operate their projects within certain guidelines (e.g. voltage, frequency, and harmonics).

Given their mandate to maintain the safety, security, and reliability of their electrical distribution systems, utilities are required to use proven technologies and practices to accommodate the interconnection and operation of distributed generators. Such proven technologies and practices include:

- Installing voltage regulators,
- Retrofitting voltage regulators with controllers that can accommodate reverse power conditions caused by the operation of distributed generators,
- Replacing the phase conductors with larger wire sizes (i.e. "reconductoring") to reduce voltage drop/rise along the circuit,
- Installing express (i.e. dedicated) distribution circuits for the interconnection of distributed generators, and
- Installing remote control and direct transfer trip ("DTT") equipment to disconnect the distributed generator from the distribution system when necessary.

Additional techniques for mitigating the system impacts of distributed generation on rural circuits focus more on generator siting, equipment, and operations. These techniques may include:

- Limiting the capacity of distributed generation to be connected to a given distribution circuit;
- Specifying allowable ramp rates for fluctuations in generator output and/or equipping the distributed generation with an Energy Storage System ("ESS");
- Curtailing generator operation during certain system load levels, operating conditions or circuit configurations;
- Incorporating power system devices in the project that can more quickly correct for voltage variations such as Static Var Compensators ("SVC") and Static Synchronous Compensators ("STATCOM") devices[4]; and,

---

[4] SVC and STATCOM devices are generally referred to as FACTS (Flexible AC Transmission System) devices. FACTS devices are more prevalent on transmission systems although they can also be used on distribution systems to mitigate system impacts resulting from the operation of distributed generation. SVC devices may include both capacitors and reactors that are switched via thyristor valves to adjust the system capacitance and reactance in order to mitigate voltage fluctuations on electrical systems. STATCOM

- Equipping the distributed generator with grid support features or making use of existing grid support features that are available from certain types of distributed generation such as dynamic var/voltage control.

Installing SVC, STATCOM, and ESS

Installing SVC, STATCOM, and ESS, by larger generators as part of the interconnecting facility, is being studied by some of the electric utilities in Massachusetts as a strategy to mitigate the impacts of distributed generators on power quality. For example, NSTAR is expecting several PV project developers in close proximity to each other in Freetown to install SVC devices as part of their projects to mitigate voltage flicker issues. NSTAR intends this as a pilot to study impacts on power quality. The utilities reason that the distributed generator is triggering the need for such devices and therefore should have the responsibility for installing them.

As a matter of engineering practice, installing the FACTS devices as part of the utility distribution system, such as at the distribution substation, could be more effective and/or cost effective than installing them on a given distribution circuit as part of one or more distributed generation interconnection facilities. For example, undesirable harmonic interactions can occur between SVC's and the power electronics in wind turbine generators and PV inverters. A centralized STATCOM device is inherently more benign from the perspective of harmonic interactions and could provide an ancillary benefit of "soft-switching" of capacitor banks, minimizing the voltage variations associated with traditional capacitor bank switching. However, FACTS devices are more expensive than the interconnection and mitigation equipment that has been traditionally used by electric utilities.

The Commonwealth should consider encouraging and supporting electric utility research and experimentation into DG interconnection innovation. Utility preference for installing the devices at the generator may be due to utilities not having distribution system standards for installing FACTS devices on their own systems. We suggest that, as part of the Commonwealth's support for distributed generation, electric utilities need opportunities, regulatory support, and funding to evaluate the efficacy of addressing innovation for interconnection, such as installing FACTS devices on distribution systems, and, further, to develop the distribution standards for such existing devices, not yet considered "utility-grade." In addition, the regulatory process for approval of capital improvement plans need to recognize the higher costs of FACTS devices.

Integrating DG grid-support features with utility equipment

An additional technical challenge is to further develop and use grid support features built into larger distributed generation equipment, including dynamic var control, and integrate it with the electric utility-owned equipment. Electrical simulations studying the integration of grid support features will need to consider the response characteristics of all the equipment involved under

---

devices use voltage source converters to create a current waveform that is either leading or lagging the system voltage as necessary to maintain the power system voltage within an allowable range, typically ± 3% of nominal voltage. STATCOM devices can be coupled with ESS to comply with ramp rate restrictions and improve power quality.

different combinations of circuit loading and distributed generator output. Integration will require additional communications, monitoring, and control between the electric utility and the distributed generator.

Distributed generators can be equipped with or may already include design features that provide grid support to the electric utility distribution system in a way that could mitigate voltage regulation and voltage flicker issues. However, current industry standards (e.g. IEEE 1547) do not adequately address the use of distributed generators to actively regulate the distribution circuit voltage through dynamic var control. For example, a Type 3 (doubly-fed induction generator) wind turbine generator with the appropriate controls is capable of dynamically regulating the voltage at the point of interconnection to the electrical distribution system by modifying the generator reactive power output. The use of these features would reduce reliance on the electric utility-owned voltage regulation equipment.

Electric utilities usually require distributed generators to operate at a fixed power factor to ensure that the distributed generator doesn't interfere with the operation of the electric utility-owned voltage regulation equipment. Larger PV inverters have the ability to operate at a fixed power factor ranging from 95% leading to 95% lagging thus creating a source or sink of reactive current to the distribution circuit. This feature has been used as an effective mitigation strategy for addressing voltage fluctuations. However, the use of these features can reduce the sensitivity of anti-islanding detection techniques.

New, more flexible utility approaches to interconnecting distributed generation

Some of the electric utilities interviewed for this report are beginning to evaluate grid-support features on a pilot basis. If grid-support features prove to be workable, the utilities will need to integrate the technical details of these features with their existing distribution system equipment standards, construction standards, and operating procedures (collectively referred to as "distribution system standards"). Distribution system standards typically include detailed drawings and itemized material lists for the installation of distribution system equipment and for various types of overhead distribution construction that are typical for a given electric utility company.

The electric utilities need to be provided with opportunities, regulatory support, and funding to study grid support features of distributed generators. Further, utilities should develop distribution standards that include these features and integrate them into the newly created "Common Technical Manual for DG Interconnection."[5]

This approach will be further studied by distributed generation project developers through programs such as the Massachusetts Clean Energy Center ("MassCEC") Demonstration Project Pilot Program (RFP No. 2013-DEMO-01) in which MassCEC seeks Concept Paper Applications for

[5] The Technical Standards Review Group was created by agreement with the DG stakeholder community as part of DPU 11-75 and has already produced a draft document that will serve as a transparent comprehensive and common document listing utility-specific technical requirements with a higher level of detail than the existing tariffs.

demonstration projects. For example, one of the developers interviewed for this report, Cotuit Solar LLC, has submitted a proposal to the MassCEC to study and construct a distributed generator demonstration pilot project to evaluate a photovoltaic project with inverter-based reactive power support.

Protecting against "islanding"

"Islanding" occurs when a distributed generator continues to operate in parallel with a portion of the electric utility distribution circuit and other utility customers after it has been separated from the electric utility source. Unintentional islanding can damage both customers' and the electric utility's equipment.

In certain cases, a distributed generation project could require the installation of Direct Transfer Trip ("DTT") equipment, which prevents islanding. Electric utilities are more likely to require DTT on distribution circuits that are lightly loaded relative to the capacity of the distributed generator, often the case where distributed generators are interconnecting to rural distribution circuits. Also, rural distribution circuits are highly sectionalized to improve reliability, creating additional situations where islanding is possible.

With DTT, protective relays at one or more supply points within the electric utility system can send a signal to open (i.e. "trip") the circuit breaker that interconnects the distributed generator to the distribution circuit when conditions call for it. DTT equipment requires a communication channel between the electric utility equipment and the distributed generator. These channels can be a specialized telephone circuit, fiber optic cable, or radio. Obtaining and coordinating such a communication channel can be complicated and adds costs to the project, especially when DTT needs to be triggered from more than one point on the electric utility system.

As there are an increasing number of distributed generators that require DTT, utilities are finding that the additional operational and maintenance associated with DTT is a growing management burden. All four Massachusetts electric utilities express their willingness to investigate more efficient methods for eliminating islanding conditions and to use the least cost option for DTT communications that works. National Grid, for one, is investigating a less costly, easier to operate and maintain approach that uses power line carrier communications (i.e. a pulse or tone transmitted on the distribution circuit) to eliminate island conditions at greatly reduced cost to the DG customer. WMECO is researching a similar concept as well.

5.4 Case studies on interconnecting rural distributed generation

The following brief case studies reflect some of the issues associated with interconnection in rural areas of Massachusetts. Meetings were held with three renewable distributed generation developers (solar PV arrays, CHP, anaerobic digesters) as part of this study to capture their concerns and assess what the limitations are on project development in rural areas and/or where only single-phase distribution is available. Meetings focused on recent or would-be developers and explore their experiences as well as future plans. A fourth project (actually a cluster of projects) was identified to Peregrine and included as a case study as well.

CASE STUDY: Robert Brothers Lumber Company, Ashfield, MA

Roberts Brothers Lumber Company Inc. ("Roberts Brothers") wants to develop a biomass fueled CHP generation project at their existing lumber milling business, which is presently supplied by a single-phase distribution circuit. The proposed project would be located in a rural area within WMECo's service territory in Ashfield, MA. The proposed three-phase generator will require the extension of WMECO's three-phase, 23 kV distribution circuit a distance of approximately four miles along a state highway that is presently served by a single-phase circuit. The cost of the extension has been estimated to be $2.2 million, which is prohibitive to the project.

As envisioned by Roberts Brothers, wood chips produced as a by-product of lumber milling will be transformed into a combustible gas to be used as fuel for an engine-generator set with a rated electrical output of 1,000 kW. The generator would operate in parallel with the WMECo distribution circuit. The electrical output from the generator will exceed the maximum load of the existing lumber milling business, and excess power will flow into the WMECo distribution circuit and be net metered. Waste heat from the generator will be used to dry the feedstock wood chips for improved conversion efficiency and also used to dry other wood chips that will be processed on-site and sold as pelletized fuel for wood-burning furnaces. The project plans are to install additional gasifier/generator stages for an ultimate project generation capacity of approximately 2,000 kW.

The lumber mill already has three-phase electrical motors necessary for the millworks that must be supplied by a three-phase diesel generator located on the premises because only single-phase power is available from WMECO in this location. Burning diesel fuel has resulted in air quality compliance issues that are a risk to the future mill operation.

<u>Summary</u>:

- The proposed project could ultimately result in 2 MW of new renewable distributed generation. It could also help the mill address air quality issues caused by its need to run diesel generators to power three-phase motors.
- The developer does not believe the project can carry the additional $2.2 million cost for the conversion of four miles of single-phase circuit to three-phase.
- To date, the project developer has had discussions with WMECo regarding the project, but has not yet submitted an interconnection application.
- The extension of the three-phase circuit could provide new business and expansion opportunities for other customers along the circuit, which include the Town of Ashfield Highway Department and a school.
- If there are service reliability issues in the area, it is also possible that the extension could be part of a larger distribution system improvement plan by WMECo to improve service reliability to area customers.

CASE STUDY: Pine Island Farm, Sheffield, MA

Pine Island Farm, a dairy farm located in Sheffield, MA, installed an anaerobic digester/CHP project that produces biogas and heat (the "AD/CHP project"). The biogas is used to fuel an engine-generator set with a maximum three-phase electrical output of 225 kW. Waste heat from the engine is used to heat water needed for feeding calves and to provide radiant floor-heating in one of the farm buildings. The energy produced by the 225 kW generator exceeds the usage of the farm. The excess energy produced is net metered and allocated to a local business in the hospitality industry that wants to source as much of its requirements locally as possible, including electric power. The project has been in operation since November 2011. The farm hopes to add a second 225 kW gen-set at some point.

Pine Island Farm is located in a rural area within the National Grid service territory. The electrical service to Pine Island Farm was converted from single-phase to three-phase in 1994 to support increased electric load levels on the farm. The three-phase service to the farm was through an overhead bank of three single-phase distribution transformers rated 50 kVA each for a total supply capacity of 150 kVA. Because the Pine Island Farm was a positive load customer, i.e. its power purchases would increase as a resulting of the upgrade, with commensurate increase in utility revenue generated, National Grid shared the cost for the service upgrade with the customer.

The interconnection of the 225 kW generator associated with the AD/CHP project required replacement of existing distribution transformers with a pad-mounted three-phase distribution transformer with a higher capacity and a different winding configuration. These upgrades were identified in the National Grid system impact study prepared in response to the farm's interconnection application. The upgrade costs of approximately $23,000 were borne solely by the farm.

<u>Summary</u>:

- The project, which requires a three-phase interconnection, was made simpler and less costly due to the three-phase conversion completed in 1994 to supply increased load levels at the farm.
- The recent interconnection upgrades for the distributed generation were borne by the farm and were modest enough so the project remained economically viable.
- Excess energy produced is net metered and allocated to a local business.
- The farm realizes additional savings by utilizing the excess heat from the AD/CHP project for on-farm processes and displacing oil-fired heaters.
- The on-farm inputs to the AD/CHP project are decontaminated of pathogens and weeds by the AD process and used for fertilizer and cattle-bedding. The use of decontaminated fertilizer reduces the application of weed-controlling chemicals in the fields.

- The owners of Pine Island Farm indicated that the project has been a positive experience, despite having been more complicated and expensive than originally contemplated.

CASE STUDY: Cotuit Solar PV Project, Acushnet, MA

Cotuit Solar LLC is a photovoltaic project developer that had recently completed the installation of a 1 MW (ac output) PV project in Acushnet, MA and has proposed the interconnection of a second 2 MW (ac output) PV project in Acushnet, MA. The projects are located in a rural area within NSTAR's service territory.

The interconnection of the 1 MW PV project to NSTAR's 13.2 kV distribution circuit was made via a circuit recloser. When the NSTAR 13.2 kV distribution system is in its normal configuration, the project can operate without curtailment. If the 13.2 kV distribution system becomes reconfigured as a result of a single contingency outage (referred to as an "N-1" operating condition), the operation of the PV project can cause excessive voltage fluctuations. Therefore, NSTAR will disconnect the PV project during N-1 operating conditions by tripping the interconnection recloser.

NSTAR's system impact study for the 2 MW PV project indicated that the low grid stiffness factor[6] of the circuit where Cotuit wants to interconnect, combined with fluctuating PV project generation output levels due to its inherent intermittency, can adversely affect power quality to other customers on the distribution circuit. This effect would be exacerbated by the close proximity of the proposed 2 MW project and the existing 1 MW project that would increase the likelihood that cloud cover events would affect both projects simultaneously. NSTAR's system impact study identified that voltage changes greater than 2 volts (on a 120 volt nominal base) could occur on the circuit as a result of cloud cover events at a frequency of occurrence that would have a pronounced and adverse affect on other customers supplied by the circuit. This effect was possible even if the distribution circuit conductors were replaced with the most robust conductor size utilized by NSTAR on their 23 kV distribution system (795 kcmil, aluminum conductors) and not typical of NSTAR's 13.2 kV distribution system. Additional grid construction solutions that were identified included the installation of a dedicated 13.2 kV circuit to interconnect the project at a cost of $2.7 Million.

Rather than pay for a dedicated interconnection circuit for the 2 MW project, Cotuit Solar LLC would like to pursue a pilot project to study and install grid support features such as dynamic var support that could alleviate the voltage flicker issue. As part of this effort, Cotuit Solar LLC responded to the Massachusetts Clean Energy Center ("MassCEC") Demonstration Project Pilot Program (RFP No. 2013-DEMO-01) in which MassCEC seeks Concept Paper Applications for demonstration projects.

[6] A measure of the maximum available fault current at the point of interconnection compared to the project output current

Summary:

- Cotuit is proposing to install a 2 MW PV project.
- Although a prior 1 MW project was able to interconnect with a recloser to address conditions when the generator could cause voltage fluctuations, adding a second 2 MW PV project nearby created power quality risks that NSTAR could not accept.
- NSTAR identified a solution for interconnecting the 2 MW system, proposing a dedicated feeder at an estimated cost ($2.7 million), but that additional cost made the project unviable.
- Cotuit hopes to install and test grid support features as a strategy to alleviate the voltage flicker issue and is seeking state funding to support this effort.

CASE STUDY: PV Project Cluster, Freetown, MA

For DG projects requiring three-phase distribution service in the NSTAR territory, it has been more common that a distribution circuit must be extended to the DG project site than for a single-phase section of the distribution circuit to be converted three-phase. Further, as the larger PV projects require a significant amount of land, NSTAR has noticed clustering of larger PV projects in rural areas. In Freetown, for example, there are five PV projects, each 1 to 2 MW, in close proximity to each other.

In the case of the five PV projects in Freetown, MA, any one of the PV projects would have required the upgrade of the existing distribution circuit or the construction of a new distribution circuit dedicated to the project interconnection. If the PV projects were studied by NSTAR one at a time, the capacity of the distribution system improvement made by NSTAR (either the upgraded or new distribution circuit) would have been based on the capacity of the individual PV project that was being studied.

Instead, with the knowledge that five projects in close proximity were proposed for interconnection, NSTAR studied four of the projects as a cluster (the first of the projects in the queue decided to be studied on a stand-alone basis). NSTAR is executing separate interconnection agreements with each of the PV projects. The agreements assume that NSTAR is constructing a new, dedicated distribution circuit with the capacity to serve all the projects.

The PV project developers came to an agreement among themselves as to how they would share the costs associated with the new dedicated circuit. Each of the projects will also install, own, and operate a Static Var Compensator ("SVC") to mitigate voltage flicker issues that can be caused by the operation of the PV project. NSTAR will monitor the voltage and power quality at the point of interconnection of each PV project to the NSTAR distribution circuit. The SVC installation at each PV project is considered a pilot project by NSTAR.

Summary:

- Five PV projects are interconnecting in close proximity in NSTAR territory.

- With prior knowledge of the requirements that the cluster of projects will have for interconnection, NSTAR has developed a solution that meets the needs of all and creates economies that benefit the bottom line of the proposed projects.
- Each of the projects will also install, own, and operate a Static Var Compensator ("SVC") to mitigate voltage flicker issues.
- NSTAR is constructing a new, dedicated distribution circuit more than five (5) miles in length in order to interconnect all the projects to the grid.

6.0 Costs for circuit upgrades and other interconnection technologies

The authors researched and evaluated interconnection technology options and associated costs, as well as costs for upgrading distribution lines from single-phase to three-phase in different utility service territories. Sources of information included meetings and interviews with electric utility companies, cost estimates provided in system impact studies that have been conducted by electric utilities and their consultants for distributed generation projects, technical papers published by peer-reviewed journals of the Institute of Electrical and Electronic Engineers ("IEEE"), and technical information provided by manufacturers of STATCOM devices and other Flexible AC Transmission System ("FACTS") devices such as American Superconductor Corporation. The electric utility companies also provided information about their line extension policies and cost sharing for distribution system improvements that benefit multiple customers.

6.1 Conversion of single-phase circuits to three-phase

Construction costs for converting single-phase distribution circuit construction to three-phase construction were obtained from NSTAR, National Grid, and WMECO. Unitil had no recent conversion costs for Massachusetts projects. The utilities reported construction costs ranging from $45 - $85 per circuit-foot (National Grid estimate) to $55 per circuit-foot (NSTAR estimate), and up to $100 - $120 per circuit-foot (WMECo estimate). For distribution system improvements that are dedicated to a distributed generation customer, NSTAR generally will base the capacity of the new distribution equipment (e.g. conductor size) on the capacity of the distributed generator.

The lower price in each of these utility company 'per circuit-foot' ranges assumes ideal conditions (e.g. flat terrain, good roadway access to the work, limited clearing work, use of existing pole locations, limited secondary work) while the higher figure reflects a variety of circumstances that can increase the cost or extend the work schedule. These variables include: reductions to the span lengths between poles, encountering ledge during new pole sets, construction restrictions due to environmental concerns, modifications to the project design and routing required by permitting authorities, or when new distribution equipment is added (e.g. a circuit recloser needs to be installed at a location where a fused-cutout was previously used).

The lower figures obtained in the utility interviews compare reasonably well to another cost estimate for conversion of $400,000 per mile (approx. $75 per circuit-foot) that was obtained from the Massachusetts Distributed Generation Interconnection Working Group report dated September 14, 2012. Circuit conversions typically require the installation of new, taller poles.

These figures do not include the cost of transferring wires owned by other companies, such as for telephone circuits, fiber and cable TV, from the old poles to the new poles. These costs are directly payable to those utilities from the distributed generation customer. As an aside, some towns have telephone company-maintained poles while other towns have electric company-maintained poles, in either case shared with other wires companies.

6.2 Cost sharing of distribution upgrades for DG

The practice for cost recovery of upgrades required to serve distributed generators is addressed in the DG tariff and can be different than the practice associated providing service to new loads.

For example, in NSTAR's territory, for distribution system improvements that are built to serve new customer load, NSTAR has system development guidelines that could specify the installation of distribution equipment that is rated at a higher capacity than the new customer load if, for example, the distribution system improvements are along a main roadway. In that case, the customer would pay some portion of the distribution system improvements based on their load as a portion of the rated capacity of the new distribution equipment. There is no similar mechanism for NSTAR and distributed generation customers to share the cost of distribution system improvements dedicated to the interconnection of distributed generation customers.

Currently, electric utilities do not appear to have uniform practices statewide for cost sharing for distribution system improvements that are paid for by distributed generation projects. For example, if an interconnecting distributed generator pays the electric utility to convert a single-phase lateral to three-phase construction to allow the interconnection of a three-phase generator, this conversion may make it possible for a second distributed generation customer to interconnect on the converted circuit. One of the MA Distributed Generation Working Group's tasks is to determine how cluster studies will be conducted, how costs will be allocated, and how any potential refunding strategy will work going forward.

Per National Grid's present line extension policy, the utility will partially reimburse the distributed generator interconnection customer who originally paid for a conversion with funds obtained from the second interconnection customer, provided that the original customer requests it within a five (5) year period. Although NSTAR does not have a similar policy for distributed generation customers to share the cost of distribution system improvements, NSTAR has facilitated a cost sharing for distribution system upgrades when there are multiple projects interconnecting concurrently on the same circuit, described below.

A recent set of projects on the NSTAR system offers an excellent model for proactive utility system planning when information is available about multiple DG projects being undertaken in the same time frame in a relatively contiguous area. Larger ground-based photovoltaic distributed generation projects require significant land area (typically available in rural areas), as well as a three-phase interconnection to the electric utility distribution system. This has led to the clustering of distributed generation projects in rural areas that are supplied by existing three-phase distribution circuits. For cluster of distributed generation project, it can be more cost-effective for DG project developers when the electric utility studies and plans for the projects as a group rather than individually.

Recently, NSTAR received interconnection applications for five (5) different photovoltaic projects, each with a capacity of 1 – 2 MW, in very close proximity to each other in Freetown. Any one (1) of the PV projects would have required the upgrade of the existing distribution circuit or the construction of a new distribution circuit dedicated to the project interconnection. If the PV projects were studied individually, the requirements for NSTAR distribution system improvement (an upgraded or a new distribution circuit) would be determined based on the capacity of the single PV project being studied. In this case, however, NSTAR analyzed project impacts and requirements for the group. This allowed NSTAR to identify system upgrades to accommodate interconnecting the cluster that are more economical than if each project had been considered individually. In this case, the project developers agreed to share the mutually beneficial upgrade costs and are now contemplating the execution of individual interconnection agreements with NSTAR.

6.3 Sample Distribution Upgrade Costs for Interconnecting DG Projects

The cost estimates provided below are excerpted from system impact studies prepared in response to the interconnection applications over the past year. All of these sample distributed generation projects are three-phase generators/inverters. All four Massachusetts investor-owned electric utilities are represented in these six sample projects. Estimates include distribution system improvements and electrical interconnection equipment recommended for each project. Estimates do not include tax liability for system improvements and interconnection equipment

Sample Project #1

Project #1 was a 1.5 MW PV project with three 500 kW inverters connected to a 13.8 kV distribution circuit. This project required the conversion of 3,200 circuit-feet of 4.16 kV distribution circuitry, as fed from a 13.8 kV circuit via a 13.8 kV – 4.16 kV step-down transformer, to 13.8 kV construction. Estimated cost was $200,000 ($62.50/circuit-foot).

Sample Project #2

This project was a 2.5 MW wind turbine generator connected to a 23 kV distribution circuit. Though larger than a typical distributed generation project, it offers a look at a variety of interconnection costs.

- 150 feet of new, three-phase, 25 kV class construction. Estimated cost was $12,000 ($80/circuit-foot)
- One (25 kV class, 3 pole, gang-operated loadbreak disconnect switch. Estimated cost was $17,000
- One 25 kV class, pole-top recloser. Estimated cost was $70,000
- One 25 kV class, three-phase primary metering assembly. Estimated cost was $30,000

Sample Project #3

Project #3 was 2.0 MW PV project with four (4) 500 kW inverters connected to a 13.8 kV distribution circuit. This project required the installation of a 13.8 kV capacitor switch and switch control on an existing, fixed, three-phase capacitor bank rated 1,200 kVAr. Estimated cost of the work was $14,000

Sample Project #4

This 4.0 MW wind turbine generator project consists of two 2.0 MW wind turbine generators connected to a common point of interconnection on a 23 kV circuit. The project required a 23 kV line extension including one 35 kV class recloser (note: higher voltage class specified by utility), two sets of 25 kV class disconnect switches, two 25 kV class primary metering assemblies, and eight (8) utility poles with associated overhead equipment. Estimated cost of the work is $182,000

Sample Project #5

Project #5 is a 2.0 MW PV project with four (4) 500 kW inverters connected to a new 23 kV distribution circuit dedicated to the PV project. It requires 35,700 circuit-feet of new, 25 kV class, three-phase, overhead circuitry. Estimated cost of the work is $2.7 Million (approx. $75/circuit-foot).

Sample Project #6

1.0 MW Bio-mass/CHP Project requiring the conversion of a single-phase, overhead distribution circuit to 25 kV class, three-phase construction. The estimated cost to upgrade 3.8 miles of existing single-phase distribution circuitry to three-phase construction is $1.88 Million (approx. $94/circuit-foot).

6.4 Strategies other states use to support distribution line upgrades for DG

Research did not identify strategies used by other states to support and fund distribution system improvements in support of distributed generation. Responsibility for distribution system upgrades required for a distributed generation project typically is the responsibility of the project developer.

In Massachusetts, the cost of distribution system upgrades required for interconnecting DG is the responsibility of the project developer per the DG Tariff. As described elsewhere in this report, these costs can be higher than originally contemplated by developers and result in abandonment of otherwise viable projects. Massachusetts might, in the context of creating policies to support its goals for renewable energy generation, examine how costs for distribution line upgrades required for distributed generation are treated to determine whether there are sufficient societal benefits from such upgrades to justify utility cost sharing with developers and recovery of shared costs.

6.5 Federal funding available to support rural DG development

Rural electrification occurred in the 1930s as a result of the creation of the federal Rural Electrification Administration (REA) as part of the New Deal. Creating the REA was in response to a market evolution of power distribution whereby investor owned utilities were bringing urban households and businesses electricity (and telephone) service while rural areas remained without due to high network construction costs, relatively few potential retail customers, and limited opportunity for profit.

As a result of the REA, government financing provided subsidized loans to private companies, public agencies, including municipal utilities, and cooperatives for construction of electric supply infrastructure. Today, almost all of the country is electrified.

In 1994, Congress established the Rural Utilities Service as a federal agency within the U.S. Department of Agriculture (USDA), and it absorbed the REA. The USDA views utility services as the foundation of rural infrastructure and as a way to help rural areas expand economic opportunities and improve the quality of rural life. To that end, its utility programs fund sustainable renewable energy development and conservation.

The Rural Energy for America Program (REAP) provides financial assistance to agricultural producers and rural small businesses to purchase, install, and construct renewable energy systems, in the form of grants and guaranteed loans. Eligible projects include renewable biomass, anaerobic digesters, small and large solar, and small and large wind, among other renewable technologies. From FY2009 and FY2011, REAP has funded 5,733 projects in all 50 states. In Massachusetts, 44 projects have been funded during that period, of which three were biomass, one wind, and 31 solar.

More information about REAP can be found at www.rurdev.**usda**.gov/energy.html.

7.0 Conclusions and Areas for Further Consideration

The federal government intervened in rural electrification in the 1930s when market forces alone were not motivated to deliver needed services to less populated rural areas. While these rural areas are connected to the power grid today, there are still economic barriers that limit the evolution and improvement of the rural energy infrastructure and impede rural development of large distributed generation projects. While there is a long history in the state regarding utility distribution system planning, the State may want to adopt policies that can address these weaknesses comprehensively to achieve renewable energy development policy objectives by including geographic considerations more equitably.

Rural areas of Massachusetts, from a renewable resource and land availability perspective, are often well suited for siting larger clean energy-based distributed generation facilities. All power generation seems to encounter fewer local objections when it can be located in less populated rural areas.

- Solar photovoltaic projects require large areas of open land for ground-based systems, and competition for this open space is less acute in rural areas.
- Biomass-fired generation benefits from close proximity to fuel sources and to power users like lumber mills with their three-phase motors and their desire to eliminate diesel generator use.
- Anaerobic digesters that produce methane that can be burned in combined heat and power generators are natural complements to farm operations that produce and must dispose of animal waste and that need both electricity and hot water.
- Wind turbines can be sited more easily in rural locations with good wind regimes where there are few neighbors concerned about noise, shadow flicker, and property value impacts.

The only resources that larger distributed generation requires, but that rural areas do not always have, are stiff electrical service and extensive three-phase distribution circuitry. There is, for historic and economic reasons, a significantly higher share of single-phase (vs. three-phase) distribution circuitry in rural areas. Further, at locations towards the end of extended distribution circuits, power quality can be harder for utilities to maintain, although utilities will address specific power quality issues as they arise. The addition of distributed generation to these circuits can create new power quality issues.

Per the DG Tariff, the utility treatment of distributed generators who are seeking to interconnect from those locations otherwise best suited for their facilities remains a work in progress. Utilities must reconcile their obligation to ensure that the power quality on distribution circuits is what retail customers and regulators expect with the challenges associated with interconnecting localized distributed generators on distribution circuits. Utilities are naturally risk-averse and conservative when confronting these matters due to regulatory uncertainty about the treatment of new and/or higher costs this could entail. But nevertheless, procedures for evaluating and mitigating system impacts of proposed interconnections are improving all the time, with utilities and generation developers learning from their experiences collaborating together and applying workable solutions.

The costs for distribution system upgrades to meet utility interconnection requirements can be very significant, and interconnecting distributed generators are obligated to absorb these costs into their projects. This appears to be driving large projects to locations in distribution systems that are already three-phase circuits, if suitable sites can be found. Of course, there may be limits on such sites, and all three-phase circuits are not created equal in terms of “stiffness” and their ability to accommodate multiple generators, as this report describes.

If a goal of Massachusetts’ energy policy is to continue to encourage the growth of distributed generation to achieve a societal benefits, this policy, if it is to continue to succeed, must also address the electrical distribution system infrastructure and how upgrades necessary to interconnect distributed generators in rural areas are planned for, managed, and paid for.

Some ideas to consider include:

- More comprehensive utility planning for and commitment to distribution system upgrades based on resource opportunities for distribution generation,
- Additional infrastructure enhancements to attract developers to specific locations,
- Cost sharing for distribution upgrades between generators and the utility rate base, in recognition of the societal benefits created by these upgrades and renewable projects,
- More pilot programs and experimentation with emerging power quality protection strategies, including opportunities, regulatory support, and funding to evaluate the efficacy of installing FACTS devices on distribution systems and to develop distribution standards for FACTS devices, and
- Increased transparency and information sharing by electric utilities about distribution system characteristics, up to the limits of legitimate security concerns, with state agencies, regulators, and would-be DG developers to support future project siting.

Attachments

Appendix 1 – Local circuit-miles of single-phase and three-phase NSTAR distribution circuits

Appendix 2 – Local circuit-miles of single-phase and three-phase WMECO distribution circuits