	Substations[1]			Feeders[2]			Capacitors[3]				
	Total	Automated	Percentage	Total	Automated	Percentage	Total	SCADA Control	Percentage	Automated Response	Percentage
NSTAR	200	120	60%	1579	995	63%	830	640	77%	95	11%
WMECo	28	10	36%	233	134	58%	250	62	25%	77	31%
National Grid	258	138	53%	1028	567	55%	2500	0	0%	1800	72%
Unitil	11	4	36%	36	14	39%	135	0	0%	40	30%

Category Definitions	[1] Substation automation is defined as the full SCADA integration (status, control and analog data) of the substation for all major equipment (power transformers, substation capacitors and breakers/reclosers). This may or may not include the power transformer LTC and/or individual phase regulators for distribution feeders. In some cases partially automated substations (portion of a substation is fully automated without all distribution feeders being fully automated) have been included in the count (a very small percentage of feeders are in this category). "Full" automation does not typically include feeder phase regulators but does include LTC automation for new installations.	[2] Feeder automation is defined as the full SCADA integration (status, control and analog data) of the feeder breaker/recloser within the substation fence and/or the SCADA control of automatic sectionalizing devices outside the substation fence on the distribution feeder. Additionally non-communication enabled automated loop sectionalizing schemes and/or preferred/alternate schemes have been included as well as more advanced multi-switch/multi-feeder communicating FDIR schemes. These figures include both overhead and underground feeders	[3] Capacitor counts included in this table are line banks only, not substation banks. SCADA control is defined as the ability to send a signal to remotely operate the bank and may or may not include status of the bank. Automated response is defined as the presence of a local control capable of operating the bank programmatically based on time, day, date, temperature and/or power quantity values (voltage, current, KW flow, KVAR flow, etc.).

NSTAR

	System Location	Notes
Fault Detection, Isolation, Restoration (FDIR)	Distribution system and substations	80 auto reconfiguration loops, with 100 additional planned for 2013
Automated Feeder Reconfiguration	Distribution system and substations	FDIR devices continuously monitor system, alerting operators of loading concerns.
Integrated Volt/VAR Control, Conservation Voltage Reduction	Transmission, distribution, substations	830 Capacitor bank, of which 640 are controllable remotely. No CVR.
Remote Monitoring & Diagnostics (equipment conditions)	Transmission, distribution, substations	All major equipment is remotely monitored via SCADA i.e. Substation transformers, remote controlled switches, communications, etc..
Remote Monitoring & Diagnostics (system conditions)	Transmission, distribution, substations	All remote controlled reclosers and ASUs monitor the system providing voltage, current and power factor.

WMECo

	System Location	Notes
Fault Detection, Isolation, Restoration (FDIR)	Distribution system	120 recloser loop schemes on its system. All loop schemes operate automatically in response to loss of source voltage.
Automated Feeder Reconfiguration	None	
Integrated Volt/VAR Control, Conservation Voltage Reduction	Distribution system and substations	Manage voltage within a +/- 5% bandwidth, no CVR
Remote Monitoring & Diagnostics (equipment conditions)	Substation	Alarms alert operators for various abnormal conditions. No capability to remotely sense specific equipment conditions (e.g. oil levels) or diagnose problems.
Remote Monitoring & Diagnostics (system conditions)	Distribution system and substations	DSCADA for remote monitoring and diagnostics of system conditions.

National Grid

	System Location	Notes
Fault Detection, Isolation, Restoration (FDIR)	Distribution system	Approximately XX non-communicating or communicating loop sectionalizing schemes and/or preferred/alternative schemes Small rollout of Advanced Distribution Automation (multi-switch/multi-feeder communicating system) as part of SG pilot
Automated Feeder Reconfiguration	None	
Integrated Volt/VAR Control, Conservation Voltage Reduction	Distribution system	Advanced Local Volt/Var Control: Small rollout as part of SG pilot 2.5/5% voltage reduction on 75% of feeders per NE-ISO operating procedures
Remote Monitoring & Diagnostics (equipment conditions)	Transmission, distribution, substations	A small subset of large power transformers have remote condition monitoring via SCADA, additionally SCADA alarms alert operators of various abnormal conditions on a wider range of distribution and transmission equipment. A small rollout of devices as part of the SG pilot will provide equipment monitoring on all new devices.
Remote Monitoring & Diagnostics (system conditions)	Transmission, distribution, substations	SCADA for remote monitoring and diagnostics of system conditions within the substation fence. Also remote controlled reclosers monitor the system providing voltage, current and power factor. A small rollout of new equipment as part of the SG pilot will provide near real time monitoring of system conditions at several locations on the pilot feeders.

Unitil

	System Location	Notes
Fault Detection, Isolation, Restoration (FDIR)	Distribution system	One circuit currently has FDIR recloser combination
Automated Feeder Reconfiguration	None	
Integrated Volt/VAR Control, Conservation Voltage Reduction	Distribution system and substations	Manage localized circuit level power factor and voltage through the use of capacitor banks that are automatically controlled based on system condition or time of day.
Remote Monitoring & Diagnostics (equipment conditions)	None	
Remote Monitoring & Diagnostics (system conditions)	Distribution system and substations	SCADA is installed in 4 of 11 substations. This includes remote monitoring on 4 capacitor banks, approximately 45 breakers/reclosers, and 6 transformers.

Type	When Installed	Most Recent Upgrade	Future Plans	Notes
NSTAR				
Distribution Management System (DMS)/SCADA				
GE SCADA/EMS: Trans, Sub-trans, North Distribution	1994	2007	Migrate and implement auto-restoration schemes	1,100+ supervisory, and 60,000+ analog & digital points
GE Powerlink Advantage: South Distribution	2005	2011		750+ supervisory, and 40,000 analog & digital points.
Outage Management System (OMS)				
CGI PragmaLine v2.03	2000	Replaced		
GATOR	2003		Planned replacement 2013-2014	
Geospatial Information System (GIS)				
Editor: Custom ESRI	North: 1990s, South: 2004	Upgrade in progress		
Viewer: ESRI ArcMap with customization	2004	Upgrade in progress		
Transmission Editor: ArcFM	2008	Upgrade in progress		
GIS-OMS Integration				
GATOR-GUI	2003 (within OMS upgrade)	GIS upgrade in progress	OMS Replacement 2013-2014	
Billing System				
	1991	Continuous		
Metering System				
Premierplus4	?	Replaced		
FCS (Field Collection System)	2012	Underway		
Route Smart ArcGIS	2007	2011		
MV90 (Interval Meter Collection)	2006	2009	Upgrade in 2013	for 7000 TOU meters via modem and cellular networks
Meter Data Management System (MDM)				
Lodestar	2011			
OMS-AMR/AMI Integration				
	N/A	N/A		
Communication Systems				
Various systems	2008-2010			

Type	When Installed	Upgrades	Future Plans	Notes
WMECO				
Distribution Management System (DMS)/SCADA				
Siemens Spectrum Power TG	2002	currently upgrading		2400+ devices, 280,000+ analog & digital points.
Outage Management System (OMS)				
Oracle Network Management System	2004	2007	upgrade/replacement in 2014	
Geospatial Information System (GIS)				
Editor: GE Smallworld Editor	2002	2008		
Viewer: GE SIAS Viewer	2010			
Transmission Editor	N/A	N/A	Integration into Smallworld editor around 2013	
Viewer: ESRI SilverLight Viewer - custom	2012			
GIS-OMS Integration				
Smallworld	2004	2008	replacement in 2014	
Billing System				
C2 Application	2008	Continuous		
Metering System				
Fieldnet	1990s	2012	Upgrade in 2014	
Prime Read (Interval Meter Collection)	2008		Move all to MV90 and retire application	
ION Revenue	2005		Move all to MV90 and retire application	
Meter Data Management System (MDM)				
Lodestar MDM	2013			
SerViewCom	?	2010	Move all to MV90 and retire application	
EVEE Meter Data Warehouse	2003	2012		
OMS-AMR/AMI Integration				
	N/A	N/A		
Communication Systems				
Fiber	2005-2013			
Microwave	2005-2013		Some will be replaced by fiber, where appropriate	
Mobile Radio	2005-2008			
DSCADA Radios	2012-2013			

Type	When Installed	Upgrades	Future Plans	Notes
National Grid				
Distribution Management System (DMS)/SCADA				
None	N/A	N/A	Planned OMS and EMS SCADA interface after OMS installation in fall 2013 to support potential future DMS	
Outage Management System (OMS)				
PowerOn	2006		PowerOn to be replaced with ABB OMS as part of EMS upgrade during fall of 2013	
Geospatial Information System (GIS)				
GE Smallworld	2004	2011	Currently using latest version (V4.2), no upgrade plans for a least three years. T Current GIS is integrated with OMS and WMS	
GIS-OMS Integration				
Fully Integrated - GE Smallworld/PowerOn	2006		PowerOn to be replaced with ABB OMS as part of EMS upgrade during fall of 2013	
Billing System				
Customer Service System (CSS)	2008		Integration of SG Pilot meter data	
Metering System				
Solid State (22%)	around 2000	2012	none planned, but Smart Grid Pilot underway	.297 million meters. 92% of all National Grid meters read via Drive-by AMR

Electromechanical Meters (78%)	around 2000	2012	none planned, but Smart Grid Pilot underway	1.05 million meters. 92% of all National Grid meters read via Drive-by AMR
Meter Data Management System (MDM)				
Itron - Field Collection System	2003	2012		Based on AMR drive by and manual walking route collection, meter data stored in Energy Resource System (ERS)
Itron - IEE MDMS	2013			This AMI system will be used for Worcester Smart Grid Pilot only ~ 15,000 meters
OMS-AMR/AMI Integration				
Customer Service System (CSS)	2008		CSS feeds customer outage information (Calls) into OMS for analysis	In house developed system
Communication Systems				
Private fiber optic	N/A	N/A		Used for voice, protection, network and SCADA
Private microwave	Late 1980's, 1996	Present	Analog system expected to be replaced by 2015	Used for voice, protection, network and SCADA, System spans both analog and digital systems
Land mobile radio system	Various	~2010	System updated over last four years	Used for voice
Type	**When Installed**	**Upgrades**	**Future Plans**	**Notes**
Unitil				
Distribution Management System (DMS)/SCADA				
Areva E-terracontrol	Early 2000's		replacement with efacec ACS SCADA system in use elsewhere	
Outage Management System (OMS)				
ABB Network Manager OMS	2010			
Geospatial Information System (GIS)				
ESRI with Schneider Electric ArcFM	Early 2000's	Several		
GIS-OMS Integration				
Fully-integrated	Integrated in 2010		routine software upgrades	
Billing System				
HTE-based CIS	1990's		Replacement (over 2 years) beginning 2013	
Metering System				
Landis and Gyr TS2 AMI system	2006			
Meter Data Management System (MDM)				
"home grown" - meter reads and billing info	?		Purchase of MDM with integration of new CIS system	
OMS-AMR/AMI Integration				
	integration after OMS rollout	2011 AMI system integration		
Communication Systems				
SCADA: Telephone	Installed at new sites			
AMI: Powerline carrier tech	2006			
Unitil Offices: T1				
Unitil Offices: Fiber				

MA DPU Grid Modernization Working Group
Questions for Utilities Regarding Grid-Facing Systems

Unitil – Fitchburg Gas and Electric Light Company Responses
April 8, 2013

This document provides Unitil's responses to the MA DPU Grid Modernization Working Group *Questions for Utilities Regarding Grid Facing Systems* dated March 18, 2013. These responses are based Unitil's experience with the given enablers. Unitil has attempted to answer the questions as completely as possible. Unitil has identified the areas where Unitil has not previously evaluated a certain enabler.

The costs provided in the responses are meant to be used as high level estimates to offer some level of information. In addition to the costs identified in the responses, there might be other costs that have not been identified. For instance, if the implementation of an enabler requires a communication system that does not currently exist, then the cost to implement that enabler may increase substantially due to the cost of implementing a communication system. The total cost of a project requires detailed evaluation and engineering design work specific to the individual electric system before a complete estimate can be provided.

The utility electric systems in Massachusetts have been evolving for the past 100 years. There are valid reasons why each of the systems is different (customer density, customer load profiles, amount of load, seasonality of the load, type of equipment, voltage class of equipment, miles of distribution, etc.). The application of any given enabler may be different for a given electric system and a one-size-fits-all approach may not provide the same opportunities or address the same goals from system to system. A particular enabler may provide a benefit to one electric system while it does not for another. Therefore a direct comparison of these answers between the utilities may not provide any useful basis upon which to draw any conclusions. Careful consideration and investigation must occur prior to implementing any of these enablers.

Functionality: Network System Utilization

Enabler: Distribution Management System (DMS/SCADA)

Responses to questions related to Grid Facing Taxonomy Matrix:

a) **Provide a description of the system your company has.**

Unitil as an Areva's E-terracontrol SCADA system. Where SCADA is installed, it is capable of both status and control of the field devices that it is connected to.

b) **Describe the year of installation; years of any significant upgrade; current plan for retirement or replacement, and current plans for changes or updates.**

This system was originally installed in the early 2000's and has been expended over time to include SCADA installations at four of Unitil's eleven substations. Unitil currently has plans to replace this system with an efacec ACS SCADA system that is currently installed in our other operating companies and more easily integrates with our OMS system.

c) **Describe:**

i. **Any characteristics that enable or facilitate grid modernization goals and objectives.**

The Areva E-terracontrol SCADA system is a typical SCADA system that will allow status and control of any distribution or substation device.

ii. **Any characteristics that represent challenges or barriers to grid modernization goals and objectives.**

The Areva E-terracontrol SCADA system does not easily or effectively integrate with our ABB OMS system. As such, Unitil has plans to replace this SCADA system. This system is deployed in four of Unitil's eleven substations. To facilitate grid modernization, SCADA may need to be expanded to all of the distribution substations as well as out on the distribution circuits.

iii. **Any additional upgrades necessary to enable or facilitate grid modernization goals and objectives.**

Reference the response above.

iv. **Approximate cost estimates for any such upgrades, to the extent they are available.**

The installation of SCADA at a substation is very specific to the size of the substation and the amount of equipment that you are trying to connect to the SCADA system. Typical costs for Unitil may range between $50,000 to $200,000 per location depending on the size and complexity of the substation.

v. **The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)**

This SCADA system is currently installed at four substations (one transmission and three distribution substations) and is in the process of being extended to two different distributed generation installations.

Functionality: Network System Utilization

Enabler: Outage Management System (OMS)

Responses to questions related to Grid Facing Taxonomy Matrix:

a) **Provide a description of the system your company has.**

Unitil installed ABB's Network Manager OMS System in 2010. This system is integrated with our GIS, IVR, AMI and CIS systems. The OMS system uses information from customer calls, AMI and eventually SCADA(once the SCADA system is replaced) to predict the location of the potential outage device. It also reports estimated restoration times and provides information to the customer facing web map.

b) **Describe the year of installation; years of any significant upgrade; current plan for retirement or replacement, and current plans for changes or updates.**

Unitil's OMS system was placed into operation in 2010. Since that time, Unitil has been working to improve the performance and reporting capability of the system. All upgrades to the system are currently focused upon reporting and customer facing information.

c) **Describe:**

i. **Any characteristics that enable or facilitate grid modernization goals and objectives.**

Unitil's OMS system is focused on reducing the duration of outages while providing the customers information about restoration times.

ii. **Any characteristics that represent challenges or barriers to grid modernization goals and objectives.**

The OMS system works extremely well during most events. However, during the most extreme weather events when most of your system is on the ground, the OMS may not provide much value until the end of such event.

iii. **Any additional upgrades necessary to enable or facilitate grid modernization goals and objectives.**

Improvements to the OMS system are focused on reporting and customer facing information. As those requirements change, so will the OMS system.

iv. **Approximate cost estimates for any such upgrades, to the extent they are available.**

The near term costs may generally be between $200,000 and $500,000. There will continue to be ongoing hardware, maintenance, training, integration, back office, network and communication costs as long as this system is in service. These costs are not known at this time.

v. **The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)**

The OMS system is used primarily on Unitil's distribution system.

Functionality: Network System Utilization

Enabler: Geospatial Information System (GIS)

Responses to questions related to Grid Facing Taxonomy Matrix:

a) **Provide a description of the system your company has.**

Unitil has an ESRI based GIS system with a Schneider Electric (Telvent, Miner & Miner) ArcFM version 9.3 utility database overlay. The GIS system in integrated with our CIS, OMS, AMI, Milsoft circuit analysis and field inspection systems.

b) **Describe the year of installation; years of any significant upgrade; current plan for retirement or replacement, and current plans for changes or updates.**

This GIS system has been installed since the early 2000's. This system has gone through many different version upgrades since it has been in service.

c) **Describe:**

i. **Any characteristics that enable or facilitate grid modernization goals and objectives.**

A fully functional GIS system which identifies all equipment, customers and system connectivity is part of the foundation for grid modernization goals. Unitil has spent a great deal of time on the accuracy and configuration of our GIS system to make certain it can be leveraged for grid modernization.

ii. **Any characteristics that represent challenges or barriers to grid modernization goals and objectives.**

None at this time.

iii. **Any additional upgrades necessary to enable or facilitate grid modernization goals and objectives.**

The GIS system configuration may continue to be modified as new technologies are developed which rely on GIS for accurate spatial information. There are no planned upgrades besides from version upgrades at this time.

iv. **Approximate cost estimates for any such upgrades, to the extent they are available.**

There will continue to be ongoing hardware, maintenance, training, integration, back office, and network costs as long as this system is in service. There are no planned upgrades at this time.

v. **The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)**

Unitil's GIS system is primarily used for distribution.

Functionality: Network System Utilization

Enabler: GIS-OMS Integration

Responses to questions related to Grid Facing Taxonomy Matrix:

a) **Provide a description of the system your company has.**

Unitil's GIS system is fully integrated with our OMS system. The GIS system provides all of the circuit related information (i.e. equipment, circuit connectivity, customer connectivity, etc.) used by the OMS system for managing outages.

b) **Describe the year of installation; years of any significant upgrade; current plan for retirement or replacement, and current plans for changes or updates.**

Unitil's GIS and OMS systems were integrated in 2010. This integration has performed very well and there are no upgrades planned other than routine software version upgrades.

c) **Describe:**

i. **Any characteristics that enable or facilitate grid modernization goals and objectives.**

Unitil's GIS system provides necessary circuit and customer connectivity required by the OMS outage prediction engine. This integration facilitates the full use of OMS and the information that OMS provides.

ii. **Any characteristics that represent challenges or barriers to grid modernization goals and objectives.**

None identified.

iii. **Any additional upgrades necessary to enable or facilitate grid modernization goals and objectives.**

There are no planned upgrades other than routine software version upgrades.

iv. **Approximate cost estimates for any such upgrades, to the extent they are available.**

There are no planned upgrades other than routine software version upgrades.

v. **The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)**

Unitil's GIS-OMS integration is primarily used for distribution.

Functionality: Network System Utilization

Enabler: Billing System

Responses to questions related to Grid Facing Taxonomy Matrix:

a) **Provide a description of the system your company has.**

Unitil's Customer Information System (CIS) is an HTE based system that runs off of an AS/400 platform.

b) **Describe the year of installation; years of any significant upgrade; current plan for retirement or replacement, and current plans for changes or updates.**

Unitil's CIS system was installed in the late 1990's. Unitil has begun a process to evaluate replacement CIS systems and will start a project to implement a new CIS system beginning this year. This project may last approximately 2 years.

c) **Describe:**

i. **Any characteristics that enable or facilitate grid modernization goals and objectives.**

The new system will be able to meet all of the known billing and customer information requirements.

ii. **Any characteristics that represent challenges or barriers to grid modernization goals and objectives.**

There are no known challenges or barriers with the new system.

iii. **Any additional upgrades necessary to enable or facilitate grid modernization goals and objectives.**

There are no known additional upgrades required with the new system.

iv. **Approximate cost estimates for any such upgrades, to the extent they are available.**

The integration plan of the new CIS system has not been fully identified as of yet. The cost of the project will be based upon which system is ultimately selected. It may take approximately 2 years to implement a new CIS system.

v. **The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)**

Not applicable.

Functionality: Network System Utilization

Enabler: Metering System

Responses to questions related to Grid Facing Taxonomy Matrix:

a) **Provide a description of the system your company has.**

Unitil has a Landis and Gyr (Hunt Technologies) TS2 AMI system which uses powerline carrier as its means for two-way communication between the Command Center and the metering endpoints. The two-way communication of the AMI system allow for daily customer meter readings, outage reporting, meter diagnostics, on-demand reads, demand resets, remote read-in/read-outs, etc.

b) **Describe the year of installation; years of any significant upgrade; current plan for retirement or replacement, and current plans for changes or updates.**

The AMI system was installed in 2006. There are no significant upgrades scheduled at this time.

c) **Describe:**

i. **Any characteristics that enable or facilitate grid modernization goals and objectives.**

The design and operation of the AMI system facilitates Unitil's grid modernization goals by providing customer load data for more accurate system planning, customer outage data on a real time basis for use in conjunction with our OMS, and a communications infrastructure which can be used for other automation schemes (i.e. capacitor bank controls, etc).

ii. **Any characteristics that represent challenges or barriers to grid modernization goals and objectives.**

The communications infrastructure is limited in what it can do and the speed at which it can be accomplished. For instance, the communication infrastructure is not robust enough to use in protection schemes or automatic load restoration schemes. These types of schemes would require a different means of communication.

iii. **Any additional upgrades necessary to enable or facilitate grid modernization goals and objectives.**

There are no known upgrades scheduled at this time other than routine software version upgrades.

iv. **Approximate cost estimates for any such upgrades, to the extent they are available.**

There are no planned upgrades other than routine software version upgrades.

v. **The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)**

Unitil's AMI system is primarily used on the distribution system.

Functionality: Network System Utilization

Enabler: Meter Data Management System (MDM)

Responses to questions related to Grid Facing Taxonomy Matrix:

a) **Provide a description of the system your company has.**

Unitil has a home grown MDM system which is primarily focused on meter reads and billing information.

b) **Describe the year of installation; years of any significant upgrade; current plan for retirement or replacement, and current plans for changes or updates.**

Unitil's home-grown MDM has been in place for several years. Unitil plans on purchasing an MDM with the integration of a new CIS system as described above.

c) **Describe:**

i. **Any characteristics that enable or facilitate grid modernization goals and objectives.**

Unitil's existing MDM is basic and is essentially designed to manage meter readings and some billing information.

ii. **Any characteristics that represent challenges or barriers to grid modernization goals and objectives.**

This system does not facilitate grid modernization which is one of the reasons for implementing an MDM with the CIS.

iii. **Any additional upgrades necessary to enable or facilitate grid modernization goals and objectives.**

The new MDM will be specified for the functionality required to facilitate grid modernization objectives.

iv. **Approximate cost estimates for any such upgrades, to the extent they are available.**

The integration plan of the new CIS system has not been fully identified as of yet. The cost of the project will be based upon which system is ultimately selected. It may take approximately 2 years to implement a new CIS system. The MDM will be implemented as part of this project.

v. **The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)**

Not applicable.

Functionality: Network System Utilization

Enabler: OMS-AMR/AMI Integration

Responses to questions related to Grid Facing Taxonomy Matrix:

a) **Provide a description of the system your company has.**

Unitil's OMS system is integrated with Unitil's AMI system. The two-way communication design of Unitil's AMI system allows meter specific outage information to be passed from the AMI system to the OMS system. This information is used to verify existing and restored outages.

b) **Describe the year of installation; years of any significant upgrade; current plan for retirement or replacement, and current plans for changes or updates.**

Unitil's OMS-AMI integration occurred following the initial rollout of the OMS system. In 2011, the AMI system was integrated and training provided to the OMS operators.

c) **Describe:**

i. **Any characteristics that enable or facilitate grid modernization goals and objectives.**

This integration allows for Unitil to identify outages in its OMS system without the requirement for customer calls. Outage information down to the individual customer level allows for a more managed restoration response.

ii. **Any characteristics that represent challenges or barriers to grid modernization goals and objectives.**

None identified.

iii. **Any additional upgrades necessary to enable or facilitate grid modernization goals and objectives.**

There are no known upgrades scheduled at this time other than routine software version upgrades.

iv. **Approximate cost estimates for any such upgrades, to the extent they are available.**

There are no known upgrades scheduled at this time other than routine software version upgrades.

v. **The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)**

Unitil's OMS-AMI integration is used primarily on the distribution system.

Functionality: Network System Utilization

Enabler: Communication Systems (Fiber, Micorwave, Radio, etc.)

Responses to questions related to Grid Facing Taxonomy Matrix:

a) **Provide a description of the system your company has.**

Unitil's communications systems which are primarily used for grid modernization activities are telephone line communication for the SCADA system and powerline carrier technology for the AMI system. Unitil also uses typical T1 and fiber based communications architecture between and within the Unitil company offices.

b) **Describe the year of installation; years of any significant upgrade; current plan for retirement or replacement, and current plans for changes or updates.**

The AMI communication infrastructure was installed with the AMI system in 2006. The telephone lines for SCADA are installed as new sites are added to the SCADA system. Unitil is currently evaluating the various communication options with respect to the different grid modernization technologies and will implement as the new technologies are implemented.

c) **Describe:**

i. **Any characteristics that enable or facilitate grid modernization goals and objectives.**

The communication infrastructures in place are reliable and effective for the uses in which they have been implemented. Future grid modernization projects may more than likely require different communication requirements and systems that Unitil does not currently have in place.

ii. **Any characteristics that represent challenges or barriers to grid modernization goals and objectives.**

Future grid modernization projects may more than likely require different communication requirements and systems that Unitil does not currently have in place.

iii. **Any additional upgrades necessary to enable or facilitate grid modernization goals and objectives.**

There are no specific upgrades identified at this point.

iv. **Approximate cost estimates for any such upgrades, to the extent they are available.**

There are no specific upgrades identified at this point.

v. **The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)**

Unitil's existing communication systems are used at the transmission, distribution, substation and individual customer load levels.

Functionality: Distribution System Optimization

Enabler: Fault Detection, Isolation, Restoration

Responses to questions related to Grid Facing Taxonomy Matrix:

a) **Provide a description of the "enabler" (i.e. this might be a device type) your company has.**

Unitil only has one instance of FDIR on its system. The FDIR that Unitil has in place is a combination of reclosers equipped with fault and voltage detection. If the primary source for the circuit downstream of this point experiences a fault and ultimately zero voltage, the primary source will be automatically switched to and adjacent circuit, restoring all of the customers beyond this point.

b) **The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate.**

i. **The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).**

One installation with 2 reclosers.

ii. **The percentage of the system on which this enabler is currently deployed and expected to be deployed.**

One installation on 36 circuits.

iii. **The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.**

One installation with 2 reclosers.

iv. **The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)**

This is installed on a distribution circuit.

c) **Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).**

Typical costs for an installation such as this may be between $100,000 and $250,000 depending upon the number devices involved and the complexity of the system. There will continue to be ongoing hardware, maintenance, training, integration, back office, network and communication costs as long as this system is in service. These costs are not known at this time.

Functionality: Distribution System Optimization

Enabler: Automated Feeder Reconfiguration

Responses to questions related to Grid Facing Taxonomy Matrix:

a) **Provide a description of the "enabler" (i.e. this might be a device type) your company has.**

Unitil does not have any automated feeder reconfiguration systems installed.

b) **The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate.**

i. **The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).**

Unitil does not have any automated feeder reconfiguration systems installed and does not have any defined plans at this point to install such a system.

ii. **The percentage of the system on which this enabler is currently deployed and expected to be deployed.**

Unitil does not have any automated feeder reconfiguration systems installed.

iii. **The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.**

Unitil does not have any automated feeder reconfiguration systems installed.

iv. **The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)**

Unitil does not have any automated feeder reconfiguration systems installed.

c) **Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).**

Unitil does not have any automated feeder reconfiguration systems installed. Unitil has not designed a project such as this and therefore do not have any relevant cost comparison information. The total cost would depend upon the number devices involved and the complexity of the system.

Functionality: Distribution System Optimization

Enabler: Integrated Volt/VAR Control, Conservation Voltage Reduction

Responses to questions related to Grid Facing Taxonomy Matrix:

a) **Provide a description of the "enabler" (i.e. this might be a device type) your company has.**

Unitil accomplishes its system level VAR control through monitoring the VAR flow at the substation level. SCADA is used to switch substation capacitor banks to maintain a VAR flow within a specified range.

Unitil manages localized circuit level power factor and voltage support through the use of distribution capacitor banks that are automatically controlled on a combination of voltage, VAR, temperature and time of day settings. Unitil does not have any CVR installed on its system.

b) **The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate.**

i. **The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).**

4 of 11 substation capacitor banks have SCADA control. Approximately 40 of 135 distribution capacitor banks have an automated control.

ii. **The percentage of the system on which this enabler is currently deployed and expected to be deployed.**

Approximately 75% of the distribution circuits capacitor banks with an automated control.

iii. **The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.**

40% substation capacitor banks have SCADA control. Approximately 30% distribution capacitor banks have an automated control.

iv. **The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)**

VAR control is used at the substation and distribution circuit level.

c) **Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).**

Typical costs for an installation such as this may be between $50,000 and $150,000 depending upon the number devices involved and the complexity of the system. There will continue to be ongoing hardware, maintenance, training, integration, back office, network and communication costs as long as this system is in service. These costs are not known at this time.

Functionality: Distribution System Optimization

Enabler: Remote Monitoring & Diagnostics (equipment conditions)

Responses to questions related to Grid Facing Taxonomy Matrix:

a) **Provide a description of the "enabler" (i.e. this might be a device type) your company has.**

Unitil does not currently have any remote monitoring and diagnostics system installed.

b) **The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate.**

i. **The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).**

Unitil does not currently have any remote monitoring and diagnostics system installed.

ii. **The percentage of the system on which this enabler is currently deployed and expected to be deployed.**

Unitil does not currently have any remote monitoring and diagnostics system installed.

iii. **The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.**

Unitil does not currently have any remote monitoring and diagnostics system installed.

iv. **The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)**

Unitil does not currently have any remote monitoring and diagnostics system installed, but this would most typically be installed in substations if Unitil had any.

c) **Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).**

Unitil does not have any remote monitoring and diagnostic systems installed. Unitil has not designed a project such as this and therefore do not have any relevant cost comparison information. The total cost would depend upon the number devices involved and the complexity of the system.

Functionality: Distribution System Optimization

Enabler: Remote Monitoring & Diagnostics (system conditions)

Responses to questions related to Grid Facing Taxonomy Matrix:

a) **Provide a description of the "enabler" (i.e. this might be a device type) your company has.**

Unitil's SCADA system captures voltage, current and status information from the devices connected to the SCADA system. Typical devices connect to the system are breakers/reclosers, transformer LTCs, and capacitor banks.

b) **The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate.**

i. **The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).**

SCADA is installed in 4 of 11 substations. This includes remote monitoring on 4 capacitor banks, approximately 45 breakers/reclosers and 6 transformers.

ii. **The percentage of the system on which this enabler is currently deployed and expected to be deployed.**

40% of the system.

iii. **The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.**

Approximate: substation capacitor banks – 50%, transformers – 35%, breakers/reclosers – 60%

iv. **The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)**

All of this equipment is located in transmission and distribution substations.

c) **Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).**

The installation of remote system monitoring at a substation is very specific to the size of the substation and the amount of equipment that you are trying to connect to the SCADA system. Typical costs for Unitil may range between $50,000 to $200,000 per location depending on the size and complexity of the substation.

Functionality: Distributed Resource Integration

Enabler: Remote Distributed Generation Disconnect

Responses to questions related to Grid Facing Taxonomy Matrix:

a) **Provide a description of the "enabler" (i.e. this might be a device type) your company has.**

Unitil does not have any remote distribution generation disconnect at this time. Unitil is in the process of installing a remote disconnect at two recently installed DG installations which will include a recloser, direct transfer trip and SCADA. This remote disconnect will be accomplished through Unitil SCADA system in conjunction with the customers equipment.

b) **The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate.**

i. **The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).**

Unitil is in the process of installing two remote distributed generation disconnects.

ii. **The percentage of the system on which this enabler is currently deployed and expected to be deployed.**

0%

iii. **The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.**

0%

iv. **The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)**

This enabling equipment will be installed between the customer location on the distribution system and the substation that the customer is served from.

c) **Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).**

Typical costs for an installation vary depending upon the number devices involved and the complexity of the system. There will continue to be ongoing hardware, maintenance, training, integration, back office, network and communication costs as long as this system is in service. These costs are not known at this time.

Functionality: Distributed Resource Integration

Enabler: Voltage Regulation

Responses to questions related to Grid Facing Taxonomy Matrix:

a) **Provide a description of the "enabler" (i.e. this might be a device type) your company has.**

Unitil uses traditional voltage regulation to manage voltage on its distribution circuits. Unitil has not been required to install advanced voltage regulation technologies which can be used by utilities to manage fluctuations in voltage caused by large amounts of distributed generation relative to the amount of load in a given section of the utility grid.

b) **The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate.**

i. **The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).**

None.

ii. **The percentage of the system on which this enabler is currently deployed and expected to be deployed.**

None.

iii. **The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.**

None.

iv. **The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)**

None.

c) **Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).**

Unitil does not have any advanced voltage regulation installed on our distribution system designed to manage fluctuations in voltage caused by large amounts of distributed generation relative to the amount of load in a given section of the utility grid. Unitil has not designed a project such as this and therefore do not have any relevant cost comparison information. The total cost would depend upon the number devices involved and the complexity of the system.

Functionality: Distributed Resource Integration

Enabler: Load Leveling and Shifting

Responses to questions related to Grid Facing Taxonomy Matrix:

a) **Provide a description of the "enabler" (i.e. this might be a device type) your company has.**

Unitil does not have any load leveling or shifting systems installed which would alter the pattern of demand to more closely match output from non-dispatchable, intermittent distributed resources such as solar PV.

b) **The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate.**

i. **The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).**

None.

ii. **The percentage of the system on which this enabler is currently deployed and expected to be deployed.**

None.

iii. **The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.**

None.

iv. **The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)**

None.

c) **Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).**

Unitil does not have any load leveling or shifting schemes installed on our distribution system designed to alter the pattern of demand to more closely match output from non-dispatchable, intermittent distributed resources such as solar PV. Unitil has not designed a project such as this and therefore do not have any relevant cost comparison information. The total cost would depend upon the number devices involved and the complexity of the system.

Functionality: Distributed Resource Integration

Enabler: Streamline DG Interconnection

Responses to questions related to Grid Facing Taxonomy Matrix:

a) **Provide a description of the "enabler" (i.e. this might be a device type) your company has.**

Unitil uses the distributed generation interconnection process that was developed as part of the MA DG Working Group. Unitil believes that the current process is a streamlined process which strives to work with the customers to move the process forward as expeditiously as practicable. The amount of time it takes to evaluate a distributed generation application is proportional to the size and complexity of the application, amount of existing and proposed DG on the circuit, and the amount of applications ready for processing.

b) **The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate.**

i. **The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).**

Not applicable.

ii. **The percentage of the system on which this enabler is currently deployed and expected to be deployed.**

Not applicable.

iii. **The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.**

Not applicable.

iv. **The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)**

Not applicable.

c) **Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).**

Not applicable.

Functionality: Distributed Resource Integration

Enabler: Intentional Islanding (microgrid) control

Responses to questions related to Grid Facing Taxonomy Matrix:

a) **Provide a description of the "enabler" (i.e. this might be a device type) your company has.**

Unitil does not have any intentional islanding or microgrid schemes installed on the system.

b) **The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate.**

i. **The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).**

None.

ii. **The percentage of the system on which this enabler is currently deployed and expected to be deployed.**

None.

iii. **The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.**

None.

iv. **The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)**

None.

c) **Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).**

Unitil does not have any intentional islanding or microgrid schemes installed on the system. Unitil has not designed a project such as this and therefore do not have any relevant cost comparison information. The total cost would depend upon the number devices involved and the complexity of the system.

Functionality: Demand Optimization

Enabler: Access to Customer Information

Responses to questions related to Grid Facing Taxonomy Matrix:

a) **Provide a description of the "enabler" (i.e. this might be a device type) your company has.**

This enabler has not been fully defined as of yet. However, Unitil believes that this enabler is describing access to real-time customer information (i.e. load, outage, etc.) by the customer. For instance, if the customer knows their usage at any given time, they can make different decisions about what they are using and when they are using it. Unitil's OMS system can provide customer outage information in near real time. Unitil's AMI system provides individual customer load every day, but for the previous day.

b) **The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate.**

i. **The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).**

See description above.

ii. **The percentage of the system on which this enabler is currently deployed and expected to be deployed.**

See description above.

iii. **The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.**

See description above.

iv. **The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)**

See description above.

c) **Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).**

Unitil has not evaluated a project to provide real time information to customers. The total cost would depend upon the number devices involved and the complexity of the system.

Functionality: Demand Optimization

Enabler: Home Area Network Communications Capability

Responses to questions related to Grid Facing Taxonomy Matrix:

a) **Provide a description of the "enabler" (i.e. this might be a device type) your company has.**

The home area network provides customers with access to granular usage data and price signals. The HAN communications capability refers to the technology located in the customer's meter needed for data to travel between utility and customer. Unitil's used the home area network communications technology in its recent TOU Pilot. Since the pilot was completed, Unitil has removed the technology that was installed at participating customer's residences.

b) **The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate.**

i. **The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).**

Unitil does not have any HAN equipment installed at this time.

ii. **The percentage of the system on which this enabler is currently deployed and expected to be deployed.**

Unitil does not have any HAN equipment installed at this time.

iii. **The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.**

Unitil does not have any HAN equipment installed at this time.

iv. **The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)**

Unitil does not have any HAN equipment installed at this time.

c) **Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).**

Unitil's TOU pilot was successful in developing an estimate for the amount of load shifting that can be expected. It was also successful at developing an overall estimate for the equipment and installation in the field. Unitil's pilot found that each of these installations can cost between $1,000 and $3,000 per customer installation. There will also be back office and systems integration costs which are not known at this time. The total cost would depend upon the number devices involved and the complexity of the system.

Functionality: Demand Optimization

Enabler: Utility/3rd Party DR Programs

Responses to questions related to Grid Facing Taxonomy Matrix:

a) **Provide a description of the "enabler" (i.e. this might be a device type) your company has.**

A load control demand response program is one where a signal is sent to a customer device (e.g. water heater or air conditioner) telling that device to reduce energy consumption. A two-way signal allows the sender of the signal to confirm whether the device has responded or the customer has decided to over-ride the signal. Unitil does not have any utility or 3rd party DR programs in place. However, as part of Unitil's TOU Pilot project, this technology was evaluated and determined that it could be successfully implemented. Unitil has subsequently removed all of the equipment associated with the pilot.

b) **The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate.**

i. **The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).**

None.

ii. **The percentage of the system on which this enabler is currently deployed and expected to be deployed.**

None.

iii. **The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.**

None.

iv. **The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)**

This would be used at the customer load.

c) **Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).**

Similar to the HAN, Unitil's TOU pilot was successful in developing an estimate for the amount of load shifting that can be expected with this technology. It was also successful at developing an overall estimate for the equipment and installation in the field. Unitil's pilot found that each of these installations can cost between $1,000 and $3,000 per customer installation. There will also be back office and systems integration costs which are not known at this time. The total cost would depend upon the number devices involved and the complexity of the system.

Functionality: Demand Optimization

Enabler: Time Varying Pricing

Responses to questions related to Grid Facing Taxonomy Matrix:

a) **Provide a description of the "enabler" (i.e. this might be a device type) your company has.**

Time varying pricing or time-of-use rates is specifically designed to change customer behaviors with respect to their electricity usage patterns. Unitil recently completed a successful TOU Pilot where it was proven that time-of-use rates were successful at changing customer usage patterns. The pilot also indicated that a TOU rate without accompanying technology was not as successful as a TOU rate in conjunction with a HAN and a utility DR program. A basic TOU program is rather simple for Unitil to implement. The existing AMI system can handle up to 4 time periods and the meters can be reprogramed through the AMI system to support TOU rates. The existing billing system will handle 3 time periods, but the new billing system will support at least 4.

b) **The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate.**

i. **The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).**

All existing AMI meters can be reprogrammed remotely to implement TOU rates.

ii. **The percentage of the system on which this enabler is currently deployed and expected to be deployed.**

All existing AMI meters can be reprogrammed remotely to implement TOU rates.

iii. **The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.**

All existing AMI meters can be reprogrammed remotely to implement TOU rates.

iv. **The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)**

This would be used at the customer load

c) **Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).**

The cost for Unitil to implement a basic TOU rate is rather small. Existing AMI meters can be reprogrammed remotely to accommodate up to 4 TOU rate periods. There would be some configuration costs for the AMI and billing systems to accommodate TOU rates.

Functionality: Demand Optimization

Enabler: Customer Choice

Responses to questions related to Grid Facing Taxonomy Matrix:

a) **Provide a description of the "enabler" (i.e. this might be a device type) your company has.**

This enabler is not well defined and does not appear to fit with these questions.

b) **The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate.**

i. **The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).**

Not applicable.

ii. **The percentage of the system on which this enabler is currently deployed and expected to be deployed.**

Not applicable.

iii. **The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.**

Not applicable.

iv. **The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)**

Not applicable.

c) **Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).**

Functionality: Demand Optimization

Enabler: Advanced Load Forecasting

Responses to questions related to Grid Facing Taxonomy Matrix:

a) **Provide a description of the "enabler" (i.e. this might be a device type) your company has.**

Advanced load forecasting is the process of making more accurate and discrete predictions about future system loads based on customer usage data. Improved forecasts enable operators to better schedule and dispatch generation. Unitil at this point in time does not schedule and dispatch generation.

b) **The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate.**

i. **The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).**

Unitil at this point in time does not schedule and dispatch generation..

ii. **The percentage of the system on which this enabler is currently deployed and expected to be deployed.**

Unitil at this point in time does not schedule and dispatch generation..

iii. **The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.**

Unitil at this point in time does not schedule and dispatch generation..

iv. **The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)**

This would be used on the distribution system.

c) **Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).**

Unitil at this point in time does not schedule and dispatch generation. Unitil has not evaluated a project to produce advanced load forecasts. This could be as simple as daily peak load prediction or as complex as an hour load prediction for every customer. The total cost would depend upon the number devices involved and the complexity of the system.

Functionality: System Hardening

Enabler: Elevated Substations

Responses to questions related to Grid Facing Taxonomy Matrix:

a) **Provide a description of the "enabler" (i.e. this might be a device type) your company has.**

Utilities with substations in flood prone areas may have the desire to consider elevating the substation to alleviate the flooding concerns. Unitil does not have a history of flooding problems within substations. Therefore, Unitil has not evaluated a project to elevate a substation.

b) **The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate.**

i. **The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).**

None.

ii. **The percentage of the system on which this enabler is currently deployed and expected to be deployed.**

None.

iii. **The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.**

None.

iv. **The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)**

This would be used at a substation.

c) **Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).**

Unitil does not have a history of flooding problems within substations. Therefore, Unitil has not evaluated a project to elevate a substation. The total cost would depend upon the number devices involved and the complexity of the substation.

Functionality: System Hardening

Enabler: Equipment Hardening (submersibles, spacer cables, undergrounding)

Responses to questions related to Grid Facing Taxonomy Matrix:

a) **Provide a description of the "enabler" (i.e. this might be a device type) your company has.**

Equipment hardening can be effective in certain circumstances. For instance, approximately 27% of the Unitil system is underground construction. This is a combination of inner-city underground feeders and secondary network as well as more traditional underground residential developments.

b) **The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate.**

i. **The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).**

Primary Open Wire Overhead Construction - ~400 miles
Covered Primary Wire – ~80 Miles
Spacer Cable – ~20 miles
Underground – ~180 Miles

ii. **The percentage of the system on which this enabler is currently deployed and expected to be deployed.**

Covered Primary Wire – ~12%
Spacer Cable – ~3%
Underground – ~27%

iii. **The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.**

Not applicable.

iv. **The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)**

This type of equipment is located on distribution systems.

c) **Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).**

Undergrounding can be 10 to 20 times the cost of overhead construction depending on the size and complexity of the installation. Spacer cable also can be 2 to 5 times the cost of traditional overhead distribution construction. Both spacer cable and undergrounding has ongoing maintenance costs.

Functionality: System Hardening

Enabler: Distributed Generation/Storage

Responses to questions related to Grid Facing Taxonomy Matrix:

a) **Provide a description of the "enabler" (i.e. this might be a device type) your company has.**

Distributed generation with storage can provide some benefit to the distribution system if can be controlled and relied upon when the need presents itself. If a utility plans to rely on distributed generation, diversity of units is required to ensure an adequate amount of supply at a reduced amount of risk. Unitil has not installed any utility owned distributed generation and does not control any of the privately owned distributed generation systems that have been interconnected to the Unitil system.

b) **The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate.**

i. **The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).**

Unitil does not own nor control any of the DG units interconnected to the Unitil system.

ii. **The percentage of the system on which this enabler is currently deployed and expected to be deployed.**

Unitil does not own nor control any of the DG units interconnected to the Unitil system.

iii. **The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.**

Unitil does not own nor control any of the DG units interconnected to the Unitil system.

iv. **The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)**

These are generally installed on the distribution system.

c) **Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).**

Unitil has evaluated the installation of DG on its distribution system. The costs associated with the DG systems that Unitil evaluated had a very large range of $5,000 to $100,000 per installed kW. The total cost would depend upon the technology involved and the complexity of the system.

Functionality: System Hardening

Enabler: Vegetation Management

Responses to questions related to Grid Facing Taxonomy Matrix:

a) Provide a description of the "enabler" (i.e. this might be a device type) your company has.

Unitil believes that a well-rounded approach to vegetation management will provide the best cost/benefit reliability improvement out of any other enabler listed in this document. A well-rounded approach to vegetation management includes: 1) circuit pruning; 2) hazard tree mitigation; 3) mid-cycle review; 4) forestry reliability assessment; 5) brush removal; and 6) storm resiliency work. The Storm Resiliency program targets critical sections of circuits for tree exposure reduction by removing all overhanging vegetation or pruning "ground to sky", as well as performing intensive hazard tree review and removal along these critical sections and the remaining three phase of the circuit. The goal of this program is to reduce tree related incidents and resulting customers interrupted along these portions in minor and major weather events. In turn, the aim is to reduce the overall cost of storm preparation and response, and improve restoration.

b) The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate.

i. The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).

Unitil is in the early stages of implementing this program.

ii. The percentage of the system on which this enabler is currently deployed and expected to be deployed.

Unitil is in the early stages of implementing this program.

iii. The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.

Unitil is in the early stages of implementing this program.

iv. The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)

Vegetation management is generally completed on the transmission and distribution systems.

c) Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).

The implementation of a program such as this for Unitil would be between $1.5 and $2.0 million per year.

Functionality: Workforce Management

Enabler: Mobile Workforce Management Systems

Responses to questions related to Grid Facing Taxonomy Matrix:

a) **Provide a description of the "enabler" (i.e. this might be a device type) your company has.**

Unitil has mobile workforce management that it uses on the metering and customer related side of the business. This system has been in place for a couple of years. This system is a home grown system that can be modified to expand to other workforce management assignments.

b) **The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate.**

i. **The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).**

Not applicable.

ii. **The percentage of the system on which this enabler is currently deployed and expected to be deployed.**

Not applicable.

iii. **The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.**

Not applicable.

iv. **The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)**

Not applicable.

c) **Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).**

Unitil has not evaluated a project to expand its mobile workforce management system. The total cost would depend upon the complexity of the system.

Functionality: Workforce Management

Enabler: Mobile GIS Platforms

Responses to questions related to Grid Facing Taxonomy Matrix:

a) **Provide a description of the "enabler" (i.e. this might be a device type) your company has.**

Unitil uses mobile GIS that for its distribution inspections. This system was developed in 2012.

b) **The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate.**

i. **The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).**

Limited to a few tablets used by the plant inspectors.

ii. **The percentage of the system on which this enabler is currently deployed and expected to be deployed.**

Limited to a few tablets used by the plant inspectors.

iii. **The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.**

Not applicable.

iv. **The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)**

This is generally used for distribution system purposes.

c) **Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).**

Unitil has not evaluated any upgrades or expansions to the mobile GIS platform. The total cost would depend upon the technology involved and the complexity of the system.

Functionality: Workforce Management

Enabler: OMS-ERP-CIS Integration

Responses to questions related to Grid Facing Taxonomy Matrix:

d) Provide a description of the "enabler" (i.e. this might be a device type) your company has.

This enabler is not well defined and does not appear to fit with these questions.

e) The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate.

v. The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).

Not applicable.

vi. The percentage of the system on which this enabler is currently deployed and expected to be deployed.

Not applicable.

vii. The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.

Not applicable.

viii. The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)

Not applicable.

f) Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).

Additional Requests and Clarifications:

The above questions direct the utilities to look at the taxonomy/functionality matrix, and to provide an inventory of the enablers. However, we recognize that this is not a prescriptive list. As such, we would like to ensure that the inventory includes the following: just answer these as they stand. No need for anything special here……

1. **How many distribution substations do you have in service and how many of those are automated?**

   As described under the SCADA question, Unitil has 11 substations (1 transmission and 10 distribution). Four of these stations are equipped with SCADA for control and automation. The typical SCADA installation would include status and control of substation breakers or reclosers, motor operated switches, capacitor banks, transformer LTCs and telemetry where available.

2. **How many capacitor banks do you have in service and how many of those are automated?**

   As described in the questions about Integrated Volt/VAR Control, 4 of 11 substation capacitor banks have SCADA control. Approximately 40 of 135 distribution capacitor banks have an automated control that operates the capacitor bank based upon voltage, VAR, temperature and time of day/week settings.

3. **How many distribution system feeder circuits do you have in service and how many of those are automated?**

   The Unitil system has 36 distribution circuits and 7 – 69kV lines. SCADA system covers 14 of 36 distribution circuits and 6 of 7 – 69kV lines.

   a) **Describe, at a high level (e.g., create categories) the level of automation on the feeders.**

      Automation of circuits is limited to the substation breaker or recloser. The SCADA system will provide status and control of the breaker or recloser as well as any telemetry values that may be available. Unitil does not have any automation located out on the circuit as of yet.

4. **Please include relevant information regarding:**

   b) **Technologies deployed.**

      Unitil as an Areva’s E-terracontrol SCADA system. This system was originally installed in the early 2000’s and has been expended over time to include SCADA installations at four of Unitil’s eleven substations. Unitil currently has plans to replace this system with an efacec ACS SCADA system that is currently installed in our other operating companies and more easily integrates with our SCADA system.

      Unitil does not have any other smart grid based technologies deployed other than the items listed in these responses.

   c) **ARRA program investments.**

      Unitil has applied for but has not been successful in receiving any ARRA funding grants.

   d) **Percent of feeders covered.**

      Unitil has 14 of 36 circuits with SCADA control of the substation breaker or recloser.

   e) **Is it cost effective to make similar investment on all feeder circuits? If not, approximately what percent should have additional automation / communication?**

      SCADA installation on distribution circuits is evaluated on a case by case basis. In some instances, the distribution circuit would not benefit from the installation of SCADA (i.e. small, compact, rarely experiences outages, etc.). In other instances, the installation of SCADA may have a direct positive impact on reliability or may assist with direct transfer trip protection schemes.

5. **This list should also include appropriate information (e.g., total number of units, level of deployment) of the following:**

   a) **SCADA (supervisory control and data acquisition).**

   Unitil as an Areva's E-terracontrol SCADA system. This system was originally installed in the early 2000's and has been expended over time to include SCADA installations at four of Unitil's eleven substations. Unitil currently has plans to replace this system with an efacec ACS SCADA system that is currently installed in our other operating companies and more easily integrates with our SCADA system.

   b) **Remote terminal units (RTUs).**

   Unitil's SCADA system is not designed with RTUs for the most part. The Unitil SCADA system is designed more like a computer network where the SCADA system is communicating directly with IEDs within the substation. There are only a couple of RTUs on the Unitil SCADA system.

   c) **Programmable logic controllers (PLCs).**

   Unitil's SCADA system is not designed with PLCs for the most part. The Unitil SCADA system is designed more like a computer network where the SCADA system is communicating directly with IEDs within the substation. There are no PLCs on the Unitil SCADA system.

MA Grid Modernization Taxonomy Enabler –
Distribution Management System (DMS/SCADA)

1. For all the "enablers" (i.e., items) listed under the heading "Network Systems," provide the following (in no more than a few sentences each):
    a) A brief description (including function and capability) of the system your company has.
    b) The year of installation; years of any significant upgrade; current plans for retirement or replacement, and current plans for changes or updates.
    c) Depending on applicability for each system (i.e., a company may not need to answer all these for each; the point is to solicit and note any helpful or relevant information for the group), describe:
        i. Any characteristics that enable or facilitate grid modernization goals and objectives.
        ii. Any characteristics that represent challenges or barriers to grid modernization goals and objectives.
        iii. Any additional upgrades necessary to enable or facilitate grid modernization goals and objectives.
        iv. Approximate cost estimates for any such upgrades, to the extent they are available.
        v. The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)

Response:

a) National Grid does not currently have a DMS system.

b) After the installation of the new ABB OMS system, currently planned for the fall of 2013, an interface will be created between OMS and EMS SCADA to provide real-time updating of the OMS network model, maintaining real-time system configuration. This interface will allow for tagging information on points that are common between OMS and EMS to be passed between the 2 systems, and will also provide real-time analog values of three phase voltage and current on the OMS network model map for use by Control Room Operators as they operate and manage the distribution system.

c) Addition of the interface between OMS and EMS SCADA will help provide a platform to support future upgrades for advanced DMS analysis applications like unbalanced load flow and fault isolation / system restoration, and additional automation on the distribution networks. Approximate cost ranges for such future upgrades are not available at this time.

MA Grid Modernization Taxonomy Enabler –
Outage Management System (OMS)

1. For all the "enablers" (i.e., items) listed under the heading "Network Systems," provide the following (in no more than a few sentences each):
   a) A brief description (including function and capability) of the system your company has.
   b) The year of installation; years of any significant upgrade; current plans for retirement or replacement, and current plans for changes or updates.
   c) Depending on applicability for each system (i.e., a company may not need to answer all these for each; the point is to solicit and note any helpful or relevant information for the group), describe:
      i. Any characteristics that enable or facilitate grid modernization goals and objectives.
      ii. Any characteristics that represent challenges or barriers to grid modernization goals and objectives.
      iii. Any additional upgrades necessary to enable or facilitate grid modernization goals and objectives.
      iv. Approximate cost estimates for any such upgrades, to the extent they are available.
      v. The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)

Response:

a) National Grid currently uses the General Electric PowerOn Outage Management System. PowerOn functionality includes the following: A custom set of device prediction rules analyze system trouble based on the distribution of customer calls across the electric distribution system, and predict the most likely device that has operated, from the substation distribution breaker out along the feeder(s). Operators of the system are able to create crews and assign them to orders. Operators work outage orders to the point of restoration and closure; Estimated Time of Restoration (ETR) management can be done both manually within the OMS as well as automatically based on a set of customizable rules that assign ETR values based on a device type and an area. During storms, there is a batch process triggered by a user that will create wire down and forestry orders which then can be assigned to the Wire Down and Forestry departments to handle.

b) PowerOn was installed in New England in June of 2007. In October 2011, additional CPU and memory were added to increase system throughput. PowerOn is currently scheduled to be replaced by ABB's OMS in the fall of 2013.

c) The version of PowerOn currently in use by the Company has not been updated to the latest version, and is no longer fully supported by the vendor. It does not enable or facilitate grid modernization goals and objectives. Implementation of the new OMS system will provide a platform to support future advanced distribution analysis applications and additional automation on the distribution networks. The estimated cost to purchase and implement the new OMS system provided by ABB is in the range of $40 Million. This will provide a new OMS system for New England. The new OMS system will not have the ability to support Smart Grid features without enhancements. Additional investment in DMS capabilities will be necessary to support a Smart Grid platform. Please see the DMS response.

MA Grid Modernization Taxonomy Enabler – **Geospatial Information System (GIS)**

1. For all the "enablers" (i.e., items) listed under the heading "Network Systems," provide the following (in no more than a few sentences each):
   a) A brief description (including function and capability) of the system your company has.
   b) The year of installation; years of any significant upgrade; current plans for retirement or replacement, and current plans for changes or updates.
   c) Depending on applicability for each system (i.e., a company may not need to answer all these for each; the point is to solicit and note any helpful or relevant information for the group), describe:
      i. Any characteristics that enable or facilitate grid modernization goals and objectives.
      ii. Any characteristics that represent challenges or barriers to grid modernization goals and objectives.
      iii. Any additional upgrades necessary to enable or facilitate grid modernization goals and objectives.
      iv. Approximate cost estimates for any such upgrades, to the extent they are available.
      v. The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)

Response:

a) National Grid uses Smallworld GIS version 4.2 for its Electric Distribution GIS. The GIS serves as a repository of physical and operational asset information. The GIS models the electrical network from the substation breaker to the customer's meter and includes sophisticated connectivity to facilitate integration and use of Outage Management, Load flow, Transformer Load and other analysis\systems. Lastly, the GIS also has an integrated geographic based design package that is interfaced with the Work Management system for estimates, materials and other key info for work completion.

b) The current GIS system was deployed starting in 2004 replacing a system called NEEGIS previously deployed in 2002. The system was upgraded in to the current vendor version (4.2) in late 2011. As the system is on the latest version there are no plans within the next 3 years for retirement or replacement but the company evaluates this as business needs and IS technology changes. The company is currently in the process of moving its

Transmission GIS information onto the Smallworld GIS 4.2 platform (from a previous Smallworld version – 4.0). Having this information in the same system will facilitate the possibility of modeling connectivity from Generation to the customer. The company will continue to evaluate prudent system functionality upgrades on an ongoing basis based on business need and cost\value factors.

c) An integrated GIS allows the company to track assets related to grid modernization (i.e., Smart Grid equipment) and how they relate to the network. This functionality enhances the ability to perform analysis both spatially and not spatially. Additionally, the integration of GIS to OMS and other corporate systems will allow the company to leverage this information across the enterprise as the company continues investment for a modern grid.

MA Grid Modernization Taxonomy Enabler – **GIS OMS Integration**

1. For all the "enablers" (i.e., items) listed under the heading "Network Systems," provide the following (in no more than a few sentences each):
    - a) A brief description (including function and capability) of the system your company has.
    - b) The year of installation; years of any significant upgrade; current plans for retirement or replacement, and current plans for changes or updates.
    - c) Depending on applicability for each system (i.e., a company may not need to answer all these for each; the point is to solicit and note any helpful or relevant information for the group), describe:
        - i. Any characteristics that enable or facilitate grid modernization goals and objectives.
        - ii. Any characteristics that represent challenges or barriers to grid modernization goals and objectives.
        - iii. Any additional upgrades necessary to enable or facilitate grid modernization goals and objectives.
        - iv. Approximate cost estimates for any such upgrades, to the extent they are available.
        - v. The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)

Response:

a) The Company's distribution GIS system (Smallworld 4.2) and OMS system (currently PowerOn – being replaced by ABB OMS in 2013) are tightly integrated. The GIS is used to capture all assets and model connectivity to the customer. This information is sent to the OMS system on a weekly basis, analyzed and appropriate changes are made to the OMS to model the current network configuration. The GIS is also integrated with the Work Management and Customer systems driving a consistent process of updates from the work lifecycle and providing the OMS with current information without the need to perform updates in two systems which would require more time and cost.

b) The current GIS system was deployed starting in 2004 replacing a system called NEEGIS previously deployed in 2002. The system was upgraded to the current vendor version (4.2) in late 2011. The current OMS system, PowerOn, was deployed in 2007 replacing a previous system called ASRS. The company is in the process of finalizing and rolling out a new ABB OMS system with expected implementation later this year

(2013). The interfaces between the systems are built and modeled based on the previous interface between GIS and PowerOn factoring in the technical needs of the ABB system.

As both systems will be on the latest version of their respective software packages there are no plans within the next 3 years for retirement or replacement. However, the company evaluates this as business needs and IS technology changes. In addition the company evaluates functionality changes\upgrades on an ongoing basis.

c i) The integration between the GIS and OMS brings the benefit of having system configuration updates as close to real-time as possible. As additional technologies are deployed (equipment\systems) it is expected that the Company will be able to take advantage of what each technology does well to increase the ability to analyze and react to network issues in an increasingly expeditious, cost-effective manner driving greater value for our customers.

MA Grid Modernization Taxonomy Enabler –
Billing System

1. For all the "enablers" (i.e., items) listed under the heading "Network Systems," provide the following (in no more than a few sentences each):
    a) A brief description (including function and capability) of the system your company has.
    b) The year of installation; years of any significant upgrade; current plans for retirement or replacement, and current plans for changes or updates.
    c) Depending on applicability for each system (i.e., a company may not need to answer all these for each; the point is to solicit and note any helpful or relevant information for the group), describe:
        i. Any characteristics that enable or facilitate grid modernization goals and objectives.
        ii. Any characteristics that represent challenges or barriers to grid modernization goals and objectives.
        iii. Any additional upgrades necessary to enable or facilitate grid modernization goals and objectives.
        iv. Approximate cost estimates for any such upgrades, to the extent they are available.
        v. The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)

Response:

a) National Grid currently has two billing systems in use in Massachusetts. The Customer Service System (CSS) bills Massachusetts retail electric customer. The Customer Related Information System (CRIS) bills Massachusetts retail gas customers. The responses below will refer to the CSS billing system as this request does not relate to gas infrastructure improvements. CSS (otherwise known as Customer/1 Cooperative or simply C/1) is the hub system of the Customer Service organization. CSS provides residential, commercial, industrial, and municipal billing and bill print, service order, financial and retail access services. CSS employs a Graphical User Interface (GUI) linked real-time to customer and company asset data to facilitate handling of customer requests and inquiries. The GUI operates with the services of Accenture's Foundation (FCP) operating environment and communicates with a DB2 database through a

TCP/IP connection with the Customer Information Control System (CICS). CSS communicates to customers through an array of automatic and on-demand correspondences, and tracks information on all customer contacts. In addition to the many functional interfaces the system operates with, CSS also enables external application connections to its services such as our Web and Voice Response Unit (VRU). CSS handles exceptions and cross-department user transaction flow through its Work Flow Manager (WFM) services.

b) CSS was purchased from Accenture (then Andersen Consulting) and installed at Niagara Mohawk in Upstate NY in 1999. Following National Grid's acquisition of Niagara Mohawk, its New England electric customer billing was converted to the CSS system in 2008. Another acquisition, Rhode Island gas, was converted to CSS in 2012. The company will be converting its Long Island gas customers to CSS at the end of 2013. Discussions are underway regarding the conversion of Massachusetts gas and NY City gas customers to CSS. Throughout its life, the CSS system has been constantly enhanced with new meter reading, billing, financial, retail choice, energy efficiency, and service functions. Major enhancements include Automated Meter Reading (AMR), retail choice, soft-off connect and disconnect, positive customer id and scoring, hourly pricing, electronic billing and payments, behavior-based collections, low-income programs, on-bill financing, street lighting enhancements, new web and IVR functions, and a complete bill redesign in 2007. The Rhode Island gas conversion scheduled an 8-year amortization period (out to 2020) recognizing that utility CIS systems like it are being retired at 25-30 years of age. This suggests that the CSS system should likely be retired between 2024 and 2029. Major upgrades to the CSS system being planned include the MA Smart Grid Pilot and new forms of electronic bill and payments capability (text, mobile, EDI, etc.).

c)

   i. CSS is very "open" in its "SOA" and "Web Services wrapper" architecture to new interfaces both real-time and batch. It already has many real-time interfaces including work management and customer service. The system's rate modeling function is also very adaptable. CSS only goes "offline" for roughly 15 minutes a day (in the early morning) when financials are cutoff for the current day and a "date flip" occurs.
   ii. More specific information on the grid modernization goals and objectives as they relate to billing is needed to make this determination. However, generally speaking, lead time is required to make changes to the billing system prior to the effective date.

Adding new rates or significant programming changes to existing rates typically takes 3-6 months to design, program and test.

iii. CSS relies on Accenture’s “Foundation” architecture which needs to be upgraded to allow desktop upgrade from Windows XP to Windows 7 or higher. Additionally, the company is looking to upgrade its real-time Application Gateway Services (AGS) with a more robust Web Services architecture.

iv. Cost and timeline to upgrade the Accenture “Foundation” architecture and AGS are being evaluated now.

v. Not applicable.

MA Grid Modernization Taxonomy Enabler –
Metering System

1. For all the "enablers" (i.e., items) listed under the heading "Network Systems," provide the following (in no more than a few sentences each):
    a) A brief description (including function and capability) of the system your company has.
    b) The year of installation; years of any significant upgrade; current plans for retirement or replacement, and current plans for changes or updates.
    c) Depending on applicability for each system (i.e., a company may not need to answer all these for each; the point is to solicit and note any helpful or relevant information for the group), describe:
        i. Any characteristics that enable or facilitate grid modernization goals and objectives.
        ii. Any characteristics that represent challenges or barriers to grid modernization goals and objectives.
        iii. Any additional upgrades necessary to enable or facilitate grid modernization goals and objectives.
        iv. Approximate cost estimates for any such upgrades, to the extent they are available.
        v. The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)

Response:

a) The Company has an installed base of 1.35 million electricity meters. This population is made up of both older electromechanical meters and solid state devices, with solid state meters making up about 22% of that population. Meter readings are primarily obtained using a meter reading system that supports data collection via both handheld reading units and Drive-by Automatic Meter Reading (AMR). Almost 92% of the existing Massachusetts electric meters are read via Drive-by AMR. Less than 1% of the existing Massachusetts meters are remotely interrogated via telephone or wireless communications for specific applications. All of the electricity meters currently in service connect to their data collection systems as one-way devices.

b) Major deployment to our in-service population took place around 2000. The support system software applications and handheld units have been upgraded twice since then, most recently in 2012. There are no current, active plans for replacement, upgrade, or retirement of this system. However, the Company is currently implementing a 15,000 meter Smart Grid Pilot in the city of Worcester.

c) In and of itself, there are no characteristics of metering systems as defined by the Grid Facing Subcommittee that enable or facilitate grid modernization goals or objectives. Any modernization of the existing metering systems that would enable enhanced communications (two-way, for example) would require replacement of the actual electricity meters themselves along with their associated data collection systems and hardware. Based on the Smart Grid Pilot, the cost is on the order of $125 per meter installed. The associated field communication systems on a per unit meter basis is on the order of $90 per unit. Other back-office computer systems would also have to be upgraded, such as the Meter Data Management System and the back office communication systems to route and direct data.

MA Grid Modernization Taxonomy Enabler –
Meter Data Management System (MDM)

1. For all the "enablers" (i.e., items) listed under the heading "Network Systems," provide the following (in no more than a few sentences each):
    a) A brief description (including function and capability) of the system your company has.
    b) The year of installation; years of any significant upgrade; current plans for retirement or replacement, and current plans for changes or updates.
    c) Depending on applicability for each system (i.e., a company may not need to answer all these for each; the point is to solicit and note any helpful or relevant information for the group), describe:
        i. Any characteristics that enable or facilitate grid modernization goals and objectives.
        ii. Any characteristics that represent challenges or barriers to grid modernization goals and objectives.
        iii. Any additional upgrades necessary to enable or facilitate grid modernization goals and objectives.
        iv. Approximate cost estimates for any such upgrades, to the extent they are available.
        v. The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)

Response:

Field Collection System (Itron) –

1.
    a. The Field Collection System (FCS) is utilized by National Grid to collect electric and gas residential, small commercial, and survey usage reading in Massachusetts. This system is used for AMR collection using a drive-by model and a manual walking collection model. The meter data collected is used for measuring basic usage, time-of-use, net metering, demand customer billing and for load shape surveys.
    b. The Itron PP4 Meter Reading System was originally implemented in 2003 in New England. In 2006 the PP4 Meter Reading System was expanded to include upstate NY. In 2012 the PP4 System was upgraded to the Itron Field Collection System which replaced the legacy PP4 Application.

c.

  i. The Field Collection System (AMR) is not capable of enabling grid modernization goals and objectives for time varying rates or planning.

  ii. The AMR system would need to be replaced along with all back office functionality and capability which supports an AMI system. This would be a considerable investment that would require careful consideration.

  iii. See the response to C.ii.

  iv. The Company has not estimated the cost to convert to an AMI system.

  v. The Ert technology utilized for this system is located at the customer site.

Worcester Smart Grid Pilot (Itron) –

2.

a. The Itron Enterprise Edition (IEE) Meter Data Management System will be used by National Grid for a 15,000 customer Smart Grid Pilot program in Worcester, Massachusetts. This system leverages Advanced Metering Infrastructure (AMI) to collect 5 and 15 Minute Interval data which will be used for customer billing.

b. The Smart Grid Pilot program is currently scheduled to continue until the end of 2015.

c.

  i. The intent of the Worcester Smart Grid Pilot is to test many of the grid modernization goals outlined in the original Department order.

  ii. The pilot will test many of the functionalities of the grid modernization techniques employed for the pilot. A challenge to implementing the MDM comes from whether customers save money and costs in such a manner to justify a large scale roll-out.

  iii. See the response to c.ii.

  iv. The MDM Software Cloud is currently supported by Itron and is located in Liberty Lakes, Washington. The AMI technology used for this system is located at the customer site and Network Communication devices are installed in the Worcester field service territory.

Multi-vendor system (MV-90 xi) (Itron) –

3.

a. **MV-90 xi -** Is a multi-vendor system for collecting data from the complex metering devices used for large commercial and industrial (C&I) customers. Mv90 is used to collect, associate, validate, and process electric meter data for C&I customers in New England. In addition, MV-90 xi offers powerful data management and analysis tools that ensure data integrity and process consistency. MV-90 xi collects data from over 150 types of metering devices and supports a wide variety of communications, including PSTN, cellular, handheld file import, and TCP/IP. Inbound and outbound calls, daisy-chaining and parent/child communication configurations. Mv90 collects interval meter data into usable electrical units (i.e., kilowatt hours, kilowatts or reactive kilovolt-amperes, etc.) that show exactly how much and when energy was generated, transmitted or consumed and provides this information to customers in a variety of formats.

b. MV-90 has been installed for several years and National Grid has plans to upgrade to version 3.0 during the 2013/14 Fiscal year.

c.

i. MV-90 is a modern system used for large commercial customers that can support hourly pricing but would not be scalable to achieve grid modernization goals and objectives.

ii. The Mv-90 system would need to be replaced along with all back office functionality and capability which supports an AMI system. This would be a considerable investment that would require careful consideration.

iii. See the response to C.ii.

iv. The Company has not estimated the cost to convert to an AMI system.

v. The technology used for this system is located at the customer site.

Energy Resource System (ERS) –

4.

a. ERS is the Data Repository where electric and gas data is delivered. It is a central repository where consistent secure and auditable processes are enforced, and where all users can access accurate and reliable meter data. ERS is the primary interface to the CSS billing system.

b. ERS has been installed for several years at National Grid.

c.

i. The ERS data repository is a Legacy system and not capable of enabling grid modernization goals and objectives for time varying rates or planning.

ii. The ERS system would need to be replaced along with all back office functionality and capability which support an AMI system. This would be a considerable investment that would require careful consideration.

iii. See the response to C.ii.

iv. The Company has not estimated the cost to convert to an AMI system.

v. The technology used for this system is a Data Repository supported by the National Grid Information Technology Organization.

Settlement Systems –

5.

a) New England Power Company (NEP) is the Host Participant and Assigned Meter Reader and completes energy and capacity settlement with the ISO-NE per filed tariffs. NEP utilizes several applications to complete the energy market and capacity market settlement with the ISO-NE. The supplier hourly load settlement and capacity market settlement use a combination of a PC based and mainframe based table configuration, “PULSE”, which uses SAS to aggregate, reconcile and format data. The settlement of wholesale data, reflecting generators and tie lines is accomplished using an oracle database with a custom “front end”. The application is entitled Wholesale Settlement System (WSA). WSA also references a data aggregation application called PI. This application aggregates the six second data that is obtained from the remote terminal unit Energy Management System measurements. Additionally, NEP has responsibility for reporting the Regional Network Load to the ISO-NE. This is accomplished by using excel spreadsheets and the PULSE application that was previously mentioned.

b) PULSE was installed prior to 2002. WSA was installed in 2005. There are no concrete plans that exist for retirement or replacement at this time.

c)

i. The settlement system can be used to settle all customer accounts if they have actual hourly data. This would allow the opportunity for different product offerings to customers based upon their specific load shapes unlike the market today in which most customers are settled using a class average load shape and not their own.

ii. It is uncertain whether the current systems are scalable for individual customer data. If not, the replacement of the PULSE system and WSA applications would requires a multi-million dollar expenditure.

iii. Additional server and data storage capability will be necessary to process the massive data generated with AMI.

iv. National Grid does not have an estimate for the cost since the design and engineering requirements for any upgrade have not been developed. However, if upgrades are necessary, the cost could be significant.

v. Settlement systems affect transmission, distribution and customer load financial transactions in the energy and capacity markets.

Energy Profiler Online (EPO)

6. For all the "enablers" (i.e., items) listed under the heading "Network Systems," provide the following (in no more than a few sentences each):

a) National Grid offers it's Time of Use (G3) Customers, the ability to subscribe to Energy Profiler Online (EPO), a third party hosted website. EPO has been available for approximately ten years and allows customers to: view graphs showing loads increasing and decreasing throughout the previous day; compare one day to another day; view and analyze interval data using various tables and graphs; view load shapes of multiple facilities to identify best practices and see when peaks occur; and consider changes in operations to reduce peak use. It also allows potential energy suppliers to construct the best power supply offer using detailed information from EPO. Interval data from approximately 3,000 meters is uploaded on a daily or monthly schedule, depending on data collection frequency. Approximately 360 National Grid customers subscribe to EPO on an annual basis.

b) EPO has been installed for several years. National Grid does not plan to upgrade or retire this system.

c)

i. EPO facilitates market promotion through the provision of hourly usage data from participating customers to their suppliers.

ii. It is unclear if EPO could be scalable for all customers. Also, the data is not available in near real-time for customer use.

iii. The system would require upgrades to allow scalability for all customers. Also, upgrades would be necessary to provide more real-time information to customers, planners and dispatchers.

iv. National Grid has not determined the requirements necessary for providing these capabilities and, as such, does not have an estimate of the cost.

v. The EPO is provided through an online portal accessible to subscribing customers.

MA Grid Modernization Taxonomy Enabler –
OMS AMR/AMI Integration

1. For all the "enablers" (i.e., items) listed under the heading "Network Systems," provide the following (in no more than a few sentences each):
    a) A brief description (including function and capability) of the system your company has.
    b) The year of installation; years of any significant upgrade; current plans for retirement or replacement, and current plans for changes or updates.
    c) Depending on applicability for each system (i.e., a company may not need to answer all these for each; the point is to solicit and note any helpful or relevant information for the group), describe:
        i. Any characteristics that enable or facilitate grid modernization goals and objectives.
        ii. Any characteristics that represent challenges or barriers to grid modernization goals and objectives.
        iii. Any additional upgrades necessary to enable or facilitate grid modernization goals and objectives.
        iv. Approximate cost estimates for any such upgrades, to the extent they are available.
        v. The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)

Response:

a. The "enablers" listed under the heading "Network Systems" include OMS, AMR, and AMI. However, National Grid's Customer Service System (CSS) is also a critical piece of this "enabler" and should be included as part of the response. The focuses of this enabler is to highlight integration opportunities to know, through the use of technology, when customers are without power and when a customer is restored. Also see Outage *Management System Definition (OMS)*, and *Metering System Definition*

   Currently, when the customer calls in their outage to the Customer Contact Center the call is logged in the Customer Service System (CSS). When call volume is heavy, an automated system takes and logs the call into CSS. An automated link from CSS to the Outage Management System (OMS) ensures that the each customer outage call will be properly analyzed, prioritized and dispatched for restoration.

b. Please refer to Outage Management System Definition (OMS), and Metering System Definition.

c. The next generation would be to automate customer outage notification from the meter to the outage management system, and do the same for when the customer is restored to service. The benefit would be at the back end of outage restoration after a storm event. Knowing specifically who is still out, versus a calculation from an Outage Management System, is expected to have a dramatic impact for putting the right restoration crews in the right locations, to expedite the final 20% of storm cleanup.

   i. The characteristics that will enable this feature start with an AMI system that is in two-way communication with CSS. With appropriate links already built between CSS and OMS, a utility can start to see immediate benefits during large storm events.

   ii. The AMR system would have to be upgraded to an AMI system (see *Metering System* response).

   iii. In addition, a slight modification to the Meter Data Management System to create a new link to CSS would be necessary. Finally, an application would likely be needed to manage the outage data volume during a large event. These barriers are not technically challenging and not expected to be costly.

   iv. See the *Metering System* response for upgrading AMR to AMI. For the items in iii above, National Grid is testing this capability with the exception of the data volume application, for an estimate of $100K in the Worcester, MA, Smart Grid Pilot.

   v. The AMI upgrades are at the customer premise and on the distribution system. The remaining upgrades would be computer systems and/or upgrades, located centrally.

MA Grid Modernization Taxonomy Enabler – **Communications Systems (Fiber, Microwave, Radio, Etc.)**

1. For all the "enablers" (i.e., items) listed under the heading "Network Systems," provide the following (in no more than a few sentences each):
    a) A brief description (including function and capability) of the system your company has.
    b) The year of installation; years of any significant upgrade; current plans for retirement or replacement, and current plans for changes or updates.
    c) Depending on applicability for each system (i.e., a company may not need to answer all these for each; the point is to solicit and note any helpful or relevant information for the group), describe:
        i. Any characteristics that enable or facilitate grid modernization goals and objectives.
        ii. Any characteristics that represent challenges or barriers to grid modernization goals and objectives.
        iii. Any additional upgrades necessary to enable or facilitate grid modernization goals and objectives.
        iv. Approximate cost estimates for any such upgrades, to the extent they are available.
        v. The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)

Response:

a) National Grid owns and maintains a private fiber and microwave system comprised of approximately 80 nodes. Bandwidth ranges from analog circuits to 10Gbps. Areas of connectivity span from Northern New Hampshire through Central Massachusetts. The system carries operational traffic such as voice radio communications, transmission line protection, SCADA, etc.

    National Grid's land mobile radio systems are comprised of repeater-based networked voice communications systems. The systems are used for voice communications between company vehicles as well as between company vehicles and System Control Centers to support the daily work involved with the construction, operation, and maintenance of our electric network.

b) The analog microwave network is late 1980's vintage; fiber networks were installed between 2002 and present. Digital microwave networks were installed in 1996 through present. The analog microwave network is slated for replacement in 2015.
National Grid's land mobile radio systems were upgraded over the last 4 years and are comprised of repeater based networked voice communications systems. Over the last 4 years new base stations, antenna systems, control stations and Internet Protocol-based console systems have been installed. New fleet mobile radios (over 1500) were installed as part of the land mobile radio system upgrades.

c)

i. The National Grid's digital microwave and fiber systems allow for back haul connectivity needed for future modernization goals such as Smart Grid.

ii. The legacy analog microwave system does not allow for communications using internet protocol methods.

iii. The replacement of the analog microwave system is necessary. There are plans to extend our private microwave and fiber systems further into National Grid's key substations.

iv. The cost estimates for upgrade of the analog microwave system is not available. These facilities are used for backhaul of data and receive regular attention and upgrades as appropriate. In order to pick-up data down to the customer and distribution grid device level, an increase in more **scalable** wireless two-way communication systems are required. Many systems utilities are using today are point-to-point systems that are not very scalable for communications of significant amounts of data that two-way power flow down to the distribution system will require if placed in service. An estimate of cost for these systems can be provided from our Smart Grid Pilot in Worcester, MA. This estimate is approximately $3.5M (40% fixed/scalable and 60% is variable based on coverage). In Worcester, this system covers 15,000 customers and 11 distribution feeders in a suburban setting. Cost will vary based on topology (i.e., urban, suburban, rural).

v. These facilities typically terminate in corporate facilities and substations. Intermediate communication links leverage substations, transmission lines and 3rd party sites. When fiber is used, distribution facilities are leveraged for mounting the cable.

MA Grid Modernization Taxonomy Enabler – **Fault Detection, Isolation, Restoration (FDIR)**

a) A description of the "enabler" (i.e., this may be a device type), if it is helpful to have detail beyond what is on the definitions sheet (e.g., may include detail on function and capability).

b) The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate:

   i. The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).

   ii. The percentage of the system on which this enabler is currently deployed and expected to be deployed.

   iii. The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.

   iv. The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)

c) Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).

Response:

a) This enabler is described as Advanced Distribution Automation by National Grid and consists of a control scheme provided by S&C Electric Co. using their IntelliTeam Smart Grid system for FDIR. This system uses distributed controls with reporting and remote manual operation via the EMS/SCADA system. The scheme uses both new and retro-fitted switches from multiple vendors.

b) The current planned level of deployment consists of the Worcester Smart Grid Pilot footprint including:

   i. The approximate number of units planned over the course of the pilot is:

Device Type	Count
Viper-S Recloser with SEL control	43
Existing Recloser with Cooper Form 6 control	5

Device Type	Count
Viper-ST Recloser with SEL control	2
IntelliRupter PulseCloser	8
Padmounted Remote Supervisory Switchgear	8

ii. The planned deployment serves approximately 1% of the system (based on customer count).

iii. 100% of the devices will be automated with communications back to the EMS/SCADA system.

iv. This equipment is located at the distribution level.

c) The approximate unit cost for overhead switches ranges from $20,000 (retrofit) to $80,000 (new) for overhead (the unit cost of the most common OH switch is approximately $60,000) and from $130,000 to $150,000 for underground switches. This estimate is just the one-time cost associated with the purchase, installation, testing and EMS commissioning of the switch and does not include any ongoing O&M costs or the cost of the communications infrastructure (except for the equipment in the switch control) required to support device communications.

MA Grid Modernization Taxonomy Enabler –
Automated Feeder Reconfiguration

a) A description of the "enabler" (i.e., this may be a device type), if it is helpful to have detail beyond what is on the definitions sheet (e.g., may include detail on function and capability).

b) The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate:

   i. The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).

   ii. The percentage of the system on which this enabler is currently deployed and expected to be deployed.

   iii. The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.

   iv. The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)

c) Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).

Response:

a) National Grid does not have any Automated Feeder Reconfiguration equipment on the distribution system.
b) National Grid does not currently have any equipment deployed for Automated Feeder Reconfiguration. However, the equipment and base technology required for this type of function will be in place in the Worcester Smart Grid Pilot footprint.
c) No cost information is available at this time.

MA Grid Modernization Taxonomy Enabler – **Integrated Volt/VAR Control, Conservation Voltage Reduction**

a) A description of the "enabler" (i.e., this may be a device type), if it is helpful to have detail beyond what is on the definitions sheet (e.g., may include detail on function and capability).

b) The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate:

   i. The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).

   ii. The percentage of the system on which this enabler is currently deployed and expected to be deployed.

   iii. The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.

   iv. The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)

c) Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).

Response:

a) Integrated Volt/VAR Control–

National Grid describes this enabler as the use of advanced local capacitor controls (using three phase primary current/voltage sensors and communications-enabled, advanced electronic capacitor control) to provide enhanced power factor control, peak demand/loss reduction and a flattened voltage profile. Implementation consists of a complete feeder analysis (in CYMEDist) possibly resulting in the relocation and/or addition of capacitor banks (600 kVAR standard). This is not a centrally-controlled system, but is a significant advancement when compared to the standard capacitor control (time-based with voltage/temperature override) used at National Grid. This system will be centrally-monitored via a comms link to the EMS/SCADA system.

Conservation Voltage Reduction–

In addition to these advanced capacitor controls, National Grid also employs a 2.5/5% voltage reduction feature via the System Control Center to conform to NE-ISO operating procedures. This voltage reduction feature is tied to the distribution substation feeder voltage regulators and power transformer LTC's.

b) Integrated Volt/VAR Control–

The current planned level of deployment consists of the Worcester Smart Grid Pilot footprint including:

i. 47 new and retrofitted capacitor banks. Based on the outcome of the pilot, this program may be expanded but there are currently no plans for expansion.

ii. The planned deployment is < 2% of system (based on unit counts)

iii. 100% of devices are automated but this technology can also be installed without communications using just the local control without central monitoring via EMS.

iv. This equipment is located at the distribution level.

Conservation Voltage Reduction–

The voltage reduction feature has been implemented on many of the existing distribution substations and is part of all new substations and/or upgrades of existing substations associated with the distribution feeders:

i. This feature has been deployed on approximately 75% of the distribution feeders in Massachusetts.

ii. See i. above

iii. 100% of devices are automated using various methods based on the vintage of the equipment.

iv. This equipment is located at the distribution level.

c) Integrated Volt/VAR Control–

Estimated cost per installed bank is $28,000 for new installations and $15,000 for retrofit installations. This cost is just the one-time cost associated with the purchase, installation, testing and EMS commissioning of the bank and does not include any ongoing O&M costs or the cost of the communications infrastructure (except for the equipment in the capacitor control) required to support device communications.

Conservation Voltage Reduction–

The estimated cost for the installation of voltage reduction is not easily quantified as it is normally implemented as a small part in a much larger project.

MA Grid Modernization Taxonomy Enabler – **Remote Monitoring and Diagnostics (equipment conditions)**

a) A description of the "enabler" (i.e., this may be a device type), if it is helpful to have detail beyond what is on the definitions sheet (e.g., may include detail on function and capability).

b) The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate:

   i. The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).

   ii. The percentage of the system on which this enabler is currently deployed and expected to be deployed.

   iii. The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.

   iv. The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)

c) Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).

Response:

a) Most of National Grid assets condition assessment is done by a regime of periodic inspections to Stations, Transmission and Distribution facilities (not remotely). A relatively new set of remote monitoring devices is being installed in some Stations and will be described as enablers as part of this response.

Enabler	**Description**	**Capability**
RTU/EMS (Substation)	Remote Terminal Unit to Energy Management System	A Remote Terminal Unit ("RTU") is a device used to transfer operational information from a substation to an Energy Management System ("EMS"). An RTU allows for remote operation, monitoring and management of the substation equipment, providing benefits in incident response, recovery and system performance.
DRM	Dynamic Ratings	This unit is used to monitor transformer's Top Oil, Hot Spot Oil cooling fan status and alarms based in

	Monitor (Transformer)	operating conditions. For Load Tap Changers (LTC), it monitors status and main tank differential temperatures.
DGA	Dissolved Gas Analysis	Used for on-line Dissolved Gas Analysis
Beckwith Controls	Regulators Control Unit	Monitoring On Load Tap Changer (LTC) position, output volts, and VAR flow
Morgan Schaffer Calisto	Hydrogen and Moisture monitoring (Transformer)	Monitoring of any arcing in oil in large power transformers in ***Transmission*** substations

At this time, National Grid does not have any equipment condition monitoring installed on distribution feeders. However, the capacity for such monitoring will expand (be enabled) by expansion of communications systems that might be installed for deployment of Advanced Grid Applications.

i. There is currently no strategy in place to increase the number of remote asset monitoring devices at the station. Most of the equipment described is under review, in a "pilot" mode or part of our standard installations (LTCs for large and medium power transmission and distribution transformers). Therefore, "projected installations" were not included in the following tables.

Enabler	**Units Installed**
RTU/EMS(Substation)	231 RTUs[1]
DRM	50
DGA	1
Beckwith Controls	In All LTC units in NG territory
Morgan Schaffer Calisto	25

[1] **It is projected that 15-36 new stations will have EMS installed by 2018**

ii.

Enabler	**Units Installed**	**Comment**
RTU/EMS (Substation)	71%	Percentage of all NE Substation with EMS capabilities
DRM	30%	Percentage of large and medium power transformers in transmission and distribution substations
DGA	1%	Only 1 Unit deployed as pilot
Beckwith Controls	100%	All LTC units in NG territory
Morgan Schaffer Calisto	59%	Percentage of large transformers in Transmission Substations

iii. All the units shown in part ii enable remote sensing capabilities. Remote control capabilities depend on the type of device considered (RTU/EMS and Beckwith Controls enablers only).

iv. National Gird's RTUs are installed in our Transmission, Distribution and customer owned substations. DRMs have been installed on large and medium power transformers in transmission and distribution substations. DGA monitoring systems have only been deployed in one location (Station). Beckwith Controllers have been deployed on all large and medium power transmission and distribution substation transformers where LTCs are in use. Morgan Schaffer Calisto monitors have been deployed on large power transformers in transmission substations.

c)

Enabler	**Cost per unit (dollars)**
RTU/EMS (Substation)	\$100k-\$500k[1]
DRM	\$20k
DGA	\$11k
Beckwith Controls	\$20k
Morgan Schaffer Calisto	11k

[1] **Dependant on the complexity and number of devices per station**

MA Grid Modernization Taxonomy Enabler –
Remote Distributed Generation Disconnect

a) A description of the "enabler" (i.e., this may be a device type), if it is helpful to have detail beyond what is on the definitions sheet (e.g., may include detail on function and capability).

b) The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate:

   i. The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).

   ii. The percentage of the system on which this enabler is currently deployed and expected to be deployed.

   iii. The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.

   iv. The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)

c) Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).

Response:

a.) To ensure the safe operation of the electric distribution system, during normal operations and contingencies, it is necessary to have a means of remotely disconnecting generators from the distribution system. This is accomplished by reclosers on the National Grid system.

In addition to providing a remote means of disconnect, a recloser also incorporates protective functions. Continued investments and advances in protection systems, coupled with communication systems are required as the penetration of renewable generation increases. Maintaining a stable transmission and distribution system becomes increasingly complex with additional customer generation or generation on the distribution grid. Additional investment will be necessary in order to not limit interconnectors.

b.)

i) We do not have a specific count of reclosers installed at distributed generation customers readily available.

ii) National Grid requires reclosers for all distributed generation interconnections rated 500kW or above. For installations below 500kVA, the risks at this time are deemed small enough that remote disconnect is not required.

iii) 100% of new reclosers installed for distributed generation customers are remote operable.

iv) Reclosers are installed at the customer’s point of interconnection to the utility electrical system typically, but not always, on the customer’s property.

c.) The installed cost of a recloser is approximately $55,000.

MA Grid Modernization Taxonomy Enabler –
Voltage Regulation

a) A description of the "enabler" (i.e., this may be a device type), if it is helpful to have detail beyond what is on the definitions sheet (e.g., may include detail on function and capability).

b) The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate:

   i. The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).

   ii. The percentage of the system on which this enabler is currently deployed and expected to be deployed.

   iii. The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.

   iv. The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)

c) Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).

Response:

a) Distribution systems that serve customer loads are generally required to maintain steady state voltage within a range specified by ANSI guidelines. National Grid accomplishes this through a combination of devices including voltage regulators, load tap changers, and capacitors. Generation connected to distribution circuits is required to maintain those ranges so as not to disturb other customers. This is accomplished through the generator's control systems.

   Distribution circuits that are dedicated to DG customers or unregulated subtransmission systems are not required to have voltage regulation.

   Steady state voltage regulation must achieve stability requirements for all stakeholders involved in operating and connecting to the power system. Investment increases in Protection and Communication will be required to maintain power system stability, while allowing for greater amounts of output from distributed generation.

Some sources of distributed generation, particularly wind and solar, can have variable output that leads to voltage flicker that is objectionable to other customers. In some cases, distributed generation connected at a particular location may be limited due to potential flicker concerns. Flicker can be reduced or eliminated by the installation of energy storage devices at the generation location so as to provide a steady output. This would be done by the customer at the customer's site. In the absence of energy storage devices, this generation would need to be isolated and the flicker managed through engineering methods to avoid any degradation in service to neighboring customers of the generation.

To date, there do not appear to be any widely accepted, cost effective solutions for energy storage at a DG site.

Managing stability with greater amounts of distributed generation and with new uses such as electric cars will require greater amounts of investment on the part of utilities, and possibly customers as well. (Customers would be defined as everyone who connects to the grid whether a consumer or producer of electricity.) The amount of this investment is unknown but will increase with greater expansion of generation and electric cars.

MA Grid Modernization Taxonomy Enabler – **Load Leveling and Shifting**

a) A description of the "enabler" (i.e., this may be a device type), if it is helpful to have detail beyond what is on the definitions sheet (e.g., may include detail on function and capability).

b) The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate:

  i. The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).

  ii. The percentage of the system on which this enabler is currently deployed and expected to be deployed.

  iii. The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.

  iv. The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)

c) Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).

Response:

a) Load leveling and shifting involves altering the pattern of demand to more closely match output from non-dispatchable, intermittent distributed resources such as solar PV. Advanced applications may also feature the use of on-site energy storage. This technology can mitigate reverse power flows and localized disturbances typically associated with high levels of intermittent distributed generation.

b) Presently, no load leveling and shifting equipment exists on the National Grid system in MA. Future installations are considered as follows:
  i. Energy storage devices are being considered by National Grid to be installed as part of a DOE "Smart Grid Demonstration Program" near renewable generation facilities. Load leveling and shifting use cases include: 1) Capacity firming for the output of renewable energy sources and, 2) Demand management (peak shaving) of load.

   ii. National Grid is also evaluating possible cost effective non-wires alternatives to control the demand on certain distribution circuits in Massachusetts. The non-wires alternative concept evaluates cost effective technologies that can be implemented either inside the customer premises or on the distribution system and in the proximity of the served customer load.
   iii. Please refer to the Worcester Smart grid Pilot.

c) Cost Information
   i. Please refer to the DG Energy Storage response for the cost of energy storage equipment.

MA Grid Modernization Taxonomy Enabler – **Streamline DG Interconnection**

a) A description of the "enabler" (i.e., this may be a device type), if it is helpful to have detail beyond what is on the definitions sheet (e.g., may include detail on function and capability).

b) The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate:

   i. The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).

   ii. The percentage of the system on which this enabler is currently deployed and expected to be deployed.

   iii. The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.

   iv. The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)

c) Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).

Response:

a) The interconnection process is currently governed by either FERC or Massachusetts regulations. Not all projects need to go through each step of the process. The existing process roughly consists of:

- Screen Application
    - Intended to allow "low risk" projects to proceed expeditiously
- Perform more detailed study
    - Required for most larger projects
    - Reviews the following:
        - Protection
            - Assure that the anti-islanding is appropriate.
            - Assure that overcurrent and other protection meets requirements.

-
    -
        -
            - Recommends generator facility grounding to maintain utility grounding effectiveness.
        - Impacts on the utility system and other customers
            - Steady-state voltage
            - Voltage flicker
            - Thermal limits
            - Operational
            - Metering
        - Communication requirements
            - Generally above 1 MW, communication with the company's EMS system is required to ensure safe and reliable day-to-day operation as well as collect data for long-term planning.
        - ISO-NE and Transmission impacts
            - For larger projects ISO-NE requires stability studies.
        - Configuration of interconnection
            - The details of the required substation and line construction will be determined in the study phase.
            - Least cost/most reliable way to serve.
- Construction
    - Generally, construction for Distributed Generation projects encounters the same issues as any construction project including weather delays.
    - Additional issues with interconnecting a DG project include coordinating customer payments for construction and the classification of some distribution line construction as transmission lines for siting and regulatory purposes.
- Testing and commissioning
    - Assures that protection and communication systems operate as designed and as intended.

b) The Massachusetts' DG proceeding DPU 11-75 ordered revised tariffs in March 2013 that changes the interconnection process regulating National Grid and other utilities.

A FERC notice of proposed rule making (NOPR) issued January 17th, 2013 proposes reforms to the Commission's *pro forma* Small Generator Interconnection Procedures (SGIP) and Small Generator Interconnection Agreement (SGIA). Public comments are due by June 3rd, 2013.

c) National Grid established two groups in 2011 to focus attention to the DG interconnection process based on escalating volumes of simplified and complex DG applications since 2010. A customer facing group provides the business relationship, meeting a DG customer's need according to the tariff, and a technical group provides the engineering study and acceptance review of a complex DG installation to National Grid's electric power system.

Requests to interconnect distributed generation with the local distribution system have been rising significantly over the past seven years. Not only has the number of requests increased but so have the scale and complexity of the DG requests.

- In 2005, the Company received 44 requests, and in 2011 the number of requests reached 982.
- In 2008, 85% of the requests met the criteria for a simplified review (i.e., <10 kW single phase or 25 kW three phase) and only 15% of the requests were "complex".
- In 2011, 39% of the requests were deemed complex, with more than half of these projects requesting interconnection of over 500kW.
- For 2012, the approximately 2000 requests are double that of 2011 with 21% deemed complex projects.

The volume, size and intermittency of these generators present significant technical challenges to the distribution system which led to National Grid's issuance of a technical guideline in May 2012 (ESB 756 Appendix C). This document provides consistency of the technical requirements interconnecting DG under the tariff in MA for National Grid and the public.

MA Grid Modernization Taxonomy Enabler –
Intentional Islanding (microgrid) control

a) A description of the "enabler" (i.e., this may be a device type), if it is helpful to have detail beyond what is on the definitions sheet (e.g., may include detail on function and capability).

b) The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate:

   i. The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).

   ii. The percentage of the system on which this enabler is currently deployed and expected to be deployed.

   iii. The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.

   iv. The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)

c) Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).

Response:

a) Distributed Generation (DG) is not currently permitted to energize a portion of the electric distribution and disconnect from the remainder of the system (intentionally island). Allowing a DG source to energize an islanded portion of the distribution system raises both safety and operational concerns.

   A section of the distribution system that is energized from a DG source may subject utility workers to voltages where they are expecting none leading to potential safety hazard to the workers. This is particularly hazardous during storm restoration. In addition to the potential hazard to utility workers, a DG supplying an island may fail to detect a downed conductor or other abnormal condition creating a significant hazard to the public.

   In addition to the safety hazard posed by an intentional island, there is concern that a DG source may not be able to continuously meet the service standards, particularly voltage, frequency and flicker, required to provide adequate, safe service to a utility's other customers. The customer would need to invest or pay for synchronizing equipment that would also be required to re-energize the island from the normal utility source.

b) i.-iv; Not applicable
c) Not applicable

MA Grid Modernization Taxonomy Enabler –
Access to Customer Information

a) A description of the “enabler” (i.e., this may be a device type), if it is helpful to have detail beyond what is on the definitions sheet (e.g., may include detail on function and capability).

b) The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate:

   i. The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional “layers” of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).

   ii. The percentage of the system on which this enabler is currently deployed and expected to be deployed.

   iii. The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.

   iv. The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)

c) Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).

Response:

a. Presently customers are able to access their usage information through their monthly bills. For the customers that choose to use MyAccount (a National Grid web portal) to manage billing and payment, there is some access to monthly consumption data there as well.

   The Company’s approved smart grid pilot program will provide access to hourly consumption data on-line for 15,000 customers. In addition, 3,200 of these customers who elect to receive an in-home display will have real-time access to consumption data through the in-home device.

b. The billing and MyAccount information is available to all customers; about 300,000 customers in Massachusetts currently use MyAccount. Our near real-time and real-time data access options, respectively, will only be available to 15,000 Smart Grid Pilot in early 2014.

c. At this point in time we are unable to determine the cost for a system wide deployment of in-home displays and near real-time access to customer data via a web portal and supporting AMI network.

MA Grid Modernization Taxonomy Enabler –
Home Area Network Communications Capability

a) A description of the "enabler" (i.e., this may be a device type), if it is helpful to have detail beyond what is on the definitions sheet (e.g., may include detail on function and capability).

b) The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate:

   i. The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).

   ii. The percentage of the system on which this enabler is currently deployed and expected to be deployed.

   iii. The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.

   iv. The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)

c) Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).

Response:

a. The "enabler" associated with National Grid's 2012 Worcester, MA Smart Grid Pilot ("Pilot") includes an end-to-end network architecture which begins in the customer home through the Home Area Network communications or HAN. The HAN consists of the communications between both the in-home devices and from the in-home devices to the new Smart Grid meter. The HAN communication capability is typically limited at 50 to 100 feet.

Each meter deployed as part of the Pilot will have Zigbee communications enabled. This technology will provide a communications path from the meter into the home. Real time consumption information, simple messaging, and demand response communications will be able to be transmitted automatically through the Zigbee communications module. All hardware will support Smart Energy Profile (SEP) 1.0 with the ability to upgrade to 2.0 when that standard is ratified. Utilizing Zigbee SEP 1.0 ensures compatibility with a wide range of vendor hardware for use in the home.

By following this standard, National Grid will be able to test multiple hardware configurations as part of the Pilot. Zigbee will provide a base communications capability into all customer homes. For a subset of customers in the Pilot, advanced in-home energy management devices, including a web portal, home energy management tools and remote control of appliances and lighting will be available.

The in-home energy management technology offerings are designed to “enable” customers to participate at multiple levels. Customers will be provided with energy consumption information to provide them choice about their energy usage at the time of use. If customers elect to become more engaged, the information and tools available to them to actively manage their energy consumption and usage become increasingly detailed, timely and interactive, with more options and greater flexibility for the customer.

Four different levels of in-home energy management technologies will be provided to customers. The levels and offerings are noted below.

Level 1 (or the platform) offering will include a smart meter which will provide customers with 15-minute interval information about their energy use. All pilot customers will be given Level 1 equipment and services.

The offering also includes ways for customers to manage their energy usage through the phone, the internet and/or mobile devices. For those customers who use the internet, these tools allow them secure access to a website hosted by National Grid where they can view their own energy usage information.

Lastly, the consumer will be able to receive targeted educational content from National Grid through written, audio or video media (via phone, web, text and/or email) to provide information to them about techniques that they can employ to reduce their energy consumption.

Level 2 (or energy window) offering will include everything in Level 1. Also, Level 2 offering will include a home display unit (HDU).

The HDU opens a two-way education and communication tool with our customers allowing them to learn more about their own energy use. Along with assisting the customers in participating in demand response events, the home display unit will also provide customers with near real-time consumption information directly from the meter and informational alert messages from National Grid.

Level 3 (or advanced HVAC control) offering will include a smart meter, phone, internet and mobile access to energy consumption as well as targeted educational material. Also, Level 3 will include automatic heating, ventilation, and air conditioning (HVAC) controls.

b. **(Includes response to b, i-iv and c above)**
In 2011, National Grid began an Early Field Trial ("EFT") of approximately 5,000 AMI meters, at no cost to National Grid. Through the EFT, National Grid has been testing its AMI data collection and Local Area Network (LAN) communication technology using the latest interoperability and security protocols to evaluate its success in communicating meter information and customer demand patterns to the Company.

The EFT does not include any "enabling" Home Area Network communications (0% of the "enabling" in-home technology) other than the 5,000 meters noted above. The 5,000 meters represent 1/3 or 33.3% of the total population being deployed in 2013 for the Pilot.

As part of the Pilot, National Grid will deploy the following "enabling" HAN communications and technology noted above. This technology will be deployed in National Grid's customer homes in the Worcester, MA Pilot area. Please refer to the table below for the counts and cost of each of the HAN technologies.

In-Home Energy Management

Summary	2012		Response to data request DPU-6-15					
	# devices	Cost	a Vendor	b Vendor Estimate # Units	Unit Price	Total	c Filing Page Referenc	Notes
Programmable Thermostat	3,200	$ 248,160	EcoFactor	3,200	$ 77.55	$ 248,160	Exh. CAW-9, at 20	
Home Display Units	3,280	196,800	Ceiva	3,280	$ 60.00	$ 196,800	Exh. CAW-9, at 9	
Energy Management Gateways	3,200	368,000	Tendril	3,200	$ 115.00	$ 368,000	Exh. CAW-9, at 41	
In-Home Software								
Communication Devices								
Circuit Level Monitor, gateway	80	30,800	TBD	80	$ 385.00	$ 30,800	Exh. CAW-9, at 37	
Load Control Switch	100	17,500	TBD	100	$ 175.00	$ 17,500	Exh. CAW-9, at 41	
Zigbee Enabled Smart Outlet	1,600	200,000	TBD	1,600	$ 125.00	$ 200,000	Exh. CAW-9, at 41	
Range Extenders	100	8,000	TBD	100	$ 80.00	$ 8,000	Exh. CAW-9, at 41	
Installation (includes freight, handling, kitting)		365,562	EcoFactor	3,200	$ 100.00	$ 320,000	Exh. CAW-9, at 20	Installation - programmable thermostats
			TBD	80	$ 150.00	$ 12,000	Exh. CAW-9, at 37	Installation - circuit level monitors
			Tendril	5,100	$ 4.62	$ 23,562	Exh. CAW-9, at 41	HW Freight/Handling/Kitting
			N/A	100	$ 100.00	$ 10,000	N/A	Est. for licensed electrician to install load control switches
Maintenance / Warranty Cost								
Total In-Home Energy Management		**$ 1,434,822**				**$ 1,434,822**		

MA Grid Modernization Taxonomy Enabler – **Utility/3rd Party DR Programs (load control)**

a) A description of the "enabler" (i.e., this may be a device type), if it is helpful to have detail beyond what is on the definitions sheet (e.g., may include detail on function and capability).

b) The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate:

   i. The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).

   ii. The percentage of the system on which this enabler is currently deployed and expected to be deployed.

   iii. The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.

   iv. The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)

c) Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).

Response:

a) National Grid concurs with the definition from the definitions sheet.

b)

   i. National Grid does not have a formal demand response pilot program in Massachusetts.

However, in Massachusetts National Grid is hosting two separate demand response experiments. One experiment currently underway is the Automatic Temperature Control demonstration which is part of the R&D Demonstration program for residential electric customers. This program is using 34 demand response load shifting thermostat devices with a projection of 50 devices being installed during 2013. National Grid will also be starting the Worcester Smart Grid Pilot in early 2014. This program will be installing approximately 3200 HVAC switches, 1600 load switches, and 100 hot water switches.

The Company used to have a program with water heaters and pool pump switches but the program was dissolved and the assets were abandoned in the early 2000s.

ii. About .003% (34 devices amongst about 1,000,000 Massachusetts electric customers) of National Grid’s customers currently have a load control switch. This figure will be about .498% (4984 devices among about 1,000,000 Massachusetts electric customers) when the Smart Grid pilot switches are installed.

iii. 100% of the switches use a remote signal to activate the control technology at the customer’s location.

iv. The enabling equipment is placed in customer homes as a part of a variety of National Grid pilots or demonstrations. The devices are primarily placed on customer loads to shed load and evaluate the potential benefit to the distribution and transmission systems as well as the energy savings for the customer.

c) The approximate cost per HVAC thermostat is $129.63 - $200.00 depending on the thermostat. The approximate cost for a hot water heater switch is $ 204.62. The approximate cost for a pool pump switch is $ 204.62. The price for an outlet load control is $119.62. The prices represent the cost of the equipment incurred by the Empower pilot in Rhode Island, labor is not included. Also, the cost to provide widespread communication to these control mechanisms has not been estimated because it would require a complete examination of options and their costs.

MA Grid Modernization Taxonomy Enabler – **Time Varying Pricing**

a) A description of the "enabler" (i.e., this may be a device type), if it is helpful to have detail beyond what is on the definitions sheet (e.g., may include detail on function and capability).

b) The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate:

   i. The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).

   ii. The percentage of the system on which this enabler is currently deployed and expected to be deployed.

   iii. The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.

   iv. The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)

c) Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).

Response:

a) National Grid agrees with the definition of time varying pricing in the definitions sheet. Time varying pricing creates prices that more accurately reflect the costs on the system at different times.

b)

   i. National Grid provides a form of Time of Use pricing to its approximately 3000 G3 commercial/industrial customers in Massachusetts and to residential customers: 185 residential customers are on the R-4 Time-of Use tariff. These rates have not been reviewed for more than 20 years regarding the appropriateness of their design. In addition, the generation component, Basic Service, is the element of cost that has the greatest variability in cost over time and is the largest element on the customer's bill. Yet, this component is a flat price that varies only monthly. Lastly, the distribution component of both rates was designed at the time of Industry Restructuring to maintain the peak/off-peak differentials from the rates in effect prior to Industry Restructuring. Thus, the distribution prices reflect differentials that were created from estimates of generation costs, not distribution costs. National Grid will be implementing a Smart Grid pilot in Worcester offering approximately 15,000 customers time varying pricing which more appropriately reflects the costs to produce electricity.

ii. The percentage of the Company's customers in Massachusetts for which this enabler is currently deployed is less than one percent. The percentage increases to approximately 1.5% if customers participating in the Worcester Smart Grid Pilot are included.

iii. The present rates do not include any type of direct load control. National Grid will offer load control devices for customers in the Smart Grid Pilot area.

iv. Please see the response to b.i.

c) The Company does not have an estimate of costs for full deployment of time varying rates. Costs would include meter deployment, billing system modifications, potential communication systems, additional computer servers, computer storage and customer outreach/education.

MA Grid Modernization Taxonomy Enabler –
Customer Choice

a) A description of the “enabler” (i.e., this may be a device type), if it is helpful to have detail beyond what is on the definitions sheet (e.g., may include detail on function and capability).

b) The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate:

   i. The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional “layers” of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).

   ii. The percentage of the system on which this enabler is currently deployed and expected to be deployed.

   iii. The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.

   iv. The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)

c) Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).

Response:

a. Customers presently have choice as to their supplier. Customers are able to choose a competitive supplier or use National Grid as their supplier of last resort. Additionally, customers may choose to enroll in budget billing which allows them to pay the same amount monthly and payments are trued-up to consumption semi-annually. Through our Smart Grid Pilot program customers will have the choice of either a Critical Peak Pricing time varying rate or a peak time rebate offer along with several types of home energy management technology such as in-home displays, programmable communicating thermostats and smart plugs/load control devices.
b. All customers may choose competitive suppliers or enroll in budget billing. 15,000 pilot customers in Worcester will have time of use rate options. 4,800 pilot customers in Worcester will have in-home energy management technology options. Both will become available in early 2014. Customers in the pilot area who are served by a competitive supplier will not be eligible for these offerings.

c. At this point in time we are unable to determine the cost for deployment to the entire system for time of use rate options and in-home energy management technology.

MA Grid Modernization Taxonomy Enabler – **Advanced Load Forecasting**

a) A description of the "enabler" (i.e., this may be a device type), if it is helpful to have detail beyond what is on the definitions sheet (e.g., may include detail on function and capability).

b) The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate:

  i. The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).

  ii. The percentage of the system on which this enabler is currently deployed and expected to be deployed.

  iii. The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.

  iv. The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)

c) Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).

Response:

a) National Grid's load forecasting models are econometric regression models which use aggregated customer usage data as an input. The primary independent variables are economics (employment, income, gross metro/state product, households, population, etc.) and weather (heating and cooling degree days for volumes; weighted temperature – humidity for summer peaks; no weather for customer counts). Seasonal variables and other calendar type indicators may also be used. This method has been in place for several years with minor adjustments year to year. The models are generally run annually for sales, peak and customer count forecasts. They can also be run as needed for special cases (rate cases). Individual meter data is not used, only the aggregated data (by rate class, geographic area, etc.).

b) This load forecasting method is used across the state. The remaining subparts of this question do not apply to this enabler.

c) This question does not apply to this enabler.

MA Grid Modernization Taxonomy Enabler – **Elevated Substations**

a) A description of the "enabler" (i.e., this may be a device type), if it is helpful to have detail beyond what is on the definitions sheet (e.g., may include detail on function and capability).

b) The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate:

   i. The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).

   ii. The percentage of the system on which this enabler is currently deployed and expected to be deployed.

   iii. The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.

   iv. The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)

c) Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).

Response:

a) Some substations and equipment located within the substation may be potentially vulnerable to major events where flooding may impact electrical equipment and create risks to reliability.

b) National Grid has 313 substations in MA. National Grid has performed Substation Flood Risk Assessments of substations located in MA. The assessment included the identification of high risk substations through GIS software. This process consisted of locating inland and coastal FEMA flood zone extents and flood risks as well as the physical limits (perimeter fence, driveway) of our substations. Special consideration was given to substations which had sustained flooding in the past. Approximately 45 substations in MA have been identified.

A review of existing drawings for these substations revealed insufficient elevation information for a comparison of yard grade to the base flood elevation presented on the FEMA maps.

A field survey is required to be conducted at each location to obtain the deficient elevation information which includes yard elevation, foundation elevation, and certain equipment panel elevations. The estimated time table to complete the field survey is September 2013.

This information will then be compared to the base flood elevation to determine at risk equipment.

c) Recommendations to mitigate at risk equipment will be placed in future capital project plans for funding and implementation.

MA Grid Modernization Taxonomy Enabler –
Equipment Hardening

a) A description of the "enabler" (i.e., this may be a device type), if it is helpful to have detail beyond what is on the definitions sheet (e.g., may include detail on function and capability).

b) The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate:

   i. The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).

   ii. The percentage of the system on which this enabler is currently deployed and expected to be deployed.

   iii. The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.

   iv. The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)

c) Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).

Response:

a) The Company is evaluating options for hardening its distribution system from adverse impacts during various storm levels. Enhancement plans are expected to continue to evolve. In addition to internal efforts, the Company is participating in a three year study effort with the Electric Power Research Institute (EPRI) entitled "Grid Resiliency Initiative" which will lead to a model that will allow the Company to prioritize and apply options to improve grid performance.

b) Currently, the Company is progressing projects to increase the resilience of the distribution system in select areas of the service territory that have experienced repeated outages during adverse weather days in an effort to improve reliability performance and customer satisfaction for those Customers Experiencing Multiple Interruptions. Work included in these projects include replacement of bare or small conductor with TREE Wire, use of Grade B construction at critical poles (Junction poles, Switch Poles and Road/Rail/Water crossings), addition of sectionalization as appropriate (reclosers, fuses and switches), aggressive application of lightning arrestors and grounds for enhanced lightning protection and enhanced Vegetation Management in the area. In Massachusetts there were 118 feeders on which customers had experienced at least 4 interruptions during minor storm events during the five year period (2007 – 2011). In FY2014, the Company is progressing projects to harden poor performing segments on two feeders, the Risingdale 1109W1 and 1109W3. The Risingdale 1109W1 and 1109W3 feeders serve 3,094 and 3,379 customers respectively. The Risingdale 1109W1 feeder serves a large portion of the town of Great Barrington, New Marlboro, the southern part of Monterey and a portion of Sheffield. The Risingdale 1109W3 feeder serves a large portion of Great Barrington, Egremont and the entire town of Alford and West Stockbridge.

c) The estimated cost to complete the proposed projects on these two feeders is $2.3M. Each project in Feeder Hardening is unique and the costs cannot be estimated on an average basis.

MA Grid Modernization Taxonomy Enabler –
Distributed Generation/Storage

a) A description of the “enabler” (i.e., this may be a device type), if it is helpful to have detail beyond what is on the definitions sheet (e.g., may include detail on function and capability).

b) The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate:

   i. The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional “layers” of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).

   ii. The percentage of the system on which this enabler is currently deployed and expected to be deployed.

   iii. The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.

   iv. The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)

c) Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).

Response:

a) Distributed Generation (DG) generally refers to any grid-connected generation not considered traditional central-station generation. DG covers a wide variety of electric generation options rated from single-digit kilowatts (residential DG) through multi-megawatt (larger commercial/industrial generation) installations, generally connected to the utility sub-transmission or distribution systems. DG may be renewable or powered by various fuels. Interface to the electric system may be via rotating machinery, or solid-state inverter-based power electronics.

   Electric Energy Storage is a customer load on the system when the storage is being charged and is DG when the stored electricity is providing kWs to the customer’s load or input to the grid. Interface with the electric system may be via rotating machinery, or solid-state inverter-based power electronics. The energy storage medium may be chemical, mechanical, etc. Due to inefficiencies in energy conversion, the electric energy consumed is greater than the energy

provided. Electric energy storage can be dispatched as either a generator or a load. Most storage technologies can switch between these characteristics very quickly (some have millisecond response).
Other types of energy storage, e.g. thermal (ice or heat), are dispatchable loads, which can be utilized to tailor peak or off-peak system demand.

In MA, utilities are not permitted to own generation; however, an exception was made via the Green Communities Act ("GCA"), as set forth in the Massachusetts General Laws, chapter 164, section 1A(f) to allow utilities to own a limited amount of solar generation. Through the GCA, National Grid submitted a filing in 2009 to the Department of Public Utilities (DPU) to construct, own and operate approximately five megawatts of solar generation facilities on five separate properties owned by National Grid. They include sites in Dorchester, Everett, Haverhill, Revere, and the Sutton/Northbridge border. National Grid obtained approval from the DPU in 2009 to construct these facilities. In 2010 four out of the five sites were placed in service and the fifth site was placed in service in 2011.

Additionally, since 2009 customers in Massachusetts interconnected approximately 85 MW of distributed generation to the National Grid electrical network. The interconnected distributed generation is made up of roughly 75% solar generation facilities.

    i. The Company is currently considering the installation of approximately one MW energy storage demonstration projects that will be installed as part of a DOE "Smart Grid and Demonstration Program" The energy storage demonstrations are intend to Evaluate: 1) Capacity firming for the output of a renewable energy source, 2) Time-of-Use rate optimization, and, 3) Demand management (peak shaving).

b) Cost Information
    i. The cost to develop the National Grid solar generation facilities mentioned above ranged from approximately $4,500 per kW to $8,000 per kW.
    ii. Energy storage equipment is presently considered to be in pre-, or early-commercial stages of availability. Present costs for utility-size devices range from approximately $1M to $2M per MWh with 500kW to1MW power ratings. The engineering, installation and testing costs are not included in the aforementioned numbers.

MA Grid Modernization Taxonomy Enabler –
Vegetation Management

a) A description of the "enabler" (i.e., this may be a device type), if it is helpful to have detail beyond what is on the definitions sheet (e.g., may include detail on function and capability).

b) The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate:

    i. The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).

    ii. The percentage of the system on which this enabler is currently deployed and expected to be deployed.

    iii. The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.

    iv. The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)

c) Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).

Response:

a) The Company's Vegetation Management ("VM") Program is an essential component of the Company's plan to maintain the safety and the reliability of its electric distribution network. Trees are a significant factor in service reliability since tree contact with the distribution system during windy/stormy conditions may cause a phase to phase fault, which will trip either a line fuse, pole recloser or a station breaker and cause a service interruption. The Company has developed a strong VM program which provides a measure of safety for the public/workforce, favorable operational efficiency, and minimizes the number of customer interruptions due to trees. The Company's VM program consists of two main components – circuit pruning and hazard tree removal.

Circuit pruning consists of the scheduling of every overhead distribution circuit for pruning on a fixed timeframe or rotation. The pruning work performed is based on a dimension clearance specification. The Company utilizes a five-year interval as the optimum pruning cycle based on tree growth rates and the acceptable clearance dimensions obtained at the time of pruning.

National Grid's Enhanced Hazard Tree Mitigation program (EHTM) was implemented to identify and remove dying or structurally weakened trees and overhanging leads along the three phase sections of overhead distribution circuits. The three phase portion of the circuit is the most susceptible to tree caused faults and also serves the highest number of customers per exposed mile, thus intuitively providing the highest benefit per hazard tree removal dollar. The Company uses an industry leading tree risk assessment protocol to identify hazard trees.

b) i-iv; The circuit based pruning program was put into place in 2003. It is used on 100% of the Company's overhead distribution system with 20% of the circuit mileage completed each year. The EHTM program was first implemented in 2004. The purpose of this program is to produce service reliability improvements on poor performing circuits due to tree interruptions. The program is used on approximately 35 to 40 circuits per year depending on circuit length.

c) The total Distribution Vegetation Management program budget for FY13 was approximately $20.9 million with $9.6 million for circuit pruning and $4.4 million for hazard tree removal. The remaining funds supported other vegetation work such as customer requests, spot trimming, minor trouble work and police details.

MA Grid Modernization Taxonomy Enabler – **Mobile Workforce Management Systems**

a) A description of the "enabler" (i.e., this may be a device type), if it is helpful to have detail beyond what is on the definitions sheet (e.g., may include detail on function and capability).

b) The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate:

   i. The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).

   ii. The percentage of the system on which this enabler is currently deployed and expected to be deployed.

   iii. The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.

   iv. The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)

c) Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).

Response:

a) The Company uses STORMS as its core work management system. This system is largely used by office based workers with work packages deployed via two means. For most short cycle work (i.e., a meter change) work is sent via STORMS to our mobile platform called MWork. This is done via a scheduling engine (iScheduler). Field workers receive the order, perform work and capture results via the MWork unit. For long cycle work (i.e., a line extension) work packages are put together in the office and given to the crew performing the work. They perform the work and capture relevant details on paper documents. These documents are returned to the Work Closure and Maps\Records groups who update the records in the core systems.

b) i)
Mwork has been deployed to approximately 120 field workers in MA. These workers include electric Customer Meter Services and Operations Trouble

crews. Currently, extension beyond these work groups is not planned. However, the company evaluates need on an ongoing basis.

c) Costs for each worker\crew are approximately: $5000 for a ruggedized laptop, $1000 for vehicle mounts\power and $20 per month in communication charges. Costs for the software are additional to these field specific costs.

MA Grid Modernization Taxonomy Enabler – **Mobile GIS Platforms**

a) A description of the "enabler" (i.e., this may be a device type), if it is helpful to have detail beyond what is on the definitions sheet (e.g., may include detail on function and capability).

b) The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate:

  i. The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).

  ii. The percentage of the system on which this enabler is currently deployed and expected to be deployed.

  iii. The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.

  iv. The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)

c) Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).

Response:

a) GIS data is provided on a mobile platform via three main channels. The first method is via the use of DVD's that are produced on a quarterly basis (IDS) and does not require network\internet connectivity. The company provides the ability to connect to the company's network via internet connectivity. GIS is available as part of this function (Citrix Appportal). Lastly, the company has run a very successful pilot of an easy to use web based mapping tool, currently referred to as IMAP. This platform allows company users to see a variety of company information and the Company plans to expand on the pilot uses to include the ability to see more detailed GIS information over the coming 1 – 3 years.

b i) IDS – Approximately 100 DVD's produced and distributed on a quarterly basis

Appportal – Capacity for hundreds of users so long as the user has laptop able to connect to the internet via cell or other network

IMAP - Capacity for hundreds of users so long as the user has a tablet, laptop or other device able to connect to the internet via cell or other network

ii) 100% of MA is covered

iii) Not Applicable

iv) Not Applicable

c)

IDS – Approximately $20k for licensing annually, $40 per DVD quarterly; $10k for larger system changes. Changes are done on average 1 time annually.

Appportal – System is utilized to provide remote access to a variety of Company systems, of which GIS is just one. Costs specific to GIS are minimal.

IMAP – Approximately $80k for web server access and space. Mobile GIS functionality is inherent in the software which is covered under an enterprise agreement with ESRI for a variety of products and isn’t specifically broken out for the pieces used to provide this functionality.

MA Grid Modernization Taxonomy Enabler –
OMS-ERP-CIS Integration

a) A description of the "enabler" (i.e., this may be a device type), if it is helpful to have detail beyond what is on the definitions sheet (e.g., may include detail on function and capability).

b) The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate:

   i. The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).

   ii. The percentage of the system on which this enabler is currently deployed and expected to be deployed.

   iii. The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.

   iv. The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)

c) Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).

Response:

Please refer to the information presented in the data request titled "OMS/AMR/AMI Integration".

MA Grid Modernization Taxonomy Enabler –
Primary Equipment

a) A description of the "enabler" (i.e., this may be a device type), if it is helpful to have detail beyond what is on the definitions sheet (e.g., may include detail on function and capability).

b) The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate:

   i. The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).

   ii. The percentage of the system on which this enabler is currently deployed and expected to be deployed.

   iii. The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.

   iv. The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)

c) Relevant cost information (<u>e.g.</u>, cost per unit, cost per feeder, or the estimated cost to deploy for whole system).

Response:

a) The enabler for Primary Equipment is asset replacement programs for circuit breakers, indoor substations, switchgear, power transformers, and voltage transformers. Additionally, programs to ensure adequate equipment spares and mobile substations are included.

b)

i.The total number of units installed are as follows:

- 443 power transformers
- 2,068 circuit breakers
- 104 switchgear,
- 20 voltage transformers
- 25 indoor substations

- 5 mobile substations
- 50 spare power transformers

The following replacements are planned over a five-year timeframe:

- 10 power transformer,
- 103 circuit breakers,
- 7 switchgear,
- 2 mobile substations,
- 6 voltage transformers,
- 4 indoor substations,
- 7 substation transformer spares

ii. The following represents the percentage of the system which is currently deployed and expected to be deployed over a five-year timeframe.

- 2% power transformers,
- 5% circuit breakers,
- 7% switchgear,
- 33% mobile substations,
- 30% voltage transformers,
- 16% indoor substations,
- 14% spare power transformers

iii. Approximately 59% of the power transformers and circuit breakers have remote monitoring, status and control.

iv. The asset replacement programs are utilized at substations.

c) The estimated cost to replace the power transformers is $9.25M. The estimated cost to replace the circuit breakers is $11.1M. The estimated cost to replace the switchgear is $24.5M. The estimated cost to replace the mobile substations is $3.5M. The estimated cost to replace the voltage transformers is $0.050M. The estimated cost to address the concerns in the indoor substations varies significantly and is typically from $1M to $10M per location. The estimated cost to acquire spare power transformers is $6.48M.

MA Grid Modernization Taxonomy Enabler – **Secondary Equipment**

a) A description of the "enabler" (i.e., this may be a device type), if it is helpful to have detail beyond what is on the definitions sheet (e.g., may include detail on function and capability).

b) The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate:

   i. The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).

   ii. The percentage of the system on which this enabler is currently deployed and expected to be deployed.

   iii. The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.

   iv. The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)

c) Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).

Response:

a) The enabler for Secondary Equipment is asset replacement programs for batteries, under frequency (UF) relays, remote access pulse recorders (RAPR) and human machine interface (HMI). Additionally, the program to expand the energy management system (EMS) and install remote terminal units (RTUs) is included.

b)

i.The total number of units installed are as follows:

- 197 batteries,
- 183 UF relays,
- 4 RAPRs,
- 13 HMIs,

- 231 RTUs,

The following replacements or installations/expansions are planned over the following five-year timeframe:

- 25 batteries,
- 88 UF relays,
- 4 RAPRs,
- 5 HMIs,
- 55 RTUs

ii. The following represents the percentage of the system which is currently deployed and expected to be deployed over a five-year timeframe:

- 13% battery,
- 48% UF relay,
- 100% RAPR,
- 38% HMI
- 44% RTU

iii. Approximately 76% of the substation batteries may have remote sensing. Approximately 5% of UF relays have remote resetting. 100% of RAPRs provide remote access of stored data. 100% of RTUs provide remote monitoring, status and control of devices, and provides remote indication of RTU communication failure. 20% of HMIs provide local remote control.

iv The asset replacement programs are utilized at substations.

b) The estimated cost to implement the programs are as follows:

- $ 1.250M battery,
- $ 1.76M UF relay,
- $ 0.060M RAPR,
- $ 0.270M HMI,
- $15.125M RTU

MA DPU Grid Modernization Working Group

Questions for Utilities Regarding Grid-Facing Systems

March 18, 2013

Responses Due April 5, 2013

Introduction:

On behalf of the Working Group, several parties -AGO, DOER, and DPU – have coordinated topose questions for the distribution companies in order to gather an inventory of the level of grid facing technologies already on the distribution system. To achieve this goal, we have developed: (1) a set of specific questions, and (2) additional requests and clarifications regarding information which we would like included in the responses.

We encourage the utilities to work together to develop a common format for the response, including a common list of those items to be inventoried.If these questions do not provide enough of a guide for an inventory, or if the utilities need more direction, we can organize an additional meeting or call with the utilities, AGO, DOER, DPU (and whomever else) to work out what items should be on the inventory.

Please usethe common inventory terms in the "Definitions Accompanying MA Grid Mod Taxonomy/Functionality Matrix" and add to that, as needed.

Questions related to Grid Facing Taxonomy Matrix:

1. *For all the "enablers" (i.e., items) listed under the heading "Network Systems," provide the following (in no more than a few sentences each):*
    - *a) A brief description (including function and capability) of the system your company has.*
    - *b) The year of installation; years of any significant upgrade; current plans for retirement or replacement, and current plans for changes or updates.*
    - *c) Depending on applicability for each system (i.e., a company may not need to answer all these for each; the point is to solicit and note any helpful or relevant information for the group), describe:*
        - *i. Any characteristics that enable or facilitate grid modernization goals and objectives.*
        - *ii. Any characteristics that represent challenges or barriers to grid modernization goals and objectives.*
        - *iii. Any additional upgrades necessary to enable or facilitate grid modernization goals and objectives.*

This will vary depending on the goal or objective to be accomplished and functionality to be enabled.

- *iv. Approximate cost estimates for any such upgrades, to the extent they are available.*

Cost information for grid modernizations technologies varies greatly depending the capabilities of the technology and the nature of the application. Providing cost information for this exercise has the potential to lead to inaccurate conclusions.

v. *The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)*

See attachment NSTAR 1 and WMECO 1 for available information.[1]

2. *For all the enablers (i.e., items) listed under the other headings ("Distribution System Automation," "Distributed Resource Integration," "Demand Optimization," "System Hardening," and "Workforce Management"), provide:*

   a) *A description of the "enabler" (i.e., this may be a device type), if it is helpful to have detail beyond what is on the definitions sheet (e.g., may include detail on function and capability).*

   b) *The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate:*

      i. *The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).*

      ii. *The percentage of the system on which this enabler is currently deployed and expected to be deployed.*

      iii. *The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.*

      iv. *The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)*

   c) *Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).*

Cost information for grid modernizations technologies varies greatly depending the capabilities of the technology and the nature of the application. Providing cost information for this exercise has the potential to lead to inaccurate conclusions.

See attachment NSTAR 2 and WMECO 2 for available information.[2]

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[1] Please note any future projects identified in NSTAR Electric and WMECO's responses are based on current and known factors. As these factors change or as new factors are identified, the Companies may be required to modify, as appropriate, their future projects to ensure that the project remains the best path forward. It is important for NSTAR Electric and WMECO to maintain flexibility in order to respond to system needs and conditions as they arise.

Additional Requests and Clarifications:

The above questions direct the utilities to look at the taxonomy/functionality matrix, and to provide an inventory of the enablers. However, we recognize that this is not a prescriptive list. As such, we would like to ensure that the inventory includes the following:

1. *How many distribution substations do you have in service and how many of those are automated?*

WMECO has 28 substations serving customers at 13.8 kV or 23 kV. Ten of these substations (36%) have some DSCADA capability.

NSTAR has approximately 200 substations, all our transmission bulk substations have full SCADA control. All our major 23kV and 13kV substations have SCADA control. There are a number of smaller substations, each supplying a small number of customers that do not require SCADA control. Overall NSTAR has SCADA control on 120 of our 200 substations. This accounts for 80% of our customers.

2. *How many capacitor banks do you have in service and how many of those are automated?*

WMECO has 250 capacitor banks on its system. Of the capacitor banks, 110 are manually operated, 77 operate independently in the field in response to VAR or voltage levels and 62 are operated remotely via radio controls. The radio controlled capacitors have only one-way communication capability and are operated remotely based on forecasted load levels; there is no signal back to the remote operator to confirm the capacitor actually turned on or off.

NSTAR has approximately 640 capacitor banks on the system with 485 of those having one way pager radio control. There are an additional 190 fixed or time clock controlled. There are currently 155 sets of voltage regulators on the overhead system.

3. *How many distribution system feeder circuits do you have in service and how many of those are automated?*
    a) *Describe, at a high level (e.g., create categories) the level of automation on the feeders.*

WMECO currently has 120 recloser loop schemes on its system deployed on 78 overhead circuits (approximately 50% of overhead and overhead / underground hybrid circuits

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[2] Please note any future projects identified in NSTAR Electric and WMECO's responses are based on current and known factors. As these factors change or as new factors are identified, the Companies may be required to modify, as appropriate, their future projects to ensure that the project remains the best path forward. It is important for NSTAR Electric and WMECO to maintain flexibility in order to respond to system needs and conditions as they arise.

serving customers at 13.8 kV and 23 kV). These loop schemes benefit approximately 53% of customers served by the overhead system.

NSTAR currently has over 1850 remote controlled switches that are used to monitor the system loading and improve loading conditions on the system. Approximately 995 or 63% of the circuits had some level of automation, either the breaker, recloser or line/tie switch. Those circuits supplied approximately 937,000 or 80% of NSTAR's customers.

4. *Please include relevant information regarding:*

   b) *Technologies deployed.*

   c) *ARRA program investments.*

   d) *Percent of feeders covered.*

   e) *Is it cost effective to make similar investment on all feeder circuits? If not, approximately what percent should have additional automation / communication?*

NSTAR is the prime recipient of three DOE ARRA stimulus grants and the sub-recipient to the ISO-NE of a fourth award. The three projects for which NSTAR is a prime recipient are:

1) Grid Self Healing & Efficiency Expansion: Create an "auto restoration" or "self healing" capability on the distribution system, using modern sensing, communications and information processing based on digital technologies.

2) Urban Grid Monitoring & Renewables Integration: Allows for the interconnection of inverter-based distributed generation in a safe manner onto the secondary area network grids.

3) AMR Based Dynamic Pricing: Involves the deployment of advanced technology to enable real-time measurement and two-way communication of energy consumption using existing AMR meters.

The fourth project is in conjunction with ISO-NE. NSTAR has installed Phasor Measurement Units (PMU) in four substations to enable real-time phasor data applications. The project is an essential part of ISO New England's plans for infrastructure development based on the expansion of its PMU-based disturbance detection and monitoring system. This pilot will test the provision of real-time data to ISO NE every 1/60th of a second, rather than once every 10 seconds.

5. *This list should also include appropriate information (e.g., total number of units, level of deployment) of the following:*

   a) *SCADA (supervisory control and data acquisition).*

   b) *Remote terminal units (RTUs).*

   c) *Programmable logic controllers (PLCs).*

These technologies are described in the sections above and corresponding attachments, as applicable.

Row	Enabler	1.a Brief description (including function and capability) of the system your company has;	1.b The year of installation; years of any significant upgrade; current plans for changes/ updates;	1.c.i Any characteristics that enable/ facilitate grid modernization	1.c.ii Any characteristics that represent challenges/ barriers to grid modernization	1.c.v The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)				
1	Distribution Management System (DMS)/SCADA	**GE GEN4 SCADA/EMS:** - Monitoring and control of Transmission, Subtransmission and **North Distribution** - North Distribution: Approximately 1,100+ Supervisory devices, 60,000+ analog & digital points **GE Powerlink Advantage:** - Monitoring and control of South Distribution - Approximately 750 + Supervisory devices, 40,000 analog & digital points - 80 Auto-Restoration (Grid Self-Healing) schemes	**GE GEN4 SCADA/EMS:** - Initial install (SNC-Lavalin GEN3 SCADA): 1994 - Upgrade to GEN4 SCADA: 2007 - Future: Migrate Transmission/Subtransmission to new system Migrate North Distribution to GE Powerlink Advantage and implement 100 Auto-Restoration schemes **GE Powerlink Advantage:** - Initial install of v3.0: 2005 - Upgrade to v4.3: 2011 - Future: Migrate Distribution to new DSCADA platform	Distribution SCADA allows for remote communications / control	None Latest technology installed	Distribution system				
2	Outage Management System (OMS)	**GATOR (Graphical Analysis Tools for Outage Restoration)** Key functions include: - Call-Taker module - Customer Self-Service Outage Reporting (IVR, Web) - Incident/Job Management - Dispatching/Crew Management - Advanced Customer Messaging - Reporting: DPU, MEMA, internal - Permit/Planned Outage Management	CGI PragmaLine v2.03 (original OMS): 2000 GATOR Upgrade (OMS v2.04.04 & new GATOR-GUI): 2003 Many enhancements/improvements installed 2004-2012 Future: Planned OMS Replacement Project 2013-2014	New OMS has an mobile dispatch and damage assessment module		Distribution system				
3	NSTAR Geospatial Information System (GIS)	**GIS Editor:** Custom developed ESRI GIS application based on ArcStorm technology to maintain Distribution and Landbase GIS assets **GIS Viewer**: ESRI ArcMap 8.3 corporate viewer with some customization to view all the GIS assets **Transmission Editor:** ArcFM version 9.1 editor to maintain the Transmission GIS assets	**GIS Editor:** v82. North 1990's South 2004 **GIS Viewer**: v8.3 2004 **Transmission Editor:** v9.1 2008 **Future:** - ESRI/ArcFM v10 Upgrade In Progress	N/A	Potentially require data model changes for new device types	Distribution and Transmission				
4	NSTAR GIS-OMS Integration	**GATOR-GUI:** Custom developed by ESRI GIS-based application integrated to OMS (landbase, circuits, devices, etc) - Utilized to plot outage calls and create polygons (jobs). - Regularly imports circuit and service point data from GIS.	Implemented as part of GATOR Upgrade: 2003 Future: Planned OMS Replacement Project 2013-2014 GIS Upgrade Project: In Progress	N/A	Potentially require data model changes for new device types	Distribution				
5	Billing System (NSTAR)	Billing system including budget billing, payment processor, online real-time updates, processing & inquiries of 36 months of historical account data, generation point for field meter & service orders, commercial deposit processing, internal and external supplier processing, produces & supports reporting for regulatory, finance etc. Produces energy bills, online/hardcopy reporting , field orders, transmits and receives fuel payment and collection agency payments.	Initial version 1991 System is continuously modified as a result of Regulatory Directives and/or business requirements.	N/A	CIS is NSTAR's billing system of record. CIS is comprised of 2.7 million lines of code, 42 databases, 2000 modules, 1300 batch jobs, and 75 interfaces. Enhancements may be lengthy & costly due to an IMS database architecture (IMS = Information Management System), customized system written in COBOL, and testing requirements.	N/A				

Row	Enabler	1.a Brief description (including function and capability) of the system your company has;	1.b The year of installation; years of any significant upgrade; current plans for changes/ updates;	1.c.i Any characteristics that enable/ facilitate grid modernization	1.c.ii Any characteristics that represent challenges/ barriers to grid modernization	1.c.v The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)				
6	Metering System	**FCS (Field Collection System)** Key functions include: - Provides route, assignment and data management for handheld and mobile meter data collection for 1.5 million "" meters - Client PC: Running FCS Desktop application for system operations - Mobile Collection: Itron Drive-by AMR devices - Handheld Collections with FC300 Itron units running FCS handheld application - Related Applications: Such as RouteSmart GIS, MV-90 xi, IEE and other utility applications	**FCS (Field Meter Collection)** - Installed Version 2.4 SP2 of FCS to replaced Premierplus4 (P4) application in Q3 2012. Project underway in 2013 to add Route Smart (FCS) interface to provide daily temporary and permanent re-routing on a cycle, meter reading office or territory.	Support AMR based system several options available i.e., IP, Fixed networking drive by	Currently used for AMR based system Electronic ITRON meters with RF ERTS	Distribution system				
7		**Route Smart ArcGIS** Key functions include: - Provides route optimization. Utilize geocoding and Centrus to route meters.	**Route Smart ArcGIS** Installed in 2007 and upgraded in Q1 2011. Upgraded to Route Smart for ArcGIS 2010	N/A	N/A					
8		**MV90 (Itron Interval Meter Collection)** Key functions include: - Provides interval meter collection via Modem, Verizon 1XRTT wireless networks for 7000 TOU meters. -Allows for manual field collections via DAP 9800 and via laptops for small population of meters - Provide interval data for Customer and Supplier subscriptions	**MV90** Installed in 2006 -Upgraded to version 2.0 Service Pack 1, in January 2009 -Plans to Upgrade in 2013 to Version 3.0 to provide to support Technology compatibility to Windows 7 and new Day Light Saving vendor enhancements.	N/A	N/A					
9	Meter Data Management System (MDM)	**Lodestar Meter Data Management** Key functions include: - Provides Interval data for ISO Load data management and analysis and - Provides interval data for Customer Supplier Subscriptions	**Lodestar Meter Data Management** Lodestar Server/Client version 1.10 and EIP ver. 1.6 were installed in Q2 2011	N/A	N/A	N/A				
10	OMS-AMR/AMI Intergration	N/A	N/A	N/A	N/A	N/A				
11	Communications Systems (Fiber, Microwave, Radio, etc..)	Various state-of-the-art communications systems, including, high speed fiber, microwave and digital radio network	All installed with-in the last 3-5 years	Presently being used for grid modernization	None	Distribution and Transmission				

Exhibit WMECO-1

Row	Enabler	1.a Brief description (including function and capability) of the system your company has;	1.b The year of installation; years of any significant upgrade; current plans for changes/ updates;	1.c.i Any characteristics that enable/ facilitate grid modernization	1.c.ii Any characteristics that represent challenges/ barriers to grid modernization	1.c.v The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)
1	Distribution Management System (DMS)/SCADA	**Siemens Spectrum Power TG** - Monitoring and Control of CL&P and WMECO Reclosers and Station Breakers - 2400+ Devices, 280,000+ Analog and Digital Points - All circuits are "self-healing" based upon loop scheme configurations	**Siemens Spectrum Power TG** -Initial Install of v7.3F in service date April 2002 - Upgrade to v7.3H October 2003 - Upgrade to v8.2 Decemeber 2007 (included test 5000RTU's, 650,000 Analog and Digital Points) - Currently upgrading to v9.0	Distribution SCADA allows for remote communications / control	DMS-based functionality available but is not currently installed	Distribution system
2	Outage Management System (OMS)	**Oracle Network Management System** V.1.7.1 SP2 · Call Taking from Customer Information System, IVR, Web, and Offline Backup · Event life-cycle management · System-generated, operator-entered, division global, and district global ERTs · Dispatching / crew management · Restoration callbacks via CIS	Installed April 2004 Upgraded to current version in December of 2007 Future upgrade / replacement slated for 2014	AMI module and interface required for grid modernization	N/A	Distribution system
3	GIS-OMS Integration	Smallworld map extraction .mb file format. OMS import of .mb files via vendor model-build process.	Initial installation April 2004 Upgrade in 2008 Replacement slated for 2014	N/A	Potentially require data model changes for new device types	Distribution and Transmission
4	WMECo Geospatial Information System (GIS)	**GE Smallworld Editor:** GE Core Spatial Technology product used to maintain landbase and electric distribution asset information. **GE SIAS Viewer**: GE Smallworld Internet Application Server provides intranet access to Smallworld data including searching and limited printing facilities, with minor custimozations. **Transmission Editor:** Transmission assets currently not in GIS. **ESRI SilverLight Viewer:** Custom built .NET Silverlight based GIS viewing application that lets the user have a Google Maps type of experience. Developed by EPOCH solutions.	**GE Smallworld Editor:** 3.1 installed in 2002, upgraded to 4.1.1 in 2008. **GE SIAS Viewer**: versioin 4.1.2 installed in 2010 **Transmission Editor:** Future plan is for transmission assets to be pulled into Smallword and maintained via Smallworld editor. ~2013 **ESRI SilverLight Viewer:** version 1.0.1 installed in 2012	N/A	Potentially require data model changes for new device types	
5	Billing System (WMECO)	C2 Application Bill Calculation, Bill Presentment, Customer Inquiry, Customer management, Online services, Orders, Rate management, Receivables and Payment posting, Supplier Mangement	System was implemented in 2008 System is continuously modified as a result of Regulatory Directives and/or business requirements.	Foundation exists to expand components and functionality	Although foundation exists to expand components and functionality,enhancements may be lengthy & costly due to a customized system written in COBOL, and testing requirements.	N/A
6	Metering System	**Fieldnet** (Field Activity Tracking and Scheduling and Meter Reading system) Key functions include: - Provides route, assignment and data management for handheld and mobile meter data collection and service orders - Client PC: Running Fieldnet Desktop application for system operations - Mobile Collection with MC3 Neptune Drive-by AMR devices (WMECO only) - Handheld Collections with DAP Bulverde (Neptune) handhelds running Fieldnet handheld application (Windows CE5) - Route management (Rerouting) - Optical Probe capability for extracting interval data - Exception processing - Same day dispatching - ROAM GIS route optimization and management - Related Applications: PRIMEREAD, POWERTRACK, STORMS, MDM, C2 interface - Installed system services WMECO, CL&P, PSNH (for same day service orders)	**Fieldnet** - Installed Original installation early 1990's - Multiple upgrades and improvements - Current version 4.0.2 was installed in January 2012. - Plan to upgrade to most current version available based on product strategy in 2014 to incorporate: 1) Real time communication between handheld devices and customer information and meter management systems and 2) A more robust route optimization and management system.	N/A	N/A	Distribution system
7		**Prime Read (Interval Meter Collection)** Key functions include: - PrimeRead is an electrical data collection application specifically designed and built for Utilities and end-users. The application works with Smart Metering Devices that register electrical Channels from substations and customers. This information can be collected on a scheduled basis remotely and with an unattended operation. This data if useful for billing, energy balance, operations, maintenance and commercial. - Used to capture 15 minute interval data for WMECO Commercial and Industrial meters.	**Prime Read (Interval Meter Collection)** Install March 05, 2008 - Last Upgrade on PrimeRead Version v7.9 in 2008 - Future plans: move entire meter population to MV90 and retire this application	N/A	N/A	

Exhibit WMECO-1

Row	Enabler	1.a Brief description (including function and capability) of the system your company has;	1.b The year of installation; years of any significant upgrade; current plans for changes/ updates;	1.c.i Any characteristics that enable/ facilitate grid modernization	1.c.ii Any characteristics that represent challenges/ barriers to grid modernization	1.c.v The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)
8		**ION Revenue** Key functions include: -ION Enterprise is an interval data collection system. It is used to program meters, create reports, trouble shoot meter issues, present data on the web. It manages energy information from installed metering and control devices and offers comprehensive power quality and reliability analysis.	**ION Revenue** Installed ION Enterprise 5.6 in 2005 - Future plans: move entire meter population to MV90 and retire application.	N/A	N/A	
9	Meter Data Management System (MDM)	**Lodestar Meter Data Management** Key functions include: - Provides meter estimation, validation and reconciliation for WMECO meters - ProvidesMeter Determinants to the Customer Billing System for monthly cycle based and totalized billing - Tightly integrated with Billing and Meter Asset systems to improve data accuracy across each system. - Provides data to Meter Data Warehouse	**Lodestar Meter Data Management (MDM)** Lodestar 1.6 installed in January 2013	Loadstar MDM could be expanded to enable additional functionality but it is not a standalone enabler.	Must be expanded and coupled with a Networked enable head in system. Would need to be expanded to include interval data.	
10		**SerViewCom** Key functions include: gathering 15 minute interval data from IP based and phone home meters and exporting to EVEE data warehouse on a daily basis.	**SerViewCom** Upgrade to version 1.60.7 in 2010 Future plans: move entire meter population to MV90 and retire application	N/A	N/A	
11		**EVEE Meter Data Warehouse** Key functions include: - Provides Interval data warehouse, estimation and validation of Interval Meter data - Provide Meter Determinates to Customer Billing System - Provide Load Analysis data for ISO reporting purposes	**EVEE Meter Data Warehouse** - Installed March 2003 - Server hardware upgrade September 2012	N/A	N/A	
12	OMS-AMR/AMI Intergration	N/A	N/A	N/A	N/A	N/A
13	Communication Systems (Fiber, Microwave, Radio, etc.)	**WMECo Fiber-** the optic ground wire (OPGW) installed at WMECo will utimately create a large OC-3 SONET ring collecting data and bringing it back to E.Springfield where it connects to other fiber rings that go to NH and CT. The WMECo ring is used for SCADA, Relaying, and Substation traffic. **WMECo Mirowave-** an extensive microwave system consisting of OC-3, DS3, 4T1, and unlicensed links that support the mobile radio system and other coporate communincations. **WMECo Mobile Radio-** a multi-channel trunked radio system that can support both mobile radio and DSCADA applications. Although this is primarily for voice there are 157 DSCADA units, mostly reclosers, on this system. **WMECo DSCADA Radios**- a separate IP radio system specifically for DSCADA (4 master sites, 8 remote units to date) that compliments the mobile radio system by off loading some of the RTU data at conjested sites.	**WMECO Fiber-** Mostly built out over the last 8 years and continues to be built as Transmission lines are built or upgraded. **WMECo Microwave-** 90% of the microwave equipment has been installed in the last 8 years. Where appropriate fiber will replace some microwave but low density microwave will always be appropriate for radio sites, spurs, as back up, and as alternate routes. **WMECo Mobile Radio-**installed between 2005-2008. **WMECo DSCADA Radios-**this is all new within the last year.	**WMECO Mobile Radio-** this system covers 95% of WMECo and includes 24 radio sites throughout the state.	**WMECo-**the terrain, sparse suburban population, lack of primary data use frequencies, and antenna height restrictions.	

Row	Enabler	2.a A description of the "enabler" (i.e., this may be a device type), if it is helpful to have detail beyond what is on the definitions sheet (e.g., may include detail on function and capability);	2.b.i The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).	2.b.ii The percentage of the system on which this enabler is currently deployed and expected to be deployed.	2.b.iii The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.	2.b.iv The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)			
1	**Distribution System Optimization**								
2	Fault Detection, Isolation, Restoration (FDIR)	On the NSTAR system, FDIR functionality in the overhead system is achieved through circuit breakers, reclosers and overhead ASUs (automatic sectionalizing units – remote controlled loadbreak switches.) The ASUs act as line or tie switches and work in conjunction with reclosers or circuit breakers to limit the initial outage and the dispatcher then performs remote switching to further isolate the faulted area. This function is currently being fully automated in many cases through automatic restoration schemes as part of the Grid Self Healing & Efficiciency Expansion ARRA project. In the underground network areas, the network feeders and secondary grid are designed such that no customers experience an outage for a fault on the primary system (network feeders) and very few, if any, customers experience an outage for faults on the secondary system. In the underground non-network areas some of the low voltage (5 kV) circuits have VFIs (vacuum fault interrupters) with or without remote control and indication that open to isolate faulted sections. On the medium voltage (15 kV, 25 kV) circuits, the	There are more than 1850 radio controlled switches on the NSTAR system consisting of more than 1240 overhead switches, 415 reclosers, nearly 110 pad-mounted switches and 85 underground VFI switches. There are currently nearly 80 A/R (auto-restoration loops) in service with 100 more scheduled for 2013. When a fault occurs on one of these loops, an algorithm will produce a solution to restore the unfaulted areas of the system. This solution can either be applied automatically or by operator acknowledgement.	The spreadsheet filed in the Company's annual SQI filing shows that there were 1580 circuits in service at some time during the 2012 calendar year. Approximately 995 or 63% of the circuits had some level of automation, either the breaker, recloser or line/tie switch. Those circuits supplied approximately 937,000 or 80% of the system customers.	80% of customers have automation, or 63% of the circuits. 640 cap banks, 485 pager controlled	Distribution & Substation			
3	Automated Feeder Reconfiguation	On the NSTAR system, load monitoring of the system is accomplished by automation system continuously monitoring loads and voltages throughout the system using data from the breakers, reclosers and ASUs. The system will produce an alarm for overcurrents or undervoltages that can trigger remote action by the dispatcher.	The same 1850 radio controlled switches referenced above are used in conjunction with station breakers to correct for overloads.	80% of customers will have some form of automation by year end of 2013		Distribution & Substation			
4	Integrated Volt/VAR Control, Conservation Voltage Reduction	On the NSTAR system, power factor and voltage control along the overhead distribution circuits are achieved through dispatchable capacitor banks, fixed or time clock controlled capacitor banks and line voltage regulators. There are two types of dispatchable capacitor banks, radio controlled and pager controlled. All capacitor banks on the 15 kV and 25 kV systems are dispatchable. Eventually all dispatchable banks will be pager controlled. Pager controlled capacitors have voltage overrides such that they will automatically disconnect when they sense high voltage or connect when they sense low voltage. Fixed capacitors are connected to the system at all times. Fixed and time clock controlled banks are small units limited to the low voltage (5 kV) system. Voltage regulators operate automatically to adjust for low or high voltage based on a predetermined bandwidth. The Company does not have a CVR program. In addition to the distribution system installations, the company maintains capacitors and reactors at the transmission system and on the distribution system at the substation level.	There are nearly 640 dispatchable capacitor banks on the system with 485 of those having the pager controls. There are an additional 190 fixed or time clock controlled. There are currently 155 sets of voltage regulators on the overhead system. There are 13 stations on the NSTAR system with reactors at the 115 kV or 345kV (transmission) level and 12 stations with capacitor banks on the transmission level. More of each of these are currently in the planning stage. There are more than 35 bulk or distribution stations with capacitors installed and more in the planning stage.	76% of dispatchable capacitor banks have pager controls (485 of 640)		Transmission, Distribution & Substation			
5	Remote Monitoring & Diagnostics (equipment conditions)	Essentially all major equipment is remotely monitored and alarmed via SCADA i.e. Substation transformers, remote controlled switches, communications, etc.. On the NSTAR system, all remote controlled reclosers and ASUs monitor the system by providing voltage, current and power factor.	We are in a very advanced state of remote monitoring. As stated above there are over 1850 remote controlled switches that are used to monitor the system loading and improve loading conditions on the system. In addition, the Company has SCADA monitoring on the major bulk distribution stations including all bulk or network supply stations.	See above for FDIR. 60% of the Company's bulk or distribution stations (including all bulk or network supply stations) have SCADA monitoring.		Transmission, Distribution & Substation			
6	Remote Monitoring & Diagnostics (system conditions)	Essentially all major equipment is remotely monitored and alarmed via SCADA i.e. Substation transformers, remote controlled switches, communications, etc.. On the NSTAR system, all remote controlled reclosers and ASUs monitor the system by providing voltage, current and power factor.	We are in a very advanced state of remote monitoring. As stated above there are over 1850 remote controlled switches that are used to monitor the system loading and improve loading conditions on the system. In addition, the Company has SCADA monitoring on the major bulk distribution stations including all bulk or network supply stations.	See above for FDIR. 60% of the Company's bulk or distribution stations (including all bulk or network supply stations) have SCADA monitoring.		Transmission, Distribution & Substation			
7	**Distributed Resource Integration**								

Row	Enabler	2.a A description of the "enabler" (i.e., this may be a device type), if it is helpful to have detail beyond what is on the definitions sheet (e.g., may include detail on function and capability);	2.b.i The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).	2.b.ii The percentage of the system on which this enabler is currently deployed and expected to be deployed.	2.b.iii The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.	2.b.iv The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)
8	Remote Distributed Generation Disconnect	On the NSTAR system, the remote disconnection of 1MW or larger distributed generation is accomplished with radio controlled source sensing reclosers. The recloser monitors load and voltage and opens on undervoltage upon the loss of the NSTAR feeder to prevent the generators from feeding into the faulted area. Remote indication is accomplished by distributation automation.	There are between 30 and 40 of these installations currently active.			Distribution
9	Voltage Regulation	Prior to interconnecting a distributed generation facility, the Company conducts studies to determine if additional equipment is required on the system to ensure voltage levels remain in the required bandwidth. NSTAR is working with Cooper to evaluate move advanced voltage regulator controls.	DG customers shoud consider using storage devices.	DG customers are presently not being required to install batteries, other states require battary storage devices.		Distribution
10	Load leveling and shifting	At this time, DG developers do not deploy storage to match the output of intermittent distributed generators to the load.				N/A
11	Intentional Islanding (microgrid) control	At this time, NSTAR does not have a program to intentionally island load served solely by a distributed generation source(s). The Company does deploy equipment on the system to ensure large generators do not unintentionally island a portion of the system. In addition, At various locations, DG developers do intentionally island load served solely by a DG source(s)				N/A
12	**Demand Optimization**					
13	Home Area Network Communications Capability	Home Area Network Communications Capabilities are being deployed as part of the NSTAR Smart Energy Pilot to enable two-way communicat to the customer using the Internet.	Approximately 2,700 customers had HAN equipment installed as part of the pilot.	0.25% (consistent with Green Communities Act)		Customer
14	Utility/3rd party DR programs (load control)	Load control is also being tested as part of the NSTAR Smart Energy Pilot. Qualifying customers received a smart Programmable Controllable Thermostat with capabilities to re-program over the Internet, or by receiving a load control signal from NSTAR to temporarily raise by a few degrees during Critical Events in the summer.	There are approximately 320 customers in the Peak Time Rebate group and 310 customers in the Time of Use rate with CPP group.			Customer
15	Time Varying Pricing	On the NSTAR system, there are various time of use rates available for retail customers depending on the billing rate for the former operating Companies. In the Boston Edison Territory, for example, there are two mandatory and two optional rates. Customers supplied with primary voltages of 14 kV and above along with medium and large commercial/industrial customers (monthly demands of 150 kW and higher) are placed on mandatory rates. These rates vary seasonally by time of day for both energy and the determination of billing demand. There is an optional rate for residential customers and another for small non-residential customers. Similar sets of rates are in effect for the Commonwealth Electric and Cambridge Electric customers. See response to Metering Question 2.5 for full details.	5,116 customers total See response to Metering Question 2.5 for full details.	0.5% (1.1M total customers)		Customer
16	Advanced Load Forecasting	Econometric modeling using software: Eviews software version7.				N/A
17	**System Hardening**					
18	Elevated Substations	All new substations will be built to standards that take into consideration risk of flooding and are designed accordingly.				
19	Equipment hardening (submersibles; spacer cables; undergrounding)	Extensive guying of transmission poles, standard use of stronger poles, higher class materials, etc.				
20	Distributed Generation/Storage	Developers responsibility				
21	Vegetation Management	NSTAR's vegetation management includes (1) maintenance trimming (circuits are trimmed every four years); (2) enhanced tree removal; and (3) enhanced tree trimming. In addition we are working with various towns for permission to achieve required tree clearances.				
22	**Workforce Management**					

Row	Enabler	2.a A description of the "enabler" (i.e., this may be a device type), if it is helpful to have detail beyond what is on the definitions sheet (e.g., may include detail on function and capability);	2.b.i The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).	2.b.ii The percentage of the system on which this enabler is currently deployed and expected to be deployed.	2.b.iii The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.	2.b.iv The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)
23	Mobile Workforce Management Systems	Service Suite is used to schedule, assign and dispatch orders to the NSTAR Electric meter field technicians. Service Suite optimally assigns and dispatches work to the field, monitors work progress, responds to changing conditions, and measures work performance, all in real time. field personnel use rugged mobile laptops over a wireless data connection via VPN.	N/A	N/A		N/A
24	Mobile GIS Platforms	See Attachment NSTAR 1	N/A	N/A		N/A
25	OMS-ERP-CIS Integration	Most of this integration is of the batch file update variety. Customer records from CIS are combined with the GIS data to form the basis of the OMS/GATOR GUI model. This allows customers to be identified within OMS/GATOR GUI. Outage Calls (including status updates, ERT management) are handled directly in OMS not through a CIS interface. From an ERP perspective, there currently is no real-time integration to WMS, Financials, HR, etc.	N/A	N/A		N/A

Exhibit WMECO-2

Row	Enabler	2.a A description of the "enabler" (i.e., this may be a device type), if it is helpful to have detail beyond what is on the definitions sheet (e.g., may include detail on function and capability);	2.b.i The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).	2.b.ii The percentage of the system on which this enabler is currently deployed and expected to be deployed.	2.b.iii The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.	2.b.iv The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)
1	**Distribution System Optimization**					
2	Fault Detection, Isolation, Restoration (FDIR)	On the WMECO system, FDIR capability is currently performed by recloser loop schemes. A recloser loop scheme consists of a sectionalizing recloser (SR) a tie recloser (TR) and sometimes one or more mid-point reclosers (MR). The Company is also in the process of investigating the feasibility of automating gang operated air break switches (GOABS) within a loop scheme to break the circuit down into even smaller segments. For the underground network systems in urban areas, by design, the equipment automatically isolates faults and all customers remain served by other sources of supply. For this exercise, network systems were not considered an enabler for modernization. For non-network underground systems, some customers (e.g. hospitals) have site-specific auto transfer capability. The majority (72%) of non-network underground customers are served by fused loop systems with auto source transfer. This configuration was also not considered an enabler for modernization.	WMECO currently has 120 recloser loop schemes on its system In 2013, WMECO plans to install four new loop schemes and enhance four more with increased sectionalization. This project will involve installing 14 additional reclosers on the overhead system. A similar magnitude of deployment is expected for 2014 through 2017, although some of these devices may be automated air break switches with RTU's as opposed to reclosers. This level of deployment will provide benefit to approximately 4,000 more customers or an additional 2% of customers served by the overhead system per year. All loop schemes operate automatically in response to loss of source voltage.	This covers approximatlye 50% of its overhead 13.8 kV and 23 kV circuits. These loop schemes benefit approximately 53% of customers served by the overhead system.		Distribution
3	Automated Feeder Reconfiguation	At this time, WMECO does not have the capability for its system to automatically reconfigure circuits in response to real time system data.				N/A
4	Integrated Volt/VAR Control, Conservation Voltage Reduction	WMECO manages system voltage with load tap changers on substation transformers and voltage regulators on the overhead distribution system. In addition to tap changers, the Company has 123 voltage regulators on the overhead distribution system. Regulators are deployed primarily on long rural circuits where voltage sags are expected. These devices operate independently in the field and are not automated in the sense that system operators can remotely detect or control voltage levels. WMECO manages voltage within a +/- 5% bandwidth and does not have the capability to conduct a conservation voltage reduction program to remotely detect and manage voltage at all points on the system within a tighter bandwidth. Power factor is managed with the use of capacitor banks. WMECO has 250 capacitor banks on its system. Of the capacitor banks, 110 are manually operated, 77 operate independently in the field in response to VAR or voltage levels and 62 are operated remotely via radio controls. The radio controlled capacitors have only one-way communication capability and are operated remotely based on forecasted load levels; there is no signal back to the remote operator to conf	In addition to tap changers, the Company has 123 voltage regulators on the overhead distribution system. WMECO has 250 capacitor banks on its system. Of the capacitor banks, 110 are manually operated, 77 operate independently in the field in response to VAR or voltage levels and 62 are operated remotely via radio controls.	Volatage regulators and capacitor banks are deployed throughtout the WMECO distribution system.	**Cap Banks: 250 total** 110 (44%) manual 77 (31%) automated 62 (25%) remote operation	Distribution and Substation
5	Remote Monitoring & Diagnostics (equipment conditions)	WMECO has alarms in many substations to alert operators for various abnormal conditions. The Company does not have the capability to remotely sense specific equipment conditions (e.g. oil levels) or diagnose problems. Equipment monitoring and diagnosis is performed on a regular basis by substation electricians and line workers.				N/A
6	Remote Monitoring & Diagnostics (system conditions)	WMECO has deployed DSCADA on its system for remote monitoring and diagnostics of system conditions. The data is transmitted from devices to a systems operations center via a 220 MHz radio system. DSCADA is installed in substations for all new and major reconstruction projects. Substations that have DSCADA have the ability to monitor load (per phase current), status and control of the breaker, and status and control of Hot Line Tags (HLT).	Currently, 68 station circuit breakers have DSCADA. Of these 43 are underground circuits (nearly all underground circuit breakers) and 25 are on overhead circuits (17% of overhead circuit breakers). On the overhead distribution system, there are 143 DSCADA enabled devices on 57 circuits	37% of all 13.8 kV and 23 kV breakers have DSCADA. 40% of overhead 13.8 kV and 23 kV circuits have DSCADA enabled devices.		Distribution and Substation
7	**Distributed Resource Integration**					
8	Remote Distributed Generation Disconenct	WMECO has deployed DSCADA enabled reclosers at the point of interconnection for all large (over 1 MW) distributed generation facilities. These reclosers can be remotely operated to disconnect or reconnect the DG facilities from the WMECO system.				Distribution
9	Voltage Regulation	WMECO manages voltage within a +/- 5% bandwidth as described in the integrated Volt/VAR control section. Prior to interconnecting a distributed generation facility, the Company conducts studies to determine if additional equipment is required on the system to ensure voltage levels remain in the required bandwidth.				Distribution and substation
10	Load leveling and shifting	At this time, WMECO does not deploy storage to match the output of intermittent distributed generators to the load.				N/A
11	Intentional Islanding (microgrid) control	At this time, WMECO does not have a program to intentionally island load served solely by a distributed generation source(s). The Company does deploy equipment on the system to ensure large generators do not unintentionally island a portion of the system.				N/A
12	**Demand Optimization**					
13	Home Area Network Communications Capability	At this time, WMECO does not deploy any home area network communications technology.				N/A
14	Utility/3rd party DR programs (load control)	At this time, WMECO does not currently conduct direct load control programs for its customers. Third party providers may offer these services to customers directly.				N/A

Row	Enabler	2.a A description of the "enabler" (i.e., this may be a device type), if it is helpful to have detail beyond what is on the definitions sheet (e.g., may include detail on function and capability);	2.b.i The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).	2.b.ii The percentage of the system on which this enabler is currently deployed and expected to be deployed.	2.b.iii The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.	2.b.iv The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)
15	Time Varying Pricing	The Company offers mandatory TOU rates (Rate T-2 and T-5) for customers whose monthly peak demand is 350 kW and above, and optional TOU rates (Rate T-0 and T-4) for customers whose monthly peak demand is below 350 kW. See response to Metering Question 2.5 for full details.	267 customers total See response to Metering Question 2.5 for full details.	0.1% (210,000 total customers)		N/A
16	Advanced Load Forecasting	WMECO uses traditional load forecasting methods that estimate future peak loads on its system based on historical peak data and does not have the capability to base forecasts on real time system conditions.				N/A
17	**System Hardening**					
18	Elevated Substations	WMECO has not identified any substations where the risk of flooding is sufficient to require a project to elevate equipment. All new substations will be built to standards that take into consideration risk of flooding and are designed accordingly.				
19	Equipment hardening (submersibles; spacer cables; undergrounding)	For new construction, WMECO follows distribution engineering standards that require hardening to various conditions, including wind and ice loading. In addition, the Company currently has a program to futher harden certain areas of its overhead system to improve reliability in storm conditions.				
20	Distributed Generation/Storage?	WMECO has not deployed distributed generation specifically to harden its system				
21	Vegetation Management	The WMECO vegetation management includes (1) maintenance trimming (circuits are trimmed every four years); (2) enhanced tree removal; and (3) enhanced tree trimming				
22	**Workforce Management**					
23	Mobile Workforce Management Systems	Fieldnet is used to schedule, assign and process orders to the WMECO meter field technicians. Fieldnet optimally assigns work to the field which is loaded into the handheld device in the morning. At the end of their shift, completed orders are uploaded from the handheld device to the system when the technician returns to the area work center.	N/A	N/A		N/A
24	Mobile GIS Platforms	See Attachment WMECO 1	N/A	N/A		N/A
25	OMS-ERP-CIS Integration	There is an interface from OMS (via the reporting system) to Work Management to create a follow-up work order if needed. From a CIS perspective, outage calls are taken within the company's CIS system (C2). These are passed to OMS and status updates / Estimated Restoration Times are passed back to C2 for communication to customers.	N/A	N/A		N/A