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 on-line access to hourly consumption data 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 700,000 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 customers 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 –

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?
2. How many capacitor banks do you have in service and how many of those are automated?
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.
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?
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 (RTU's).
    c) Programmable logic controllers (PLC's).

Response:

1. National Grid has approximately 258 distribution substations (as of 4/2012) with varying levels of automation as follows:

Level of Automation	# of Distribution Substations	% of Distribution Substations
Status	173	67.1%

Level of Automation	# of Distribution Substations	% of Distribution Substations
Control	138	53.5%
Analog	140	54.3%
Total	258	

2. National Grid has approximately 2,500 distribution capacitor banks installed in Massachusetts. Approximately 1,800 banks have time-clock based controls with voltage and/or temperature override, the remaining 700 banks are fixed (no controls). None of these banks are equipped with communications. The 47 capacitor banks being installed/retrofitted as part of the Worcester Smart Grid Pilot will be automated, this includes advanced controls using three-phase primary sensing and communications back to our EMS/SCADA system for monitoring and control. Refer to the response on IVV/CVR for more details.

3. National Grid has approximately 1,028 distribution feeders in service in Massachusetts. The vast majority of distribution feeder automation is limited to the equipment inside the distribution substation fence and can be approximated by the percentages listed in table below:

Level of Automation	# of Distribution Feeders	% of Distribution Feeders
Status	784	76.3%
Control	472	45.9%
Analog	504	49.0%
Total	1,028	

Approximately 48% of 1,100 distribution line reclosers have been automated (have cellular-based communications with the EMS/SCADA system for monitoring and control). All new line reclosers have communications capability when they are installed. Additionally, the 10 distribution feeders (~ 1% of distribution feeders) that are part of the Worcester Smart Grid Pilot will be automated. This automation includes approximately 70 overhead and underground switches, 47 capacitor banks, 32 feeder/transformer monitors and 15 fault indicators.

4. a.) The technology employed to automate distribution substations has advanced over time. Older distribution substations would typically be limited to a small number (16 status, 4 control) of points communicating to the SCADA system via radio. More critical substations would have more status and control points as well as a small number of analog points using leased telephone line or microwave communications. As technology advanced, the level of automation increased with more status, control and analog points

at a larger number of substations (not just critical locations) communicating over more advanced radio/leased telephone/microwave systems. Currently, new substations use secure, local area networks to communicate with microprocessor-based relays and other intelligent electronic devices within the substation providing large numbers of all point types with a reduced amount of control wiring to monitor and/or control most equipment within the substation fence. This highest level of automation has only been employed at National Grid since approximately 1998 and typically only for new or completely rebuilt substations (approximate distribution substation count of 35).

b.) National Grid did not receive any ARRA funding for projects within its Massachusetts service territory.

c.) Approximately 76% of the distribution feeders (within the substation fence) are automated at various levels as detailed in Question 3 above. Automation outside the fence is very limited (Question 3 above) including only recent line recloser installations and the Worcester Smart Grid Pilot area feeders.

d.) PLC's were typically used for substation automation projects after 1998.

e.) Historically, substation automation projects were limited to new substations or substations undergoing major additions/rebuilds. This allowed for efficient investment in the system as automation was built in conjunction with other work and in substations that would not undergo additional upgrades in the future. In a limited number of cases a specific subset of substation equipment may be automated to enable a pilot or other special project (e.g., feeder automation associated with the Worcester Smart Grid Pilot).

5. The EMS/SCADA system is currently in the process of being upgraded (refer to our responses related to "enabler" 1, DMS/SCADA). Currently the EMS/SCADA system supplying MA has approximately 179 RTU's connected to National Grid distribution substations.

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 –
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 –
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 –
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 –
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 –
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 –
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 –
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.

<u>Level 1</u> (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.

<u>Level 2</u> (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.

<u>Level 3</u> (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

			Response to data request DPU-6-15					
			a	**b**			**c**	
Summary			**Vendor**	**Vendor Estimate**			**Filing Page Reference**	**Notes**
	2012			# Units	Unit Price	Total		
	# devices	**Cost**						
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 –
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 –
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 –
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 –
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 (e.g., 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 –
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 –
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 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.