Metrics and Benefits Reporting Plan

ILLUSTRATIVE SAMPLE

E&G Smart Grid Program

Contract ID: DE-OE0000XXX

Project Type: Regional Demonstration

Revision: V1 - Draft Submittal

Company Name: Gas & Electric Company

March 15, 2011

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1. Introduction

This document represents the Metrics and Benefits Reporting Plan for the Electric & Gas (E&G) Smart Grid Program. E&G is a Transmission & Distribution utility serving 500,000 electric customers in Connecticut. The E&G Smart Grid Program is classified as a Regional Demonstration. E&G will work with selected consultants, contractors and vendors to complete the installation of a service territory-wide AMI system, including necessary backhaul equipment, communication systems, pricing programs, and approximately 450,000 smart meters at residential locations, and 45,000 meters at commercial locations. Industrial customers are equipped with Interval Data Recorders that communicate hourly usage to the utility by phone line. Also, the project will consist of the deployment of distribution automation equipment on 90 circuits in our northern service region and the deployment of 10 Phasor Measurement Units (PMUs) within our transmission network.

The following sets forth the objectives, benefits, key asset deployment milestones, Build and Impact Metrics, associated data collection, aggregation and analysis methods, monetary investments, baseline data, market place innovation, and collaboration/interaction with the DOE necessary to accomplish E&G's fully integrated Smart Grid project.

For background, E&G's plan begins with a brief project overview and summary of project benefits.

1.1 Introduction to Gas & Electric Company

<Description of E&G and its service territory>

Table 1- E&G's Service Territory

E&G's Service Territory	
Total number of customers:	
Residential	450,000
Commercial	45,000
Industrial	5,000
Peak load:	
Summer	X MW
Winter	Y MW
Total MWh sales	
Residential	ABC MWh
Commercial	DEF MWh
Industrial	GHI MWh
Total number of substations	X
Total number of distribution feeders	Y
Total miles of distribution line	Z
Total number of transmission substations	ZZ

1.2 Project Overview

The E&G Smart Grid Program is a Regional Demonstration project. It includes the design and installation of a system-wide, fully integrated AMI system facilitated by the installation of the following key smart grid features, including smart meters, load control devices, a communication network and associated infrastructure, distribution automation devices, critical-peak pricing program, cyber security upgrades, and phasor measurement units (PMUs). E&G's key smart grid features will be deployed to support the following smart grid functions, including wide area monitoring, visualization, and control, automated voltage and VAR control, diagnosis and notification of equipment condition, real-time load measurement and management, and customer electricity use optimization. The successful accomplishment of these project objectives will benefit residents throughout Connecticut.

<Note: This sample MBRP depicts a Regional Demonstration without energy storage. There are additional reporting requirements for energy storage projects (e.g., specific baseline data requirements, data acquisition system (DAS) outline, energy storage applications) that are outlined in the Guidebook for ARRA SGDP/RDSI Metrics and Benefits>

Overall, specific goals and objectives of E&G's Smart Grid project include:

1. Providing customers with hourly usage information to make energy usage decision to enable Customer Electricity Use Optimization which may result in reduced electricity cost, deferred capacity investments, reduced ancillary service cost, reduced congestion cost, reduced electricity losses, and/or reduced emissions;

2. Reducing operations and maintenance costs as a result of the automation of metering reading and distribution operation activities;

3. Improving reliability and reducing restoration time through location and identification of outages by installing smart meters and integrated AMI and OMS applications to identify and scope outages;

4. Reducing peak loads (KW) and overall energy usage (kWh) by educating our customers about their energy usage;

5. Improving situational awareness and mitigate system disturbances through the analysis PMUs data;

6. Reducing outage durations and impacts on customers through the use of distribution automation equipment, primarily automated switches, to identify, locate, and restore affected portions of the distribution system that are not damaged.

1.3 Project Benefits

Specific benefits of the project are creating jobs and supporting the deployment of new products, services, technologies and infrastructure which will help customers make informed decisions about their energy usage. Combined with pricing programs and load control technologies, customers (and E&G) will be able to effectively and reliably manage their peak demand, therefore resulting in reduced customer electricity costs, reduced system-wide capacity needs, reduced electrical losses, and reduced environmental impacts. E&G's project will systematically move away from manual operation toward grid automation using advanced sensing, communications, information processing and controls, effectively improving the utilization of generation, transmission and distribution assets, improving the reliability and resilience of electric transmission and distribution systems, and effectively reducing the frequency and duration of power interruptions.

Specific smart grid benefits supported by E&G's Cross Cutting project and aligned with the DOE are included in Table 2 on the following page:

Table 2- Smart Grid Benefits for E&G's AMI Project

Benefit Category	Benefit	Provided by Project?	Remarks / Estimates
Economic	Arbitrage Revenue (consumer)*		
	Capacity Revenue (consumer)*		
	Ancillary Service Revenue (consumer)*		
	Optimized Generator Operation (utility/ratepayer)	MAYBE	The impact of demand response may not impact the generation profile, but E&G will work with ISO-NE and DOE to determine if there are benefits.
	Deferred Generation Capacity Investments (utility/ratepayer)	MAYBE	Information will be collected for these benefits however it has not been determined if these benefits will be demonstrated. Benefits will be highly dependent upon the number of customers enrolling in demand response or dynamic pricing programs.
	Reduced Ancillary Service Cost (utility/ratepayer)	MAYBE	
	Reduced Congestion Cost (utility/ratepayer)	MAYBE	
	Deferred Transmission Capacity Investments (utility/ratepayer)	MAYBE	Analysis will be performed by the E&G planning group to determine if the peak demand and energy conservation benefits will offset the need for the 2013 proposed transmission and substation projects. A variance analysis will be completed annually.
	Deferred Distribution Capacity Investments (utility/ratepayer)	MAYBE	
	Reduced Equipment Failures (utility/ratepayer)	YES	
	Reduced Distribution Equipment Maintenance Cost (utility/ratepayer)	YES	
	Reduced Distribution Operations Cost (utility/ratepayer)	YES	
	Reduced Meter Reading Cost (utility/ratepayer)	YES	
	Reduced Electricity Theft (utility/ratepayer)	YES	
	Reduced Electricity Losses (utility/ratepayer)	YES	
	Reduced Electricity Cost (consumer)	YES	
	Reduced Electricity Cost (utility/ratepayer)*		
Reliability	Reduced Sustained Outages (consumer)	YES	
	Reduced Major Outages (consumer)	YES	
	Reduced Restoration Cost (utility/ratepayer)	YES	
	Reduced Momentary Outages (consumer)	MAYBE	PQ will be monitored, but it has not been determined if the proposed corrective action plan will reduce the number of momentary outages.
	Reduced Sags and Swells (consumer)	MAYBE	
Environmental	Reduced carbon dioxide Emissions (society)	YES	
	Reduced SO_X, NO_X, and PM-10 Emissions (society)	YES	
Energy Security	Reduced Oil Usage (society)	YES	
	Reduced Wide-scale Blackouts (society)	MAYBE	Due to the early infancy of advanced transmission applications, E&G does not believe it will be able to reduce wide scale black outs within the project monitoring period, but will report this metric.

*These benefits are only applicable to energy storage demonstrations.

2. Key Technology Development and Asset Deployment Schedule

E&G's key asset deployment schedule, as identified in E&G's Project Management Plan, is included as Appendix A – E&G's Integrated Schedule. Key baseline data will be gathered and analyzed prior to asset deployment and post-deployment data will be gathered and analyzed in accordance with this Metrics and Benefits Plan and DOE reporting frequencies (i.e. Build-quarterly and Impact-*project specific*). See Section 4 of this report for more information regarding Baseline Data, including proposed timelines, data sources, and analysis methods.

In addition to the attached integrated schedule, key project milestones and how they are related to system impact goals are included as a list in Table 3 below.

Table 3- Key Project Milestones and Impact Metrics

Date	Type of Milestone	Build / Impact Dependency
xx/yy/2010	Procurement Contracts with Vendors	Engineering / Equipment Deployments
xx/yy/2010	Engineering and Design of Automated feeders and PMUs selected at optimized locations	DA and PMU equipment deployments
xx/yy/2010	Field Installation of Communications Backbone	AMI meter installation DA sensors and controls PMU installation
xx/yy/2011	Field Installation & System Commissioning of AMI Phase I and MDM System	Dynamic Pricing Pilot (PUC approved) Meter Operations Productivity In Home Displays
xx/yy/2011	AMI – MDM Complex Billing and Usage Application, Integration and Testing	Deployment of Customer Systems Net metering of solar units (system) Meter tampering detection
xx/yy/2012	PUC Approval of Dynamic Pricing Program for all residential customers	Marketing /enrollment Customer Electricity Usage reductions
xx/yy/2012	DA equipment field installation, testing, operations training and SOPs complete	Reliability improvements primarily related to SAIFI and CAIDI
xx/yy/2012	AMI - OMS integration, process re-design, and testing complete	Outage response duration improvements CAIDI improvements (potentially with DA equipment)

<Note: This sample MBRP depicts a Regional Demonstration that is substantially focused on asset deployment and not technology development. Milestones are not all-inclusive and will vary by project.>

3. Build and Impact Metrics

This section contains each of the Build and Impact Metrics that E&G will report. The metrics apply to the total project supported by the DOE and E&G cost-shared funds. Included in the tables (referenced as Appendices in the following sub-sections) are explanations of the data collection methods, frequency, and aggregation and analytical methods that will be used to determine the metrics and the associated benefits achieved by E&G project.

3.1 Monetary Investments

E&G will report funds that have been expended for the deployment of the Smart Grid Program. The report will include the DOE grants and the cost share of all recipients (as suggested in the guidance on Monetary Investments 'G-004 Monetary Investments'). E&G will report investments related to the 'installed cost of equipment' once the assets are deployed and considered utility assets.

Financial analysts will utilize the E&G Financials System to determine or estimate the monetary investments related to the installation of equipment. E&G expects to develop some estimates, based on vendor contracts and internal labor rates for equipment installation, testing, and commissioning and apply those costs as assets are installed.

Monetary Investments metrics that will be reported by E&G are highlighted in green in Table 4 on the next page:

Table 4 – Applicable Monetary Investment Build Metrics

AMI				**Customer Systems**					
Monetary Investment	AMI Back Office Systems	Communication Equipment	AMI Smart Meters	Customer Back Office Systems	Customer Web Portals	In Home Display	Smart Appliances	Programmable Controllable Thermostats	Participating Load Control Device
ARRA	-	-	-	-	-	-	-	-	-
Cost Share	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-
Other Assets and Costs that do not align with the categories listed above:									
Electric Distribution									
Monetary Investment	Back Office Systems	Distribution Management System	Communications Equipment / SCADA	Feeder Monitor / Indicator	Substation Monitor	Automated Feeder Switches	Capacitor Automation Equipment	Regulator Automation Equipment	Fault Current Limiter
ARRA		-	-	-	-	-	-	-	-
Cost Share		-	-	-	-	-	-	-	-
Total		-	-	-	-	-	-	-	-
Other Assets and Costs that do not align with the categories listed above:									
Electric Distribution – Distributed Energy Resources (DER)									
Monetary Investment	DER Interface / Control Systems	Communication Equipment	DER / DG Interconnection Equipment	Distributed Generation (DG)	Renewable DER	Stationary Electricity Storage	Plug-in-Electric Vehicles		
ARRA		-	-	-	-	-	-		
Cost Share		-	-	-	-	-	-		
Total		-	-	-	-	-	-		
Other Assets and Costs that do not align with the categories listed above:									
Electric Transmission									
Monetary Investment	Back Office Systems	Advanced Applications (Software)	Dynamic Rating Systems	Communication Equipment	PDC	PMU	Line Monitoring Equipment		
ARRA		-	-	-	-	-	-		
Cost Share		-	-	-	-	-	-		
Total		-	-	-	-	-	-		
Other Assets and Costs that do not align with the categories listed above:									

3.2 Jobs Reporting

E&G will track and report the number and types of jobs by labor category and SGDP/RDSI project classification, quarterly. In coordination with the DOE, jobs created and retained will be reported using the appropriate DOE full-time equivalents (FTEs) calculation, resulting from both ARRA funding as well as E&G's funds.

Table 5- Job Reporting by Category and Smart Grid Project Classification (FTEs)

Job Reporting by Category and Smart Grid Project Classification (FTEs)					
Job Category	**Customer Systems**	**AMI**	**Electric Distribution**	**Electric Transmission**	**TOTAL**
Managers	1 FTE	1 FTE	1 FTE	1 FTE	4 FTE
Engineers	5 FTE	1 FTE	2 FTE	2 FTE	10 FTE
Computer-related Occupations	1 FTE	2 FTE	1 FTE	1 FTE	4 FTE
Environmental and Social Scientists	N/A	N/A	N/A	N/A	0 FTE
Construction, Electrical, and Other Trades	N/A	20 FTE	5 FTE	5 FTE	30 FTE
Analysts	1 FTE	1 FTE	N/A	N/A	2 FTE
Business Occupations	1 FTE	N/A	N/A	N/A	1 FTE
Recording, Scheduling, and Computer Operator Occupations	1 FTE	1 FTE	2 FTE	1 FTE	5 FTE
TOTAL	10 FTE	25 FTE	11 FTE	10 FTE	56 FTE

<Note: Recipients can further divide each Job Category into Prime Contractor, Sub-Contractor, and Vendor.>

3.3 Equipment Asset Build Metrics

E&G will identify the equipment asset build metrics as either project or system metrics throughout the plan and reporting process. E&G will report project metrics for the assets and programs funded by the ARRA and cost share. E&G will report the system metrics for the applicable Smart Grid assets and programs that are already in place or will be deployed using only E&G funding during the reporting period. The system metrics will be listed as a cumulative amount including the project representing the total assets deployed on the Transmission and Distribution Systems. As discussed, E&G has already deployed 10,000 AMI meters as part of a pilot representing the amount on the system. The system metric for meters will equal the number of meters installed for the quarter as a result of the project plus the 10,000 meters installed as part of the pilot.

3.3.1 AMI Assets

The project will deploy 450,000 meters over the next 3 years. A pilot project consisting of 10,000 smart meters was completed in 2008, and prior to receiving this SGDP/RDSI award, it was our intention to deploy 20,000 per year until during the SGDP/RDSI monitoring period. Also, approximately 10% of AMI meters will be used for Power Quality monitoring at key distribution points. Moreover, in 2013, the AMI system will be integrated into the Outage Management System (OMS), and therefore, E&G doesn't expect any reliability impact until that time. Lastly, our AMI system will utilize an RF mesh network with wireless carrier backhaul and fiber-optic site key substations. Asset Summary:

- 440,000 residential meters (project)
- 45,000 commercial meters (project)
- 495,000 meters (system once project is complete)
- 10% of meters, used for PQ monitoring (project)
- AMI and Outage Management System (OMS) Integration (project)

Appendix B1 presents the Build Metrics for E&G's AMI Assets and their associated data collection methods, frequency, and aggregation and analytical methods.

3.3.2 Customer Systems Assets

E&G plans to deploy smart meters that can interface with customer communication networks for the eventual adoption of home area networks (HAN) by our customers (in other words, E&G will not purchase or offer a Home Area Network as part of this project). While E&G anticipates some customers to eventually purchase smart appliances, we don't intend to deploy any of these products as part of this project or expect to know when customers purchase them. Furthermore, E&G will provide a web-portal that will be available for all customers receiving AMI meters. Customers can enroll in the web-portal services and receive information related to energy usage and recommendations for better ways to manage their energy usage. As part of the marketing efforts for the Dynamic Pricing Program, E&G will offer the first 5,000 customers who enroll an In Home Display. Asset Summary:

- Web Portal with querying and customer notification capabilities (project)
- 5,000 In Home Displays (project)

Appendix B2 presents the Build Metrics for E&G's Customer Systems Assets and their associated data collection methods, frequency, and aggregation and analytical methods.

3.3.3 Electric Distribution Assets

E&G will deploy distribution automation in the northern service region. These feeders comprise xy% of our total distribution system. We intend to enable automatic feeder switching and coordinated voltage management as part of this distribution automation implementation. We expect to be able to improve reliability for our customers and reduce distribution line-loses utilizing this new functionality. Asset Summary:

- Project: 270 switches covering 90 circuits (project)
- 30 switches covering 6 feeders installed from 2004-2006 (system)
- System: 310 switches covering 96 circuits (system when SGDP project is complete)
- 310 capacitor automation upgrade packages covering 90 circuits (project)

Appendix B3 presents the Build Metrics for E&G's Electric Distribution Assets and their associated data collection methods, frequency, and aggregation and analytical methods.

3.3.4 Electric Transmission Assets

E&G will deploy 10 phasor measurement units (PMUs) within our transmission network. These devices will feed information to a Phasor Data Concentrator (PDC) node in the south east region. Based on our transmission planning estimates, we believe that these PMUs will cover 90% of our service territory including our most critical interconnections and substations. As part of this PMU deployment, we are developing an advance grid operations application for monitoring and advance notification of grid disturbances outside our transmission network. We are also deploying a dynamic line rating (DLR) system on our northern interface to improve the transfer capability over these lines from new renewable energy resources. Asset Summary:

- Project: 10 PMUs / 1 PDC (project)
- Project: DLR Equipment for Northern interface: load cells, radiation sensor, power supply, battery back, communications station (project)
- Project DLR Advanced Application (project)
- System: 10 PMUs (when SGDP project is complete)

Appendix B4 presents the Build Metrics for E&G's Electric Transmission System Assets and their associated data collection methods, frequency, and aggregation and analytical methods.

3.3.5 Distributed Energy Resources

No distributed generation is being deployed as part of this project. We currently have a net-metering tariff for our 324 residential customers with photovoltaic (PV) systems. As part of our AMI deployment, we will be changing out our legacy dual-metering assets and conducting a pilot to study the hourly output of PV for those customers. Results from that study will inform the design of a distributed renewable energy tariff for residential customers expected to start 2013.

Appendix B5 presents the Build Metrics for E&G's Distributed Energy Resources and their associated data collection methods, frequency, and aggregation and analytical methods. In summary, this includes:

- 324 PV units representing 245 kW of capacity (system)
- Additional PV added to the system will be reported (system)

3.4 Pricing Programs

We currently offer a Time-of-Use (TOU) rate for commercial and industrial customers. We plan on offering a Time-of-Use – Critical Peak Pricing (TOU – CPP) rate to all our residential customers as well. This rate is currently being reviewed by our commission and a decision is expected by March 2011. We are currently developing a marketing and awareness campaign beginning January 2011. The first 5,000 customers to enroll in this program will also receive in-home displays that will provide customers with event, usage, and price information. Program Summary:

- TOU-CPP (project, residential only)
- TOU C&I and TOU-CPP Residential (system)

Appendix B6 presents the Build Metrics for E&G's Pricing Program and their associated data collection methods, frequency, and aggregation and analytical methods.

3.5 Impact Metrics

E&G will prepare and submit Technology Performance Reports (TPRs) which shall document and summarize the status of identification and quantification of impact metrics and cost-benefit data and analyses with respect to the pre-demonstration and projected baseline system configurations and the demonstrated system configuration. Since this project is demonstrating more than one category/group of technologies, E&G will be developing TPRs for each of these. Interim TPRs will serve as a basis for E&G and DOE to collaborate on validating that the proposed metrics are optimal for fully characterizing the technical and economic performance of the system). E&G will prepare Interim TPRs semi-annually and a Final TPR for each suite of technologies. One Interim TPRs will be submitted prior to asset deployment. Appendix A – Integrated Schedule includes the planned dates for TPR submissions.

The tables included in this section outline the Impact Metrics for E&G's AMI, Customer Systems, Electric Distribution Systems, and Electric Transmission Systems and their associated data collection methods, frequency and aggregation and analysis methods, in relation to the associated benefits that the project will demonstrate and report. E&G recognizes that some impact metrics will require calculations and data normalization techniques.

3.5.1 Project and System Metrics

E&G will identify the impact metrics as either project or system metrics throughout the plan and reporting process. E&G will report project metrics for impacts observed specific to the area project assets, functionality or programs are implemented. For example, feeder load will be measured on specific circuits where voltage optimization and demand response will be implemented as a result of the Distribution and AMI & Customer system assets. E&G will report system metrics for impacts observed on the entire transmission or distribution system. For example, the impact of demand response and voltage optimization on the generation costs and resource mix will be measured at the system level.

3.5.2 AMI and Customer Systems

Our utility is a distribution company but we will collaborate with our wholesale power provider to determine the impact on the peak generation mix. Ancillary service costs will also be requested by the wholesale power provider. Hourly Customer Electricity Usage information on the project level does not currently exist. E&G currently has hourly load information only at the circuit level and will provide that information, if requested. E&G will have the ability to collect hourly load information for residential customers once the project's smart meters are installed. After the meters are installed, a representative grouping of customers will be identified and used to establish the appropriate hourly load profiles compromised of 8,760 hours of data per year until such time that system-wide interval data is available. In summary, the Impact metrics will include:

- Peak generation resources needed to meet peak demand compared to baseline which includes peak demand growth projections based on customer growth and usage per customer without AMI and corresponding Demand Response programs (system); and
- Customer electricity usage profile based on 8,760 hours and monthly data for representative customer classes compared to base line estimates which include assumptions regarding customer usage, load growth and energy prices. (project)

Appendix C1 presents the Impact Metrics for E&G's AMI Assets and Customer Systems and their associated data collection methods, frequency and aggregation and analytical method.

3.5.3 Electric Distribution Systems

We expect to be able to improve reliability for our customers and reduce distribution line-loses as a result of the distribution automation to be implemented. Automatic feeder switching will not prevent outages, but it will reduce the scope and duration of outage impacts. This will be accomplished through the automatic isolation and reconfiguration of faulted segments of distribution feeders via sensors, controls, switches, and communication systems. Also, automatic feeder switching can reduce or eliminate the need for a human operator or field crew for operating distribution switches. This saves time, reduces labor cost, and eliminates "truck rolls." Moreover, our coordinated voltage management effort will allow the transmission and distribution network to be optimized for electricity efficiently (lower losses), and can allow utilities to reduce load through "energy conservation voltage reduction" will maintaining adequate service voltage. These load reductions may reduce the amount of generation required. In summary, the Impact metrics will include:

- Reliability indices based on IEEE STD-1366 will be calculated using the OMS. Operations personnel and reliability analysts will utilize data normalization techniques when necessary to ensure a consistent data set for the comparison (project).
- The number of major events like named storms will be measured and analyzed separately (project).

- System line-losses will be calculated by the Distribution Management System (DMS) Line Loss application software. Engineering & Planning resources will estimate line losses for feeders affected by the project utilizing DMS and SCADA data (project).
- Meter Operations costs will be based on the number of manual tasks that are automated compared with baseline projections (project).

Appendix C2 presents the Impact Metrics for E&G's Electric Distribution Systems and their associated data collection methods, frequency, and aggregation and analytical methods.

3.5.4 Electric Transmission Systems

From this project, phasor data will be made available (collected) and E&G will be able to conduct engineering analysis towards use of this data in congestion management tools. The analysis results may lead to creation of new or enhanced congestion management tools creating a path towards reducing Congestion MW and/or Congestion Cost. Furthermore, this project will provide wide area monitoring and situation awareness capabilities for E&G's transmission system. This has tremendous potential for improving bulk electric system reliability, by reducing probabilities of wide area cascading outages; improving dynamic models; and voltage stability tools. In summary, the Impact metrics will include: *<Note: Not meant to be all-inclusive. Modify or add descriptions as needed for your project.>*

- Peak generation resources needed to meet peak demand compared to baseline which includes peak demand growth projections based on customer growth and usage per customer without AMI and corresponding Demand Response programs (system)
- Peak load and mix (system)
- Generation costs (system)
- Equipment failure incidents (project)
- Congestion amounts and costs (project)
- Transmission line/equipment overload (project)
- Transmission line load
- Deferred transmission capacity investments (project)
- Operations Costs (project)
- Reliability costs (project)
- Transmission losses (project)
- Transmission power factor (project)

Appendix C3 presents the Impact Metrics for E&G's Electric Transmission Systems and their associated data collection methods, frequency, and aggregation and analytical methods.

4. Baseline Data

This section provides the methods for how baseline information and forecasts will be developed for each Build and Impact Metric, including sources of data, how each metric will be estimated at project commencement, and appropriate calculations or analysis. E&G interprets the baseline as the utilities proposed Smart Grid scope, timeline, and forecasted impacts and benefits if the ARRA funding had not been awarded.

E&G, with the addition of Federal funding, will install and integrate an industry leading AMI system, distribution automation devices, and transmission assets that will facilitate the deployment of a TOU-CPP pricing program and spur greater demand reduction, energy savings, efficiency, and reliability. Without Federal funding, E&G's planned AMI project (in relation to the federally funded enhanced project) would have included the following features:

1) Limited customer access to AMI infrastructure and communications backbone over DOE SGDP/RDSI monitoring period ~ 100,000 meters based on an annual deployment of 20,000 per year over the five year monitoring period. E&G is assuming that deployment would be evenly distributed over the five year period;

2) Minimal smart meter features (i.e. interval reads, outage and reporting detection, tamper detection, etc.). Remote disconnect / reconnect switch, and PQ monitoring capabilities would not be deployed;

3) No TOU-CPP pricing program to impact demand and energy savings at the residential level based on limited marketing and customer education funding;

4) Limited to no customer system assets, including no in-home displays, no web-portals;

5) No customer interface card allowing for open integration and communication between devices;

6) Limited distribution asset upgrades for improved reliability and efficiency (The business as usual scenario was to upgrade the five worst performing circuits per year pending internal and regulatory approval.);

7) No transmission assets, PMU, PDC, or dynamic line rating system deployed;

In order to characterize the baseline data and projections for E&G's Build Metrics , E&G will conduct a thorough review of its 2-year budget capturing planned Build Metrics values had the Federal funding not been awarded. Additionally, in order to characterize the baseline data for E&G's Impact Metrics, E&G will compile all necessary sources of historical data for each Impact Metric in order to estimate project impact values had the Federal funding not been awarded. Special consideration will also be made to take into account how the baseline operating and maintenance expenses will be affected by Smart Grid assets and functionality.

At project commencement each Build and Impact Metric will be estimated from a review of the E&G Company Plan, which includes proposed levels of asset deployments (had the Federal funding not been awarded), and/or a review of the current system levels/statistics and any necessary calculations in order to capture the appropriate baseline value. Furthermore, with regards to determining each baseline Build and Impact Metric over-time, E&G will use industry accepted methods for estimating projections and forecasting values for the full five-year term of the Smart Grid Program. Specifically, Build Metrics are to be estimated using projections and forecasts while Impact Metrics, where statistics are available, are to be estimated based on 3- year historical data, including normalization where appropriate.

Also, E&G plans to collaborate with system operators and retail power providers to collect necessary data regarding generation, ancillary services, etc.

Please refer to Appendix D1 – E&G's Baseline Build Metrics for AMI.

<Note: Example is not meant to be all-inclusive. Appendix D1 should ultimately be consistent with both Appendix B – E&G's Build Metrics and Appendix C– E&G's Impact Metrics. The tables should list information related to each metrics' proposed source of data, method for estimating data at project commencement and each metrics' proposed method for determining values over-time.>

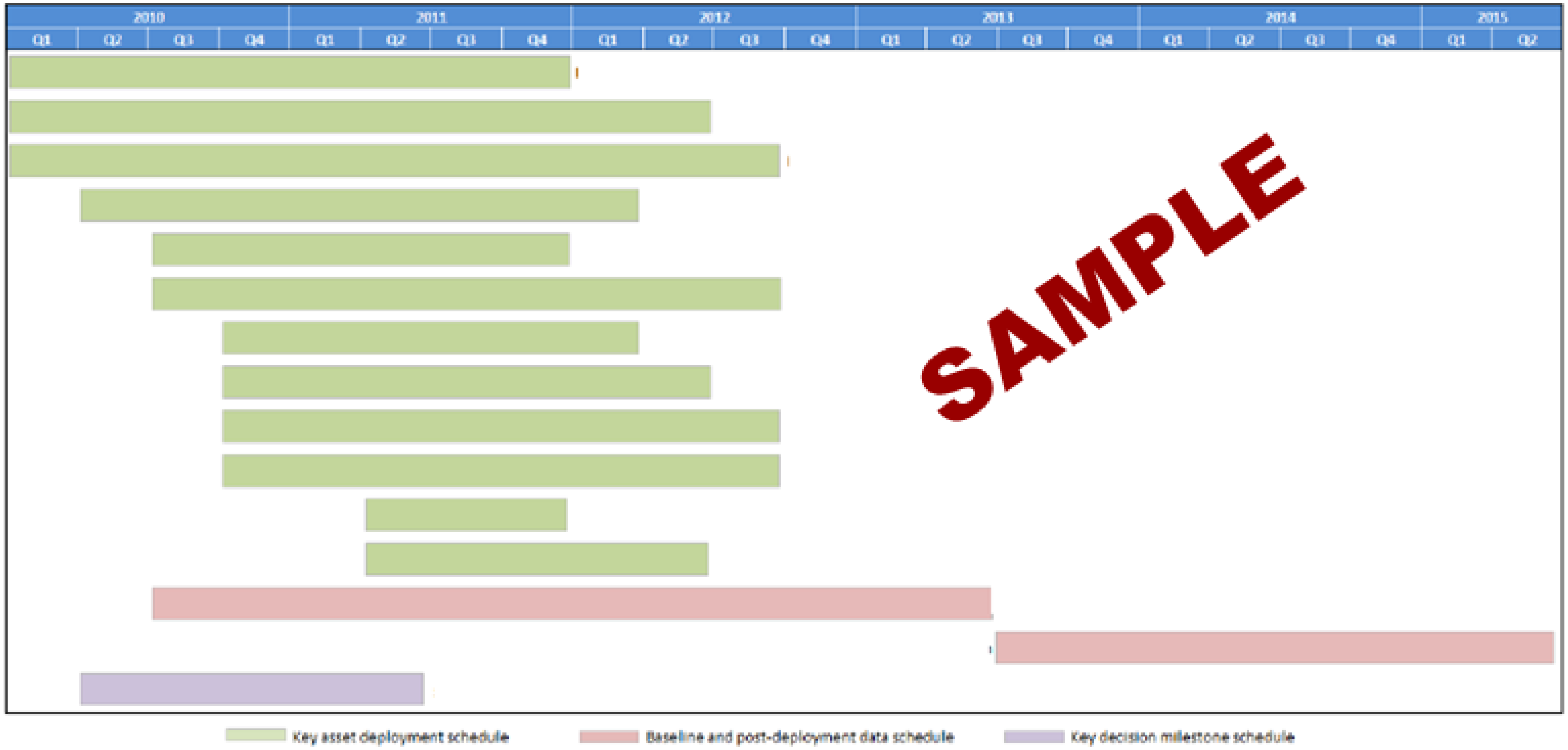
5. Market Place Innovation Reporting

E&G's project will facilitate new jobs, products, services, and markets that will develop in response to the growth of E&G's smart grid. E&G project investments, specifically AMI Customer Interface technology and gateways, will enable customers to purchase new products and services for appliance monitoring and control. E&G's system will provide the foundation to collect substantial information, in regards to market place innovation, once the key AMI, customer systems and electric distribution systems are in place. E&G will work in coordination with the DOE to provide and report on new programs and joint ventures with suppliers, as well as novel methods of taking advantage of the full functionality E&G's system provides.

6. Collaboration and Interaction

E&G will coordinate with our wholesale power provider and system operator (ISO-New England) so they can support data gathering and analysis related to generation resources and costs. Also, where appropriate E&G will coordinate and collaborate extensively with the DOE to ensure on time and on budget activities for E&G's AMI project. E&G's General Manager will be the main contact for all collaboration and interaction between the DOE and E&G. Specific areas where collaboration is necessary include: 1) key deliverables (i.e. Project Management Plan, Cyber Security Plan, Metrics and Benefits Reporting Plan, etc.), including plan reviews and timely submittals and 2) all on-going DOE and Federal reporting requirements (i.e. Monthly Progress Reports, Quarterly Jobs reporting, Quarterly Federal Financial reporting, invoicing, etc.). In addition to working with DOE staff, E&G intends to collaborate and coordinate with the DOE to support other data requests or analysis that will improve the overall impact of the Smart Grid investments.

Appendix A – E&G's Integrated Schedule



Appendix B1 – Build Metrics for E&G's AMI Assets

BUILD METRICS: AMI Assets				
Metric	Remarks	Value		Data Collection Method
		Project	System	
End-Points (meters):				
Residential	Network interface for to enable customer HAN	440,000	450,000	Installation records and/or Head End System software registration log files
Commercial		45,000	45,000	
Industrial		0	0	
Portion of Customers with AMI:				
Residential		98%	100%	Installation records and/or Head End System software registration log files
Commercial		100%	100%	
Industrial		0%	0%	
Metering Features:				
Interval reads < 1 hour		Yes	Yes	Product specification sheets and meter attributes functionality activated /listed in Head End Server
Remote Connection/Disconnection	Feature will be employed for all residential meters in the service territory	Yes	Yes	
Outage Detection/Reporting	All meters	Yes	Yes	
Power quality monitoring	Feature will be employed for 4,850 meters	Yes	Yes	
Tamper detection	All meters	Yes	Yes	
Backhaul Communications Network	Wireless carrier and utility telephone and fiber assets	Yes	Yes	# of backhaul assets operational will be queried and reported from Head End System
Meter Communications Network	RF mesh (900 MHz) LAN, ZigBee for customer interface network	Yes	Yes	System description from vendor
Head End system	Data storage, querying, command and control functionality	Yes	Yes	System description from vendor listing functionality to be employed
Meter Data Management System	Complex billing and dynamic pricing programs, and remote service connection/disconnection	No	Yes	System description and integration map from vendor
Enterprise systems integration:				
Customer Information System	Billing function is integrated as part of CIS	Yes	Yes	Selected software tests, queries, and use case or field test
Outage management system		Yes	Yes	

Appendix B2 – Build Metrics for E&G's Customer Systems

BUILD METRICS: Customer Systems Assets				
Metric	Remarks	Value		Data Collection Method
		Project	System	
In-home displays	Provides historical, current, and month-to date energy usage, prices and peak event notification	5,000	5,000	Installation records and/or CIS records
Web portal accounts	2-way system providing outbound communications	TBD	TBD	Web portal software will measure # of customers visiting the site, # of enrolled in web portal services, and # electing to receive info

Appendix B3 – Build Metrics for E&G's Electric Distribution Assets

BUILD METRICS: Electric Distribution System Assets				
Metric	Remarks	Value		Data Collection Method
		Project	System	
DA Devices:				
Portion of System with SCADA	SCADA is only used for monitoring and some substation control (not considered DA)	0%	100%	Engineering & Planning reports indicated all substations equipped with SCADA
Portion of System with DA	DA coverage is only for 3 Phase main line circuits	xy%	xy%	Engineering & Planning analysis based on total number of circuits, circuit miles, and customers
Automated Feeder Switches	Can perform fault location isolation service restoration of 15 feeders	270	300	Installation Records/System software and field tests
Automated Capacitors	Existing capacitor banks will be upgrade with communications and remote actuators on 15 feeders	310	310	Installation Records and/or System software registration log files
DA System Features/Applications:				
Fault Location, Isolation and Service Restoration (FLISR)	Features will be employed once all assets are installed and tested 3rd Quarter 2011	Yes	Yes	Distribution operations records or system software indicating the # of switching instances for maintaining reliability
Voltage Optimization	Features will be employed once all assets are installed and tested 1st Quarter 2012	Yes	Yes	Distribution operations records or system software indicating the # of switching instances for maintaining reliability

Appendix B4 – Build Metrics for E&G's Transmission Distribution Assets

BUILD METRICS: Electric Transmission System Assets				
Metric	Remarks	Value		Data Collection Method
		Project	System	
Portion of transmission system covered by Phasor Measurement systems	Coverage estimate based on key interconnection points with PMUs and customers affected	40%	40%	Engineering & Planning Estimate based on Installation Records/System software (including lines, transmission substations, and key equipment)
Phasor Measurement Systems				
PMUs	Number of PMUs	10	10	Installation Records/System software (including make and model, security measures, consistency with NASPI and synchrophasor standards, substation name, location, nominal voltage level, settings, CEII designation, PT/VT and CT transducer make and model)
	Will increase observability of the grid's dynamic behavior in near-real time	-	-	
Phasor Data Concentrators	Number of PDCs	1	1	Installation Records/System software (including make and model, security measures, consistency NASPI and synchrophasor standards, number of PMUs networked)
	Will allow for reliable data collection of the grid's dynamic behavior in near-real time	-	-	
Communications Network	RF and fiber assets	-	-	System description from vendor
Advanced Transmission Applications				
Angle/Frequency Monitoring	Applications utilizing phasor data or other Smart Grid information for transmission operations and planning	YES	NO	Selected software tests and data logs, analysis reports, to confirm applications are operational
Post-mortem Analysis (including compliance monitoring)		YES	NO	
Voltage Stability Monitoring		YES	NO	
Thermal Overload Monitoring		YES	NO	
Improved State Estimation		YES	NO	
Steady-State Model Benchmarking		YES	NO	

Appendix B5 – Build Metrics for E&G's Distributed Energy Resources

BUILD METRICS: Distributed Energy Resources				
Metric	Remarks	Value		Data Collection Method
		Project	System	
Distributed Generation:				
Number of units	Project will only monitor existing DER on the system. Metrics are not related to SGDP/RDSI funding	0	324	Installation records, system software, and asset repository (GIS)
Total installed capacity (kW)		0	700	System software and asset repository (GIS)
Total energy delivered (kWh)		0	97,000	MDM software and/or AMI Head End system

Appendix B6 – Build Metrics for E&G's Pricing Programs

BUILD METRICS: Pricing Programs				
Policy/Program	Remarks	Value		Data Collection Method
		Project	System	
TOU-CPP	Off-peak rate is 10cents per KWh on peak rate is 93centers per kWh. Value dependent on enrollment	≥ 5,000	≥ 5,000	System Records queried from customer information system and or MDM
Net Metering	Only applicable for customers with DER	No	324	

Appendix C1 – Impact Metrics for E&G's AMI and Customer Systems

IMPACT METRICS: AMI and Customer Systems				
Metric	Remarks	Value		Data Analysis
		Project	System	
Metrics Related Primarily to Economic Benefits				
Hourly Customer Electricity Usage	Average hourly residential customer usage	8760 data file	N/A	Smart meters, AMI systems, and MDMS. MDMS export file (.csv) will be provided to DOE
Monthly Customer Electricity Usage	Average monthly residential customer usage	Monthly data file	N/A	Smart meters, AMI systems, and MDMS. MDMS export file (.csv) will be provided to DOE
Peak Generation and Mix				
Diesel 1		MW	5 MW	Information will be provided by wholesale power provider for winter and summer coincidental peak Additional information may be requested from Independent System Operator (ISO) if necessary to determine impact.
Diesel 2		MW	5 MW	
Diesel 3		MW	10 MW	
Simple Cycle Gas Turbine (SCGT)		MW	100 MW	
Combined Cycle (CCGT)		MW	200 MW	
Diesel 1		MWh	MWh	
Diesel 2		MWh	MWh	
Diesel 3		MWh	MWh	
SCGT		MWh	MWh	
CCGT		MWh	MWh	
Annual Generation Cost		$	$	Information will be provided by wholesale power provider. Additional information may be estimated or modeled based on Independent System Operator (ISO)
Hourly Generation Cost		$	$	Information will be provided by wholesale power provider. If information is not specific enough for E&G above generation costs will be divided by 8,760

Appendix C1 – Impact Metrics for E&G's AMI and Customer Systems (cont.)

IMPACT METRICS: AMI and Customer Systems				
Metric	**Remarks**	**Value**		**Data Analysis**
		Project	**System**	
Metrics Related Primarily to Economic Benefits				
Ancillary Services Cost	Ancillary costs will be prorated for northern region of service territory (project) if possible	$	$	Information will be provided by wholesale power provider. Additional information may be estimated or modeled based on Independent System Operator (ISO)
Meter Operations Cost	If needed, estimates will be developed for metering tasks and applied to the number of tasks per period	$	N/A	Utility work management and accounting systems will be used to query meter operations costs applicable to the project, meter reading, meter servicing, and service connection/disconnection
Truck Rolls Avoided		#	N/A	Utilize AMI Head End system to quantify the # of metering activities that would have required a truck roll if AMI was not installed; off-cycle meter reads, service connection/termination, high bill complaints, etc.
Metrics Related Primarily to Environmental Benefits				
Meter Operations Vehicle Miles	If needed, estimates will be developed for various metering tasks and the vehicle miles associated with those task. Different ranges will be developed for urban and rural regions of a service territory	miles	N/A	Utility's work management system will be queried to determine the meter operations tasks and the mileage estimates for each task will be applied and aggregated.
CO_2 Emissions		Tons	Tons	Terrapass.com or epa.gov will be used for calculations
Pollutant Emissions (SO_x, NO_x, PM-10)		Tons	tons	Terrapass.com or epa.gov will be used for calculations
Metrics Related Primarily to AMI System Performance				
Meter Data Completeness		0%	N/A	Aggregation of daily Head End server reports
Meters Reporting Daily		0%	N/A	Head End Server reports aggregated and averaged for the reporting quarter

Appendix C2 – Impact Metrics for E&G's Electric Distribution Systems

IMPACT METRICS: Electric Distribution Systems				
Metric	Remarks	Value		Data Analysis
		Project	System	
Metrics Related Primarily to Economic Benefits				
Distribution feeder or equipment overload incidents	Switching operations that relieve equipment overloading will also be recorded	#	N/A	SCADA reports, event logs, direct equipment notification/alarm for specified equipment
Distribution feeder load	8,760 hrs for feeders affected by Demand Response	MW MVAR	N/A	SCADA and DMS reports and event logs
Deferred Distribution Capacity Investments	Not anticipated at this time	$	N/A	Semi-annual variance analysis of distribution capital investment plan
Equipment failure incidents	Limited to substation and mainline equipment e.g. station transformer, regulator, cap bank	#	N/A	SCADA reports, event logs, and supplemental information from distribution operations and maintenance team
Distribution Equipment Maintenance Cost	Average cost will be estimated for maintenance tasks	$	N/A	Utility work management system will be queried for distribution equipment maintenance tasks and cost estimates will be aggregated
Distribution Operations Cost	Average cost will be estimated for operations tasks	$	N/A	Utility cost accounting will be queried for distribution equipment operations tasks and cost estimates will be aggregated
Distribution Capacitor Switching Operations	Seasonal load and operational switching will be reported	#	N/A	DMS, Data logs from capacitor control system, or devices
Distribution Restoration Cost	A charge code will be set up for restoration on project circuits with DA technology	$	N/A	Restoration cost comparison between project and system feeders
Distribution losses (%)	Specific loss calc on project circuits compared to system average	%	N/A	DMS load information Distribution planning model analysis
Distribution power factor	Specific loss calc on power factor compared to system average	pf	N/A	DMS load information Distribution planning model analysis

Appendix C2 – Impact Metrics for E&G's Electric Distribution Systems (cont.)

IMPACT METRICS: Electric Distribution Systems				
Metric	**Remarks**	**Value**		**Data Analysis**
		Project	**System**	
Metrics Related Primarily to Economic Benefits				
Truck Rolls Avoided	Aggregation of manual distribution operations activities avoided by DA	#	N/A	Work Management System queries and logs
Metrics Related Primarily to Reliability Benefits				
SAIFI	Indices will be reported in accordance with IEEE STD-1366	Index	N/A	Reliability data and calculations will be managed from the OMS which will receive outage and restoration notifications from SCADA, AMI Head End server, and customer calls
SAIDI/CAIDI		Index	N/A	
MAIFI		Index	N/A	
Outage response time	Actual outage response will only be tracked for project circuits. An average outage response time will be estimated for the rest of the system	Minutes	N/A	OMS and CIS data will be utilized to determine time between outage notification and trouble ticket initiated for responders
Major Event Information	Named storms and other events excluded from standard reliability reports will be included	Event Statistics	N/A	Estimated outage and response times will be compared between the project and the distribution system
Metrics Related Primarily to Environmental Benefits				
Distribution Operations Vehicle Miles	If needed, estimates will be developed for various metering tasks and the vehicle miles associated with those task. Different ranges will be developed for urban and rural regions of the service territory	Miles	N/A	Work Management System or Fleet Management System will be queried to determine the meter operations tasks and the mileage estimates for each task will be applied and aggregated.
CO2 Emissions		Tons	Tons	Terrapass.com will be used to calculate CO2 emissions for vehicle miles
Pollutant Emissions (SOx, NOx, PM-10)		Tons	Tons	Terrapass.com will be used to calculate pollutant emissions for vehicle miles

Appendix C3 – Impact Metrics for E&G's Electric Transmission Systems

IMPACT METRICS: Electric Transmission Systems				
Metric	**Remarks**	**Value**		**Data Analysis**
		Project	**System**	
Metrics Related Primarily to Economic Benefits				
Peak Generation and Mix				
Diesel 1		N/A	5 MW	Information will be provided by wholesale power provider. Additional information may be estimated or modeled based on Independent System Operator (ISO)
Diesel 2		N/A	5 MW	
Diesel 3		N/A	10 MW	
SCGT		N/A	100 MW	
CCGT		N/A	200 MW	
Diesel 1		N/A	MWh	
Diesel 2		N/A	MWh	
Diesel 3		N/A	MWh	
SCGT		N/A	MWh	
CCGT		N/A	MWh	
Annual Generation Cost		N/A	$	Information will be provided by wholesale power provider. Additional information may be estimated or modeled based on independent system operator (ISO) System records; MW dispatch required to alleviate a transmission constraint System records; the associated cost to alleviate the transmission constraint
Hourly Generation Cost		N/A	$	
Peak Load and Mix		N/A	MW	
			Mix	
Annual Generation Dispatch		N/A	MWh	
Ancillary Services Cost		N/A	$	
Congestion (MW)		MW	N/A	
Congestion Cost		$	N/A	
Transmission line or overload incidents	The total time during the reporting period that project line loads exceeded design ratings	#	N/A	Data will come from the Transmission Management System (legacy EMS)

Appendix C3 – Impact Metrics for E&G's Electric Transmission Systems (cont.)

IMPACT METRICS: Electric Transmission Systems				
Metric	**Remarks**	**Value**		**Data Analysis**
		Project	**System**	
Metrics Related Primarily to Economic Benefits				
Transmission line load	Real and reactive power readings for those lines involved in the project. Information should be based on hourly loads and obtained from E&G application	MW MVAR	N/A	Data will come from the Transmission Management System (legacy EMS)
Deferred Transmission Capacity Investments	Not anticipated at this time	$	N/A	Semi-annual variance analysis of transmission capital investment plan
Equipment failure incidents	Limited to Transmission substations and major equipment	#	N/A	SCADA reports, event logs, and supplemental information from transmission operations and maintenance team
Transmission Equipment Maintenance Cost	Average cost will be estimated for maintenance tasks	$	N/A	Utility work management system will be queried for Transmission equipment maintenance tasks and cost estimates will be aggregated
Transmission Operations Cost	Average cost will be estimated for operations tasks	$	N/A	Utility cost accounting will be queried for transmission equipment operations tasks and cost estimates will be aggregated
Transmission Restoration Cost	A charge code will be set up for restoration on project circuits with PMU and DLR technology	$	N/A	Restoration costs based on three year history, excluding major events prorated for project area
Transmission losses		%	N/A	TMS load information, Transmission planning model analysis
Transmission power factor		pf	N/A	TMS load information, Transmissions planning model analysis

Appendix C3 – Impact Metrics for E&G's Electric Transmission Systems (cont.)

IMPACT METRICS: Electric Transmission Systems				
Metric	**Remarks**	**Value**		**Data Analysis**
		Project	**System**	
Metrics Related Primarily to Transmission Reliability				
BPS Transmission Related Events Resulting in Loss of Load (NERC ALR 1-4)		#	N/A	NERC Reports, supporting data and analysis
Energy Emergency Alert 3 (NERC ALR 6-2)		#	N/A	NERC Reports, supporting data and analysis
Metrics Related Primarily to Environmental Benefits				
Transmission Operations Vehicle Miles	If needed, estimates will be developed for various metering tasks and the vehicle miles associated with those task. Different ranges will be developed for urban and rural regions of a service territory	X Miles	N/A	Utility's work management system will be queried to determine the meter operations tasks and the mileage estimates for each task will be applied and aggregated.
CO_2 Emissions		Y tons	B tons	Terrapass.com or epa.gov will be used to calculate CO_2 emissions
Pollutant Emissions (SO_x, NO_x, PM-10)		X tons	A tons	Terrapass.com or epa.gov will be used to calculate pollutant emissions
Metrics Related Primarily to Energy Security Benefits				
Event Capture and Tracking				
Number, Type , and Size		Events	N/A	System records obtained from PDC and advanced applications
		Cause		
		Load lost		
Duration		Minutes/Hours	N/A	
PMU dynamic data		PMU Data	N/A	
Detection		Application	N/A	
Events Prevented (Corrective Actions)	Grid conditions observed with PMU technology that lead to operator action	XY	N/A	PMU/PDC data and supporting applications

Appendix C3 – Impact Metrics for E&G's Electric Transmission Systems (cont.)

IMPACT METRICS: Electric Transmission Systems				
Metric	**Remarks**	**Value**		**Data Analysis**
		Project	**System**	
Metrics Related Primarily to PMU/PDC System Performance				
PMU Data Completeness		X%	N/A	PDC data logs, Transmission Management System (TMS) data logs. # of data requests completed / # of scheduled and unscheduled data requests
Network Completeness		Y%	N/A	
PMU/PDC Performance	Usefulness of applications, including reliability improvements, markets and congestion management, operational efficiency	Reliability Quality	N/A	System analysis by E&G transmission operators based on PDC / TMS data logging files, and written surveys administered to transmission operators
Communications Performance		YES	N/A	
Application Performance		Description	N/A	

Appendix D1 –Baseline Build Metrics for E&G's AMI Assets

BASELINE ESTIMATES FOR BUILD METRICS: AMI Assets				
Metric	**Baseline Remarks**	**Baseline Estimate**	**Quarterly Forecast**	**Baseline Estimation Method**
End-Points (meters):				
Residential	No customer Interface	100,000	5,000	Capital budget scenarios and regulatory rulings on AMI projects in the state of CT to validate internal 5 year projection
Commercial		10,000	500	
Industrial		0	0	
Metering Features:				
Interval reads of 1 hour or less		Yes	N/A	Capital budget scenarios and regulatory rulings on AMI projects in the state of CT. Note: These baseline build metrics will affect many of the corresponding impact metrics
Remote Connection/Disconnection	No remote disconnect connect switch procured	No	N/A	
Outage Detection/Reporting		Yes	N/A	
Power quality monitoring	No PQ monitoring capability enabled	No	N/A	
Tamper detection		Yes	N/A	
Backhaul Communications Network	Wireless carrier only, utility systems telephone and fiber would not be integrated unless necessary	Yes	N/A	Capital budget scenarios and regulatory rulings on AMI projects in the state of CT Assessment of limited functionality offering to customers and (less) corresponding equipment and integration requirements
Meter Communications Network	RF mesh (900 MHz) LAN, No customer interface network purchased	Reduced Scope	N/A	
Head End system	Data storage, querying, command and control functionality	Yes	N/A	
Meter Data Management System	MDM would not be required due to limited functionality offered	No	N/A	
Enterprise systems integration:				
Customer information system	Billing function is integrated as part of CIS	Yes	N/A	Capital budget scenarios
Outage management system	Integration costs could not be supported without SGDP/RDSI funding	No	N/A	

Appendix D2 – Baseline Impact Metrics for E&G's Electric Distribution Assets

BASELINE ESTIMATES FOR IMPACT METRICS: Electric Distribution Systems			
Metric	**Remarks**	**Baseline Estimate - 6 Month Forecast**	**Baseline Estimation Method**
Metrics Related Primarily to Economic Benefits			
Distribution feeder or equipment overload incidents	Switching operations that relieve equipment overloading will also be recorded	60	3 year average of SCADA reports, event logs, notification/alarm for specified equipment for project feeders. Engineering & Planning function will estimate the contribution of increasing peak demand on number of overloading estimates and provide escalation factor of xy % per year.
Distribution feeder load	- 8,760 hrs for feeders affected by DR including forecasted increases per 6 month period - Average load for each feeder including forecasts per 6 month reporting period		Three year average SCADA and DMS reports and event log history over three years. System load growth estimate of x.4% per year applied to each feeder involved in the project.
Feeder A1		X MW Y MVAR	
Feeder A2		X MW Y MVAR	
Distribution Capacity Investments	Not anticipated at this time	$ 16 M	5 year out capital forecast for project area based on budget estimates without DR or voltage optimization
Equipment failure incidents	Limited to substation and mainline equipment e.g. station transformer, regulator, cap bank	14	SCADA reports, event logs, and supplemental information from distribution operations and maintenance team over three years. Analysis of load growth impact on equipment failure will be estimated for 'project' equipment
Distribution Equipment Maintenance Cost	Average cost will be estimated for maintenance tasks and applied for maintenance tasks within the project	$ 22 M	Utility WMS will be queried for distribution equipment maintenance tasks and cost estimates will be aggregated. Proration for the project required. Expected increases in labor, equipment, and overhead costs will be applied each year at x.y %
Distribution Operations Cost	Average cost will be estimated for operations tasks and applied for tasks completed within the project	$ 7 M	Utility cost accounting will be queried for distribution equipment operations tasks and cost estimates will be aggregated. Expected increases in labor, equipment, overhead, and contract costs will be applied each year at x.y %

Appendix D2 – Baseline Impact Metrics for E&G's Electric Distribution Assets

BASELINE ESTIMATES FOR IMPACT METRICS: Electric Distribution Systems			
Metric	**Remarks**	**Baseline Estimate - 6 Month Forecast**	**Baseline Estimation Method**
Metrics Related Primarily to Economic Benefits			
Distribution Capacitor Switching Operations	Due to the reduced costs and resources required switching operations will likely increase with E&G Smart Grid Program	~ 500	DMS, Data logs from distribution operations over a three year period.
Distribution Restoration Cost		$ 6 M	Restoration costs based on three year history, excluding major events prorated for project area
Distribution losses (%)		5.8 %	DMS load information Distribution planning model analysis of three year history. The effect of load growth on distribution losses will be estimated and a transfer function will be applied.
Distribution power factor		0.93 pf	DMS load information Distribution planning model analysis based on three year history. Engineering and planning will project changes to power factor based on business as usual which would not include capacitor upgrades