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Evaluation of Representative Smart Grid Investment Grant Project Technologies: Summary Report

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Summary

This document is the fifth of a series of reports estimating the benefits of deploying technologies similar to those implemented on the Department of Energy (DOE) Smart Grid Investment Grant (SGIG) projects. The first four reports in this series examined the technical benefits of the representative technologies: distribution automation, demand response, energy storage, and distributed generation. In the technical reports these technologies are evaluated using the DOE Office of Electricity Delivery and Energy Reliability (OE) funded GridLAB-D simulation environment, which was developed at the Pacific Northwest National Laboratory (PNNL). This report distills the technical results of the first four reports into a summary of estimated benefits from the representative technologies, as well as technical guidance for their deployment. The information in this report can be used by service providers seeking information about the impact of emerging smart grid technologies, as well by state regulators, or policy makers in their decision making process. The results in this report are meant as a basis to begin making decisions about these types of technologies, and are not a comprehensive evaluation of their capabilities. All of the simulations conducted for this report, as well as the four technical reports, were conducted using the open source software simulation environment GridLAB-D. All source code, input data, and post processing scripts used in the production of these reports is openly available via PNNL.

1 Introduction

The efforts of the United States Government to facilitate the modernization of the nation's electricity infrastructure are an ongoing process. Under Title XII, Subtitle E, of the Energy Policy Act of 2005, the federal government required state regulatory bodies, as well as non-regulated utilities, to adopt net metering practices in order to accelerate the introduction of diverse fuel sources and new technologies. Two years later, Title XIII of the Energy Independence and Security Act of 2007 took the next step in formally stating "It is the policy of the United States to support the modernization of the Nation's electricity transmission and distribution system". As a continuation of the efforts to modernize the nation's electricity infrastructure, the American Recovery and Reinvestment Act of 2009 was passed. As part of the American Recovery and Reinvestment Act, the U.S. Department of Energy, Office of Electricity and Energy Reliability, provided Smart Grid Investment Grant funding to 99 award recipients totaling $3.4 Billion [1]. Coupled with matching funds of $4.6 Billion from industry, the SGIG projects are intended to accelerate the modernization of the nation's electricity infrastructure. To help evaluate the effect of these projects, a set of impact metrics was developed by the DOE [2]. Once the SGIG projects are complete, it will be possible to analyze field data and determine the benefit(s) from each of the various technologies within each of the projects. Based on current time-lines for design, deployment, and implementation, it will be multiple years before a complete set of data will be available, or a comprehensive analysis can be performed.

In order to generate preliminary estimates of the benefits that can be derived from the technologies that are being deployed in the SGIG projects, PNNL, utilizing the DOE Office of Electricity Delivery and Energy Reliability developed GridLAB-D simulation environment, conducted extensive simulations of technologies similar to those deployed on the SGIG grant projects [3]. The impact of these technologies, at the distribution feeder level, is presented in a series of four technical reports [4]-[7]. Each of the four technical reports examines a class of technologies representative of those deployed in the SGIG projects. The four technical reports examine distribution automation, demand response, energy storage, and distributed generation. The four technical reports contain extensive amounts of raw technical data, as well as post processed data. In this document, the data from the first four reports is compiled into usable guidelines for the deployment of smart grid technologies. In this report, the results are intended to be used by utilities seeking to deploy new technologies, or policy makers evaluating the impact of new technologies.

In this report each of the technologies, or grouped technologies as appropriate, will be examined. This discussion will be broken into the following areas:

1) **Impacts of the technology**: This area focuses on two issues. The first is the general benefits that can be derived from the technology. The second is the impact of the technology on a national level deployment. The impact of a national level deployment is

based on the population statistics and estimated number of distribution feeders developed in Appendix A.

2) **Deployment strategies**: Distribution feeders in North America vary significantly and no two are identical. Variations in design, construction, equipment, load composition, operational methodologies, and climate lead to unique characteristics that have varying impacts on deployed technologies. For these reasons, the deployment of a technology will yield different results on different feeders in different regions; a careful examination of these variations can help to determine best practices for deployment. Where appropriate, deployment curves will be included. The deployment curves are constructed using the PNNL developed prototypical distribution feeders, found in Appendix A, which allow for an evaluation of deploying a technology on a national level.

3) **Relevant questions for deployment**: The deployment of any technology by a utility should be preceded by extensive technical and business case analysis. This section will provide a selection of questions that should be asked before the given technology is deployed. The questions could be asked by the utility in internal discussion, or by regulators attempting to determine the benefit to the end use customers. The questions presented are a sample of relevant questions to highlight important issues, and are not meant to be comprehensive.

2 Distribution Automation

Distribution Automation (DA) refers to a broad range of technologies that are focused on real-time monitoring and control at the distribution level. A review of the SGIG projects indicates that the DA technologies being deployed as part of the SGIG projects could be divided into five classes: Volt-VAR Optimization (VVO), Capacitor Automation (CA), Reclosers and Sectionalizers (R&S), Distribution Management Systems and Outage Management Systems (DMS&OMS), and Fault Detection Identification and Restoration (FDIR).

2.1 Volt-VAR Optimization

VVO is a utility-deployed control system that optimizes the voltage and reactive power flow of distribution feeders by controlling the settings of tap changers, voltage regulators, and shunt capacitors. By operating the average distribution feeder voltage in the lower half of the ANSI C84.1 range, annual energy consumption can be reduced. By coordinating the operation of shunt capacitors, the reactive power flow at the substation level is minimized.

2.1.1 Impacts of VVO

The primary benefit of VVO is a reduction in annual energy consumption, from 1.7% to 4.1% per feeder. For a comprehensive national deployment, this would equate to a 3.2% reduction in annual energy consumption, or 79,000 GWh; this value exceeds the annual output of Grand Coulee Dam if operated continually at nameplate capacity. Due to the reduced energy production from central generation, CO_2 emissions are reduced from 1.9% to 12.6% per feeder. For a comprehensive national deployment this would equate to a 5.2% reduction in CO_2 emissions, or 63.6 million tons.

The reduction of peak load is a secondary benefit of VVO, from 0.0% to 3.5% per feeder, with an average of 1.1%. Since the implemented VVO scheme was optimized for reductions in annual energy consumption and not peak reduction, some feeders will see no reduction in peak load.

The reduction of system losses is minor in comparison to the annual energy consumption and should not be considered a significant benefit of VVO. The minor effect of system losses is attributed to the fact that system losses compose a small amount of the total load, 3.0% to 5.0%. Because losses are a small amount of the total system load, they comprise a small amount of the impact from VVO. The primary energy reductions from VVO are at the end-use customer level.

An unfavorable impact of a VVO system is that it will generally increase the number of annual operations for tap changers, voltage regulators, and capacitors. While the increase in operations is necessary for a VVO system, it could have an impact on the equipment lifetime.

2.1.2 Deployment Strategies

Because of the variations in distribution feeder design and end-use load composition, VVO does not perform at the same level on all distribution feeders. Figure 2.1 shows a deployment curve for a comprehensive national deployment of VVO. If VVO is deployed on 100% of the distribution feeders in the nation, the full technical potential of 79,000 GWh of annual energy reduction can be achieved. But if VVO were deployed on 40% of the most effective feeders, approximately 53,000 GWh of the annual energy reduction can be achieve, or approximately 67% of the benefit. The observation that 67% of the benefit can be gained by deploying VVO on 40% of the feeders highlights the need for a well-planned deployment. In general, feeders with a higher operating voltage, e.g. 34.5 kV, and higher average load levels achieve higher reductions in annual energy consumption.

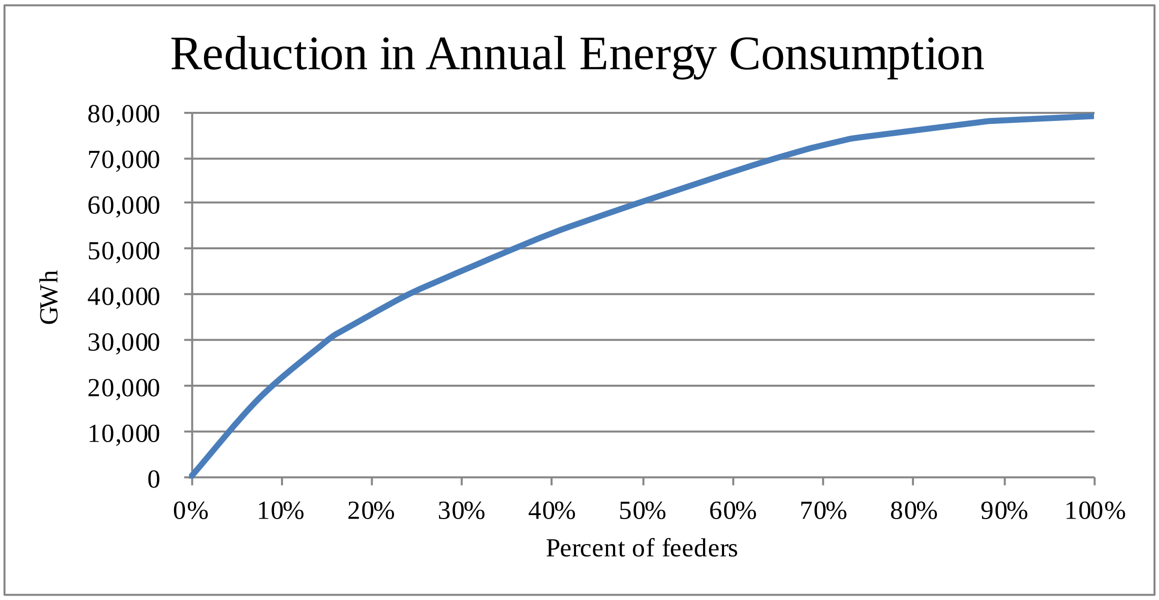

Figure 2.1: Deployment curve for VVO (reduction of annual energy consumption)

2.1.3 Relevant Questions for VVO Deployments

Below is a selection of questions that should be addressed before VVO is deployed. This is not an exhaustive set of question, but gives a sense of the issues that should be addressed.

1) “***Can Volt-VAR Optimization be effectively deployed on the existing system?***”

In order for VVO to be effective, there must be a mechanism for adjusting the voltage profile of a distribution feeder. If there are no regulators or capacitors to control or if the existing regulators and capacitors are not able to reduce voltage, then VVO cannot be effectively implemented with the existing infrastructure and additional upgrades must be considered.

2) "***On what feeders should Volt-VAR Optimization be deployed?***"

VVO may not be suitable for deployment on all distribution feeders in a service territory. Variations in feeder design and end use load composition strongly influence the effectiveness of VVO. Feeders with higher nominal voltages such as 24.9 kV or 34.5 kV, and those with higher load levels, tend to produce the largest reductions in annual energy consumption.

3) "***How comprehensive of a Volt-VAR Optimization system needs to be deployed?***"

There are numerous commercially available VVO systems, and as with any technology the capabilities, and costs, of these systems vary. Different distribution feeder types will be suited to different VVO systems. For example, a lightly loaded rural feeder may call for a relatively simple VVO system while a heavily loaded urban feeder may call for a more complicated VVO scheme.

4) "***Is Volt-VAR Optimization being deployed for distribution level or transmission level benefits?***"

The benefits of a VVO system can be applied at the distribution or transmission level. Understanding how to apply VVO to the distribution is a complex task, applying VVO benefits to the transmission level is even more complex because of system interactions. To properly understand the implications of using a distribution level asset for transmission level benefits it is necessary to fully understand the interactions between the distribution system and transmission system.

2.2 Capacitor Automation (CA)

CA, when coupled with a communications infrastructure, is a utility-deployed control system that provides capacitor status information directly to operators. CA can have the ability to operate capacitors remotely, indicate voltage and power, and adjust set points. By increasing the observability of the capacitors, to determine when their fuses blow due to events such as faults and voltage surges, asset utilization is significantly increased.

In many cases CA is accompanied by a simultaneous deployment of new capacitors to address known operational issues. The deployment of CA independent of additional capacitors will have benefits to the system operators, but they will not be as significant as a combined deployment.

2.2.1 Impacts of CA

The primary benefits of CA are a minor improvement to the voltage profile on the distribution feeder and an increased observability of the system. An improved voltage profile allows a utility to increase the load on a feeder without the need for capital upgrades. Increased observability shows the utility the status of the infrastructure and ensures that it is working correctly, increasing asset utilization. The true benefits of increased asset utilization are fully realized over a period of years to decades. Because the analysis for this report was over a one year period, the full benefits of CA could not be captured by the analysis conducted in the technical reports. Consequently, the well understood benefits that can be achieved with a CA system were outside the scope of the work; this is a limitation of the scope of the analysis method, not a limitation of the CA technology.

2.2.2 Deployment Strategies

As with most technologies, it is not appropriate to deploy capacitor automation on all distribution feeders. Capacitor automation should be deployed on feeders where there are significant daily and seasonal changes in energy consumption. It is on these feeders that proper operation of capacitors is most critical. CA automation will yield more benefits in systems which already have significant numbers of capacitors.

2.2.3 Relevant Questions for CA Deployments

Below is a selection of questions that should be addressed before CA is deployed. This is not an exhaustive set of question, but gives a sense of the issues that should be addressed.

1) "***Are there enough capacitors deployed on the system to warrant an automation system?***"

   While some utilities make extensive use of capacitors, other utilities use relatively few. Whether a utility uses a large number of capacitors or not is a result of many factors, including feeder design, end-use load composition, and load density. Since a communications infrastructure is necessary for CA, it may not be cost effective to deploy this infrastructure without a critical number of capacitors. The exception to this is if the deployed communications infrastructure will be used for other applications in addition to CA.

2) "***Do the operational characteristics of the system warrant an automation system?***"

   A large utility with numerous capacitor operating strategies, wide spatial distribution, and numerous faults may benefit a great deal from CA. In contrast, a small utility using only fixed capacitors, across a small spatial distribution, and with relatively few faults because of a primarily underground system would see little benefit.

3) "***Is the system topology constantly changing?***"

   Operational set points can be effectively determined for a capacitor if its location relative to the load is fixed and there are no switching operations that transfer it to an adjacent feeder. While this is a valid assumption for some feeders, it is not for others. The topology of a rural feeder rarely changes because there may not be any adjacent feeders. In contrast, an urban feeder may have multiple adjacent feeders and the topology is constantly changed for load balancing purposes. In this case the ability to change capacitor set points remotely can be valuable.

2.3 Reclosers and Sectionalizers

Reclosers and sectionalizers are devices that are designed to minimize the impact of faults on a distribution system, increasing the reliability. In contrast to over-current fuses, reclosers and sectionalizers are dynamic devices that have active measurements and internal control logic. This capability allows them to reclose after a fault and automatically reenergize portions of the circuit. Reclosers are designed to clear momentary faults, typically caused by animals or tree branches, decreasing the need for truck rolls. Conversely, sectionalizers are designed to isolate faults, preventing larger outages.

2.3.1 Impacts of R&S

The primary benefit of R&S is increased reliability as measured by the System Average Interruption Frequency Index (SAIFI) and the System Average Interruption Duration Index (SAIDI). SAIFI represents how often the average customer experiences a sustained interruption over a predefined period of time, and SAIDI represents the total duration the average customer experiences a sustained outage over a predefined period of time [8]. R&S has the potential to significantly improve SAIDI metrics, from 10.0% to 40.0% per feeder. R&S cannot prevent the occurrence of a fault, but when faults do occur, this technology can minimize the number of customers affected. Because of this, benefits from R&S will be localized, with certain areas obtaining significant benefits while other areas receive no benefit.

2.3.2 Deployment Strategies

Only distribution feeders with low reliability issues should be considered for R&S systems. The Std IEEE-1366 includes a survey of SAIFI and SAIDI values from participating utilities, and their results are divided into 4 quartiles from lowest to highest values. The lower values of SAIFI and SAIDI, the 1st and 2nd quartiles, represent the more reliable distribution feeders while the higher values of SAIFI and SAIDI, 3rd and 4th quartiles, represent the less reliable distribution feeders. R&S should be targeted towards feeders in the 3rd and 4th quartiles for SAIDI and SAIFI; i.e., numerous outages or lengthy repair times.

Figure 2.2 shows a deployment curve similar to the one shown for VVO in Figure 2.1. Both the curves in Figure 2.1 and Figure 2.2 were generated using prototypical feeders, which are feeders with “common” characteristics. R&S is suited to feeders with higher than normal reliability problems, which is not the assumed case for the prototypical feeders. The prototypical feeders tend to have reliability numbers that put them in the 1st and 2nd quartile of the IEEE-1366 statistics.

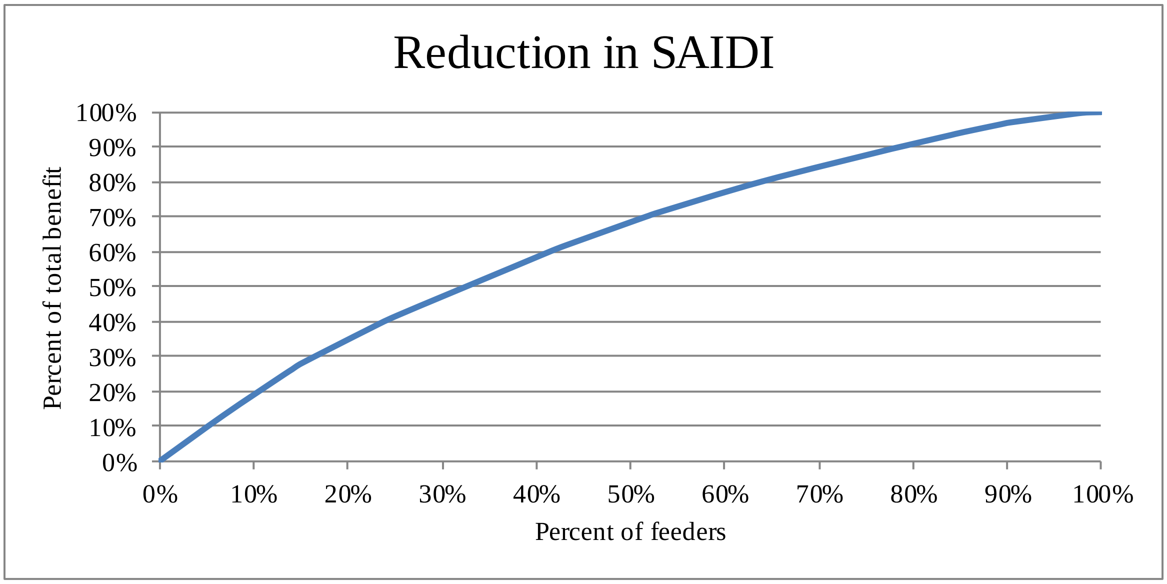

Figure 2.2: Deployment curve for R&S

If R&S were deployed with a set of prototypical feeders that contained feeders in the 3rd and 4th quartiles then the curve in Figure 2.2 would be less linear, indicating that a larger proportion of the reliability improvement can be achieved by targeting feeder with the lowest reliability.

2.3.3 Relevant Questions for R&S Deployments

Below is a selection of questions that should be addressed before R&S is deployed. This is not an exhaustive set of questions, but gives a sense of the issues that should be addressed.

1) "***Does the existing system have reliability issues?***"

   R&S is a technology that only provides benefits if there are faults on the system. If the system typically has few faults and/or repair times are relatively short, then deployment of this technology is not warranted. However, for those feeders with high SAIDI and SAIFI metrics, R&S can provide significant improvement.

2) "***Are the faults on the system primarily momentary or sustained?"***

   For momentary faults, such as those that can be experienced in arid desert regions with loose vegetation, reclosers provide the most benefit. If the faults are a combination of momentary and sustained, such as those often seen in a heavily forested region, then a combination of reclosers and sectionalizers is warranted.

3) "***What is the topology of the distribution feeder?***"

If a distribution feeder has a relatively small number of branches, e.g., 3 or 4, then sectionalizers coordinated with a recloser can significantly reduce the number of customers affected by a fault. If a feeder has a large number of lightly loaded branches, then traditional over-current fuses may be more appropriate instead of installing sectionalizers on numerous lightly loaded laterals.

2.4 Distribution Management and Outage Management Systems

DMS&OMS are separate management systems that can have various levels of integration. The DMS, through the Supervisory Control And Data Acquisition (SCADA) system, is able to monitor and control various elements of the distribution system. The OMS is able to integrate Geographic Information Systems (GIS), Customer Information Systems (CIS), and call-in systems to determine the occurrence and location of a fault. It is also possible for an OMS to receive inputs from the DMS to indicate the status of breakers and other equipment to further improve the ability to detect and locate a fault.

2.4.1 Impacts of DMS&OMS

The deployment of a DMS provides a utility with better observability and controllability of their system, as well as providing a point of interconnection for other information and control systems. Improved observability and controllability allow a utility to better plan and operate their system, which results in a more efficient system over time. When an OMS is integrated with the DMS, a utility is able to gain additional observability that aids in locating faults. By reducing the time necessary to locate faults, and providing better fault outage management tools, DMS&OMS increases the system reliability. For the purposes of this work it was assumed that a DMS&OMS allows a utility to identify the location of a fault 15% quicker than without one; the time to repair the fault was unaffected. The 15% reduction in fault location time is an estimated benefit and actual values will vary depending on the actual DMS&OMS system. The reduced fault location time resulted in SAIDI reductions from 7.2% to 17.2%.

2.4.2 Deployment Strategies

The deployment of DMS&OMS should be treated as separate issues. DMS is the general control system that gives a utility better operational control, and OMS is the system designed to directly address outages. Most utilities could benefit from the deployment of a DMS; the increase in observability and controllability enables a utility to better plan and operate their system. An OMS can be standalone, but its effectiveness is increased when it is integrated with a DMS. An OMS is deployed when a utility is attempting to reduce the time necessary to correct an outage.

2.4.3 Relevant Questions for DMS&OMS Deployments

Below is a selection of questions that should be addressed before DMS&OMS is deployed. This is not an exhaustive set of questions, but gives a sense of the issues that should be addressed.

1) "***Based on the system complexity, how complete of a DMS&OMS is necessary?***"

   The capabilities of DMS&OMS can vary significantly. When a utility is selecting this technology the capabilities of DMS&OMS should be in line with the complexity of the system? In general, the more complex the system, based on the size of the service territory and the complexity of operational issues, the more capable the DMS&OMS system should be.

2) "***Are there enough faults on the system to warrant an integrated OMS?***"

   If a utility has a high level of reliability, the deployment of an OMS may not make a significant difference in reliability.

3) "***What other systems can the OMS be integrated into?***"

   A standalone OMS can include a GIS and a CIS, which allows a utility to better locate a fault and plan the restoration. If the OMS is integrated into the DMS, then it is possible to integrate field measurements to aid in fault location, as well as automatically control switches in the system to shift load. OMS also has the potential to integrate into AMI systems, which allows it to determine which customer meters are energized and which are not. Integration at this level allows the OMS to rapidly determine which customers have power, and which do not, aiding in the location of a fault, or faults, in the event of a large disturbance.

2.5 Fault Detection Identification and Restoration (FDIR)

FDIR is a class of technologies whose goal is to identify the occurrence of a fault, record the occurrence, determine the fault location, and aid in the restoration process. It is a combination of advanced DMS&OMS systems, as well as a close integration of feeder level assets with the DMS. FDIR systems can also use automated switching, e.g., reclosers and sectionalizers, to help minimize the number of customers affected by a fault. Because FDIR can be integrated with R&S and DMS&OMS, it is a more complete, and complex, solution for reliability issues.

2.5.1 Impacts of FDIR

The primary benefit of FDIR is increased reliability. R&S cannot prevent the occurrence of a fault, but when faults do occur, FDIR technology can rapidly locate the fault and potentially coordinate the fault response. FDIR systems are sometimes referred to as “self-healing” systems. For the purposes of this work it was assumed that a FDIR system allows a utility to identify the location of a fault 30% quicker than without one; the time to repair the fault was unaffected. The reduced fault location time is partially due to the integration of information from the R&S systems. The 30% reduction in fault location time is an estimated benefit and actual values will vary depending on the actual FDIR system. The reduced fault location time resulted in SAIDI reductions from 20% to 76%.

2.5.2 Deployment Strategies

Only distribution feeders with significant reliability issues should be considered for FDIR systems. This technology should be targeted towards feeders in the 4th quartiles for SAIDI and SAIFI. Reliability issues for feeders that are not in the 4th quartile for SAIDI can generally be addressed with less complex systems such as R&S or DMS&OMS; this decision will depend on the business strategy of the specific utility.

2.5.3 Relevant Questions for FDIR Deployments

Below is a selection of questions that should be addressed before FDIR is deployed. This is not an exhaustive set of question, but gives a sense of the issues that should be addressed.

1) “***Are there numerous faults on the system?***”

   Similar to R&S and DMS&OMS, FDIR is a technology that only provides benefits if there are faults on the system. If there are relatively few faults, then deployment of this technology is not warranted. Because FDIR is a far more complete method of addressing reliability and requires significantly more resources, it is best suited for systems with complex reliability issues, or a strong need for increased reliability.

2) “***Is the existing communications infrastructure adequate?”***

   Since FDIR integrates the operation of multiple systems, as well as numerous devices, there is a need for an effective communications infrastructure. If there are excessive latencies or connectivity problems, then the effectiveness of FDIR can be reduced.

3) “***How extensive of an FDIR system is necessary?***”

   Once it is determined that the reliability issues warrant an FDIR system, the deployed system can range from a relatively simple system to a very complex system. For example, a rural distribution feeder with no adjacent feeders does not need to have an FDIR system that is able to automatically transfer load to adjacent feeders. However, it could still benefit from an FDIR system that coordinates the R&S devices.

3 Demand Response

Demand response (DR) refers to a broad range of technologies that are focused on actively engaging the end-use customers to modify their power and energy consumption. A review of the SGIG projects indicated that deployed DR technologies could be divided into two classes of technology: Time of Use (TOU) and Critical Peak Price (CPP), and Direct Load Control (DLC).

3.1 Time of Use and Critical Peak Price

TOU and CPP are tiered rate structures that are designed to engage the end-use customer by encouraging customers to shift demand from high to low price time periods. The end-use customers can react to the price rate or signal manually, or via automated controls, such as programmable thermostats. The goals of these systems are to introduce load elasticity in the end-use customers so that they reduce consumption when the system is at relatively higher load levels. Customers still have to the ability to consume energy whenever desired, but they are monetarily incentivized to reduce their consumption on peak.

3.1.1 Impacts of TOU/CPP

The primary benefit of TOU/CPP is a reduction in peak demand; however, depending upon the strategy for deployment, available DR resource, and various other factors, the level of reduction is different. The level of automation and customer involvement highly influences the ability to achieve peak demand reduction goals. Utilizing HVAC, hot water heater, and pool pumps, automated controls for TOU/CPP demand reduction, instantaneous reductions from 13% to 58% were observed. However, as time progressed, reductions decreased significantly until at the end of the six hour critical period, demand reductions were less than 16% as the DR resources were exhausted. This can also cause a rebound or payback effect. As the price signal went back to non-critical pricing, the loads synchronized their behavior and increased peak demand by as much as 25%, but at a later period of time. Sustained peak reductions between 9% and 34% were observed when advanced controls are used to evenly distribute the available energy reduction across the six hour period while managing the rebound effect. The inclusion of automated controls and other technologies increased the peak reduction by 14% (of peak) on average over cases without additional technologies, or nearly doubling the average response.

TOU and TOU/CPP programs also provide a secondary benefit. Annual energy consumption is reduced by approximately 1.0%, on average, leading to an average reduction of CO_2 emissions by 2.0%. Loss reduction was not determined to be a significant benefit that could be associated with TOU programs, as the reduction was less than 0.05% of total annual energy consumption.

Table 3.1 gives an overview of load reductions available due to CPP for signals that are 6 hours or less (TOU values are not included, but may be found at [5]).

Table 3.1: Peak reduction for various CPP signal types

Signal Type	Maximum Reduction	Minimum Reduction	Average Reduction
Instantaneous Peak Reduction	58.1%	13.4%	40.0%
Six Hour Peak Reduction	15.5%	-1.2%	8.8%
"Flattened" Peak Reduction	36.6%	10.0%	23.2%
"Flattened" including Rebound	34.6%	9.0%	21.4%

The impact of CPP is significantly dependent on the presence of automated controls and consumer feedback tools, without which the impact is significantly decreased. For example, the 21.4% reduction that can be expected for the average performance of a “flattened” profile including rebound is reduced to 2.8% sustained reduction without the deployment of automated controls to flatten the load and automate the consumer response. Costs of such programs should be carefully weighed against the potential benefits.

3.1.2 Deployment Strategies

Deployment strategies will vary depending upon the goal of the utility or provider of the DR program. To increase the potential for peak reduction, the complexity of the system deployed increases, as does the price; this must be taken into consideration during the decision making process. If the deployment goal is to reduce system-wide peak demand across a large system (e.g., TVA), a simple TOU or TOU/CPP program without automation may be more cost effective than a more complex control scheme. However, if the goals are to reduce demand to a very specific level (e.g., a capacity constrained system) investment in automated controls may be more appropriate.

The potential for peak reduction increases with an increased availability of the DR resource. Feeder circuits with a high penetration of relatively large, controllable loads, such as HVACs or hot water heaters, provide considerable more benefit per cost of deployment than feeder circuits which are primarily gas heated systems or without air conditioning. Because the resource is finite, consideration should be made as to whether the resource will be deployed over a short time period (e.g., 15-minutes) versus a long time period (e.g., 6-hours) as the level of available reduction will decrease as the time period for reduction increases.

3.1.3 Relevant Questions for TOU/CPP Deployments

Below is a selection of questions that should be addressed before TOU/CPP is deployed. This is not an exhaustive set of questions, but gives a sense of the issues that should be addressed.

1) "***What are the utility goals for deploying the TOU/CPP program?***"

The level of complexity (and cost) of the deployed system will vary greatly depending upon the goals of the utility, and there is no "one size fits all" type of strategy. Careful consideration should be made about the operational goals, whether it is to reduce exposure to wholesale energy price fluctuations, defer capital investment, provide emergency services, etc. The DR program should be chosen to meet these goals, while minimizing the cost of deployment.

2) "***Is the program designed for local or system wide benefit?***"

The DR program should be designed to meet the goals of the operator, whether at the local level or for system wide benefit. For those with a goal of system wide benefits, simpler, less costly deployments may be more appropriate, while those trying to achieve local benefits (such as constraint management) may require more complex deployments.

3) "***How long is the reduction necessary? And does it need to be evenly sustained?***"

If reductions are necessary to relieve local congestion or a constrained piece of equipment (e.g., a substation transformer), then the reduction will need to be sustained for the duration of the overload and a rebound cannot be allowed to occur. This reduces the potential of the peak reduction. However, if the reduction does not need to be sustained (e.g., if the requirement is only to move local peak off of system peak), then the complexity of the program can be decreased while increasing the potential reduction.

4) "***What is the available resource within the system?***"

Systems with high penetrations of relatively large, controllable loads will provide greater benefit per cost of deployment. Feeder circuits with mild summer temperatures and low penetration of air conditioning systems will provide little benefit in the summer time. Feeders with a significant natural gas or oil infrastructure for heating and hot water heating will see very few benefits in the winter time.

5) "***What controls and additional programs are necessary to accomplish the utility goals?***"

It has been repeatedly shown that using automated controls and/or human interface devices, which educate and provide information directly to customers about their usage, significantly increases the impact of DR programs. However, they also increase the complexity (and cost) of the deployment. Careful consideration should be made to whether the additional costs provide enough benefit to justify, as many of these more complicated programs require additional investments (such as a communication system), this should be factored in the cost analysis. However, if these can be leveraged across multiple uses or technologies, this should reduce the associated cost.

3.2 Direct Load Control

DLC programs are designed to send a signal directly to automated controls such as thermostats or hot water heater switches. The control signal and associated controls are designed to either immediately turn the load off, or adjust the duty cycle of the device to reduce power consumption over a given time period. DLC is typically only called on 10-15 peak days per year. These programs have the advantage that the utility has much more direct control over the loads in the system as compared to a rate structure DR program that relies upon customers shifting their behavior.

3.2.1 Impacts of DLC

In the SGIG proposals, the primary benefit of DLC was a reduction in peak demand. By directly controlling the HVACs, hot water heaters, and pool pumps, instantaneous reductions of up to 51.3% were observed. As seen with TOU/CPP, the reduction declined over time, so that at the sixth hour, reductions were generally less than 10%. A significant rebound was seen on many of the feeders as the control signal released loads back to normal operation, in this case, as high a 60% over the original peak. Again, if load reduction were distributed in way to flatten the load over the given time period, reductions between 3.5% and 37% were observed.

DLC provided little to no secondary benefits, as it was only applied 15 days per year. Results for loss reduction, energy consumption, and CO_2 emissions were mixed; losses were impacted by less than +/-0.15% of total energy consumption, annual energy consumption were impacted by less than +/- 0.1%, and CO_2 emissions were impacted by less than +/- 0.5%.

3.2.2 Deployment Strategies

Similar to CPP, DLC deployment strategies will vary depending upon the goal of the system operator. Careful consideration for the manner in which the demand response is to be utilized is essential. DLC deployment strategies will have similar considerations as the CPP cases. As the DLC resource is finite, the depth of the load reduction is also dependent upon the length of time the load needs to be reduced. Again, feeder circuits with higher penetration of controllable loads would provide more benefits per cost of deployment. Since DLC requires minimally a one-way communication system, higher concentrations of controllable loads (e.g. neighborhoods that are 100% heat pump) would reduce the costs of deployment. DLC will not provide any significant secondary benefits for energy reduction or CO_2 emissions, and this should be considered when comparing to TOU/CPP programs.

Table 3.2, similar to Table 3.1, gives the high level values for DLC load reduction signals.

Table 3.2: Peak reduction for various DLC signal types

Signal Type	Maximum Reduction	Minimum Reduction	Average Reduction
Instantaneous Peak Reduction	51.3%	0.7%	23.2%
Six Hour Peak Reduction	19.0%	-11.6%	2.4%
"Flattened" Peak Reduction	40.9%	3.5%	20.7%
"Flattened" including Rebound	37.3%	3.5%	18.8%

3.2.3 Relevant Questions for DLC Deployments

Below is a selection of questions that should be addressed before DLC is deployed. This is not an exhaustive set of question, but gives a sense of the issues that should be addressed.

1) "***What are the utility goals for deploying the DLC program?***"

The level of complexity (and cost) of the deployed system will vary greatly depending upon the goals of the utility, and there is no "one size fits all" type of strategy. Careful consideration should be made about the operational goals, whether it is to reduce exposure to wholesale energy price fluctuations, defer capital investment, provide emergency services, etc. The DR program should be chosen to meet these goals, while minimizing the cost of deployment.

2) "***Is the program designed for local or system wide benefit?***"

The DR program should be designed to meet the goals of the operator, whether at the local level or for system wide benefit. For those with a goal of system wide benefits, simpler, less costly deployments may be more appropriate, while those trying to achieve local benefits (such as constraint management) may require more complicated deployments.

3) "***How long is the reduction necessary? And does it need to be evenly sustained?***"

If reductions are necessary to relieve local congestion or a constrained piece of equipment (e.g., a substation transformer), then the reduction will need to be sustained for the period of the overload and a rebound cannot be allowed to occur. This reduces the potential of the peak reduction. However, if the reduction does not need to be sustained (e.g., if the requirement is only to move local peak off of system peak), then the complexity of the program can be decreased while increasing the potential reduction.

4) "***What is the available resource within the system?***"

Systems with high penetrations of relatively large, controllable loads will provide greater benefit per cost of deployment. Feeder circuits with mild summer temperatures and low penetration of air conditioning systems will provide little benefit in the summer time. Feeders with a significant natural gas or oil infrastructure for heating and hot water heating will see very few benefits in the winter time.

4 Energy Storage

ES refers to a range of technologies designed to shift the time at which energy is consumed. The time range can vary from seconds to hours. A review of the SGIG projects indicated that the only form of energy storage being deployed was Thermal Energy Storage (TES).

4.1 Thermal Energy Storage

TES is a technology that can be deployed by a utility, or an end-use customer, and is designed to shift energy use from on-peak times to off-peak times. Load shifting is accomplished by freezing water at night during off-peak times and using the ice during on-peak times for cooling, deferring on-peak energy consumption. For end-users with large cooling loads, TES can provide significant peak load reductions.

4.1.1 Impacts of TES

The primary benefit of TES is the reduction of peak feeder load, from -0.0% to 5.2% per feeder, with an average of 2.0%. This level of peak reduction is achieved when approximately 20.0% of the commercial buildings utilized TES. In the analysis for this report, TES was deployed to reduce customer peak, which is not always coincident with the feeder peak. Additional reductions in the peak feeder load could be achieved if the deployed TES was optimized to reduce the feeder, and not the customer, peak.

The reduction of system losses is a secondary benefit of TES, but the impacts are in most cases were less than 1.0%. The primary reason for the minimal reduction is that TES decreases line flow during peak times, but increases them off-peak. Due to the non-linearity of line losses, the reduction of line flow on-peak has a larger effect than the increase off-peak, but only marginally.

An unfavorable impact of TES is a possible increase in annual energy consumption due to the energy necessary to operate the TES system, less than 0.2% per feeder. Corresponding to the increase in annual energy consumption, there is a potential increase in CO_2 emissions, but less than 1.2% per feeder. This unfavorable impact generally occurs in regions where the night time generation sources (supplying the "recharging" power to the TES) are carbon intensive.

4.1.2 Deployment Strategies

TES is designed to shift cooling loads from on-peak to off-peak periods, but depending on who owns the resource, deployment strategies are different to obtain maximum effectiveness. When deployed by utilities, it is best utilized on systems which have high on-peak to off-peak load ratios caused by commercial cooling systems, thereby increasing system asset utilization. When deployed by end-use customers, the goal is to reduce the customer peak, not necessarily coincidental with system peak. Commercial customers that have peak rate charges (i.e., their rate is determined by their peak power consumption) for example, could extract monetary benefit from deploying TES to reduce their energy rates. This may also provide a secondary benefit to utilities if the customer and system peak are coincidental.

4.1.3 Relevant Questions for TES Deployments

Below is a selection of questions that should be addressed before TES is deployed. This is not an exhaustive set of questions, but gives a sense of the issues that should be addressed.

1) "***Will thermal energy storage be deployed for reducing or shifting feeder peak, or customer peak?***"

   Thermal energy storage has flexibility on when it can be activated. For a commercial customer deployment, this may be normal daylight hours, with a customer peak in the afternoon. For a utility deployment, this may be later in the afternoon with the system load peak. A customer deployment may start thermal energy storage earlier to mitigate higher electricity rates, while a utility deployment would want to activate the thermal energy storage later to help reduce feeder loading. Each deployment would need to consider which peak and loading (customer or feeder) that it wishes to influence.

2) "***What benefit is the deploying entity trying to gain from thermal energy storage?***"

   Thermal energy storage is primarily deployed to shift load from one portion of the day (during a peak in customer or feeder load), to a portion of the day with lower load. If a feeder load reduction is desired, storage operation can be optimized to reduce that peak. If customer load reduction is desired, storage operation can be optimized for that benefit. If a benefit other than a peak reduction and shift is desired, thermal energy storage may not be an effective technology.

3) "***Are off-peak electricity rates sufficiently lower to justify a commercial customer deployment?***"

   Thermal energy storage helps reduce customer peak load during normal HVAC operation hours, but needs to recharge this energy in the evening or early morning hours. To effectively deploy thermal energy storage, the rates during this recharging period need to be low enough to justify the capital expenditure.

4) "***Does a utility deployment of thermal energy storage make sense for this building?***"

   Thermal energy storage can be deployed on residential or commercial facilities. A utility deployment would likely focus on reducing the feeder peak load, therefore the deployment strategy needs to focus on the right customers to achieve maximum effectiveness. Thermal energy storage deployed on a larger commercial building will provide greater impact on the feeder load profile, assuming the TES is proportionally larger. Deploying thermal energy storage on a small strip mall may not be as effective as deploying it on a two-story office building, in terms of impact on system demand.

5) "***Does a utility deployment of thermal energy storage on this building have any secondary benefits?***"

Building location in the feeder structure can aid in the effectiveness of the utility deployment. If two buildings of similar load levels are deployed at two ends of the feeder (near the substation compared to down a lateral), the deployment of thermal energy storage further from the substation would provide additional benefit. With the reduction in peak load consumption, system losses in the distribution lines are also reduced, providing further benefit to the utility.

6) "***Does a utility deployment of thermal energy storage require centralized control?***"

Thermal energy storage can either be a locally-controlled device, a centrally-controlled device, or a mixture of both. If a utility is deploying thermal energy storage, they need to consider if they want control over when the thermal energy storage is utilized, if it will be controlled by an availability schedule, or if it will be scheduled with the utility ability to activate it during special conditions. Additionally, price incentive signals must be considered.

5 Distributed Generation

DG refers to generation connected at the distribution level, with a generating capacity of less than 10MW. A review of the SGIG projects indicated that the DG technologies could be divided into two classes of technology: solar photovoltaic (PV) and wind turbine generators (WTG).

5.1 Photovoltaic (PV) Integration

PV is a technology that can be deployed by the end-use customer or the utility to reduce the need for energy from the transmission system; or in the case of deployments by end-user, the customer's energy from the distribution system is reduced. In this evaluation, end-use residential PV was 3 kW to 5 kW per installation and commercial PV was rated at 100 kW per installation.

5.1.1 Impacts of PV Integration

The primary benefit of residential PV is a reduction in the effective annual energy consumption, from 0.1% to 2.3% per feeder. For a comprehensive national deployment, this equates to a 1.0% reduction in annual energy consumption, or 25,000 GWh. This value is roughly equivalent to the annual output of two 1,500 MW coal plants running continuously for a year. For the examined work, residential PV penetrations of up to 6.0% of peak load per feeder were used, with an average penetration of 2.2% of peak load. This penetration level of residential PV resulted in reduced CO_2 emissions from 0.1% and 5.9% per feeder. For a comprehensive national deployment, this would equate to a 1.6% reduction in CO_2 emissions, or 20.6 million tons.

The reduction of peak load is a secondary benefit of residential PV, from -1.9% to 6.2% per feeder, with an average of 1.2% (Note that one feeder type showed an increase in peak load due to fundamental system changes associated with the PV deployment). Peak load reduction is not a primary benefit of PV because the peak incident solar energy may not be coincident with the peak feeder load.

The primary benefit of commercial PV is a reduction in the effective annual energy consumption, from 0.1% to 3.0% per feeder. For a comprehensive national deployment, this would equate to a 1.7% reduction in annual energy consumption, or 43,000 GWh. This is a value greater than the annual output of three 1,500 MW coal plants running continuously for a year. For the examined work, commercial PV penetrations of up to 8.2% of peak load per feeder were used, with an average penetration of 2.4%. This penetration level of commercial PV resulted in reductions of CO_2 emissions of between 0.5% and 7.1% per feeder. For a comprehensive national deployment this would equate to a 2.9% reduction in CO_2 emissions, or 36.3 million tons.

The reduction of peak load is a secondary benefit of commercial PV, from -0.8% to 5.1% per feeder, with an average of 2.2% (Note that several feeder type showed an increase in peak load due to fundamental system changes associated with the PV deployment). Peak load reduction is not a primary benefit of PV because the peak incident solar energy may not be coincident with the peak feeder load.

5.1.2 Deployment Strategies

The single most important issue to consider when deploying PV is the available solar resource. The next most important issue is whether the PV units are end-use customer or utility controlled. End-use consumers can install 3 kW to 5 kW on top of single family residences while utility installation are 100 kW on large commercial roof tops; ground-based commercial units are possible in areas with a low population density. Figure 2.3 and Figure 2.4 show deployment curves for residential and commercial solar deployments. As expected, there are a large percentage of distribution feeders for which there is minimal benefit from either residential or commercial solar PV. These variations are primarily due to regional differences in solar incidence.

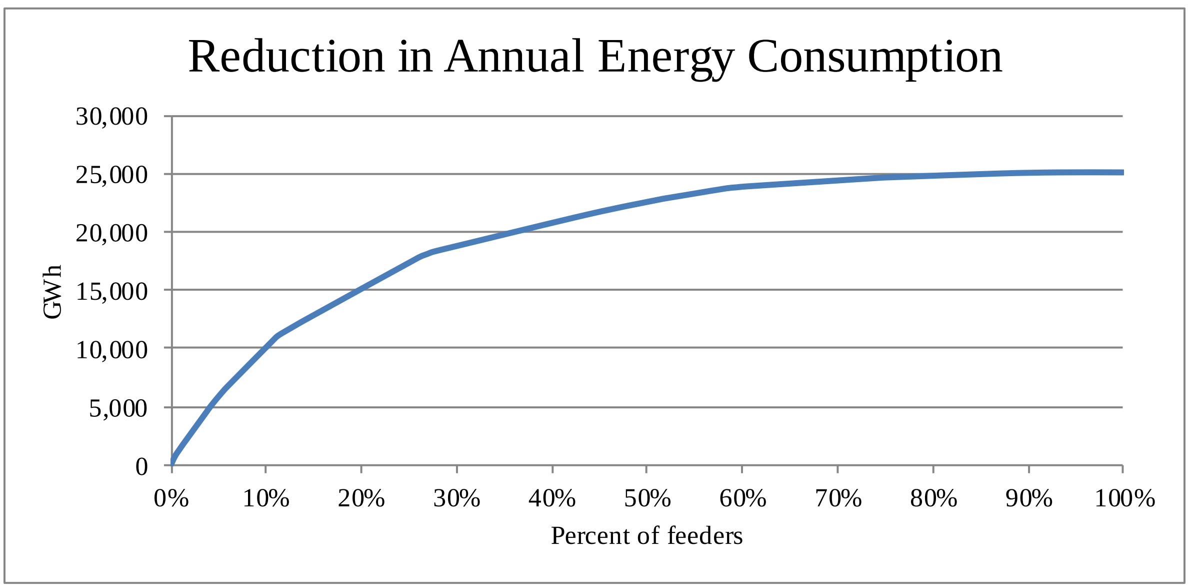

Figure 2.3: Deployment curve for residential PV (reduction of annual energy consumption)

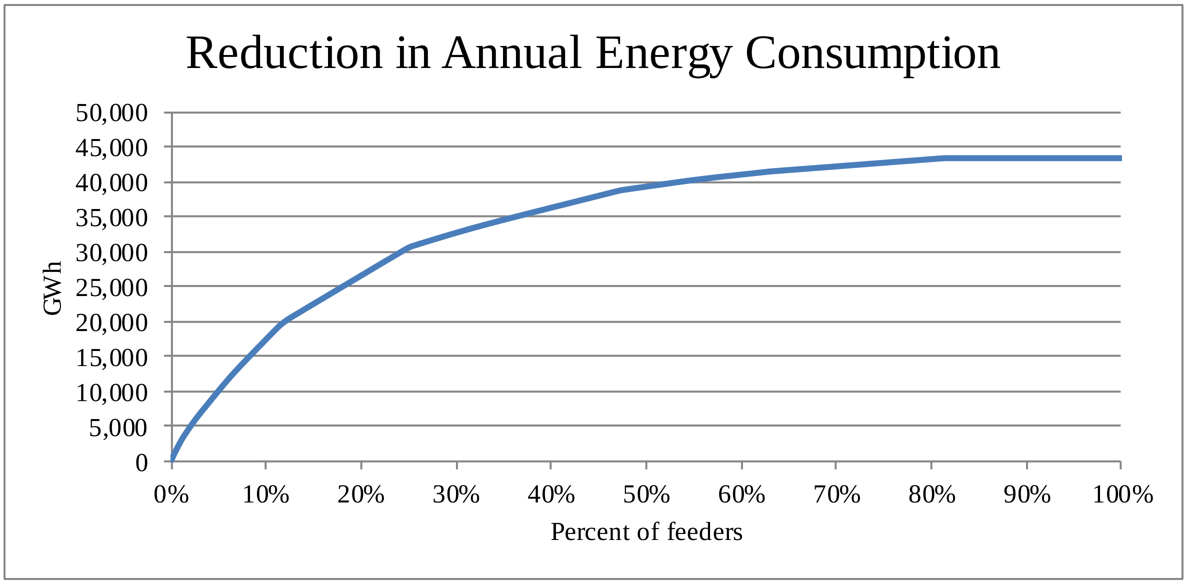

Figure 2.4: Deployment curve for commercial PV (reduction of annual energy consumption)

5.1.3 Relevant Questions for PV Deployments

Below is a selection of questions that should be addressed before PV Integration is deployed. This is not an exhaustive set of questions, but gives a sense of the issues that should be addressed.

1) "***Are there sufficient solar resources available?***"

   PV is a technology that is best suited for regions with a high solar irradiance. If there is not a sufficient resource, then the deployment may not be practical.

2) "***Will there be voltage regulation impacts on of the feeder?***"

   For large penetrations of solar, "cloud transients" have the potential to cause large variations in the distribution feeder voltage, possibly outside of the ANSI C84.1 voltage standards. A single large spot installation, such as a 100kW solar array attached on a weak system, can drive the voltage outside of the desired range. The ability of a feeder to integrate PV without voltage problems must be fully examined.

3) "***How will this affect protection coordination?***"

   The majority of distribution feeders implement a coordinated fuse protection scheme that assumes a radial construction and unidirectional power flow. Larger residential solar installations and larger commercial installations have the potential to reverse the power flow, which can cause conditions that are not addressed by a typical coordinated fuse protection scheme.

5.2 Wind Turbine Generator (WTG) Integration

At the distribution level, it is possible to connect larger WTGs to the primary three phase backbone. Deployment of a large WTG at the distribution level is generally performed by the utility or a large commercial or industrial customer. Depending on the size of the distribution feeder, a single 1.8 MW WTG can provide a sizable amount of the annual energy of the feeder.

5.2.1 Impacts of WTG Integration

The primary benefit of commercial WTGs is a reduction in the effective annual energy consumption, from 4.0% to 23.0% per feeder. For a comprehensive national deployment this would equate to a 1.7% reduction in annual energy consumption, or 24,000 GWh. For the examined work, commercial WTG penetrations up to 66.8% of peak load per feeder were used, with an average penetration of 2.2%. The low average penetration is due to the WTGs only being deployed on a small number of prototypical feeders. This penetration level of WTG resulted in reduced CO_2 emissions of between 5.0% and 65.0% per feeder. For a comprehensive national deployment, this would equate to a 1.2% reduction in CO_2 emissions, or 15.6 million tons.

The reduction of peak load is a secondary benefit of commercial WTG, from -0.5% to 4.0% per feeder, with an average of 3.2%. Despite the fact that peak wind production is not coincident with feeder peak, the large size of the WTGs can provide significant peak reductions for the feeders on which they are deployed.

5.2.2 Deployment Strategies

The deployment of a 1.8 MW WTG at the distribution level requires the proper feeder selection. The ideal feeder to target will have a substantial peak load, 5 MW+, and strong electrical characteristics. Specifically, large conductors with a low voltage drop so that variations in the output of the WTG do not cause corresponding large voltage variations on the distribution feeder.

Figure 2.5 shows a deployment curve for a comprehensive national deployment of WTGs. The most significant issue to observe on Figure 2.5 is that the majority of benefits are derived from a small number of distribution feeders. This is due to the fact that WTGs were only deployed on the GC-12.47-1 feeders that represent large commercial or industrials loads. WTG were not deployed on other feeders which were primary residential or light commercial. This resulted in only approximately 7.7% of the feeders being populated with a WTG, resulting in a 24,000 GWh reduction in annual energy consumption.

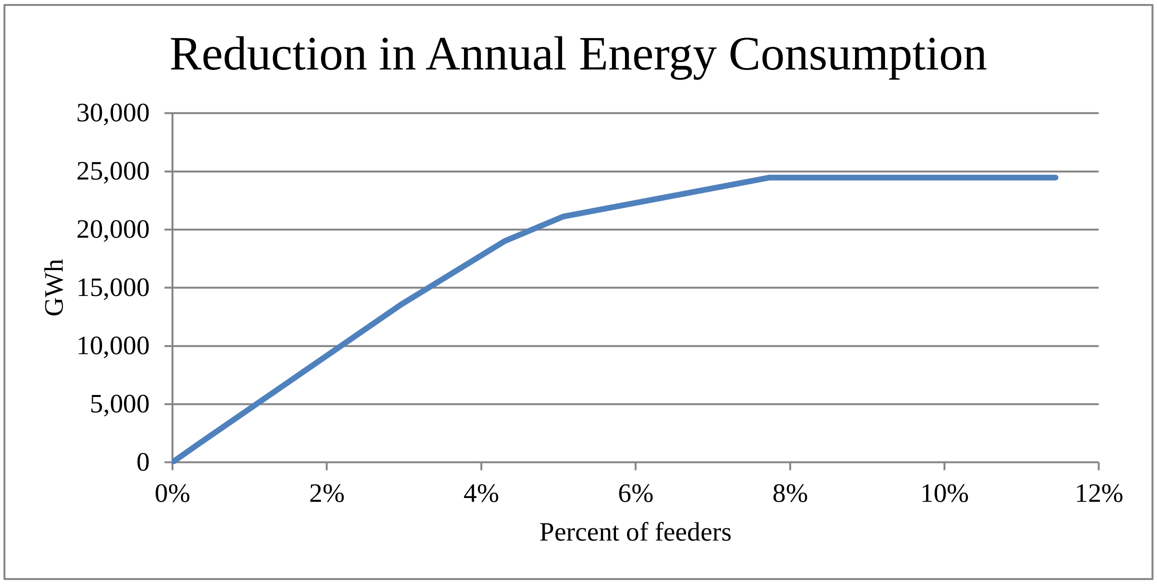

Figure 2.5: Deployment curve for WTG (reduction of annual energy consumption)

5.2.3 Relevant Questions for WTG Deployments

Below is a selection of questions that should be addressed before WTG integration is deployed. This is not an exhaustive set of question, but gives a sense of the issues that should be addressed.

1) "***Are there sufficient wind resources available?***"

   WTGs are a technology that is best suited for regions with a high wind resource. If there is not a sufficient resource, then the deployment may not be practical.

2) "***Will there be voltage regulation impacts on of the feeder?***"

   Because of the variability of wind and the large size of the units, the WTG can go from providing a large portion of the feeder load to zero output in a relatively short time. If the WTG is connected to a weak system, then there may be significant voltage regulation problems.

3) "***How will this affect the protection coordination system?***"

   The majority of distribution feeders implement a coordinated fuse protection scheme that assumes a radial construction and unidirectional power flow. A single large WTG can easily reverse the power flow on a feeder, requiring a revised protection scheme.

6 Concluding Comments

This report has summarized the impacts of the technologies in the four technical reports, both at a per feeder level and on a comprehensive national deployment. The impacts of the various technologies have been tracked using the SGIG impact metrics where applicable. Overall, the various technologies have the potential to reduce annual energy consumption, increase system reliability, reduce the system peak, and reduce emissions. While there are significant gains to be achieved by deploying the representative technologies, these reports have shown that there are issues that need to be further addressed to achieve the maximum value for deploying them. For the deployment of utility centric technologies such as VVO, a carefully planned deployment is necessary because of variations in regions, end-use load behaviors, and distribution feeder design and operation. For technologies that engage the end-use customer, such as TES and DR, it is also necessary to consider what the optimal utilization of the resource is, and how the customers will respond to the technology.

The technologies that were analyzed in these reports are representative technologies; they do not represent any single specific commercial solution or any utility specific deployment. The proprietary solutions that are provided by commercial vendors are generally tailored to individual customers, and would be expected to outperform the representative systems used in this report. Collaborative work between government and industry could help to better estimate the benefits of new technologies as well as increase the benefits that can be achieved from these technologies.

The four technical reports and this summary report have shown that the types of technologies deployed as part of the SGIG projects have the potential to address the important issues facing the nation's electrical infrastructure. This work gives a first glance at the type of results that can be expected from the SGIG projects, both on a per feeder basis, and the national level. These results can be used to make decisions on specific technologies or to benchmark the performance of technologies on specific systems.

Appendix A: Regional Distribution of Taxonomy Feeders

This appendix is designed to give a basis for extrapolating the benefits of deploying technologies on a national level. The individual results from the prototypical feeders can be scaled based on an estimate of the number of feeders in the continental United States that have similar characteristics. To estimate the number of distribution feeders in the continental United States, population information and national energy consumption number are used. The estimate from this appendix does not represent all distribution feeders in the United States; it is an estimate of the number of feeders that are primarily residential and light commercial. Networked urban cores, industrial feeders, and heavy commercial feeders are not included.

This appendix will provide the supporting data for the number of estimated feeders used for extrapolation to a national level. In the following sections, it will be shown that are approximately 150,000 distribution feeders in the Continental United States that are primarily residential and light commercial, and this number is used for extrapolation to a national level. While not explicitly calculated, it is estimated that the total number of distribution feeders in the Continental Unites States is in the range of 250,000-500,000. Determining the exact number is outside of the scope of this work since the technologies deployed as part of the SGIG projects were only focused on residential and light commercial feeders. Further work could be conducted to determine the feasibility of operating these technologies on networked urban cores, industrial, and heavy commercial feeders.

The following sections outline the basis for the 150,000+ feeder estimate. The estimate is based on primary data sources such as census data, climate data, and EIA energy consumption estimates [11]-[14].

A.1 End Use Load Models

As discussed in Appendix B of the technical reports, it has been observed that climate and energy consumption are closely related; therefore, when studying energy usage, climate must be taken into consideration. The continental United States has been divided up into five climate regions, as shown in Figure B.1 of the technical reports. In the report on distribution taxonomy for the modern grid initiative [9], there is a description of the process by which several prototypical feeder models were chosen to represent the different feeder types found in each climate region [10]. Data from the 2000 Census [11] was then used to determine the population density in each region, which allowed for the estimation of the total number of feeder types in each region. By using 2010 Census data [12], a more current and relevant estimation of regional population, the number of prototypical feeder types, can be determined. Newer, more accurate climate regions have been defined by DOE [13], but for the sake of consistency, the original five climate regions are maintained.

A.2 Regional Population

In order to determine how many of each of the prototypical feeders exists in each climate region, a population count for each climate region is needed. By using state population data from the 2010 Census [12], the population in each climate region could be totaled. Where a state is split between climate regions, population-per-county data was used to estimate the percentage of state population on either side of an approximated climate region boundary. The total estimated population numbers for each climate region are shown in Table A.1.

Table A.1: Total population in climate regions

Region	Total Est. Population
1	16,729,022
2	123,410,831
3	42,945,155
4	80,586,356
5	43,003,643

The prototypical feeders are all of a radial configuration, which excludes networked or mesh-type configurations commonly seen in urban areas. There is no data to indicate exactly how much of the population is associated with network feeders, so it is assumed that 5-10% of the population resides in urban areas using non-radial feeders. For this study, it is assumed that 10% of the population resides in an urban core and will be excluded to account for the population that cannot be represented by the prototypical feeders. The altered population estimates representing a non-urban core population are in Table A.2.

Table A.2: Non-urban core populations by climate region

Non-Urban Core Population in Climate Regions	
Region	Total Est. Population
1	15,056,120
2	111,069,748
3	38,650,640
4	72,527,720
5	38,703,279

The 2010 Census numbers for total occupied housing units in each state were used to find the total number of households for each climate region. Where a state is split between climate regions, the previously determined state population segments were used to determine the division of the total occupied housing units between climate regions. The totals for the non-urban core households in each climate region are shown in Table A.3.

Table A.3: Total households by climate region

Households in Climate Regions	
Region	Est. Number Households
1	5,503,045
2	42,914,420
3	13,476,930
4	27,886,109
5	14,611,025

A.3 Number of Feeders per Region

Each prototypical feeder model specifies the amount of commercial and residential houses served by the feeder. In [10], estimates of the relative distribution of loads between urban, suburban, and rural areas were used to determine the percentages of each prototypical feeder type within each region. Given the housing boom and recession in the recent past, the rate of growth of the residential load is likely greater than that of commercial; therefore, the ratio of percentages in the feeder types is likely to have changed from those shown in [10]. The percentages in Table A.4 have changed from those in [10] by roughly 1% towards an increase in predominantly residential feeders and a decrease in predominantly commercial feeders.

The estimated numbers of households in Table A.3 correspond to residential houses in the feeder models. When converted to a GridLAB-D format, the prototypical feeders model a large home in place of an apartment building. It is assumed that roughly 8% of the residential houses in the GridLAB-D prototypical feeder models are multi-unit buildings with 12 housing units in each building. Considering that the people at a residence are also the people that populate the non-residential buildings and make up the non-residential loads (i.e., commercial, agricultural and industrial), only the residential portion of the prototypical feeders are needed to compare to the estimated number of households in each region. These percentages, the numbers of residential housing units in each feeder model and the total estimated households for each region, are used to scale the count on the number of prototypical feeders of each type in each region, which can be seen in Table A.4.

Table A.4: Regional distribution of taxonomy feeders by climate region

Region	Feeder	kV	Annual Energy (MWh)	% Within A Region	Number of Feeders	Annual Energy/Feeder Type (MWh)
1	R1-12.47-1	12.5	23,659	22%	1,022	24,179,959
	R1-12.47-2	12.47	8,788	24%	1,115	9,798,279
	R1-12.47-3	12.47	3,678	18%	836	3,074,667
	R1-12.47-4	12.47	16,771	18%	836	14,020,249
	R1-25.00-1	24.9	7,571	10%	464	3,512,842
	GC-12.47-1	12.47	17,565	8%	372	6,534,125
				Totals:	***4,645***	***61,120,121***
2	R2-12.47-1	12.47	19,643	19%	8,243	161,915,843
	R2-12.47-2	12.47	17,162	17%	7,375	126,569,413
	R2-12.47-3	12.47	25,902	18%	7,809	202,269,216
	R2-25.00	24.9	54,303	20%	8,677	471,186,309
	R2-35.00-1	34.5	39,167	19%	8,243	322,854,563
	GC-12.47-1	12.47	18,319	7%	3,037	55,636,193
				Totals:	***43,384***	***1,340,431,538***
3	R3-12.47-1	12.47	32,010	32%	5,180	165,811,033
	R3-12.47-2	12.47	14,085	28%	4,533	63,845,507
	R3-12.47-3	12.47	33,990	21%	3,400	115,564,775
	GC-12.47-1	12.47	22,418	19%	3,076	68,957,512
				Totals:	***16,189***	***414,178,827***
4	R4-12.47-1	13.8	16,778	32%	13,956	234,147,673
	R4-12.47-2	12.5	7,310	36%	15,701	114,778,553
	R4-25.00-1	24.9	3,041	30%	13,084	39,787,041
	GC-12.47-1	12.47	19,834	2%	872	17,295,439
				Totals:	***43,613***	***406,008,706***
5	R5-12.47-1	13.8	39,008	11%	812	31,674,857
	R5-12.47-2	12.47	19,501	11%	812	15,834,826
	R5-12.47-3	13.8	42,702	15%	1,107	47,271,640
	R5-12.47-4	12.47	30,343	10%	738	22,393,255
	R5-12.47-5	12.47	36,350	12%	886	32,205,677
	R5-25.00-1	22.9	48,994	10%	738	36,157,504
	R5-35.00-1	34.5	49,312	10%	738	36,392,135
	GC-12.47-1	12.47	23,432	21%	1,550	36,319,007
				Total:	***7,381***	***258,248,902***
				Total:	**115,212**	**2,479,988,094**

A.4 Validation of Estimate

In considering the accuracy of the estimated number of feeders, it is important to show the annual energy consumption calculated from the GridLAB-D feeder models closely matches the annual energy consumption from actual statistics.

From the annual load statistics in the Annual Energy Outlook 2011 [14], it is shown that the total annual energy consumption for 2010 was 3,800 billion MWh, 900 billion MWh of which is attributed to industrial loads. Since the prototypical feeder models in GridLAB-D primarily represent residential and light commercial loads, the amount of industrial consumption will be excluded from the total for the comparison. Table A.5 outlines the process of finding the annual energy consumption amount to be compared with the calculation from the prototypical feeder models. The industrial load, 900 Billion MWh, is subtracted from the total, then 5% is taken out for transmission losses and, finally, 10% is taken out for urban core (non-radial feeders).

Table A.5: Total annual residential and commercial energy consumption for 2010

Consumption in 2010 (MWh)	Less 900 Million MWh Industrial Load (MWh)	Less 5% Transmission Losses (MWh)	Less 10% Urban Core (MWh)
3,800 Billion	2,900 Billion	2,755 Billion	2,480 Billion

By comparing the energy consumption number in Table A.5 with the estimate from GridLAB-D simulations in Table A.4, it can be seen that there is close agreement. This indicates that the estimated number of feeders, 115,212, is an accurate representation for extrapolating results to a national level. Once again it must be stated that the estimate of 115,212 feeders is an estimate of the number of residential and light commercial feeders. It excludes industrial and heavy commercial feeders as well as feeders supplying urban cores.

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