U.S. Department of Energy

Office of Electricity Delivery and Energy Reliability

R&D Program Benefits Estimation

DOE Office of Electricity Delivery & Energy Reliability

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CHAPTER 1: INTRODUCTION

The overall mission of the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability (OE) is to lead national efforts to modernize the electric grid, enhance the security and reliability of the energy infrastructure, and facilitate recovery from disruptions to the energy supply. In support of this mission, OE conducts a portfolio of research and development (R&D) activities to advance technologies to enhance electric power delivery. Multiple benefits are anticipated to result from the deployment of these technologies, including higher quality and more reliable power, energy savings, and lower cost electricity. In addition, OE engages State and local government decision-makers and the private sector to address issues related to the reliability and security of the grid, including responding to national emergencies that affect energy delivery. The OE R&D activities are comprised of four R&D lines: High Temperature Superconductivity (HTS), Visualization and Controls (V&C), Energy Storage and Power Electronics (ES&PE), and Distributed Systems Integration (DSI).

This report describes the R&D program benefits estimation process undertaken by OE to meet the requirements of the Government Performance and Results Act (GPRA) of 1993[1], which requires Federal Government agencies to develop and report R&D program "results" that are integrated into each year's budgetary decision-making process. This analysis helped meet GPRA requirements for fiscal year 2008 (FY08) by identifying the potential economic, energy efficiency, and infrastructure security and reliability impacts and associated benefits of realizing OE program goals based on proposed FY08 budget levels. The projected GPRA benefits estimates reflect only the net improvements from 2008 onward of program activities included in OE's FY 2008 Budget Request (including subsequent-year funding) and do not include the benefits from past achievements.

The FY08 benefits estimation process was conducted in coordination with the Office of Energy, Science and Environment (ESE), which includes all four of the R&D Offices with the Department of Energy, i.e., the Fossil Energy (FE), Energy Efficiency and Renewable Energy (EERE), Nuclear Energy (NE) and OE programs. This was the first year in which all four R&D offices worked together using similar guidelines and methodologies to produce an integrated forecast of potential R&D program benefits. A common set of assumptions were used to determine a baseline from which all program benefits were measured, and a common set of metrics provided a framework for reporting each office's benefits in a comparable way.

The ESE benefits analysis relies primarily on two integrated energy models: The National Energy Modeling System (NEMS) and the Market Allocation Model (MARKAL). NEMS is a detailed regional model of the U.S. energy system focused on the mid-term (to 2030), while MARKAL is a more aggregate national model with a longer time horizon to 2050. Integrated ESE-wide portfolios were constructed using both models, although most Program Offices

[1] For more information about GPRA requirements, see http://www.whitehouse.gov/omb/mgmt-gpra/gplaw2m.html.

employed only a single model that seemed most appropriate for their benefits analysis.[2] Given the more mid-term focus of OE programs, NEMS was used for analyzing the OE economic and energy efficiency benefits.

However, NEMS, MARKAL and other large-scale integrated energy market models are not appropriate for estimating reliability or infrastructure security benefits. These models are extremely aggregate in scale, relative to commonly used power flow simulation models. For example, the geographic detail of the electric system in NEMS is at 13 regions based on the North American Electric Reliability Council (NERC) regions. A more important limitation of these models for reliability and security analysis is that they calculate a market equilibrium, in a *deterministic* way, where supplies expand to meet increasing demands.

In contrast, electricity reliability and infrastructure security concerns arise because of *variability* in supply – in terms of the available capacity of generation units and transmission infrastructure – at any point in time, and because of *variability* in demand for electricity from hour to hour (or even minute to minute). NEMS, MARKAL, and models of this genre do not provide estimates of future outages or power quality events, and only extremely crude estimates of transmission congestion; and it is these concepts that are at the heart of reliability concerns. Also, these models do not consider the possibility of catastrophic disruptions from terrorist attacks, cyber attacks, or large-scale natural disasters that are the basis for concerns about infrastructure security. Hence, even though NEMS is relatively detailed for a national model, it does not contain either the geographic or temporal scale required to analyze these issues.

As a result, two separate, but complementary, analyses were conducted to measure the benefits related to OE programs:

- Economic and energy efficiency benefits were developed using a modified version of NEMS, which provided the integrating framework for all the ESE R&D offices[3]; and
- Infrastructure security and reliability benefits were estimated by using empirical data and expert panels.[4]

For the OE GPRA-NEMS analysis, the focus was on the following ESE economic and environmental metrics most relevant to OE programs:

- <u>Net Consumer Savings, NPV (billion 2004$)</u>: Net present value (NPV) of total annual energy expenditure savings for all consumers (residential, commercial, industry, and transportation) plus consumer capital expenditures, beginning in year 2008, discounted at 3 percent over the lifetime of the equipment.
- <u>Electric Power System Savings, NPV (billion 2004$)</u>: Net present value (NPV) of total annual expenses and capital payments saved by the electric utility industry, including fuel costs, operating and maintenance costs, and capital

[2] FE and OE used NEMS, NE used MARKAL, and EERE used both models for their benefits analyses.

[3] These calculations were performed by OnLocation, Inc. using NEMS.

[4] This effort was conducted by the Oak Ridge National Laboratory.

expenditures for retrofits, new generation capacity, and transmission upgrades. Capital costs are amortized using a 3 percent discount rate over 30 years. The annual payments through 2030 are then discounted back to 2008 using the 3 percent discount rate.

- Avoided CO_2 Emissions, Cumulative (million metric tons carbon): Total cumulative CO_2 emissions savings, beginning in the year 2008.

Note that net consumer savings and electric system savings are not additive since some or all of the system savings are passed through to the consumer through reduced electricity prices. The OE GPRA FY08 economic and energy system benefits estimates are shown in Table 1-1.

Table 1-1 Summary of Economic and Energy Efficiency Benefits of OE's Programs – for FY2008

ENVIRONMENTAL BENEFITS	2010	2015	2020	2025	2030
Avoided Carbon Emissions, Annual (MMTCE)	0	-5	-1	-4	-6
Avoided Carbon Emissions, Cumulative (MMTCE)*	0	-7	-22	-43	-66
ECONOMIC BENEFITS					
Consumer Savings, Annual (bil 2004$)	0	0	1	3	10
Consumer Savings, NPV (bil 2004$)*	0	-1	0	11	23
Electric Power Industry Savings, Annual (bil 2004$)	0	0	0	2	6
Electric Power Industry Savings, NPV (bil 2004$)*	0	1	1	5	16

**Assumes 3 percent real discount rate. Accumulation begins in the year 2008.*

The OE GPRA FY08 reliability and security benefits estimates are shown in Table 1-2, for years 2020 and 2030. The three reliability benefits components were added together to provide an overall reliability benefit expressed as a reduction in system costs, i.e., primarily a reduction in the costs to consumers of outages and power quality events, and in transmission congestion costs, relative to what they would be without the OE R&D program. The three infrastructure security components are not strictly additive, but refer to different aspects of security. The infrastructure security benefits represent the percentage reduction in the risk associated with a catastrophic attack or natural disaster. These estimates reflect estimates of the current levels of reliability-event costs, such as outages, and the collective judgment of over 50 experts.

Table 1-2 - Summary of Reliability and Infrastructure Security Benefits of OE's Programs – for FY2008

Program or Portfolio	Outages ($ billions)		Power Quality Events ($billions)		Trans-mission Congestion ($ billions)		Total Reliability ($ billions)		Risk of Attack or Destruction (%)		Mitigating Damage with Supply (%)		Mitigating Damage with Demand Response (%)		Total Infra-structure Security Improve-ment	
	2020	2030	2020	2030	2020	2030	2020	2030	2020	2030	2020	2030	2020	2030	2020	2030
DSI	1.9	5.3	0.51	1.6	0.03	0.09	2.4	7.0	2.0	5.0	2.0	3.0	1.0	2.0	5%	10%
HTS	1.9	5.3	0.29	1.3	0.01	0.07	2.2	6.7	2.0	3.0	2.0	4.0	2.0	5.0	6%	12%
ES&PE	2.8	4.3	1.0	1.7	0.05	0.09	3.9	6.1	4.5	4.0	5.0	8.5	2.0	4.0	11%	16%
V&C	9.5	11	1.1	1.6	0.07	0.07	11	12	10	10	10	7.5	10	7.5	28%	24%
PORT-FOLIO	4.7	11	1.2	1.7	0.07	0.13	6	13	5	4	4	13	7	9	13%	19%

NOTES:
(a) Assumes Mid-level Estimates of: (i) market penetration, (ii) impact of improved technology & (iii) total annual cost of outage, power quality, and transmission congestion events
(b) Assumes Cost Escalation: Future annual costs of outage, power quality, and transmission congestion events are assumed to increase (in inflation-adjusted dollars) relative to current levels, if there is no R&D in the future by industry, DOE & others. Estimate based on expert panel projections.
(d) Program Case – benefits of the OE R&D Program, assuming that industry also carries out R&D in this technology area, but *no R&D in any other technology* areas, by industry, DOE, or others
(e) Portfolio Case – benefits of the OE portfolio of R&D programs, assuming that industry, DOE and others *have R&D* programs. Portfolio benefits might be less than those in a Program Case because the Program Case implicitly assumes no R&D (including by industry) in any of the other technology areas.

Both of these analytic efforts were conducted for the first time for the FY08 budget cycle. In addition, OE's reorganization of its R&D programmatic activities in the past year, as well as the addition of its infrastructure security and energy restoration function, led to new program goal definitions. The relative newness of methodologies and goals means that these analyses should be viewed as works in progress with future refinements anticipated for next year. For example, the economic and energy efficiency benefits estimation process required analysts to develop simplified characterizations of the OE R&D goals that could be represented within NEMS, as well as modifications to NEMS to facilitate that representation, as described in Chapter 3. The goal characterizations and their implementations will be reviewed in the coming year.

Despite the initial efforts conducted for FY08, OE has not yet developed a metric that adequately addresses benefits to grid reliability and security, as well as the overall resiliency of the energy infrastructure. These benefits are the primary goals of OE's programs, which are focused on advancing technologies that will result in an enhancement of overall system reliability, strengthening grid stability by reducing the frequency or impact of operational disturbances, and reducing vulnerability of supervisory control and data acquisition (SCADA) systems to cyber attack. Our goal for next year's benefits analysis is to:

- Develop broadly acceptable definitions of electricity reliability and energy infrastructure security with corresponding program metrics, and
- Develop and apply a methodology to translate program goals related to enhanced reliability and security into quantifiable benefits using the developed metrics.

This paper presents an overview of OE's programs (Chapter 2), followed by the methodologies used to develop economic and energy efficiency benefits (Chapter 3) and reliability and security benefits (Chapter 4). The assumptions used as input to the methodologies are given in the Appendices. Chapter 5 provides the overall benefit estimation.

CHAPTER 2: PROGRAM DESCRIPTION AND GOALS

Mission

The mission of the Office of Electricity Delivery and Energy Reliability (OE) is to lead national efforts to modernize the electric grid, enhance security and reliability of the energy infrastructure, and facilitate recovery from disruptions to the energy supply. The Office supports this mission through the efforts of its two subprograms: 1) the Research and Development subprogram and 2) The Operations and Analysis subprogram. The benefits derived from these two subprograms are intended to:

(1) Strengthen grid stability and reduce the frequency and duration of operational disturbances;

(2) Increase the efficiency of the electric delivery system through reduced energy losses;

(3) Reduce peak price and price volatility of electricity, increase asset utilization (i.e., the capacity factor of transmission and distribution), and improve accessibility to a variety of energy sources that generate electricity;

(4) Harden the energy infrastructure so it can detect, prevent and mitigate external disruptions to the energy sector; and

(5) Improve recovery after energy disruptions.

The OE GPRA08 benefits were calculated for contributions expected from the Research and Development subprogram only, as technology development within the Office is focused in this activity. However, the Office is considering developing metrics, and associated benefits, in subsequent years that may apply to the Operations and Analysis subprogram, since this activity also contributes to enhancing the reliability of the energy infrastructure, including the electric grid.

Strategic Themes and Goals

The Department of Energy's Strategic Plan identifies five Strategic Themes, each with underlying goals. The OE program supports the Department's Strategic Plan, as follows:

<u>Strategic Theme 1</u>, Energy Security: Promoting America's energy security through reliable, clean, and affordable energy.

<u>Strategic Goal 1.3</u>, Energy Infrastructure: Create a more flexible, more reliable, and higher capacity U.S. energy infrastructure.

The programs funded within the Energy Supply and Conservation Appropriation have one Program goal that contributes to the Strategic Goals. OE's program goal is as follows:

Program Goal 1.3.16.00, Electricity Delivery and Energy Reliability: Lead national efforts to modernize the electric grid, enhance security and reliability of the energy infrastructure, and facilitate recovery from disruptions to the energy supply.

Efforts within the Research and Development Subprogram

The OE R&D activities are comprised of four R&D lines: High Temperature Superconductivity (HTS), Visualization and Controls (V&C), Energy Storage and Power Electronics (ES&PE), and Distributed Systems Integration (DSI). Each is discussed here.

High-Temperature Superconductivity (HTS)

The HTS program is supporting the development of domestic manufacturing capability for second-generation, high-temperature superconducting wires for widespread use in electric power equipment. The long-term HTS goal is to reduce the footprint for new transmission and distribution infrastructure and reduce energy losses through the use of high-temperature superconducting wire. Achieving the long term goal for second-generation HTS power applications requires: 1) solving the difficult problem of manufacturing electrical wires from HTS materials, which need special processing before realizing their ability to carry large currents, and 2) improving wire performance in magnetic fields characteristic for motors, generators, and transformers.

The main objective of the program is to develop high performance, inherently low-cost superconducting wires that achieve 100 times the capacity of conventional copper wires at comparable cost and that support the development of revolutionary electric power equipment with half the energy losses and half the size/weight of conventional equipment. Specific program objectives for HTS wire and coils are:

HTS Long Term Wire Goal: By 2020, develop prototype HTS wire achieving 1,000,000 critical current- length (A-m) for second generation wire

	2005 – Baseline	2006	2007	2008	2009	2010	2011	2012	2014	2020
Current-Length (A-m)	22,149 (107A x 207m)	30,000	40,000	50,000	50,000	70,000	70,000	100,000	500,000	1,000,000

HTS Long Term Coil Goal: Maintain progress in achieving increasingly powerful HTS coils for electric power applications such as transformers and generators, measured by magnetic field (Tesla) produced by test coil at 65K

	2005 – Baseline	2006	2007	2008	2009	2010	2012	2014
Magnetic Field	0.3	0.3	1.0	1.0	2.0	2.0	3.0	5.0

Visualization and Controls (V&C)

The Visualization and Controls program addresses the reliability and system efficiency of the electric delivery system, including enhancing the utilization of transmission and distribution assets with the development of real-time information and control technologies and systems. Efforts include:

(1) Developing and testing sensors for measuring system conditions involving a variety of physical metrics across the grid. (e.g., deploying and testing advanced GPS time-synchronized sensors known as intelligent electronic devices with phasor measurement units, digital fault recorders, and circuit breaker monitors at substations).

(2) Developing visualization tools for portraying real-time information to enhance situational awareness and enable grid operators to identify disturbances before they cascade into serious problems; the approach will include developing the capabilities for real-time data collection coupled with modeling system performance leading ultimately to automatic, real-time, switchable grid operation.

(3) Advancing next-generation control and data acquisition (SCADA) systems that provide security against intentional cyber assaults with no loss of critical functionality.

(4) Developing operation equipment, including transformers and fault current limiters, which adjust and regulate power flow, and

(5) Advancing market mechanisms under competitive electricity markets for grid reliability, economic efficiency, and demand response to reduce peak prices and price volatility.

<u>V&C Long Term Goal</u>: By 2014, develop tools and algorithms to enable an automatic, smart, real-time switchable network for transmission system operations that enables secure and reliable grid operations, controls major regions of the grid, and is hardened against cyber attacks.

	2002 – Baseline	2003	2005	2008	2009	2010	2011	2012	2014
Tools	Productive Modeling	One Real-time Data Collection Tool	One Real-time Data Collection Tool		One Diagnostics/ Operator Cuing Tool	One Diagnostics/ Operator Cuing Tool	Two Diagnostics/ Operator Cuing Tool	One Diagnostics/ Operator Cuing Tool	One Automation System
Evidence	Offline Analysis	Area Control Error Real Time Monitoring System (frequency and area control error (ACE))	Wide Area Phasor Measure-ment (real and reactive power flow)		Dynamic Security Assessment (real-time assessment of voltage levels)	Electro-mechanical Grid Stability Alarm (analysis of characteristic power oscillations)	Security Evaluation Tool (analysis of cyber vulnerabilities) Contingency Evaluation Tool (analysis of system to withstand contingencies)	Operating Cueing Presentation (decision support tools)	Automatic System Reconfigurati on, (reactive power control, interruptible load, adaptive islanding
Sensors	Approxi-mately 50 Phasor Measure-ment Unit (PMUs) in Western Inter-connect		50 Phasor Measure-ment Unit (PMUs) in Eastern Interconnect	Implement 50 additional sensors	Implement 50 additional sensors		Demonstrate 50 sensors at distribution voltage	Demonstrate 50 sensors at distribution voltage	Demonstrate 50 sensors at distribution voltage

Energy Storage and Power Electronics (ES&PE)

The ES&PE program supports the development of high-voltage power electronics that will allow precise and rapid switching of electric power to support long distance transmission. Advances in speed and precision would enable the grid to respond more efficiently to system disturbances, as well as allow it to operate with lower margins and fewer constraints, thereby reducing the need for additional infrastructure. To develop devices that can work in a high-voltage, high-current domain requires research into the properties and suitability of advanced materials, like diamond and silicon-carbide, and a focus on thermal management, topology development and packaging concerns.

The program also pursues the advancement of electrical storage devices that can be applied in ways to reduce transmission system congestion, help manage peak loads, make renewable electricity sources more dispatchable, and increase the reliability of the overall electric grid. Reducing the costs and size of energy storage systems are the key to more widespread use. Additional effort is required to assess opportunities for new manufacturing processes and materials (e.g., those with higher energy density storage capabilities) to reduce the cost of existing battery storage devices without sacrificing technical performance. Advances in the design of storage devices are needed for batteries, flywheels, and capacitors, as well as evaluation of trade-offs in features and performance to lower manufacturing costs.

Long-Term Energy Storage Goal: By 2030, there will be prototype super-capacitors and/or battery systems with operating voltages that are two-to-three times greater than today's systems or have a five-fold increase in stored energy.

Metrics	2006	2007	2008	2009	2010	2011	2012
Systems	3 systems installed with CEC	2 systems installed with CEC and NYSERDA	--	--	--	--	--
Energy Density (Capacitors and Batteries)	--	--	3 ionic liquids for boosting power by 50%	10% increase in energy density	10% increase in energy density	50% increase in energy density	Factor of 2 increase

Power Electronics and Advanced Materials Long-Term Goal: By 2025, demonstrate a prototype solid state breaker (switch) with less than 1 millisecond response. When used in a breaker, these switches will not increase the cost of the system by more than 10%.

Performance Characteristics	2005 – Baseline	2008	2010	2012	2018	2025
Speed	Current mechanical breakers operate at 4-6 cycles (66 – 100 milli-seconds) Fuses operate in ¼ cycle (4 milli-seconds)		5 milli-seconds	4 milli-seconds	2 milli-seconds	1 milli-seconds
Voltage/Current	Silicon – based switches (fully controllable) 5000 volts and 10 amps	1200 volts/10 amps		10,000 volts/ 10 amps	20,000 volts/ 100 amps or 50,000 volts/ >10 amps	20,000 volts/ 500 amps or 50,000 volts/> 100 amps
Temperature Limits	Current silicon – based devices are limited to 150^{o}C			250^{o}C		400^{o}C

Distributed Systems Integration (DSI)

The overall goal of the DSI program is to demonstrate peak load reduction on distribution feeders with the implementation of distributed energy and energy management systems at a cost that is competitive with system/capacity upgrades. Currently, there are very few examples of situations where portfolios of distributed systems, e.g., generation, storage, and price-based demand response mechanisms, have been installed and expected to work together as integrated systems to meet the capacity and energy needs of utilities and consumers.

Activities include identifying local areas across the country experiencing electricity supply and delivery constraints; soliciting ideas from utilities, states, equipment manufacturers, and consumers about using distributed systems to alleviate grid congestion in those areas; establishing multi-year data collection and analysis plans for measurement of costs, benefits, and utility and consumer impacts to assist in site and system selection; and competitively awarding cost-shared agreements to install, operate, test, and evaluate distributed systems in a selected number of constrained areas. The technical objective for integrated demonstration projects is to verify and validate by 2015 the application of distributed systems to reduce congestion in areas experiencing electricity supply and delivery constraints. Evaluation of the role that advanced design strategies, such as local energy networks (e.g., microgrids), could play in the new grid architecture will be another one of the key activities for determining feasibility, assessing costs and benefits, and identifying profitable business models.

DSI Long-Term Goal: By 2015, demonstrate a 20% peak-load reduction, while providing value services and reliability levels required by customers.

	2008 – Baseline	2009	2010	2011	2012	2013	2014	2015
Percent reduction in peak load	0%	5%	10%	10%	15%	15%	15%	20%
Number of feeders analyzed/demonstrated	0	1	2	2	1	2	2	1

Efforts within the Operations and Analysis Subprogram

Under the Operations and Analysis subprogram, the Permitting, Siting, and Analysis (PSA) activity works with States and regional organizations to modernize the electric grid and enhance its reliability through the improvement of their electricity-related laws, regulations, and policies. PSA efforts include implementation of grid modernization mandates assigned to the Department of Energy though the Energy Policy Act of 2005. In addition, the International Electricity Regulatory function of the PSA activity issues permits for cross-border transmission lines and authorizes the export of electricity.

Also under the Operations and Analysis subprogram is the Infrastructure Security and Energy Restoration (ISER) activity. This activity brings DOE into compliance with the Homeland Security Presidential Directives Seven, "Critical Infrastructure Identification, Prioritization and Protection," and Eight, "National Preparedness," as well as the National Response Plan implementing the Robert T. Stafford Act. ISER's prime function is to support OE's mission with regard to "enhancing security and reliability of the energy infrastructure, and facilitating recovery from disruptions to energy supply." The President has designated DOE as the Lead Sector Specific Agency responsible for protecting the Nation's critical energy infrastructure. The ISER activity is responsible to the Secretary of Energy for coordinating and carrying out these DOE responsibilities.

CHAPTER 3: ECONOMIC AND ENERGY EFFICIENCY BENEFITS ESTIMATION

Introduction

For the GPRA FY08 budget cycle, the National Energy Modeling System (NEMS) was used for the first time to estimate future economic and energy system benefits for the OE R&D programs. The aim was to make the OE analysis consistent with that of the other GPRA FY08 analyses being conducted within the Office of Energy, Science and Environment (ESE) that also used NEMS to forecast program benefits to the year 2030. This also facilitated the creation of an ESE-wide Portfolio case within NEMS that included all the ESE R&D Offices, which includes Fossil Energy (FE), Energy Efficiency and Renewable Energy (EERE), Nuclear Energy (NE) and OE. A GPRA-NEMS modeling analysis was performed for both OE and EERE[5].

The OE benefits estimation process included the following steps:

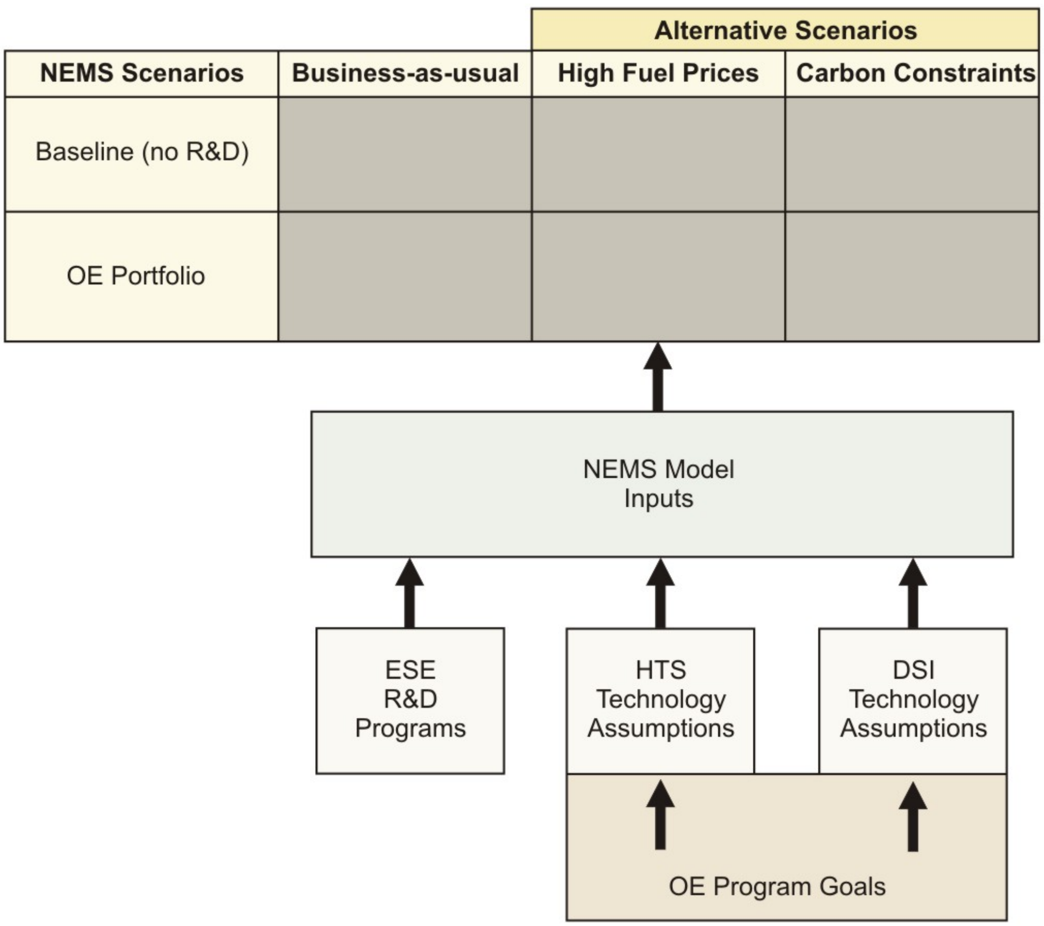
- Identified and quantified program goals and performance measures that could be used as inputs to the analysis, ensuring that the goals were tied to each program's requested budget levels;
- Identified NEMS model enhancements that were needed to capture the benefits of the R&D program goals, and coordinated these model modifications with other ESE offices in order to create a single version of the model for the GPRA FY08 analyses;
- Created a baseline scenario that assumed no future R&D funding for OE technologies, from which to measure progress in meeting the program goals;
- Developed a set of program assumptions for each OE R&D program that could be used to represent program goals within the NEMS model;
- Using these R&D program assumptions, created individual program scenarios in NEMS, as well as a portfolio scenario that combined program assumptions for all OE R&D programs;
- Measured the estimated benefits between the baseline scenario and each program scenario using GPRA benefits metrics developed by the ESE Offices;
- Combined OE Baseline and Portfolio assumptions with assumptions from the other ESE Offices to create DOE-wide integrated NEMS Baseline and Portfolio scenarios;
- Provided preliminary benefits estimates in May for use in the DOE budget formulation process in June. A final set of benefits estimates, incorporating revised program goal assumptions, was provided for use in the August budget submission; and
- Estimated OE Portfolio benefits under two alternative future energy scenarios created by the ESE Offices: 1) High Fuel Prices scenario and 2) Carbon Constraint scenario.

[5] Modeling analysis performed by OnLocation, Inc.

The OE R&D activities are comprised of four R&D lines: Visualization and Controls (V&C), Energy Storage and Power Electronics (ES&PE), Distributed Systems Integration (DSI), and High Temperature Superconductivity (HTS). The first two R&D lines contain programs that are primarily focused on infrastructure security and reliability benefits that cannot be captured in NEMS, so the NEMS modeling focused on the DSI and HTS R&D lines only. A description of the NEMS model structure and its ability to represent OE programs is included in the NEMS overview section within this chapter.

This chapter provides an overview of the NEMS model used in the GPRA-NEMS analysis, including model modifications made to represent OE program goals, detailed descriptions of the inputs and methodologies used to create the baseline and program cases within NEMS, and the resulting benefits estimates for OE under the business-as-usual and alternative scenarios. A schematic of the process can be found in Flowchart 1 below.

Flowchart 1. OE GPRA FY08 Energy/Economic Benefits Estimates



National Energy Modeling System (NEMS) Overview[6]

The National Energy Modeling System (NEMS) is a computer-based, energy-economic modeling system of U.S. energy markets for the period through 2030. NEMS projects the production, imports, conversion, consumption, and prices of energy, subject to assumptions on macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics. NEMS was designed and implemented by the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE). NEMS is used by EIA to project the energy, economic, and environmental impacts on the United States of alternative energy policies and of different assumptions about energy markets.

Baseline forecasts are developed with NEMS and published annually by EIA in the *Annual Energy Outlook*[7] (AEO). In accordance with the requirement that EIA remain policy-neutral, the *Annual Energy Outlook* projections are based on Federal, State, and local laws and regulations in effect at the time of the forecast.

Energy resources and prices, the demand for specific energy services, and other characteristics of energy markets vary widely across the United States. To address these differences, each NEMS module is regionally disaggregated to reflect the availability of data, the regional format typically used to analyze trends in the specific area, geology, and other factors, as well as the regions determined to be the most useful for policy analysis. For example, the Electricity Market Module uses 13 supply regions based on the North American Electric Reliability Council (NERC) regions, to capture the differences in generation fuel mix, electricity prices and other regional differences that exist in U.S. electricity markets.

A key feature of NEMS is the representation of technology characteristics and technology improvement over time. Five of the sectors—residential, commercial, transportation, electricity generation, and refining–include extensive treatment of individual technologies and their characteristics, such as the initial capital cost, operating cost, date of availability, efficiency, and other characteristics specific to the sector. Technological progress results in a gradual reduction in cost and is modeled as a function of time in these end-use sectors. In addition, the electricity sector accounts for technological optimism in the capital costs of first-of-a-kind generating technologies that assumes that costs decline as experience with the technologies is gained both domestically and internationally. In each of these sectors, equipment choices are made for individual technologies, as new equipment is needed to meet growing demand for energy services or to replace retired equipment.

The Electricity Market Module (EMM) represents the capacity planning, generation, transmission, and pricing of electricity. Operating (dispatch) decisions are made by choosing the mix of plants that minimizes fuel, variable operating and maintenance (O&M), and

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[6] Description was largely taken from the Energy Information Administration, *The National Energy Modeling System: An Overview 2003*, DOE/EIA-0581(2003), March 2003, pp. 1,5. For more information about the NEMS model, see http://www.eia.doe.gov/oiaf/aeo/overview/index.html.

[7] Energy Information Administration, *Annual Energy Outlook 2006*, DOE/EIA-0383(2006), February 2006. To download a copy, visit http://www.eia.doe.gov/oiaf/aeo/index.html.

environmental costs, subject to meeting electricity demand and environmental constraints. Capacity expansion is determined by the least-cost mix of all costs, including capital, O&M, and fuel. Costs and operating characteristics for fossil fuel, nuclear, and renewable generating technologies are represented. Electricity demand is represented by load curves, which vary by region, season, and time of day. The regional hourly load curves represented in the demand modules are translated into 36 time periods that represent peak and non-peak seasonal (summer, winter, and spring/fall) and time-of-day (daytime, morning/evening, and night) periods within each year, for use by the EMM dispatching sub-module. Transmission and distribution (T&D) losses are also factored into each time period in order to calculate total demand for generation.

The NEMS model was used as the integrating framework for estimating energy and economic benefits for all of the ESE R&D offices, including OE. However, the model is limited in its ability to measure the reliability and infrastructure security benefits of OE's programs:

- Thirteen supply regions is an appropriate level of aggregation for a national energy model; however, it cannot capture the impact of localized transmission congestion;
- Thirty-six time periods per year is sufficient for most applications of the model, but cannot be used to represent short-term disruptions to the grid;
- NEMS is an equilibrium model that calls each supply, conversion, and end-use demand module in sequence until the delivered prices of energy and the quantities demanded have converged within a specified tolerance, thus achieving an economic equilibrium of supply and demand for energy for each time period. Equilibrium models do not account for market imperfections such as transmission congestion and power outages, but instead assume that the infrastructure is capable of serving demand in every time period, and that it will expand as needed to meet future load requirements

NEMS Benefits Estimation Methodology

Since this was the first time OE programs were modeled within NEMS, the first step in the benefits analysis was to create a detailed mapping of how OE activities could be represented within the NEMS framework. The main purpose of the mapping was to reveal the program goals that could be reflected in the existing NEMS structure, those that could not be modeled in NEMS, and possible enhancements to NEMS that could be made to improve the representation of some of the OE activities. Based on this mapping, the following information was revealed:

- The four key attributes of OE programs are infrastructure security, reliability, energy efficiency and system efficiency. The NEMS analysis focused on program benefits related to energy efficiency and system efficiency only.
- Since the V&C and ES&PE R&D programs are primarily focused on infrastructure security and reliability benefits that cannot be captured in NEMS, the GPRA-NEMS modeling focused on the DSI and HTS R&D lines only.
- Existing model parameters, potential model modifications and associated inputs were then identified for HTS and DSI programs that could be used to represent each

program's goals and technologies within the NEMS framework. These were categorized as:

- o <u>Endogenous</u>: included program activities and technologies where NEMS could provide full economic evaluation and market adoption projections;
- o <u>Impact Only</u>: included program features where NEMS can capture only the impact represented based on externally derived adoption rates; or
- o <u>Not measurable in NEMS</u>: included programs focused primarily on infrastructure reliability and security.

Table 3-1 summarizes the final mapping of OE programs to NEMS capabilities.

Table 3-1: Mapping OE Programs to NEMS

Program	OE Activities/ Technologies	NEMS Model Parameters	Model Inputs Needed for Each Scenario
Distributed Systems Integration	***Endogenous***	***Suggested modification:***	
	Load Shifting Technology	*(Preferred Method)* Modeled as electric supply option similar to DG; competes for market share	Technology cost; capacity factor; operating cost; year of technology deployment
	Impact Only	***Suggested modification:***	
	Load Shifting Technology	*(Alternate Method)* Modeled as end-use load shift over time with specified market penetration assumptions	Technology peak load shift; estimated market adoption rate
Program	**OE Activities/ Technologies**	**NEMS Model Parameters**	**Model Inputs Needed for Each Scenario**
High Temperature Super-conductivity	***Impact Only***	***Existing structure:***	
	Improved efficiency of large motors	Industrial load reduction	Maximum market potential for new, replacement; kWh saved per unit; market adoption rate; technology cost differential
	Improved efficiency of transformers	T&D losses	Maximum market potential for new, replacement; kWh saved per unit; market adoption rate; technology cost differential
	Improved efficiency of generators	Utility technology heat rates and capital costs for new capacity, or T&D losses	Maximum market potential for new, replacement; kWh saved per unit; market adoption rate; technology cost differential
	Improved efficiency of underground power cables; increased cable carrying capacity	Electric distribution losses (included as T&D losses in NEMS)	Maximum market potential for new, replacement; kWh saved per unit; market adoption rate; technology cost differential; cable capacity
Program	**OE Activities/ Technologies**	**NEMS Model Parameters**	**Model Inputs Needed for Each Scenario**
Visualization and Controls; Energy Storage and Power Electronics	***NEMS cannot measure***	***Existing structure:***	
	Reduced frequency and duration of outages, advanced technologies for cyber security of control systems, etc.	none	Cannot measure system reliability, power quality, and system security in NEMS

Once the model parameters and inputs were identified, the next step in the analysis was to construct a base case and three program cases:

- Base (No R&D) Case: A reference case that is intended to represent the future U.S. energy system without the effect of DOE R&D programs, built upon a Business-As-Usual (BAU) projection of energy markets as provided in the AEO2006 Reference Case. The "No R&D" case helps ensure that changes within the energy system (including private sector technology development) that may occur absent OE's R&D efforts are not counted as part of the benefits of the OE programs. This case was constructed in conjunction with other ESE R&D offices to provide a consistent starting point for all program cases.
- HTS R&D Case: A program case that estimates projected benefits gained from the OE HTS program, using technology assumptions provided by the HTS program for superconducting motors, transformers, generators and cables.
- DSI R&D Case: A program case that estimates projected benefits gained from the OE DSI program, using program assumptions provided by the DSI program managers that represent a "technology-neutral" load-shifting technology.
- OE R&D Portfolio Case: A program case that combines the HTS and DSI program assumptions to create an integrated set of projected benefits for OE.

Benefits were calculated by examining the differences between the Base (No R&D) Case and each Program case, i.e. the projected impacts of the achievement of OE's program goals. The Base (No R&D) Case included assumptions provided by all of the ESE offices regarding future technology improvements in the absence of their R&D efforts. Program case assumptions reflected each program's goals as they relate to their FY08 budget request. The methodologies used by the OE managers to derive the HTS and DSI technology assumptions for the GPRA FY08 analysis are discussed in Appendix A (HTS) and Appendix B (DSI).

Two alternative baseline scenarios were also modeled, using ESE guidelines, to help quantify some of the market uncertainties inherent in the BAU No R&D case. The alternative scenarios were defined as a High Fuel Prices case and a Carbon Constraint case, and provided the basis for estimating OE benefits under alternative sets of market assumptions.

Following is a detailed description of the methodologies and model inputs used for the Base Case and Program cases.

Baseline (No R&D) Assumptions

The Base (No R&D) Case reflects a projection of benefits without the effect of DOE R&D programs, using the AEO2006 Reference Case assumptions as the starting point. The OE HTS program manager assumed that utilities and other market players would continue progress on HTS technology R&D without DOE R&D funding, albeit at a much slower rate, and that this progress was not reflected in the AEO2006 forecast. Therefore the Base (No R&D) Case was modified slightly to reflect the resulting expected reduction in electricity demand and reduction in electricity losses associated with this view. The DSI program managers assumed no change in AEO2006 assumptions regarding the market adoption of load shifting technologies. Changes impacting the baseline projection of electricity markets made by other ESE R&D offices include:

- Renewable Energy: addition of an offshore wind technology by EERE that required NEMS model modifications, and more optimistic assumptions about land-based wind technology improvements and distributed photovoltaics markets;
- Fossil Energy: reduced improvements of advanced fossil-fueled electric generating technologies; and
- Nuclear Energy: no change from the AEO2006 assumptions.

The resulting Base Case ("ESE BAU Base") is very similar to the AEO2006 in terms of fuel prices, total electricity demand, electric generation fuel mix, and other key factors that affect OE programs. The greatest differences were in the electric generating technology mix where the ESE BAU case has more electric capacity additions of renewables and distributed generation relative to the AEO2006. Base Case fuel prices are shown in Figure 3-1, electricity demand by sector in Figure 3-2, and electric generation capacity additions by fuel/technology are shown in Figure 3-3.

Figure 3-1: Historical and Projected Fuel Prices
ESE Business-as-Usual Base Case

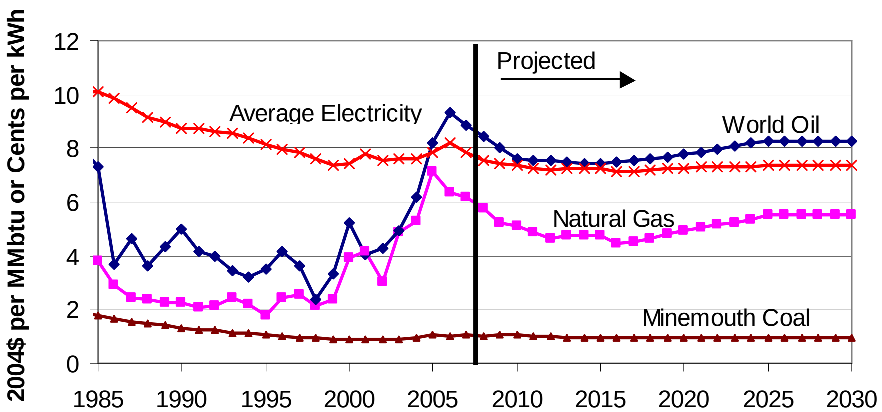


Figure 3-2: Electric Demand by Sector

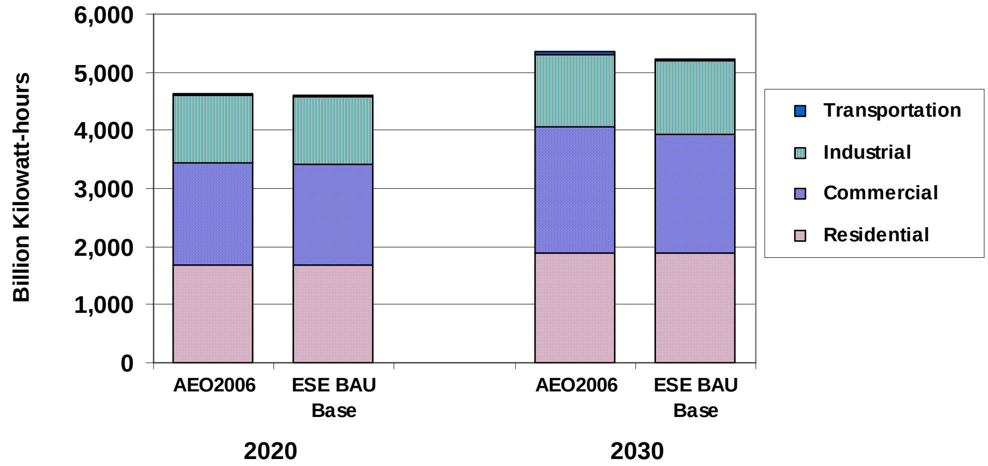
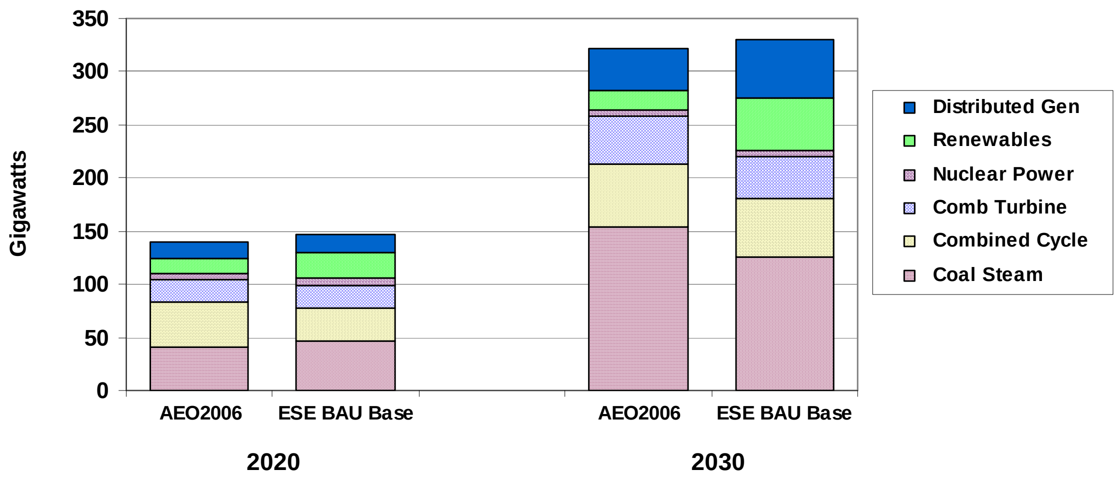


Figure 3-3: Electric Capacity Additions After 2005 (Above Base Capacity of 985 GW in 2005)



HTS Program Assumptions

Key model assumptions for both the Base (No R&D) Case and the HTS R&D program case provided by the OE HTS program manager included annual average equipment sales rates within the target market (both new and replacement equipment), market adoption projections per year (percent of total sales expected to be HTS equipment), and maximum market saturation for each of the four HTS technologies, as well as technology cost and efficiency differentials compared to conventional technologies. HTS market adoption rates were provided through 2020 or 2025, and were extrapolated to 2030, factoring in the maximum market saturation. Average technology costs for conventional technologies were provided in dollars per kilowatt ($/KW), along with average KW size of the equipment. The exception was the data provided for HTS cables, which were expressed in dollars per mile and average miles per kilowatt-hour (KWh). Cost differentials included the purchase price of the HTS device, HTS wire and cryogenic cooling devices, but did not include the value of energy savings since that was calculated endogenously in the NEMS model. These assumptions and their derivation are discussed in Appendix A.

Table 3-2 below highlights the key HTS technology assumptions developed for use in the NEMS Base and R&D Cases. Annual equipment sales (in KWh) for each target market were calculated using the average sales rates and the AEO2006 projections for industrial and total electricity sales through 2030, as well as the electric capacity additions projections to determine HTS generator sales. HTS technology KWh efficiency savings were also calculated using the efficiency differentials and AEO2006 electricity sales projections. Cost savings for each technology were derived using the average cost of the conventional technology, the cost differential, and the projected annual equipment sales. Cost savings related to the energy efficiency savings were calculated endogenously within NEMS.

These assumptions were translated into the following NEMS model inputs for the HTS Base and R&D cases:

- Reduced electricity transmission and distribution (T&D) losses from HTS generators, transformers, and cables (Figure 3-4);
- Industrial demand savings from HTS motors (Figure 3-5);
- Annual and cumulative amortized technology cost premiums or savings relative to conventional technologies (annual costs shown in Table 3-2).

Figure 3-4: HTS T&D Loss Savings (transformers, generators, cables)

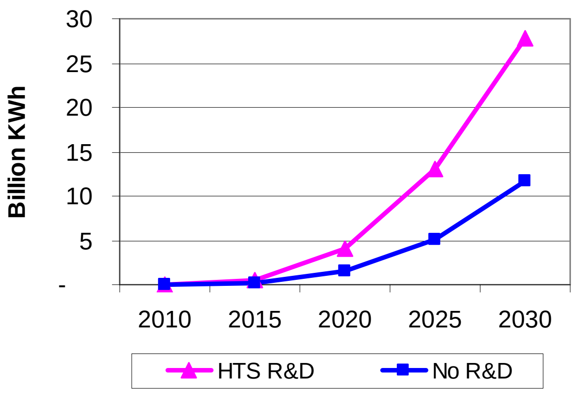
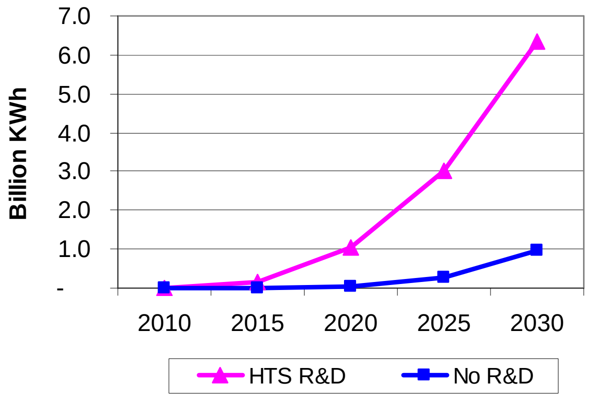


Figure 3-5: HTS Industrial Demand Savings (motors)



HTS generators were modeled in this way instead of explicitly in the technology costs and heat rates in order to avoid the need to determine an additional set of costs and performance characteristics that would include the technology improvement assumptions from the other ESE R&D offices for both the shared Baseline and combined ESE Portfolio case. Each of these offices has goals related to different generation technologies that affect the costs and efficiencies for these technologies. To combine the HTS assumptions with the assumptions from other DOE offices for each of the generation technologies would have required a complex off-line analysis to determine the characteristics of a blended HTS and conventional technology based on assumed market adoption parameters and weighted average costs and efficiencies. It was determined that the HTS generator savings could instead be captured effectively by modeling the savings as a reduction in T&D losses, based on the assumptions provided by the HTS program manager.

Table 3-2: HTS Technology Assumptions for Base (No R&D) Case and R&D Program Case

	2010	2015	2020	2025	2030
HTS Equipment Sales per Year (Billions KWh)					
HTS Motors (Base)	-	0.1	0.5	5.3	11.2
HTS Motors (R&D)	-	3.5	15.5	28.3	44.8
HTS Transformers (Base)	-	2.0	12.0	41.3	77.6
HTS Transformers (R&D)	-	16.5	40.1	206.3	410.9
HTS Generators (Base)	-	0.4	3.8	8.6	12.8
HTS Generators (R&D)	-	1.1	6.4	13.8	14.8
HTS Cables (Base)	-	3.0	18.1	32.9	54.5
HTS Cables (R&D)	-	7.5	36.1	60.9	69.2
Annual Energy Savings (Billions KWh)					
HTS Motors (Base)	-	0.0	0.0	0.3	1.0
HTS Motors (R&D)	-	0.2	1.0	3.0	6.3
HTS Transformers (Base)	-	0.0	0.1	0.5	1.5
HTS Transformers (R&D)	-	0.1	0.5	2.7	7.7
HTS Generators (Base)	-	0.0	0.7	2.6	5.9
HTS Generators (R&D)	-	0.1	1.3	4.3	8.7
HTS Cables (Base)	-	0.1	0.6	2.0	4.4
HTS Cables (R&D)	-	0.3	2.2	6.2	11.4
Annual Cost Savings Relative to Conventional Technology (millions $)*					
HTS Motors (Base)	-	(2.3)	(7.1)	(73.0)	(152.8)
HTS Motors (R&D)	-	(40.3)	(105.8)	(193.5)	(305.6)
HTS Transformers (Base)	-	(0.0)	(0.0)	(0.1)	(0.1)
HTS Transformers (R&D)	-	(0.0)	(0.0)	(0.2)	(0.4)
HTS Generators (Base)	-	(14.7)	(55.0)	(123.6)	(183.1)
HTS Generators (R&D)	-	(2.9)	(5.5)	(11.8)	(12.6)
HTS Cables (Base)	-	10.7	160.7	293.1	485.2
HTS Cables (R&D)	-	162.6	886.8	1,494.6	1,699.1

**Negative savings represent a premium over the cost of conventional. Savings are equipment cost savings only and do not include value of energy savings.*

The amortized HTS technology cost savings (or premiums) relative to conventional technologies were included in the computation of the consumer cost savings (motors) and electric power system cost savings (transformers, generators and cables).

DSI Program Assumptions

Based on the mapping of OE programs to NEMS capabilities, it was proposed to modify the model to include a load shifting technology in order to represent the DSI goal of demonstrating the economic viability of a 20 percent shift in peak demand at congested electricity distribution feeders by 2015. The GPRA version of the NEMS model was used as the basis for the modifications[8]. The GPRA version of NEMS is similar to the EIA *Annual Energy Outlook 2006* (AEO2006) version of NEMS but includes structural changes necessary to represent other ESE programs such as EERE's offshore wind program.

Two primary enhancements to the model were initially considered: adding a utility storage technology and adding a new demand elasticity structure to shift end-use demand loads from peak to off-peak. The preferred method was to achieve the program goals with an electric supply technology similar to a storage technology that competes for market share in the model; and the alternate method was to shift the end-use peak load with specified market penetration assumptions. The first method would allow the model to make an economic decision of how much to shift load and to react endogenously to changes in market conditions (i.e., alternative scenarios), while the second method would provide the modelers with a more direct approach to representing program goals.

The second approach proved to be more challenging than originally expected due to the complexity of the way the load curves are constructed and used within the model, so this approach was dropped. Instead, a hybrid of the two methods was employed: representation of the load shift through the electric supply technology but using a cost estimate that achieves a market penetration rate determined by an off-line analysis was conducted (see *Appendix B* for a complete description)[9]. This method allowed consideration of local conditions that may make load shifting particularly attractive that are not represented in the broader NEMS regionality. At the same time, the economic structure allowed the load shifting technology to respond to changing conditions in other scenarios. This hybrid methodology was used for the OE GPRA-NEMS FY08 analyses.

The new load-shifting technology in NEMS is similar to a utility storage technology that competes for market share in the model. Key technology characteristics of the new technology include a capital cost, fixed and variable operating costs, construction lead-time, forced and scheduled outage rates, typical unit size, and a "loss factor" associated with shifting load or storing and discharging the technology. The loss factor is used to create an energy balancing constraint in the model that requires that additional electricity be generated to fill the storage (or shift the load) equal to the amount of storage discharged plus any specified losses. The model then determines the most economical dispatch pattern for the

[8] This work was performed by OnLocation, Inc.

[9] This analysis was performed by Lawrence Berkeley National Laboratories

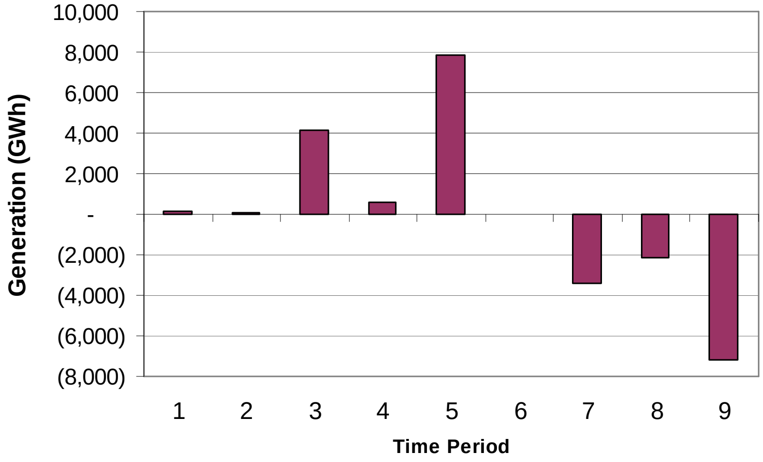
storage or load shifting technology. Also, since OE's goal is to reduce peak loads at the point of use or at the distribution feeders, the new storage/shift technology was assumed to incur no additional transmission costs, which are otherwise imposed on all new generation capacity for transmission grid upgrades. The new technology is also assumed to have a small unit size relative to other generators and therefore contributes to reliability for peak capacity purposes.

The following assumptions were used to represent the competitive load-shifting technology created in NEMS:

- The new technology assumes 0% losses to reflect a primarily demand response;
- Commercialization of the technology was assumed to occur in the year 2025 in the Base (No R&D) Case and in the year 2017 (2 years after the demonstration year of 2015) in the DSI Program Case;
- Capital cost assumptions for the load-shifting technology were adjusted in order to meet the target projected market penetration (assumed to be zero in the Base Case). The resulting capital cost used in the R&D case declined 45% from 2017-2030; and
- Initial O&M costs in the Base (No R&D) Case were assumed to be about 20% higher than the initial O&M cost in the Program case, with costs declining to the same level in both cases by the year 2030.

An example of the model's new load shifting capability is illustrated below in Figure 3-6 for the ECAR region (upper mid-west) during the peak summer season in the year 2030. The 9 summer time periods shown in the graph correspond to the 36 time periods per year represented in the NEMS dispatch sub-module (9 time periods per season), and are ordered by peak (period 1) to off-peak load periods. The number of hours in each time period varies significantly, with the first peak period representing less than 10 hours. Positive generation represents the discharge of the technology (or peak shifting) during peak load hours (periods 1-5), and negative values represents the corresponding recharging during off-peak hours (periods 7-9). Since the losses were assumed to be zero in this analysis, the discharge and recharge generation sum to zero.

Figure 3-6: Load Shifting Technology Operating Profile
ECAR Summer in Year 2030 (16 GW)



Model assumptions for the DSI R&D program case from the LBNL off-line analysis included regional and national market penetration projections to 2030 for the load shifting technology and the resulting regional and national average peak demand shift, assuming the technology is capable of shifting load 20 percent (the average peak demand shift is calculated by multiplying the 20 percent load shift per unit and the projected market penetration for each region). The final NEMS analysis used the national projections only. Figure 3-7 illustrates the national average peak demand shift, assuming market penetration projections shown in Table 3-3. The Base Case peak demand shift was assumed to be zero. A complete description of these assumptions can be found in Appendix B.

Figure 3-7: National Peak Load Shift
DSI R&D Case

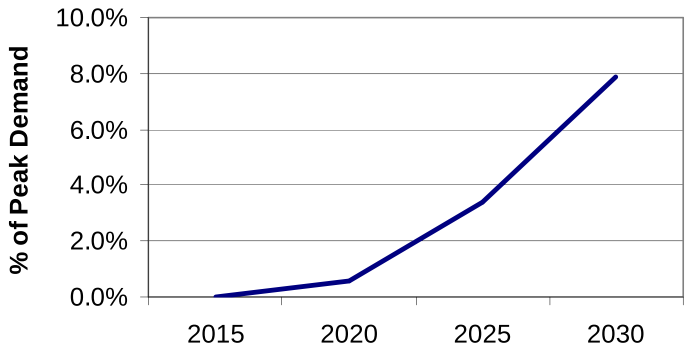


Table 3-3: National Average Target Load Shift Projection for GPRA-NEMS FY08 Load Shifting Technology

<u>**DSI Program Case**</u>	**2017**	**2020**	**2025**	**2030**
Market Adoption (% of market)	0.0%	3.2%	17.1%	39.3%
Average Peak Load Shift (% of peak)*	0.0%	0.6%	3.4%	7.9%

*Average peak load shift is calculated as market adoption multiplied by 20% load shift per unit purchased.

GPRA-NEMS Benefits Estimates: Business-As-Usual Scenario

For the GPRA FY08 analysis, ESE R&D offices created a shared set of metrics to estimate economic, environmental, security and reliability benefits for each of the DOE R&D programs. These metrics are consistent with DOE's Strategic Theme of "Promoting America's energy security through a *reliable*, *clean*, and *affordable* supply of energy."

For the OE GPRA-NEMS analysis, the focus was on the following economic and environmental metrics most relevant to OE programs:

- Net Consumer Savings, NPV (billion 2004$): Net present value (NPV) of total annual energy expenditure savings for all consumers (residential, commercial, industry, and transportation) plus consumer capital expenditures, beginning in year 2008, discounted at 3 percent over the lifetime of the equipment.
- Electric Power System Savings, NPV (billion 2004$): Net present value (NPV) of total annual expenses and capital payments saved by the electric utility industry, including fuel costs, operating and maintenance costs, and capital expenditures for retrofits, new generation capacity, and transmission upgrades. Capital costs are amortized using a 3 percent discount rate over 30 years. The annual payments through 2030 are then discounted back to 2008 using the 3 percent discount rate.
- Avoided CO_2 Emissions, Cumulative (million metric tons carbon): Total cumulative CO_2 emissions savings, beginning in the year 2008.

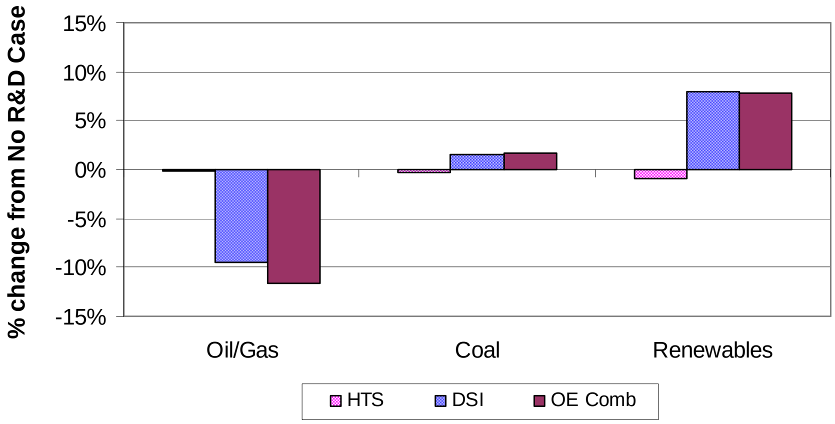
Reliability and security metrics developed by ESE were focused on avoided oil imports and transportation fuel diversity, which are not useful in measuring OE reliability and security contributions related to the electricity grid. OE's goal is to develop electricity reliability and security metrics for next year's GPRA analysis. Note that net consumer savings and electric system savings are not additive since some or all of the system savings are passed through to the consumer through reduced electricity prices.

Overall impacts from the OE programs can be summarized as follows:

- HTS technologies are more efficient than conventional technologies, thus reducing industrial electricity demand from motors and reducing T&D losses due to more efficient transformers, cables and electric generators. Reduced demand and T&D losses results in a reduction in the need to build new electric generating capacity, and reduces electricity prices and environmental emissions;
- DSI programs reduce peak electricity demand, which shifts the mix of generating technologies from peak load (mid-day) to base load (nights/weekends). This shift results in a reduction in peak electricity prices and improves the overall reliability of the electricity system.

In order to understand each program's benefits using the ESE metrics, it is helpful to first look at changes in electric generation fuel mix in each of the OE program cases. Figure 3-8 illustrates the percent change in fuel mix for each of the three program cases compared to the Base (No R&D) Case.

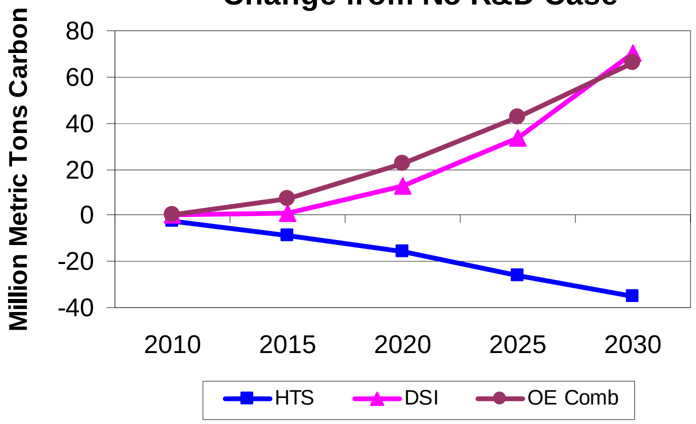
Figure 3-8: 2030 Electricity Generation Fuel Mix Change from No R&D Case



The HTS program results in reductions in all generation fuels, for a total reduction in electricity generation of about 20 billion kWh by 2030. The DSI program results in roughly 9 percent reduction in oil/gas generation due to a reduction in peakload generation from combustion turbines, but increases baseload coal and renewable generation due to the recharging requirement for the load shifting technology. A net increase of about 3 billion kWh in 2030 occurs due to customer response to lower electricity prices. Combining the two programs results in a reduction in oil/gas generation and increased coal and renewable generation for a net decrease of about 15 billion kWh in 2030. Nuclear generation was unchanged between the cases.

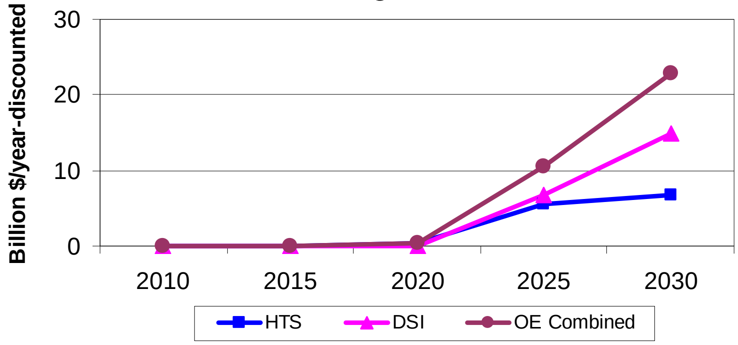
The change in fuel mix explains the resulting change in carbon emissions. Coal is the most carbon-intensive fuel, followed by oil and gas, with renewables emitting net zero carbon emissions. This would imply that the HTS program reduces carbon emissions relative to the Base (No R&D) Case, and the DSI and OE combined programs should result in a slight net increase in carbon emissions due to the increased use of coal. Figure 3-9 illustrates the GPRA results:

Figure 3-9: Cumulative Carbon Emissions Change from No R&D Case



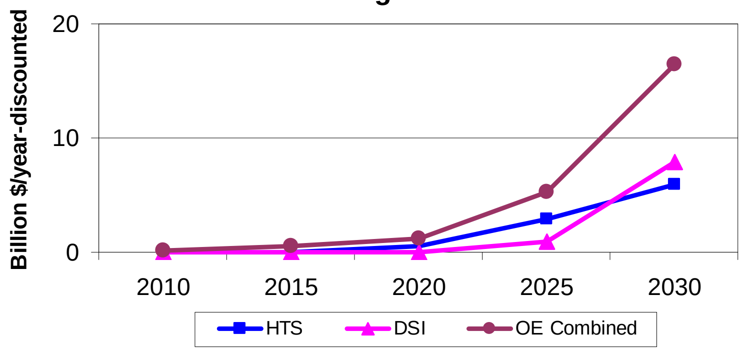
The individual programs and the combined OE portfolio lead to both net consumer savings and electricity system cost savings. The OE Combined case resulted in slightly more savings in net consumer expenditures and electricity system costs than the sum of the HTS and DSI program savings. Figures 3-10 and 3-11 illustrate these results.

Figure 3-10: Net Consumer Expenditures Cumulative* Savings from No R&D Case



Assumes 3 percent real discount rate. Accumulation begins in the year 2008.

Figure 3-11: Electricity System Costs Cumulative* Savings from No R&D Case



Assumes 3 percent real discount rate. Accumulation begins in the year 2008.

The GPRA-NEMS OE Business-As-Usual Portfolio benefits estimates are shown in Table 3-4. As previously noted, these benefits reflect the potential economic and energy system benefits of realizing OE program goals based on proposed budget levels for FY08 and subsequent years. Additional analyses were performed to estimate reliability and security benefits anticipated from OE program activities, and are described in Chapter 4.

Table 3-4: GPRA-NEMS FY08--OE BAU Portfolio Estimated Benefits

	OE BAU Portfolio Case				
	2010	2015	2020	2025	2030
ENVIRONMENTAL BENEFITS					
Avoided Carbon Emissions, Annual (MMTCE)	0	-5	-1	-4	-6
Avoided Carbon Emissions, Cumulative (MMTCE)*	0	-7	-22	-43	-66
ECONOMIC BENEFITS					
Consumer Savings, Annual (bil 2004$)	0	0	1	3	10
Consumer Savings, NPV (bil 2004$)*	0	-1	0	11	23
Electric Power Industry Savings, Annual (bil 2004$)	0	0	0	2	6
Electric Power Industry Savings, NPV (bil 2004$)*	0	1	1	5	16

**Assumes 3 percent real discount rate. Accumulation begins in the year 2008.*

GPRA-NEMS Benefits Estimates: Alternative Scenarios

The cases described in the previous section were built upon a Business-As-Usual (BAU) projection of energy markets represented in the AEO2006 Reference Case. However, there is inherently considerable uncertainty in long-term projections of energy supply, demand and prices, since they are dependent on assumptions such as future energy and environmental policies, the rate of technology development and improvement, fuel prices, international energy markets, and macroeconomic variables such as gross domestic product (GDP) and population.

Given this uncertainty, the ESE R&D Offices developed alternative scenarios to capture two of these key uncertainties in the GPRA FY08 analyses: fuel prices and climate policy. The two alternative market scenarios developed were:

1. High Fuel Prices scenario, focusing on oil and natural gas prices;
2. Carbon Constraint scenario, with a cap on future energy-related carbon emissions.

Portfolio cases with R&D programs were created for these alternative scenarios by each of the ESE R&D Offices, including OE, along with a common set of baseline cases without R&D programs. The benefits of the programs were then evaluated as the difference between each pair of portfolio and base cases, using a similar methodology as for the BAU FY08 benefits.

The off-line analyses that supported the benefits analysis were not revised for the alternative scenarios. Thus model inputs such as the projected energy savings from HTS technologies were not adjusted to account for potential changes that might occur in consumer behavior in these scenarios. This potentially leads to an overstatement of HTS benefits in both the High Fuel Prices case and the Carbon Constraint case due to reduced demand for electricity. However, the model endogenously projects reactions to the scenarios for energy supply, demand and prices, which will affect the value of energy savings associated with these technologies. On the other hand, the DSI technology implementation allowed the model to adjust market share in a cost-effective way.

Figure 3-12: World Oil Price

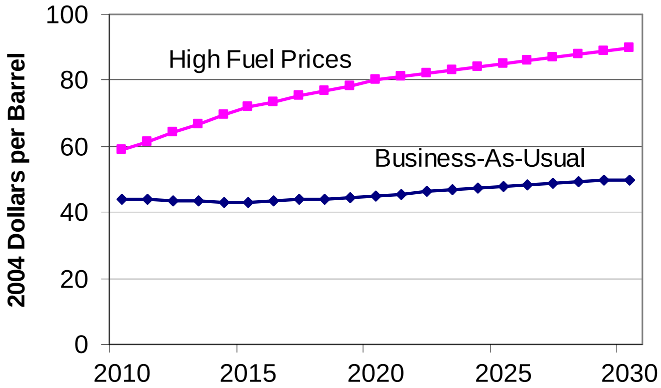
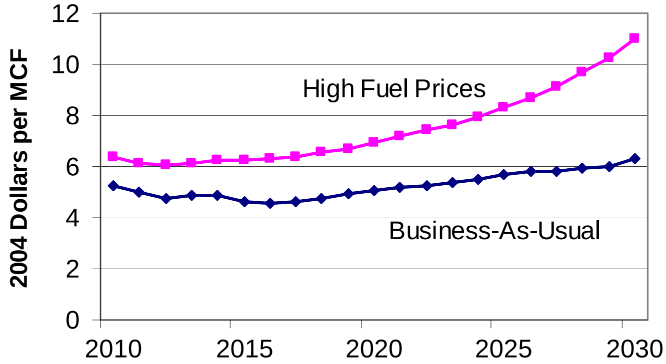


Figure 3-13: Wellhead Natural Gas Price



Following is a description of each alternative scenario along with the results of the OE estimated benefits for each scenario.

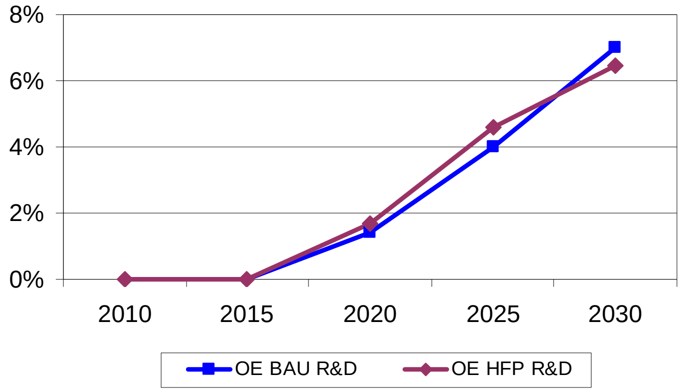
High Fuel Prices Scenario

The ESE High Fuel Prices (HFP) scenario is based on the AEO2006 High Oil Price case, with world oil prices rising to roughly $90 per barrel by 2030, combined with higher natural gas prices that were assumed to occur due to higher LNG import prices, a delay of the Alaskan pipeline, lower Canadian exports to the U.S., and reduced LNG terminal expansion. The wellhead natural gas prices were assumed to be in the range of $7.00 per million cubic feet (mcf) in 2020 and $11.00 per mcf in 2030. For comparison, the BAU base scenario oil prices rose to $50 per barrel by 2030, and natural gas prices were roughly $5.00 per mcf in 2020 and $6.30 per mcf in 2030. Coal supply assumptions were not changed, but minemouth coal prices rose by 6 to 8 percent over the forecast period due to increased mining costs associated with higher oil and gas prices, as well as increased demand for coal. Figures 3-12 and 3-13 compare the world oil price and wellhead natural gas price for both the HFP scenario and the business-as-usual scenario.

As expected, by 2030 the HFP Base Case resulted in increased electricity prices (10 percent), which reduced electricity demand (1.2 percent) compared to the BAU Baseline scenario. The electric generation fuel mix also changed, resulting in reduced oil and natural gas generation (44 percent), increased coal generation (12 percent), and increased renewable generation (11 percent) by 2030 compared to the BAU Baseline.

When OE program assumptions were added to the scenario to create the HFP R&D case, the resulting benefits were higher than in the BAU R&D case. The market penetration of the DSI load shifting technology was greater in the early years (2020 and 2025) than the BAU R&D case, but was mitigated slightly by 2030 (see Figure 3-14). The increased load shifting in the early years produced a greater reduction in electricity prices by 2030 (8 percent vs. 2 percent in the BAU R&D case), which reduced the need for additional load shifting. The lower electricity prices also caused total electricity demand to increase in 2030 (0.6 percent increase vs. –0.3 percent reduction in the BAU R&D case).

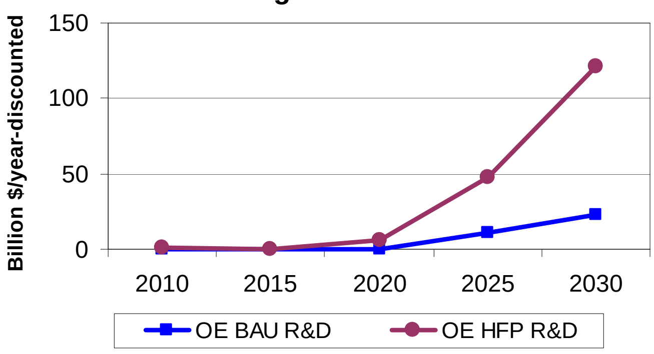
Figure 3-14: OE Peak Demand Shift



The generation fuel mix also shifted in the HFP R&D case relative to the BAU R&D case, with more reductions in oil and gas generation in the early years but less by 2030, as well as slightly greater increases in nuclear generation and a slight reduction in coal and renewable generation by 2030. Although the oil/gas generation percentage reduction was less relative to the BAU R&D case, oil/gas generation as a percent of total generation declined relative to the BAU R&D case (9 percent of total generation vs. 16 percent in the BAU R&D case in 2030) due to higher fuel prices.

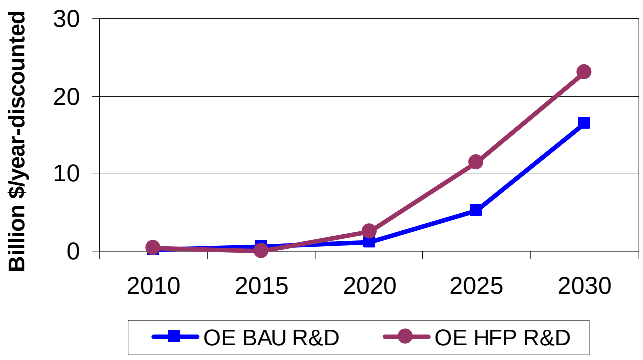
The reduction in electricity and natural gas prices caused by OE programs resulted in higher net present value (NPV) consumer expenditure savings (Figure 3-15) and higher NPV electricity system savings (Figure 3-16) relative to the BAU R&D case. The increase in carbon emissions in the HFP R&D case was greater than in the BAU R&D case (see Figure 3-17), primarily due to increased electricity demand.

Figure 3-15: Net Consumer Expenditures NPV* Savings from No R&D Case

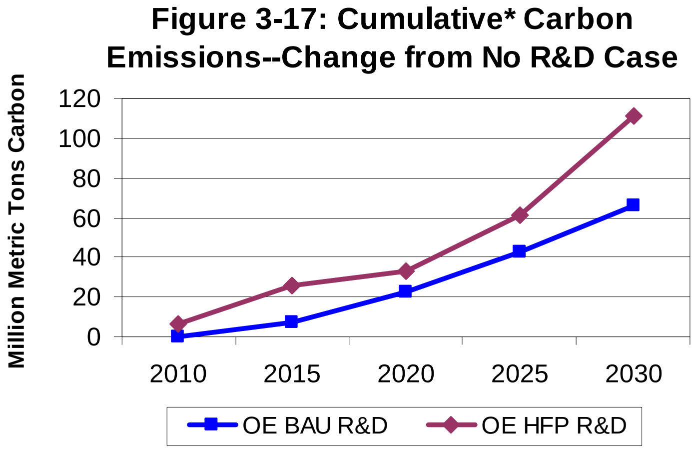


Net present value (NPV) is discounted back to 2008 using a 3 percent discount rate.

Figure 3-16: Electricity System Costs NPV* Savings from No R&D Case



Net present value (NPV) is discounted back to 2008 using a 3 percent discount rate.



*Accumulation begins in the year 2008.

The ESE metrics are shown in Table 3-5. As previously noted, net consumer savings and electric system savings are not additive since some or all of the system savings are passed through to the consumer through reduced electricity prices.

Table 3-5: GPRA-NEMS FY08--OE High Fuel Prices Portfolio Estimated Benefits

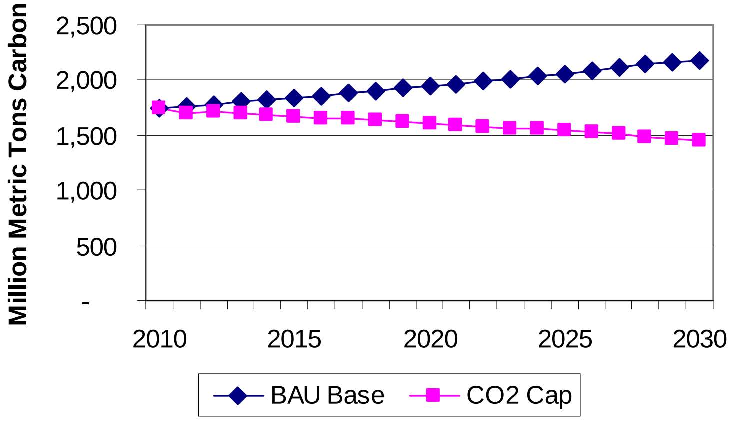
	2010	2015	2020	2025	2030
ENVIRONMENTAL BENEFITS					
Avoided Carbon Emissions, Annual (MMTCE)	-4	-5	0	-9	-12
Avoided Carbon Emissions, Cumulative (MMTCE)*	-7	-26	-33	-61	-111
ECONOMIC BENEFITS					
Consumer Savings, Annual (bil 2004$)	-1	-1	7	22	33
Consumer Savings, NPV (bil 2004$)*	1	-3	6	47	121
Electric Power Industry Savings, Annual (bil 2004$)	0	0	2	4	5
Electric Power Industry Savings, NPV (bil 2004$)*	0	-1	3	11	23

Net present value assumes 3 percent real discount rate. Accumulation begins in the year 2008.

Carbon Constraint Scenario

A second alternative scenario was designed by the ESE R&D Offices to examine the implications of GPRA benefits if a cap was applied to all energy-related carbon emissions. The cap chosen by ESE begins in year 2011, declining about 0.9 percent per year to just under 1450 million metric tons of carbon by 2030. This represents a reduction of about 34 percent from projected 2030 BAU Base Case emissions (see Figure 3-18). An economy-wide carbon allowance trading system was implemented to allow the energy system (utilities, fuel suppliers and consumers) to take a least-cost approach to meeting the cap. An allowance must be purchased annually for each ton of carbon emitted.

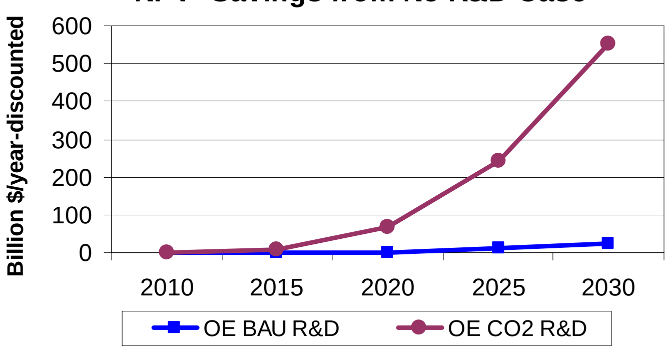
Figure 3-18: Carbon Constraint Case Projected BAU Emissions vs. Cap



The Carbon Constraint Base Case resulted in a 50 percent reduction in carbon-intensive coal generating capacity while non-carbon emitting alternatives such as nuclear and renewable capacity more than doubled by 2030 compared to the BAU Base Case. A new coal technology that employs carbon sequestration techniques (i.e., capture and long-term storage of carbon) also became cost competitive in this scenario, gaining an 18 percent share of total coal capacity by 2030. Allowance prices, which reflect the value of reducing one ton of emissions, started at about $50 per ton in 2011 and rose to over $200 per ton by 2030. The cost of allowances to fuel suppliers was reflected in fuel prices, causing natural gas delivered prices to increase roughly 40 percent, coal prices to increase almost 400 percent, and average electricity prices to rise almost 40 percent by 2030 over the BAU Base Case. The fuel price increases in turn caused cumulative net consumer expenditures to rise about 8 percent, and cumulative electricity system costs increased about 10 percent due to both higher fuel prices and increased capacity additions required to replace carbon intensive capacity.

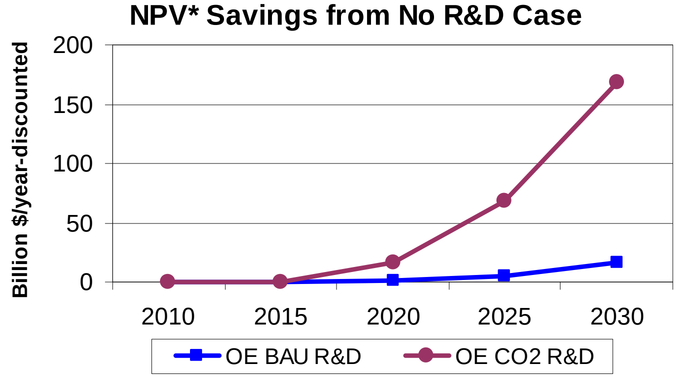
When OE technologies were introduced into this new scenario to create the OE CO_2 program case, the overall results were favorable. In general, the OE Carbon case resulted in less peak load shifting but greater benefits than the OE BAU case. Both electricity and natural gas

Figure 3-19: Net Consumer Expenditures NPV* Savings from No R&D Case



*Net present value (NPV) is discounted back to 2008 using a 3 percent discount rate.

Figure 3-20: Electricity System Costs NPV* Savings from No R&D Case



*Net present value (NPV) is discounted back to 2008 using a 3 percent discount rate.

prices declined roughly 10 percent by 2030 compared to the Carbon Constraint Base Case, creating NPV net consumer expenditure savings of about $550 billion or about 2 percent by 2030 (shown in Figure 3-19). Since the DSI peak load shifting technology relies on baseload capacity for recharging, additional baseload capacity was built in the OE Carbon case, especially nuclear capacity. However, the increased amortized investment costs were more than offset by savings in fuel costs, resulting in NPV electricity system cost savings of more than $150 billion by 2030 (see Figure 3-20).

The share of carbon-intensive conventional coal capacity used in baseload generation declined sharply between the BAU Base Case and Carbon Base Case, from 78 percent of baseload capacity in the BAU Base to about 22 percent in the Carbon Base by 2030 (see Figure 3-21). However, the high price of coal kept baseload generation more expensive than in the BAU Base Case, reducing the difference between peak and off-peak electricity prices and making the DSI peak load shifting technology slightly less attractive than in the BAU Base Case. Over time as more non-carbon baseload capacity was built to replace the existing stock of carbon-intensive capacity, off-peak prices declined allowing the load shifting technology to become more cost-effective. Figure 3-22 illustrates the comparison between the percentage of peak load shifted in the OE BAU case and the OE Carbon case.

Figure 3-21: 2030 Electric Generation Fuel Mix
Percent of Baseload Generation

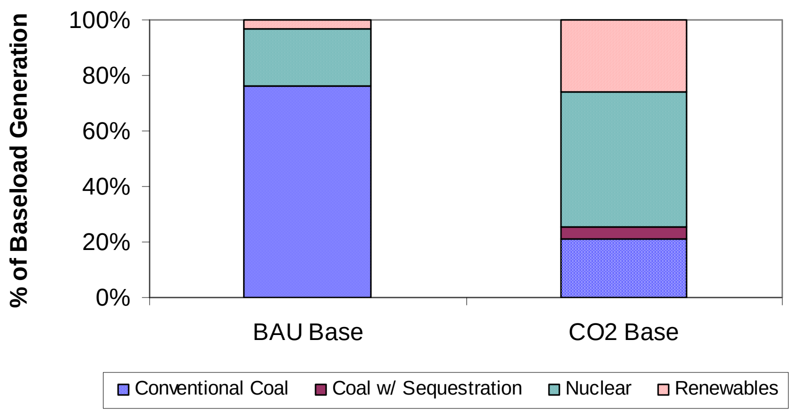
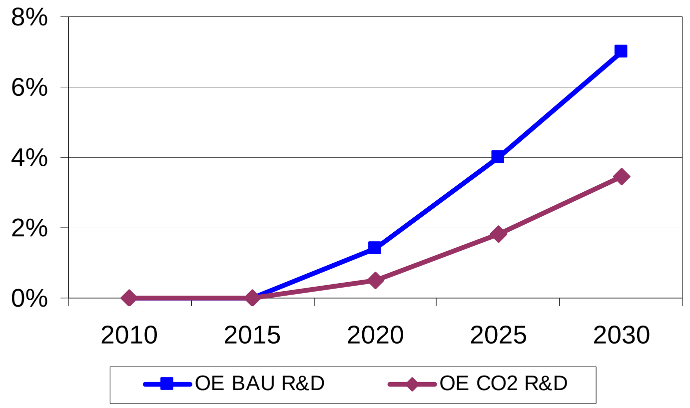


Figure 3-22: OE Peak Demand Shift



The ESE benefits metrics for the OE Carbon case are shown in Table 3-6. As previously noted, net consumer savings and electric system savings are not additive since some or all of the system savings are passed through to the consumer through reduced electricity prices. Since there are no carbon emission savings in this scenario due to the fact that the same emissions cap is applied to both the base case and program case, an additional ESE metric was created for the Carbon Constraint Case to capture the reduced cost of purchasing carbon allowances. This cost is implicitly included in both the net consumer costs and the electric system costs through the fuel prices and electricity rates, but it is helpful to break out this cost separately as one measure of the cost of complying with a carbon cap. Additional compliance costs include additional investments that utilities and consumers made to increase energy equipment efficiency and/or switch to low-carbon fuels. These investments are also captured in the net consumer costs and electric system costs.

The new metric is defined as follows:

- Cost of Carbon Allowances, Annual (billion 2004$): The allowance price ($ per ton carbon) for each policy year multiplied by the emissions cap. The allowance price is a function of the supply and demand for allowances, so the more difficult it is to meet the cap, the higher the allowance price will be.
- Cost of Carbon Allowances, NPV (billion 2004$): Net present value (NPV) of total annual cost of compliance, discounted back to 2008 using a 3 percent discount rate.

For the OE Carbon Case, the price of allowances was significantly lower than the Carbon Base Case, reflecting the improved ability to meet the carbon cap with OE technologies. The resulting net present value savings from allowance purchases totaled more than $500 billion by 2030, which is almost 20 percent of the total cost of allowances.

Table 3-6: GPRA-NEMS FY08--OE Carbon Constraint Portfolio Estimated Benefits

	2010	2015	2020	2025	2030
ENVIRONMENTAL BENEFITS					
Avoided Carbon Emissions, Annual (MMTCE)	n/a	n/a	n/a	n/a	n/a
Avoided Carbon Emissions, Cumulative (MMTCE)*	n/a	n/a	n/a	n/a	n/a
ECONOMIC BENEFITS					
Consumer Savings, Annual (bil 2004$)	-1	9	23	99	91
Consumer Savings, NPV (bil 2004$)*	-2	8	67	243	551
Electric Power Industry Savings, Annual (bil 2004$)	-1	3	6	29	32
Electric Power Industry Savings, NPV (bil 2004$)*	-2	-2	17	68	168
Cost of Carbon Allowances, Annual (billion 2004$)	0	11	22	94	77
Cost of Carbon Allowances, NPV (billion 2004$)*	0	18	80	248	514

**Net present value assumes 3 percent real discount rate. Accumulation begins in the year 2008.*

Note: n/a = not applicable.

CHAPTER 4: ELECTRICITY RELIABILITY AND INFRASTRUCTURE SECURITY BENEFITS ESTIMATION

Background for the Analysis

Estimates of reliability and infrastructure security benefits were developed for OE's four R&D programs:

- High Temperature Superconductivity (HTS)
- Visualization & Controls (V&C)
- Energy Storage and Power Electronics (ES&PE)
- Distributed Systems Integration (DSI)

The concept of "energy security" encompasses different energy systems and markets, ranging from oil security and concerns about oil cartels, to electricity reliability and infrastructure security. The common factors in these various situations are that there are disruptions to energy supply and, to varying degrees, imperfect markets and externalities, as well as broad concerns about national welfare. Within the electric power sector, the regulatory environment and the markets themselves for many electricity reliability-related services are new and evolving. Thus, markets are incomplete and imperfect, and the investment climate for the private sector uncertain. There is also the possibility of far-reaching, external costs from large-scale regional failures in the power system that result from the cascading effects of local or regional disruptions.

Definitions and Concepts

The first steps in estimating reliability and infrastructure security benefits of OE's R&D programs are to define "reliability" and "infrastructure security," and then to define the reliability and infrastructure security benefits that derive from technological improvements.

Electricity Reliability Benefits

The "reliability" of an electric power system is the degree to which it delivers power to consumers in the amount desired and within acceptable standards. The reliability of a system may be assessed with respect to its:

- Adequacy – The ability of the electric system to supply the aggregate electrical demand and energy requirements of consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements; and
- Operational Reliability[10] – The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

[10] The North American Electric Reliability Council (NERC) formerly used the term "security," but recently changed to the use of "operational reliability" to reduce confusion among those outside the industry, who might think of "security" as being "homeland security" or "oil security."

When the electric system lacks sufficient adequacy or operational reliability, there is a greater likelihood of power outages, power quality events, and transmission congestion. These situations result in damages or increased costs to electric power customers.

Reductions in damages and costs are reliability benefits, which consist of the following components:

i) Outage reductions: Electrical outage costs reflect the frequency, duration, and magnitude (amount of power) of outages, the number and type of customers affected, mitigative measures (both supply and demand) that reduce the extent or effects of outages, the costs of these mitigative measures, and the costs of restoring service. Reductions in outage costs that can be attributed to improved technologies are part of their reliability benefits.

ii) Power quality improvements: Power-quality disturbances are deviations from power being supplied as a sine wave with the amplitude and frequency given by national or system standards. Power-quality disturbances might affect the proper functioning of electronic and other sensitive equipment. Reductions in the costs of these disturbances that can be attributed to improved technologies and systems are part of their reliability benefits.

iii) Transmission congestion reduction: Transmission congestion costs are the difference between the cost of delivering electricity if there were no transmission constraints, which are the cause of the congestion, and the cost with the current (or anticipated) constrained system. Reductions in congestion costs that can be attributed to improved technologies and systems are part of their reliability benefits.

Infrastructure Security Benefits

Infrastructure security is concerned about very rare events that, if they occur, have extremely devastating consequences. Examples include major terrorist attacks, system-wide cyber attacks, and major natural disasters. To estimate infrastructure security benefits, estimates were developed of the effectiveness of improved or new technologies and systems, whose development is connected with the OE program, in reducing the risks of catastrophic damage to electricity system infrastructure that results in significant nationwide costs.

Since these events are rare, we do not attempt to estimate their expected annual cost. Rather, the measure of energy security we use is the percentage reduction in the risk of damage from a catastrophic event.

Technological and system improvements reduce this risk in the following ways (Lee 2005):

i) Reduced threat or vulnerability. Reduced likelihood of a disruptive event (which reflects the probability that a disruptive event occurs and the probability that it causes major damage if it were to occur);

ii) Mitigation of damage from technology enabling supply-related response. Mitigation in damage, given that a major disruption has occurred, through the use of technologies and systems that provide back-up or stored energy, or that isolate parts of the system so as to reduce the likelihood of major cascading failure in the system;

iii) Reduced damage from technology facilitating demand-related response. Reduced impact and damage, in the event of a disruption and given supply-related response, due to technologies or systems that alter electricity demand and loads.

Motivation for Analysis Approach

As discussed in Chapter 1, the National Energy Modeling System (NEMS) is the modeling tool that OE and other ESE offices used to estimate the prospective economic and environmental benefits of their R&D programs. All of the ESE offices used a common set of input assumptions and model outputs, to maintain consistency among the offices' analyses and projections.

However, NEMS and other large-scale integrated energy market models like the Market Allocation (MARKAL) model are not appropriate for estimating reliability or infrastructure security benefits. These models are extremely aggregate in scale, relative to commonly used power flow simulation models. For example, the level of geographic detail in NEMS is at the North American Electric Reliability Council (NERC) region level. A more important limitation of these models for reliability and security analysis is that they calculate a market equilibrium in a *deterministic* way, where supplies expand to meet increasing demand for energy.

In contrast, electricity reliability and infrastructure security concerns arise because of *variability* in supply – in terms of the available capacity of generation units and transmission infrastructure – at any point in time, and because of *variability* in demand for electricity from hour to hour (or even minute to minute). NEMS, MARKAL, and models of this genre do not provide estimates of future outages or power quality events, and only extremely crude estimates of transmission congestion; and it is these concepts that are at the heart of reliability concerns. Also, these models do not consider the possibility of catastrophic disruptions from terrorist attacks, cyber attacks, or large-scale natural disasters that are the basis for concerns about infrastructure security.

What is needed, then, is another approach that complements the analysis done on economic and environmental benefits using NEMS. The rest of this report describes the approach taken, and the estimates of reliability and infrastructure security benefits derived from this approach.

Method for Estimating Reliability Benefits

The reliability benefits of OE's R&D programs are the prospective reductions in outage, power quality disturbance, and transmission congestion costs due, in part, to new technologies and systems that could be attributed to these R&D programs. The reliability impact of OE R&D programs is the difference in the degree of reduced outage, power-quality event, and transmission congestion costs – with OE-programs versus the case without OE-programs.

Thus, reliability benefits can be estimated by adding the three components identified in Section 2.1:[11]

Reliability Benefits = [Annual cost of outages in the U.S., in the absence of any R&D
x Effectiveness of improved or new technologies, whose development is connected with the OE program, in reducing outage costs]

+ [Annual cost of power quality disturbances in the U.S., in the absence of any R&D
x Effectiveness of improved or new technologies, whose development is connected with the OE program, in reducing costs associated with power quality disturbances]

+ [Annual transmission costs in the U.S., in the absence of any R&D
x Effectiveness of improved or new technologies, whose development is connected with the OE program, in reducing transmission congestion costs]

(1)

Each of the three components is the product of two factors: the projected annual cost, absent any future R&D, times the estimated degree to which technologies and systems, developed in part by OE's programs, reduce these costs or damages.

The methodology for estimating these factors is an initial step in OE's long-term strategy to develop an analytical capability to estimate prospectively the reliability impacts of its R&D activities. In the long-run, this capability is likely to include a nationwide power flow simulation model with a stochastic component that simulates the likelihood of reliability-related conditions. Until that capability is developed, the current methodology relies on previous estimates of annual costs that are based on empirical data, for estimates of the first of the two factors, and on expert panels to provide estimates for the second factor.

Estimates of Current Annual Cost of Outages, Power Quality Disturbances, and Transmission Congestion

There are no "official" estimates of outage, power-quality disturbance, or transmission congestion costs. The literature was reviewed to obtain estimates of the current levels of these

[11] Electricity reliability standards and other system requirements dictate that an adequate level of reserves, both real and reactive, be maintained to ensure operational reliability. Reductions in the costs of providing these reserves, including any reduction in the level of reserves required for operational reliability, are classified as system-efficiency economic benefits and *not* as reliability benefits.

costs. The review identified several estimates of the current annual costs of these reliability-related events[12].

Table 4-1 lists the estimates of the *current* annual costs in these studies.[13] The Low to High range in Table 4-1 reflects the general range of estimates in the studies. From the very wide range of cost estimates, Mid values for each reliability-cost component were set, based on an assessment of the studies' methodologies and data. Studies that were more comprehensive and that used empirical data (as opposed to solely authors' subjective estimates) were given greater consideration in defining the Mid value in Table 4-1. To reflect the uncertainty about the levels of these costs, the Low, Mid and High values were all used in subsequent calculations.

Table 4-1. Range of Estimates of the Current Costs due to Lack of Reliability (Annual costs in the U.S., in billions of year 2001 dollars)

	Low	Mid	High
Outages	22	79	135
Power quality event	6	24	34
Transmission congestion	0.15	1	2.6

Source: authors

Future costs could be different from these current costs. Figure 4-1 is a graph of major disturbances in the bulk electric system from 1984 to 2002. There appears to have been an increase in disturbances in recent years. Though the long-term trend is not as pronounced, Hines et al.'s (2006) analysis of the NERC Disturbance Analysis Working Group (DAWG) data found not only a statistically significant increase in the frequency of large blackouts in recent years but also a weak positive correlation between years and frequency, over the whole time period. The latter result indicates that the long-term trend in the frequency of large blackouts in the U.S. might be increasing.

Given this empirical evidence, two alternative assumptions were considered:

i) Costs remain the same in the future. In this alternative, the future annual costs of outages, power quality events, and transmission congestion are all assumed to remain the same (in real dollars, adjusted for inflation), absent any further R&D by both OE and non-OE organizations (the latter includes other federal agencies, industry, universities, and state energy R&D offices).

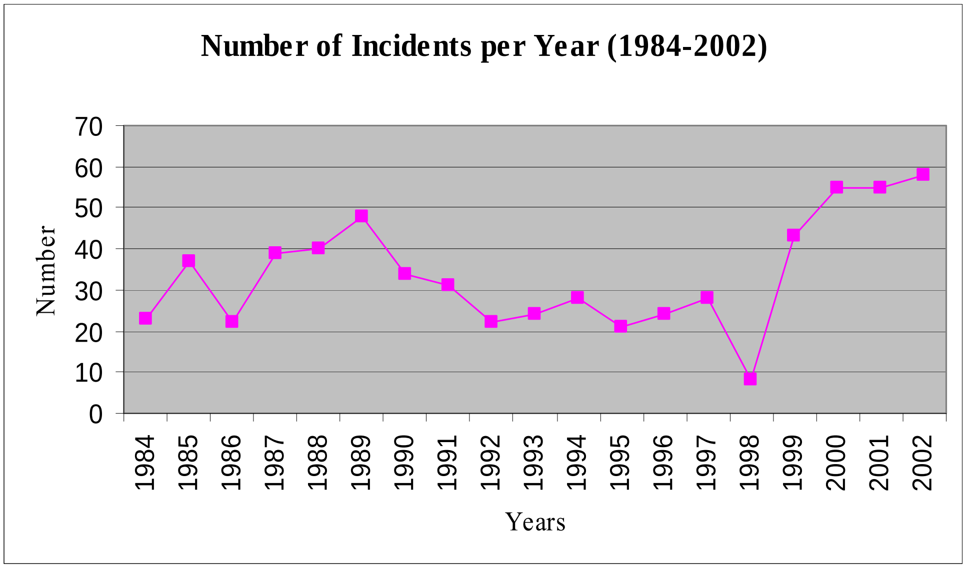
[12] (Alliant Energy 2006, California ISO 2001, Clemmensen et al.1999, DOE 2001, EPRI PEAC 2004, FERC 2001, Heffner nd, Heydt 2000, ISO New England 2001, Key nd, LaCommare and Eto 2004, Lee et al. 2002, Lesieutre and Eto 2003, Mirant 2001, Ott 2000, Performance Energy Partnership and Ferraro, Oliver & Assoc. 2005, Primen 2001, Raikar and Ilic 2001, Swaminathan and Sen 1998)

[13] All of the studies were done in the 1998-2003 timeframe. Given the imprecision and the range in these estimates, we set them all to be in year 2001 dollars. Any adjustments to account for inflation would change the estimates only slightly.

ii) Expert panel's estimate of percentage change. In this alternative forecast, it is assumed that future costs might not remain the same. To estimate the change in these costs, panels of experts were used.[14] Each panel member estimated percentage changes from current levels for outage, power quality event, and transmission congestion costs, for different years in the future. Their estimates were relative to the current level, after adjusting for inflation, assuming that there is no future R&D. The median values of all of the panel members were then used as cost escalation factors.

The results presented in this report assume that there is this cost escalation. The effect of the cost escalation varies, depending on the year and cost component. For the year 2020, for example, panels projected that outage costs would be 20% above current levels, if there were no R&D by either OE or any other non-OE organizations. For 2030, the projected estimate was 35% above current levels.

Figure 4-1. Trend in Major Incidents in the Bulk Electric System



Source: Graphed from NERC DAWG (Disturbance Analysis Working Group) database (there are data missing in the DAWG database for 1998)

Expert Panel Approach

The process of estimating the impacts of OE's R&D programs on reliability and infrastructure security utilized the expertise and insights of panels of experts (Lee 2006).[15] Four panels of experts were formed, one for each OE program, each panel consisting of about ten to twenty members. The panel members are listed in Appendix C-5. There were 52 in total. They are a

[14] The Expert Panel Approach Section and Lee et al. (2006) describe these panels in more detail.
[15] The National Research Council Committee (NRC 2005a) that is prospectively estimating the benefits of several of the R&D programs in the Office of Energy Efficiency and Renewable Energy and the Office of Fossil Energy in DOE advocates an expert panel approach as well, and the Committee is implementing the approach in its review of these programs. In a review of the Committee's work, the Office of Management and Budget (OMB) also indicated support for this approach, as long as panel bias and conflict of interest are adequately addressed (NRC 2005b).

diverse group, including individuals with equipment manufacturers, electric utilities, universities, consulting firms, and other parts of the electric power industry.

The panel members were provided with information about their task and about the R&D program (refer to Appendix C-1, C-2, C-3, and C-4). The information included definitions for reliability and infrastructure security; a program summary; a statement of the long-term goals of the program; a description of the expected outcomes from the activities; and a description of the technologies, their potential applications, and competing technologies. The information also included key input assumptions and projections from NEMS so that, to the extent possible, the panel members' estimates were consistent with the NEMS analyses done ESE-wide.[16]

Instructions were sent to panel members on providing responses to questions relating to the impacts of the R&D programs (Appendix C-6 is the list of questions asked of the HTS panel; identical questions were asked of the other panels, with slight changes in wording to reflect the name of the panel). First, panel members were asked to provide low, mid and high percentage estimates of market penetration of their respective OE program's technologies (e.g., HTS panel members provided input on all HTS technologies as a whole).

Each panel member provided market penetration estimates for the years 2010, 2015, 2020 and 2030 under the assumption that there was no OE R&D program and under the alternative assumption that there was a program as described in the document provided the panel. For two of the programs, DSI and HTS, mid-level estimates were provided to the panelists based on the NEMS projections used to estimate economic and environmental benefits (see Chapter 3). Based on the mid-level estimates, panelists were asked to provide estimates of the percentage reduction in outages, power quality disturbances, transmission congestion, and vulnerability to highly disruptive events under the same two cases (with and without OE) and years as above. Panel members were also asked to provide comments explaining the reasoning behind their estimates.

Responses from the panelists were combined into an Excel Workbook and the median percentage differences between the two cases (i.e. with and without OE R&D) were calculated for the different combinations of years, questions and programs. Thus, the *difference between the With-OE and No-OE estimates is the impact of OE's R&D program*, which is to accelerate or improve technology development. Monetary values were calculated for the impact of the OE programs on reducing outages, power quality events and transmission congestion, based on annual values estimated from the literature.

Panel input was obtained in three rounds of questions. The same questions were asked in each round, allowing panel members to refine their estimates after reviewing other panel members'

[16] This explicit connection with ESE-wide NEMS projections is a major distinction between this analysis and the approach taken by two National Research Council Committees (NRC 2005a, 2005b). Another, strategic difference is that the NRC Committee advocates using expert panels as the preferred option, whereas OE is using the panel approach as an interim measure, pending development of a power system simulation model to make projections and to estimate the prospective reliability and infrastructure security benefits, as NEMS and MARKAL do for economic and environmental benefits.

estimates and reasoning (second round), and after reviewing the other three panels' estimates and reasoning (third round). The final round of responses was used as the final set of estimates. Some panel members provided estimates in the first or second rounds, but not in the third. Their latest input was pooled with the estimates of those who responded in the third round. Although estimates in the first and second rounds did not reflect the full information-sharing of the estimates in the third round, we decided that it was preferable to include all panel members' inputs.

Panel members provided separate estimates for the hypothetical "Program Case" in which, consistent with ESE-wide analysis, only the one R&D program is funded. In the third and final round, after panel members were more familiar with the information about the programs as well as the study protocol, they also provided estimates for the "Portfolio Case" in which all OE R&D programs are assumed funded. In the Program Case, panel members were told to assume that there would be no R&D in any area other than the one in which they are engaged. This assumption also implied that there would be no R&D in these other others by the private sector as well – an assumption that has a bearing on comparing the Program Case estimates to the overall Portfolio Case estimates. In the latter case, it was assumed that R&D would take place in all technology areas, by both OE and by organizations outside OE.

Panel members also estimated the percentage change in the future costs of outages, power quality events, and transmission congestion relative to current costs, assuming that no R&D were to take place. These estimates were used to make projections of the total annual costs, absent any future R&D.

Assessment of Panel Bias

In expert panels, there is always the possibility of panel bias. DOE-funded panel members might be viewed as being more optimistic about the benefits of the programs than non-DOE funded panel members. To address this possibility, a "panel bias adjustment factor" was calculated by comparing the median values of two sets of estimates (DOE-funded panel members versus non-DOE funded members). This adjustment factor "scales down" the benefits estimates if panel bias is found. This possibility was assessed using the panel members' estimates. The median values of the responses by the two groups were compared separately for each question and for the low, mid, and high estimates. The relative magnitude of the median responses of the two groups was split – for some of the questions the DOE-funded group had higher estimates but for other questions, the non-DOE funded group had higher estimates. No systematic panel bias was found. Thus, the panel bias adjustment factor was not used.

Method for Estimating Infrastructure Security Benefits

Based on the concepts in the Definitions and Concepts section, the following expression defines infrastructure security benefits:

Security Benefits = Effectiveness of improved or new technologies whose development is connected with the OE program, measured as the percentage reduction in the likelihood of a catastrophic event causing major nationwide damage

+ Percentage reduction of damage, given that a catastrophic event has occurred, by using technologies that provide stored energy, isolate the extent of damage, or provide other supply-related relief

+ Percentage reduction in damage, given that a catastrophic event as occurred and given that supply-related responses have been effected, through the use of OE-related technologies that alter electricity loads thereby mitigating the extent of transmission congestion and the likelihood of cascading failure *(2)*

The benefits represented by the first term in Equation (2) are those of reducing the likelihood of a catastrophic disruption affecting much of the nation. The benefits represented by the second and third terms in Equation (2) are *conditional* on there being a major catastrophic, disruptive event. These latter benefits are the mitigation of damages in the event of a disaster.[17] Combined, the benefits are reductions in the risk – encompassing both the vulnerability to a disruption that is national in scope and the nationwide damages in the event of such an event.

[17] Equation (2) can be re-expressed as:

$$\text{Security Benefits} = P + S(1 - P) + D[1 - S(1 - P)]$$

where

P percentage reduction in the likelihood of a catastrophic event causing major nationwide damage,
S percentage reduction of damage by using supply-related technologies, given that a catastrophic event has occurred,

D percentage reduction in damage through the use of technologies that change electricity loads, given that a catastrophic event as occurred and given that supply-related responses have been effected,

As Section 3 discussed, expert panels provided estimates of the individual terms that define the overall reduction in risk in this equation.

Benefits Estimates

The panel members provided estimates of the percentage reductions for each reliability-related cost component, With-OE and with No-OE R&D, for the years 2010, 2015, 2020, and 2030. For a given cost-component and year, the *median* value of the differences between each panel member's estimate for the With-OE and No-OE cases was used as the estimate of the degree to which the OE R&D program would reduce these costs. An analogous procedure was followed with panel input on the impact of the OE programs on infrastructure security.

These calculations were done for each of the three reliability cost components (refer to Equation (1)) and for each of the three security terms (refer to Equation (2)), with Low, Mid, and High estimates of technology impacts. For reliability benefits, these calculations were also done with various combinations of Low, Mid, and High estimates of annual costs. The "Mid-Mid" case, for example, is the estimate assuming the Mid-level technology impact and the Mid-level estimate of total annual reliability-related cost.

Straight-line interpolations of the estimated benefits in the above-stated years were used to estimate the benefits in the intervening years. For years between 2031 and 2050, the extrapolation was based on the assumption that the market penetration and impacts of the new technologies would gradually "flatten out."[18]

Figures 4-2 through 4-4 are graphs of the estimated reliability benefits of OE's programs. The values are in year 2001 dollars, without any discounting of future benefits. All of the presented results are for the mid-case market penetration levels. The various graphs in each figure reflect different assumptions about: (a) the annual costs that the improved technologies are reducing, and (b) the effectiveness of the improved technologies.

Figure 4-2 is for the benefits of reducing outage costs. Figure 4-3 is for the benefits of reducing the costs associated with disruptions in power quality. Figure 4-4 is for the benefits of reducing transmission congestion. There is considerable variability in the estimates, reflecting the breadth of estimates of the current levels of outage and related costs (Table 4-1), which the technologies reduce, and depending on the experts' assessments of the effectiveness of the improved technologies. Note that since all of the estimates in the figures are for the mid-level estimate of market penetration, there could be even greater variability in the estimates than reflected in these figures, if the low- and high- market penetration estimates were included in the graphs as well.

[18] The formula used for extrapolations was:

$$Y(t) = Y(t\text{-}1) + ((Y(2030) - Y(2020))/10)*(0.8\text{^}(t - 2030)),$$

where Y is the benefit component, and
t is the year from 2031 to 2050.

The equation allows Y(t) to gradually flatten out, consistent with the well-known logistic function for innovation adoption and market penetration of new technologies.

Figure 4-2. Range of Reliability Benefits Estimates Reflecting Low, Mid, and High Estimates of Annual Costs of Reliability-Related Events and Low, Mid, and High Estimates of the Degree to which the Technologies Reduce <u>Outage Costs</u>

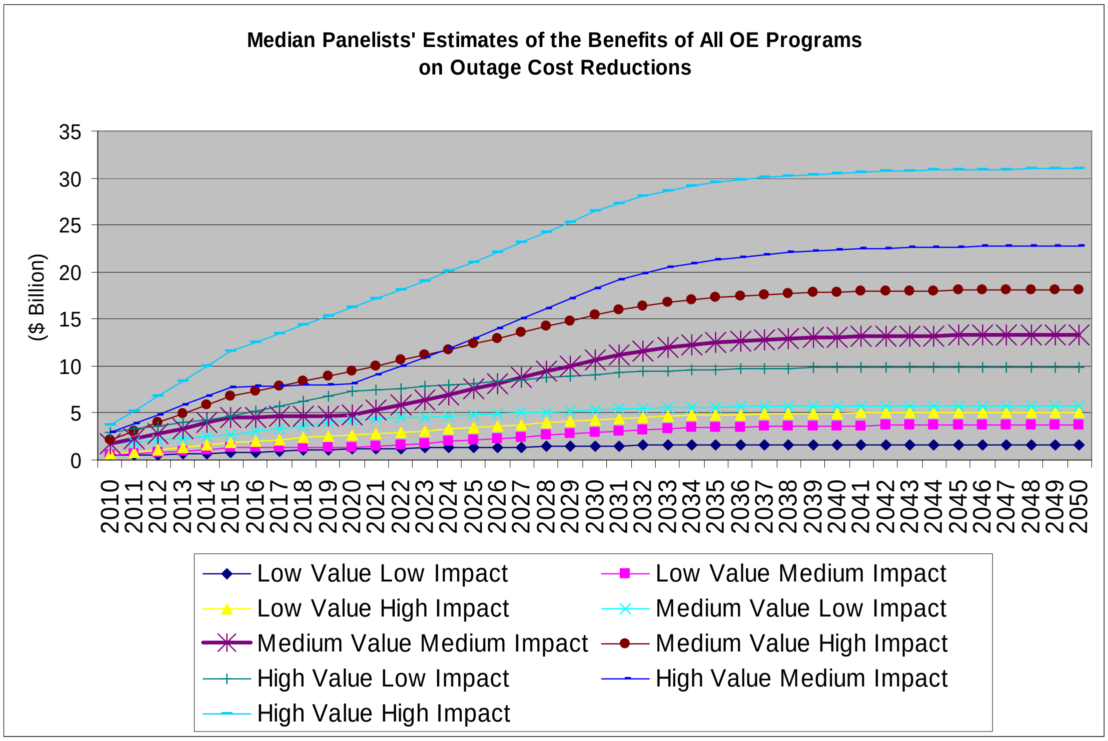


Figure 4-3. Range of Reliability Benefits Estimates Reflecting Low, Mid, and High Estimates of Annual Costs of Reliability-Related Events and Low, Mid, and High Estimates of the Degree to which the Technologies Reduce <u>Costs Associated With Power Quality Disturbances</u>

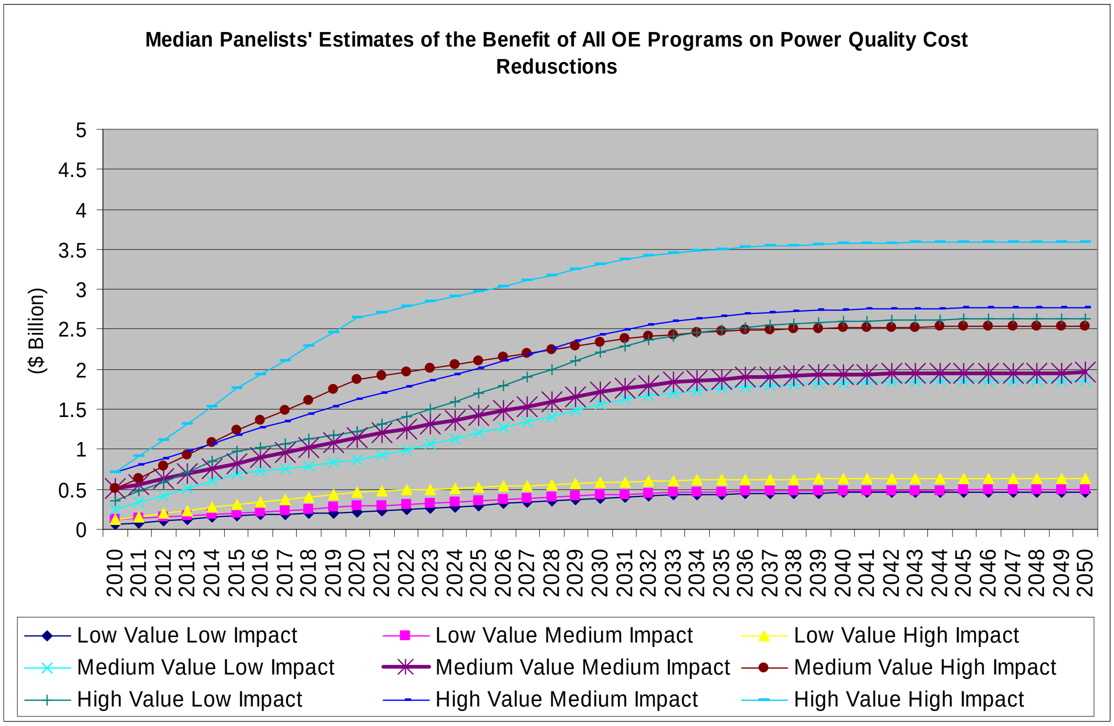
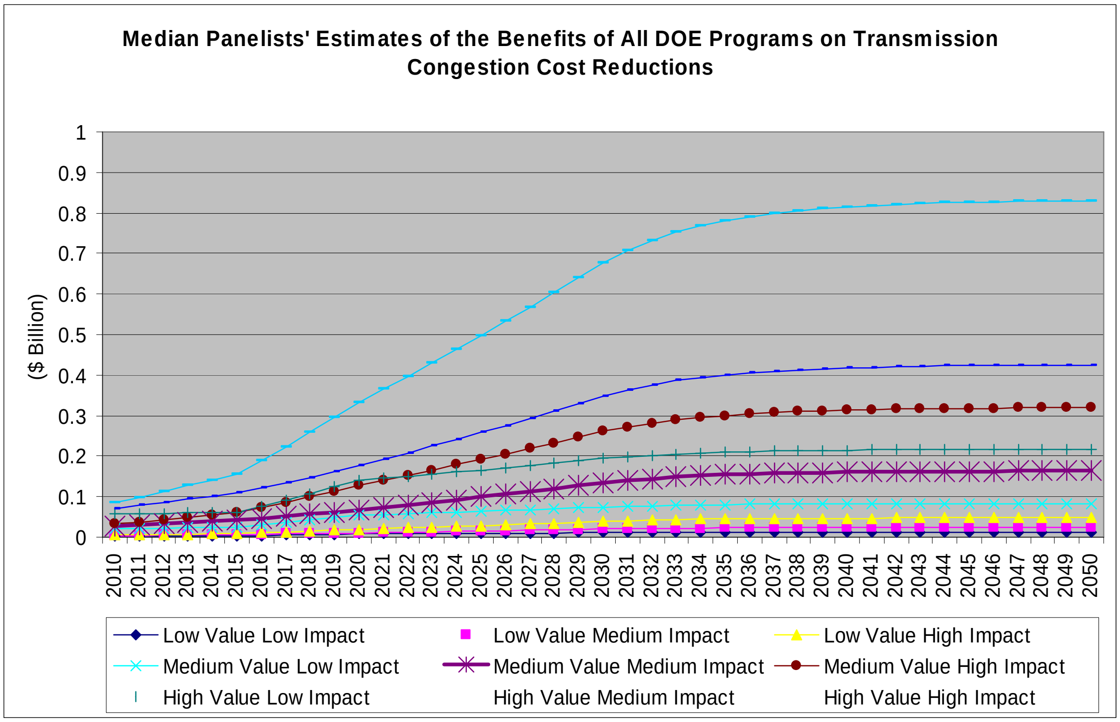


Figure 4-4. Range of Reliability Benefits Estimates Reflecting Low, Mid, and High Estimates of Annual Costs of Reliability-Related Events and Low, Mid, and High Estimates of the Degree to which the Technologies Reduce Transmission Congestion Costs



As shown in Figures 4-2 through 4-4, summed across the three components, reliability benefits generally increase as improved technologies become commercialized, ranging from a low of about $2 billion to a high of about $35 billion each year in the out years approaching 2050. The "mid" estimate is represented by the plum-colored trajectory with asterisks marking the level each year.

Note that a "high" case is not necessarily greater than a "mid" estimate. The reason is that the "high" and "mid" refer to assumptions about the effectiveness of the technologies. It is possible that the technologies could be highly effective, but yet the *difference* between the OE and non-OE impacts of these technologies is less than this difference when they are less effective. That is, the absolute impact of the technologies is also greater in the "high" case, but the incremental contribution of OE's R&D could be less than in a "mid" case.

Figures 4-5 through 4-7 are graphs of the estimated infrastructure security benefits. Infrastructure security is concerned with very low-probability, extremely high-impact events. Given this aspect, the benefits are not expressed in economic terms but rather in terms of percentage reductions in vulnerability (Figure 4-5), or percentage reductions in the extent of the nationwide damage, in the event that a disaster occurs (Figures 4-6 and 4-7).

Figure 4-5. Low, Mid, and High Estimates of the Reduction in Infrastructure Vulnerability Associated with Improved Technologies from OE R&D

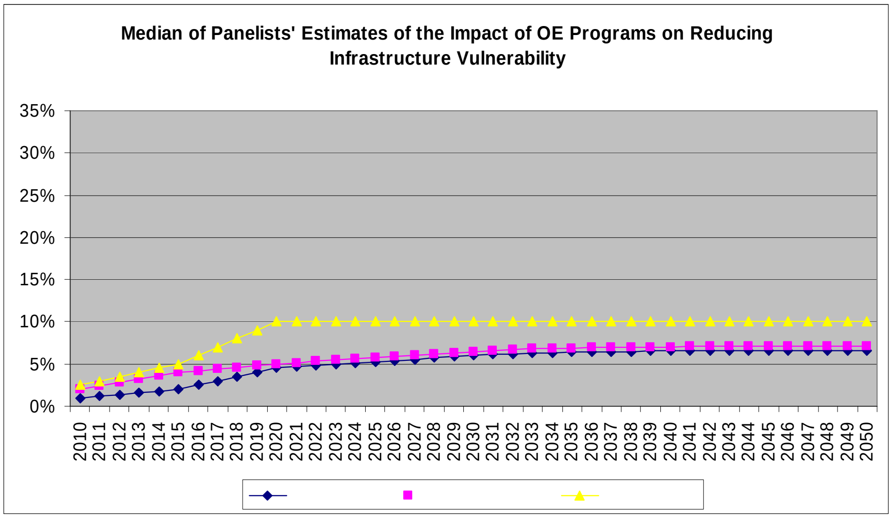


Figure 4-6. Reduction in Damages Associated with Improved Technologies from OE R&D that Increase Back-up or Replacement Supply

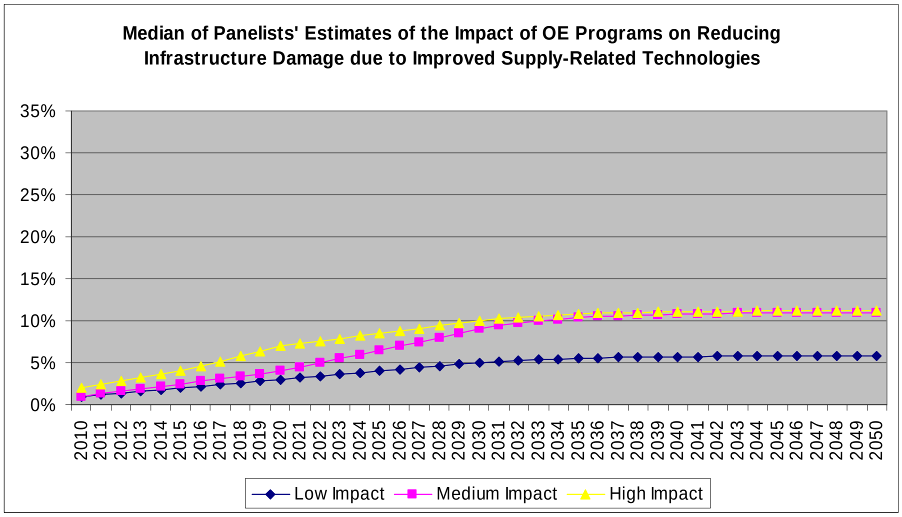


Figure 4-7. Reduction in Damages Associated with Improved Technologies from OE R&D that Alter Demand

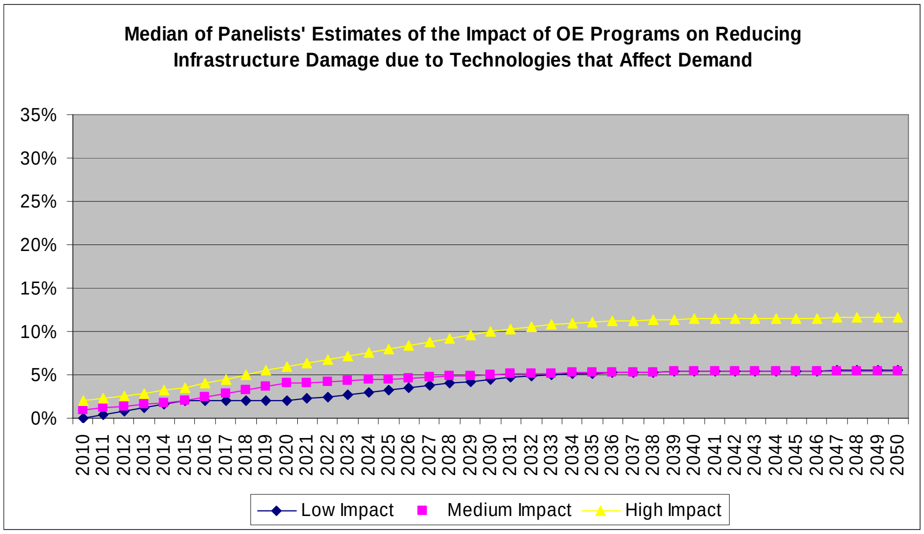


Table 4-2 summarizes estimates for selected, representative years. The values in the table are consistent with those in the graphs. The three reliability benefits components can be added to provide an overall reliability benefit. The three infrastructure security components are not strictly additive (refer to the equation in footnote 17).

Annual *outage* costs account for the greatest cost to businesses and residences, compared to the costs of power quality events and transmission congestion. Consequently, a given percentage reduction in outage costs leads to relatively greater benefits, in monetary terms, compared to power quality and transmission congestion. As expected, benefits are generally estimated to increase as the products of R&D come to fruition and technologies become commercialized.

The numerical result found in a few instances that a Program benefit is greater than the Portfolio benefit is explained by recalling that different assumptions were used. In the Program Case, it was assumed that there would be no R&D in any other technology area. For example, V&C panel members were instructed to make estimates assuming that there would be no R&D in DSI, HTS, or ES&PE – by OE, the private sector or any other organization. Under this assumption, there would be R&D only on V&C technologies and this R&D would be done by both OE and non-OE organizations (private sector, universities, other government agencies). Whereas, in the Portfolio Case, both groups of organizations would undertake R&D in *all* technology areas.

The Program Case numbers reflect hypothetical assumptions about there being no R&D in other OE technology areas. The Portfolio Case gives the more consistent set of estimates. While their range, as reflected in Figures 4-2 through 4-7, indicates considerable uncertainty about the *precise* benefits of OE's R&D portfolio, its reliability benefits are estimated to be about $6 billion in the year 2020, $13 billion in 2030, and increasing somewhat thereafter. The infrastructure security benefits are estimated to be a 13% reduction in the *risk* in the year

2020 associated with a catastrophic attack or natural disaster, and a 19% reduction in 2030. These estimates reflect estimates of the current levels of reliability-event costs, such as outages, and the collective experience, knowledge, and insights of over 50 experts.

Table 4-2. Summary of Reliability and Infrastructure Security Benefits of OE's Programs – for FY2008 Budget Request[19]

Program or Portfolio	Outages ($ billions)		Power Quality Events ($billions)		Trans-mission Congestion ($ billions)		Total Reliability ($ billions)		Risk of Attack or Destruction (%)		Mitigating Damage with Supply (%)		Mitigating Damage with Demand Response (%)		Total Infrastruc-ture Security Improve-ment	
	2020	2030	2020	2030	2020	2030	2020	2030	2020	2030	2020	2030	2020	2030	2020	2030
DSI	1.9	5.3	0.51	1.6	0.03	0.09	2.4	7.0	2.0	5.0	2.0	3.0	1.0	2.0	5%	10%
HTS	1.9	5.3	0.29	1.3	0.01	0.07	2.2	6.7	2.0	3.0	2.0	4.0	2.0	5.0	6%	12%
ES&PE	2.8	4.3	1.0	1.7	0.05	0.09	3.9	6.1	4.5	4.0	5.0	8.5	2.0	4.0	11%	16%
V&C	9.5	11	1.1	1.6	0.07	0.07	11	12	10	10	10	7.5	10	7.5	28%	24%
PORT-FOLIO	4.7	11	1.2	1.7	0.07	0.13	6	13	5	4	4	13	7	9	13%	19%

[19] NOTES:
(a) Assumes Mid-level Estimates of: (i) market penetration, (ii) impact of improved technology & (iii) total annual cost of outage, power quality, and transmission congestion events
(b) Assumes Cost Escalation: Future annual costs of outage, power quality, and transmission congestion events are assumed to *increase* (in inflation-adjusted dollars) relative to current levels, if there is no R&D in the future by industry, DOE & others. Estimate based on expert panel projections.
(d) Program Case – benefits of the OE R&D Program, assuming that industry also carries out R&D in this technology area, but *no R&D in any other technology* areas, by industry, DOE, or others
(e) Portfolio Case – benefits of the OE portfolio of R&D programs, assuming that industry, DOE and others *have R&D* programs. Portfolio benefits might be less than those in a Program Case because the Program Case implicitly assumes no R&D (including by industry) in any of the other technology areas.

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CHAPTER 5: CONCLUSIONS

Two separate, but complementary, analyses were conducted to measure the benefits related to OE programs:

- Economic and energy efficiency benefits were developed using a modified version of NEMS, which provided the integrating framework for all the ESE R&D offices[20]; and
- Infrastructure security and reliability benefits were estimated by using empirical data and expert panels.[21]

Both of these analytic efforts were conducted for the first time for the FY08 budget cycle. In addition, OE's reorganization of its R&D programmatic activities in the past year, as well as the addition of its infrastructure security and energy restoration function, led to new program goal definitions. The relative newness of methodologies and goals means that these analyses should be viewed as works in progress with future refinements anticipated for next year. For example, the economic and energy efficiency benefits estimation process required analysts to develop simplified characterizations of the OE R&D goals that could be represented within NEMS, as well as modifications to NEMS to facilitate that representation. The goal characterizations and their implementations will be reviewed in the coming year.

Despite the initial efforts conducted for FY08, OE has not yet developed a metric that adequately addresses benefits to grid reliability and security, as well as the overall resiliency of the energy infrastructure. These benefits are the primary goals of OE's programs, which are focused on advancing technologies that will result in an enhancement of overall system reliability, strengthening grid stability by reducing the frequency or impact of operational disturbances, and reducing vulnerability of supervisory control and data acquisition (SCADA) systems to cyber attack. Our goal for next year's benefits analysis is to:

- Develop broadly acceptable definitions of electricity reliability and energy infrastructure security with corresponding program metrics,
- Develop and apply a methodology to translate program goals related to enhanced reliability and security into quantifiable benefits using the developed metrics,
- Develop methodologies for measuring potential economic benefits of OE programs not included in this year's analysis, such as:
  - Examining the impact of OE's policies on enhancing the utilization of wind and other renewable technologies within the electric grid, and
  - Determining transmission cost reductions due to advancements in high-voltage power electronics and control technologies that might enable the grid to respond more efficiently and in a more integrated manner, thereby reducing the need for additional infrastructure.

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[20] These calculations were performed by OnLocation, Inc. using NEMS.

[21] This effort was conducted by the Oak Ridge National Laboratory.

APPENDIX A: HTS BASELINE AND PROGRAM ASSUMPTIONS

In order to represent HTS technologies within NEMS, key technology assumptions were developed for both the Base (No R&D) Case and the HTS R&D program case, including annual average equipment sales rates within the target market (both new and replacement equipment), market adoption projections per year (percent of total sales expected to be HTS equipment), and maximum market saturation for each of the four HTS technologies, as well as technology cost and efficiency differentials compared to conventional technologies. Cost differentials included the purchase price of the HTS device, HTS wire and cryogenic cooling devices, but did not include the value of energy savings since that was calculated endogenously in the NEMS model. These assumptions were derived from industry experts with extensive experience in the HTS application areas. The methodology used to derive these projections was consistent with the GPRA HTS benefits analyses from previous years that used a spreadsheet model developed by Energetics along with market projections from EIA's Annual Energy Outlook. The NEMS modeling of these assumptions is discussed in Chapter 3.

There were a number of assumptions made to develop market penetration rates and costs and other parameters for high temperature superconductivity technologies. For the Base (No R&D) case, it was assumed that some market deployment would be driven by equipment suppliers independent of OE R&D funding, but that the rate of technology development and deployment would be slower than if OE's programs influenced this development. In the area of motors, Rockwell Automation provided data for the Base and R&D case based on their market projections. Rockwell has extensive knowledge of mechanical power transmission products and motors and drives. It offers integrated motor and mechanical power transmission solutions for a host of automation needs. For transformers, Waukesha Electric Systems provided data for the Base and R&D case based on their extensive knowledge of transformers for electrical systems. Waukesha is one of the largest U.S. manufacturers of transformers, transformer and circuit breaker services, reverse-engineered components and replacement parts. The generator assumptions were derived from an assumed relationship with motor development, using similar growth rates and deployment schedule assumptions as for motors. The efficiency differential was assumed to be the same for both the Base and Program cases. Supporting data such as the average cost of a conventional generator and maximum saturation rates were taken from a 2002 HTS GPRA report[22] prepared by Energetics for DOE. The cable assumptions were provided by Southwire, incorporating their expertise in electrical wire and cable. Southwire is a domestic leader in the production of electrical wire with over 50 years experience. The full set of HTS assumptions provided for the NEMS modeling analysis can be found in Tables A-1 to A-4. Following is a detailed description of the terminology used in the assumptions tables.

[22] "Summary of High Temperature Superconductivity Program Benefits, Back-up to GPRA Data Call FY2004-08," Energetics, Inc., August 2002.

Maximum Market:
The market is the combination of replacements plus new growth. The *maximum market (New)* refers to the percentage of new growth that is affected by each type of application (note that this is not the same as market saturation, which refers to the maximum market penetration for HTS applications). Only large motors are considered as potential HTS applications, and large motors are estimated to consume 33% of the U.S. electricity consumption. On the other hand, the maximum markets for generators and transformers are 100% and 300% respectively, because electricity is generated once, but transformed 3 times (three times: first to step up the voltage from the generated to high-voltage long distance overhead wires; second to step it down to intermediate voltages, and third to step it down to distribution voltages. There are more step down stages during distribution, but these are not considered eligible for HTS.) Like generators, cables also have a maximum market of 100%.

The *replacement rate* refers to the percentage of existing equipment inventory that is replaced for HTS technology.

Market Penetration Assumptions
In order to obtain a standard S-shaped market penetration curve it is necessary to make assumptions for:

- the year in which new technology enters the market (initial year of technology deployment),
- the year to an arbitrary mid point between 0-50% of the market is captured (Nth year saturation*)*,
- the year until 50% of the market is captured (50% market penetration),
- and the fraction of the total market captured eventually (market saturation).

These inputs are plugged into an exponential function that yields the percentage market penetration for the technology at any point in time.

Market Adoption:
The market adoption refers to the percentage of new and replacement technologies that penetrate the market.

Efficiency Differential
The savings estimates from each HTS technology are a result between the difference in energy efficiency between HTS technology and alternative conventional technology. The efficiency differential is then paired with the market penetration for each technology to yield annual energy savings estimates.

Technology Cost Assumptions
The Technology Cost Differential represents the percentage difference in the cost between HTS systems and alternative conventional technology. The HTS Technology Cost is then calculated by multiplying the assumed Alternative Conventional Technology Costs by the Technology Cost Differential. Cost includes HTS device, HTS wire and cryogenic cooling devices, but does not include value of energy savings.

HTS equipment has a cost premium compared to alternative conventional technologies except for HTS cables, which have a cost premium in the early years of deployment, but drops below the cost of a conventional cable in the later years. This is shown in the technology cost differential percentages, where zero percent indicates that the cost is the same as the conventional alternative, a positive value indicates a cost premium, and a negative value indicates a cost savings.

The following tables depict the assumptions for motors, transformers, generators, and cables provided to the NEMS modeling team.

Table A-1. HTS Motor Assumptions Using 2G Wire

HTS Large Motors (>1000hp)				
Maximum Market (new)	33.0%	(GPRA report)		
Maximum Market (replacements)	2.0%	(GPRA report)		
Year of Technology Deployment	Initial	Nth Year	Full (50% of market)	
Base (No R&D) Case	2014	2020	2025	
R&D Case	2010	2015	2020	2006 Budget (+ 1 year)
Market Adoption	Initial	Nth Year	Full (50% of market)	
Base (No R&D) Case	0%	1%	10%	
R&D Case	0%	7%	30%	2006 Budget
assumed to be % of large motor sales overall that are HTS				
Efficiency Differential (GWh saved)	Initial	Nth Year	Full (50% of market)	
Base (No R&D) Case	1.50%	1.50%	1.55%	
Currently rated at 97% (typical large motor value)				
R&D Case	1.50%	1.60%	1.70%	
98.5% (expected for initial HTS motor value)				
Technology Cost Differential	Initial	Nth Year	Full (50% of market)	
Base (No R&D) Case	120%	120%	60%	
R&D Case	100%	50%	30%	$/MWh (GPRA model)
Additional Motor Assumptions				
Alternative Conventional Tech	2010	2015	2020	
Base (No R&D) Case	$ 113	$ 113	$ 113	$/KW (GPRA model)
R&D Case	$ 113	$ 113	$ 113	$/KW (GPRA model)
HTS Technology	2010	2015	2020	
Base (No R&D) Case	$ 249	$ 249	$ 181	$/KW
R&D Case	$ 226	$ 170	$ 147	$/KW
Avg GWH/yr/motor	4.295	(GPRA model)		
Avg KW Size	865	(GPRA model)		
Maximum Market Saturation	95%	(GPRA model)		

Sources: *High Temperature Superconductivity Program Benefits, GPRA 2004-08 Back-up Report, Energetics, Incorporated, August 2002 (GPRA Report); HTS GPRA Model, Energetics Incorporated, March 2006 (GPRA Model); Personal communication with Rockwell Automation, May 2006*

Table A-2. HTS Transformer Assumptions

HTS Transformers				
Maximum Market (new)	300%	(GPRA report)		
Maximum Market (replacements)	4.5%	(GPRA report)		
# of times elec is transformed	3.00	GPRA model		
Year of Technology Deployment	Initial	Nth Year	Full (50% of market)	
Base (No R&D) Case	2015	2018	2021	
R&D Case	2010	2013	2018	2005 Budget (+ 1 year)
Market Adoption	2014	2020	2025	
Base (No R&D) Case	0%	3%	10%	
R&D Case	3%	10%	50%	2005 Budget
Efficiency Differential (GWh saved)	2014	2020	2025	
Base (No R&D) Case	0.0%	0.3%	0.3%	
R&D Case	0.3%	0.3%	0.3%	99.8% (GPRA Report)
Technology Cost Differential	2014	2020	2025	
Base (No R&D) Case	150%	100%	80%	
R&D Case	108%	60%	48%	$/transformer (GPRA model)
Additional Transformer Assumptions (not yet reviewed by OE)				
Alternative Conventional Tech	2010	2015	2020	
Base (No R&D) Case	$ 10.5	$ 10.5	$ 10.5	$/KW (GPRA model)
R&D Case	$ 10.5	$ 10.5	$ 10.5	$/KW (GPRA model)
HTS Technology	2010	2015	2020	
Base (No R&D) Case	$ 26.3	$ 21.0	$ 18.9	$/KW
R&D Case	$ 21.8	$ 16.8	$ 15.5	$/KW
Avg GWH/yr/transformer	144.54	(GPRA model)		
Avg KW Size	30	(GPRA model)		
Maximum Market Saturation	95%	(GPRA model)		

Sources: *High Temperature Superconductivity Program Benefits, GPRA 2004-08 Back-up Report, Energetics, Incorporated, August 2002 (GPRA Report); HTS GPRA Model, Energetics Incorporated, March 2006 (GPRA Model); Personal communication with Waukesha May 2006*

Table A-3. Generator Assumptions

HTS Generators				
Maximum Market (new)	100%	(GPRA report)		
Maximum Market (replacements)	1.8%	(GPRA report)		
Year of Technology Deployment	Initial	Nth Year	Full (50% of market)	
Base (No R&D) Case	2013	2018	2024	based on motor assumptions
R&D Case	2009	2013	2019	2005 Budget (+ 1 year)
Market Adoption	2010	2015	2020	
Base (No R&D) Case	0%	4%	30%	based on motor assumptions
R&D Case	0%	10%	50%	2005 Budget
Efficiency Differential (GWh saved)	2010	2015	2020	
Base (No R&D) Case	1.1%	1.1%	1.1%	assume same as R&D case
R&D Case	1.1%	1.1%	1.1%	99.7% (GPRA Report, last page)
Technology Cost Differential	2010	2015	2020	
Base (No R&D) Case	58%	76%	32%	based on motor assumptions
R&D Case	38%	6%	2%	$/generator (GPRA model)
Additional Generator Assumptions				
Alternative Conventional Tech	2010	2015	2020	
Base (No R&D) Case	$ 45	$ 45	$ 45	$/KW (GPRA model)
R&D Case	$ 45	$ 45	$ 45	$/KW (GPRA model)
HTS Technology	2010	2015	2020	
Base (No R&D) Case	$ 71	$ 79	$ 59	$/KW
R&D Case	$ 62	$ 48	$ 46	$/KW
Maximum Market Saturation	95%	(GPRA model)		

Sources: *High Temperature Superconductivity Program Benefits, GPRA 2004-08 Back-up Report, Energetics, Incorporated, August 2002 (GPRA Report); HTS GPRA Model, Energetics Incorporated, March 2006 (GPRA Model)*

Table A-4. Cable Assumptions

HTS Underground Cables				
Maximum Market (new)	100%	of annual increase in total end-use kWh sales (GPRA report)		
Maximum Market (replacements)	0.2%	of total end-use elec kWh (GPRA report)		
Cable Carrying Capacity (amps)	242%	increase over conventional cables (=2000/825) (GPRA report)		
Year of Technology Deployment	Initial	Nth Year	Full (50% of market)	
Base (No R&D) Case	2009	2013	2019	
R&D Case	2008	2012	2018	2005 Budget (+ 1 year)
Market Adoption	2010	2015	2020	
Base (No R&D) Case	0%	4%	25%	
R&D Case	0%	10%	50%	2005 Budget
Efficiency Differential (GWh saved)	2010	2015	2020	
Base (No R&D) Case	0.5%	0.8%	1.0%	
R&D Case	1.5%	1.5%	1.5%	98.5% (GPRA Report, last page)
Technology Cost Differential	2010	2015	2020	
Base (No R&D) Case	15%	-10%	-25%	
R&D Case	6%	-61%	-69%	$/mile (GPRA model)
Additional Cable Assumptions				
Alternative Conventional Tech	2010	2015	2020	
Base (No R&D) Case	$ 1,576	$ 1,576	$ 1,576	$/mile (GPRA model)
R&D Case	$ 1,576	$ 1,576	$ 1,576	$/mile (GPRA model)
HTS Technology	2010	2015	2020	
Base (No R&D) Case	$ 1,812	$ 1,418	$ 1,182	$/mile
R&D Case	$ 1,664	$ 619	$ 488	$/mile
Avg miles cable/GWH	0.02259	(GPRA model)		
Maximum Market Saturation	85%	(GPRA model)		

Sources: *High Temperature Superconductivity Program Benefits, GPRA 2004-08 Back-up Report, Energetics, Incorporated, August 2002 (GPRA Report); HTS GPRA Model, Energetics Incorporated, March 2006 (GPRA Model); Personal communication with Southwire, May 2006*

APPENDIX B: A MARKET PENETRATION MODEL FOR AN ELECTRICITY DISTRIBUTION LOAD SHIFTING TECHNOLOGY

Introduction

OE's research development, demonstration, and deployment (RD^3) in the Distribution System Integration (DSI) line aims to achieve deployment of various technologies capable of together cost-effectively reducing the peak load on electric grid distribution feeders by 20% by 2017, based on successful demonstration by 2015. This appendix describes a model developed to forecast the penetration of such a technology, herein referred to as the *peak load reduction technology* (PLRT). As described in the main text, the National Energy Modeling System (NEMS) is used to assess the impact of PLRT penetration forecast developed here by means of a generic storage or load shifting technology.

The PLRT Market Penetration Model

The major circuits that interconnect high voltage transmission substations with customer electric loads are typically called *feeders*. The PLRT penetration model assumes that all feeders are of a standard type prior to 2017. Starting in 2017, the model considers feeders that are at capacity (due to load growth) and require enhancement. They either receive a capacity upgrade, the PLRT, or both. The share of feeders receiving a particular enhancement varies in each year, with the proportion receiving PLRT increasing over time. Similarly, new feeders required for system expansion are either installed as a standard feeder or a PLRT enhanced feeder. The proportion of new feeders receiving the PLRT enhancement also increases over time. The inventory of feeder stock is determined separately for residential, commercial, and industrial sectors in each year for each of the 13 NEMS Electric Market Module (EMM) regions. The share of the overall feeder inventory that has PLRT is then used to determine the cumulative effect of PLRT on regional peak load reduction.

Figure B-1 is a schematic of the PLRT Market Penetration Model, which is divided into two analyses, an inventory analysis and a coincidence analysis. The inventory analysis to the left begins with a given initial feeder stock for each region and sector. The change in feeder stock from the previous year to the current year is determined based on 1) the make-up of the feeder stock in the previous year, 2) the required system expansion (i.e. new feeders), and 3) the PLRT adoption trends of current feeder enhancement and new feeder installation. The coincidence analysis to the right determines the regional peak load reduction resulting from 1) the current PLRT prevalence and 2) the coincidence with the regional peak load of each sector's peak load. As can be seen in Figure 1, the inventory analysis to the left updates the current year's feeder stock in the center, while the coincidence analysis to the right determines how the changing stock affects regional peak loads. Over time, there is a linear increase in adoption percentages, i.e. the fraction of all upgrades that employ PLRT technology, from negligible amounts in 2017 to 100% adoption in 2030. Feeder lifetime is assumed to be 20 years and the term of the analysis is 13 years, so no feeder is considered for upgrade and/or

PLRT more than once. The inventory and coincidence analyses are performed separately for each of the 13 NEMS EMM regions.

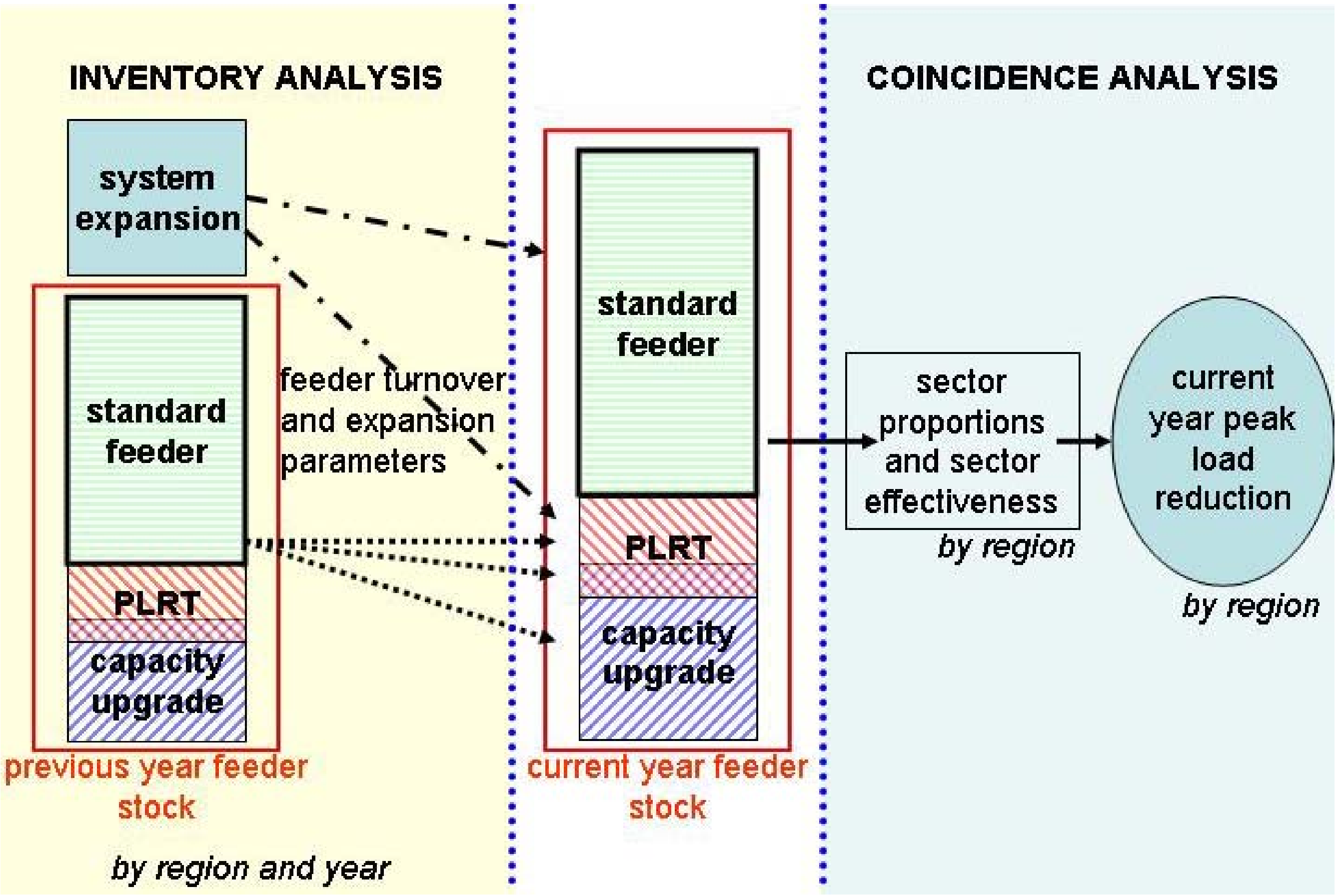


Figure B-1 PLRT Market Penetration Model calculations for a given year

To summarize, the inventory analysis is an algorithm executed each year over the period 2017 to 2030. Based on certain inputs, the feeder stock for the current year is determined, and becomes the initial condition in the inventory analysis for the next year. The current feeder stock is taken as an input to the coincidence analysis, which is also performed for each year. In the coincidence analysis the overall regional peak load reduction effect of the diffusing PLRT is calculated from the current feeder stock, sectoral shares of electricity consumption, and coincidence of each sector's peak loads with the regional peak.

Inventory Analysis

Feeder Types

The penetration model assumes three feeder types: current stock, upgraded stock, and new stock.

- The ***initial stock*** covers all feeders in place in the first year of the study, 2017. They are assumed to be the same size, and to have a uniform distribution of remaining lifetimes, ranging (in integer value) from one year remaining to the maximum lifetime, i.e. that of a newly installed feeder. In other words, the reciprocal of the lifetime is the fraction of feeders reaching the end of their lifetime each year.

- The ***upgraded stock*** contains all current feeders that have experienced capacity increases. The increased capacity of these feeders is that required to accommodate typical load growth over their lifetime; therefore, it is a function of load growth, which varies by region.
- The ***new stock*** contains green field feeders installed after the beginning year of the analysis.

For each year of the analysis, feeders in each stock are indexed by:

- region
- sector
- presence or absence of PLRT
- years remaining in lifetime

For each possible set of index values, in each year, there are a number of feeders. In each successive year, feeders get one year closer to the end of their lifetime. Nothing is done to feeders if their lifetime is not complete. If their lifetime is complete, they either get

- a capacity upgrade,
- the PLRT, or
- both.

New feeders are added to the current stock to meet the peak load growth not covered by enhanced current feeders. New feeders are installed either

- with PLRT or
- without PLRT.

Input Parameters

Data required for the inventory analysis are

- the initial feeder stock;
- feeder characteristics such as capacity, lifetime, and PLRT performance; and
- shares of current feeders receiving capacity upgrade and PLRT enhancements and proportions of new feeders receiving PLRT enhancements.

Regional Peak Load

The initial stock of feeders by region is established using the regional peak demand from the NEMS Reference Case, as shown in Table B-1.

Table B-1: Regional annual peak load (GW)

Year	ECAR 1	ERCOT 2	MAAC 3	MAIN 4	MAPP 5	NY 6	NE 7	FL 8	STV 9	SPP 10	NWP 11	RA 12	CNV 13
2017	133	86	74	69	39	38	32	63	230	55	59	52	75
2020	137	89	77	71	41	39	33	67	242	57	62	56	79
2025	145	95	82	75	43	41	35	75	264	61	68	63	87
2030	154	103	88	79	45	43	38	84	290	66	75	71	95

Feeder Parameters

Table B-2 lists the basic feeder parameters. Feeder life refers to a capacity lifetime, not a functioning lifetime, which could be very long. In other words, it is the elapsed time allowable until additional capacity is required on a given feeder. Note that this is a design choice, that is, distribution engineers implicitly decide by their upgrade choices how far ahead of load growth they will build. Based on conversations with distribution engineers, it seems this horizon is typically about 20 years, implying that upgrades are proportionately biggest where load growth is fastest. The assumed lifetime and size values used here are based on personal communications with Southern California Edison staff about that company's normal practice. For the purposes of this analysis, the key issue is that feeders only become eligible to adopt PLRT at the end of this capacity lifetime, when some sort of new investment is necessary. The 20% potential demand shift reflects the program goal of making such a shift possible cost effectively.

Table B-2: Feeder parameter values

Current Feeder Life (years)	20
Upgrade Feeder Life (years)	20
New Feeder Life (years)	20
Maximum Technology Life Extension (years)	20
Demand Shift	0.2
Average Feeder Size (MW)	8
New Feeder Size (MW)	8

Transition Proportions

In a sense, the assumptions made in this section are the most critical. The turnover of the feeder stock is a mechanical process in this model, driven by basic physical properties of the system and assumptions about planned feeder lifetime. The coincidence parameters described in the following section are estimates of what are actually knowable system characteristics, although our knowledge of them is limited. How many feeders actually get equipped with PLRT when their lifetime expires however, is currently a matter of judgment. As more information on the exact nature and economics of PLRT become available, a more sophisticated model of adoption can be developed. In the interim, it must be noted that these assumptions are key to model outcome.

In each year, some feeders are due for upgrade and/or PLRT. The transition proportions in Table B-3 are the result of assumed simple linear increases between 2017 and 2030. No feeders in the initial stock receive the PLRT prior to 2017, and by 2030, all existing feeders at the end of their lives receive the PLRT at the end of their planned lives. Half of them additionally are upgraded, and for half the PLRT is the only modification to the feeder. Similarly, no new feeders are installed with the PLRT prior to 2017, and by 2030 all new feeders are installed with the PLRT.

The "Current to…" transition shares are the proportions of existing feeders due for upgrade that receive the PLRT, the capacity upgrade, or both, respectively. Looking first at the "… to PLRT" row, only 1% of feeders at the end of their lifetime are equipped with PLRT in 2017, but by 2030 the proportion has risen to 50%. The "… to PLRT and Upgrade" row of Table

B-3 shows that the other half of current feeders get both an upgrade and PLRT. That is, all feeders that were in existence in 2016 coming to the end of their capacity life in 2030 have PLRT installed. The "New …" transition proportions are the fractions of new feeders being installed without or with the new technology. These values determine how the make-up of the new feeder population transforms over time. Eventually all new feeders are equipped with PLRT.

Table B-3 Transition Proportions

	2017	2020	2025	2030
Current To PLRT	0.01	0.13	0.31	0.50
Current To Upgrade	0.99	0.76	0.37	0.00
Current to PLRT and Upgrade	0.00	0.12	0.31	0.50
New Without PLRT	0.99	0.76	0.37	0.00
New With PLRT	0.01	0.24	0.63	1.00

Coincidence Analysis

The inventory analysis, on the left side of Figure B-1, determines how the stock of feeders might change over time as the overall national distribution network is replaced, expanded, and improved. In the baseline case, the stock of feeders has no PLRT installed so the shape of the electricity load curve that has be met by the nation's supply system is unchanged from the AEO Reference Case; however, in the program case, the upshot of feeder stock turnover is that an increasing share of feeders have PLRT, which changes total system electrical load. PLRT modifies the load shape of individual feeders, and consequently the curve faced by the electricity supply chain is changed by the sum of all the individual feeder load shifts. Having determined how the stock will change, the following section translates the changing nature of the feeder stock into a changing load shape of total electricity demand, that is, determines how the individual affects should be added up. Note that there is no energy efficiency gain or loss in this analysis, i.e. the area under the load curve is unaffected, only its shape changes.

Noncoincidence Factor

Given that peak load is reduced on a given feeder, the overall effect on the total system load will be heavily determined by *coincidence*, which roughly means how much the load on the feeder mirrors the load on the overall system. The *noncoincidence factor* is a measure of how asynchronous peak loads are across all feeders in a region, and is defined as follows:

$$\text{Noncoincidence(Region)} = \frac{\sum_{\text{feeders} \in \text{Region}} \text{FeederPeakLoad(feeder)}}{\text{PeakLoad(Region)}}$$

where FeederPeakLoad(feeder) is the annual peak load on each individual feeder in the region. A noncoindence factor of 1.4 is assumed for all regions in this study. This assumed value says that a peak load reduction of 1.4 MW on every one of 1000 feeders in a region will result in a net system load reduction of 1 GW, simply because very few feeders will experience their load reduction precisely at the system peak hour. The noncoincidence factor addresses general diversity in the system beyond the sectoral effect described below.

Sector Effectiveness
One of the characteristics of feeders that could potentially have a major impact on how much their load reduction affects system load reduction arises from the different time patterns of the residential, commercial, and industrial sectors, and how much of the load on a given feeder comes from each sector. *Sector effectiveness* is a measure of how effective peak reduction in a given sector is at reducing the regional system peak demand. Sector effectiveness is defined as

$$\mathrm{SectorEffectiveness(sector, region)} = \frac{\mathrm{RegionalPeakReduction(region)}}{\sum_{\mathrm{feeders} \in \mathrm{sector\,,\,region}} \mathrm{PeakReduction(feeder)}}$$

The sector effectiveness values for residential, commercial, and industrial sectors in all regions used in this analysis are 0.5, 0.95, and 0.9 respectively. In other words, the peak load reduction in residential sector is unlikely to be at the system peak hour, when most people are at work and not using much electricity in their homes, whereas peak loads in the commercial sector tend to drive system peaks and are highly coincident. For example, peak load reducing energy efficiency in the commercial sector will have a bigger affect than similar efforts in the residential sector. Industrial peak load reductions also tend to have big effect on the system peak simply because industrial loads are relatively flat. Conversely, it could be argued that PLRT would be unlikely to be as effective on feeders with large industrial loads, but that effect is not considered here.

Energy Proportion
To determine sectoral effectiveness, first the contribution of each sector to load must be determined. *Energy proportion* shows the share of total regional electricity consumption that each sector consumes. In addition to the three sectors considered in this analysis, the transportation sector and electricity transmission and distribution itself also consume electricity. The energy proportions used in this analysis are taken from the NEMS baseline case, and are reported in Table B-4 by the 13 EMM regions. It is assumed that peak demand proportions are equal to energy proportions, that is, no consideration of the sectors' diverse load factors is made, as mentioned above.

Table B-4: Energy proportions by region for 2017

	ECAR 1	ERCOT 2	MAAC 3	MAIN 4	MAPP 5	NY 6	NE 7	FL 8	STV 9	SPP 10	NWP 11	RA 12	CNV 13
residential	0.31	0.38	0.33	0.30	0.33	0.31	0.34	0.48	0.36	0.34	0.33	0.36	0.30
commercial	0.29	0.31	0.42	0.36	0.31	0.47	0.44	0.40	0.32	0.36	0.33	0.38	0.45
industrial	0.33	0.26	0.19	0.29	0.29	0.15	0.15	0.07	0.27	0.23	0.27	0.18	0.17
transportation	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
t&d	0.06	0.05	0.06	0.06	0.07	0.07	0.07	0.06	0.06	0.07	0.08	0.08	0.08

PLRT Adoption Model Results

The peak load reduction by region and year is presented in Table B-5 as fractions of peak by region. In the first year no feeder in any region has PLRT, i.e. the entire row is zeros. Deployment of PLRT accelerates and becomes universal by 2030, and yet it still only affects that share of the feeder stock that is turning over, so at the end of the analysis, the cumulative regional peak load reductions range from 7.5% to 8.1%. The factors causing this regional disparity are the rate of load growth and the sectoral shares of peak load.

Table B-5: Portion of peak capacity reduction by NEMS EMM region

	Region												
Year	1	2	3	4	5	6	7	8	9	10	11	12	13
2017	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2020	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.007	0.007	0.006	0.007	0.007	0.007
2025	0.033	0.033	0.034	0.034	0.033	0.033	0.034	0.034	0.035	0.034	0.035	0.036	0.036
2030	0.079	0.077	0.079	0.079	0.077	0.078	0.078	0.075	0.079	0.078	0.079	0.078	0.081

PLRT Market Penetration Model Formulation

Indices:

Index	*description*	*members*
Ft	feeder type	{standard, PLRT, upgrade, upgrade&PLRT}
Y	year	{1,2, …, 14} corresponding to calendar years 2017-2030
R	EMM region	{1,2, … , 13}
S	sector	{commercial, industrial, residential}
A	feeder age	{1,2, … , Feeder Lifetime}

Input Parameters:

Parameter	*description*
Capacity	average capacity of a standard feeder (MW)
ES(r,s)	share of energy consumed by each sector
gr(r)	annual growth rate of electricity consumption
ITPL(r)	initial total peak load (MW)
Lifetime	average lifetime of a standard feeder (years until capacity enhancement is required)
Noncoincidence (r)	noncoincidence factor
Noncoincidence(r)	ratio of contribution to sectoral peak load reduction to the peak load reduction on an individual feeder responsible for the sectoral reduction
SectorEffectiveness(s)	ratio of contribution to regional peak load reduction to the sectoral peak load reduction responsible for the regional reduction
TP_CurrentToBoth(y)	transition proportion, at capacity feeders getting both PLRT and capacity enhancement
TP_CurrentToPLRT(y)	transition proportion, at capacity feeders getting PLRT enhancement
TP_CurrentToUpgrade(y)	transition proportion, at capacity feeders getting a capacity enhancement
TP_NewPLRT(y)	transition proportion, new feeders installed as PLRT
TP_NewStandard(y)	transition proportion, new feeders installed as standard feeder

Derived Values:

value	***description***
FN(ft,y,r,s,a)	number of feeders
IPL(r,s)	initial sectoral peak load (MW)
NF (y,r,s)	number of new feeders required for system expansion
NFL(y,r,s)	new feeder load that must be met by system expansion (MW)
NP(y,r,s)	number of feeders with PLRT
RR(y,r,s)	regional peak load reduction contribution of PLRT by sector (MW)
RRtotal(y,r)	total regional peak load reduction (MW)

Inventory Analysis

The initial conditions of the inventory analysis are the numbers of feeders in each region, for each sector in the year prior to the first year of the analysis (i.e. year = 0). The peak loads in each region and sector that must be carried by the feeder stock is the product of the region's peak load, the noncoincidence factor (to account for asynchronicity of individual feeders within a sector), and the share of energy consumed by the sector.

$$\mathrm{IPL(r,s) = ITPL(r)*Noncoincidence(r)*ES(r,s)} \qquad \forall\, \mathrm{r,s} \qquad (1)$$

The number of feeders required to meet this peak load is the quotient of initial peak load and feeder size. In the initial year of the analysis, a uniform distribution of feeder ages, ranging from 1 to the lifetime of feeders (in intervals of one year) is assumed. Thus, the total number of feeders is divided by the lifetime of feeders to get the number of feeders at a given age.

$$\mathrm{FN(\text{'standard'},0,r,s,a) = [IPL(r,s)/Capacity]/lifetime} \qquad \forall\, \mathrm{r,s,a} \qquad (2)$$

There are no PLRT or capacity upgrade enhanced feeders initially.

$$\mathrm{FN(ft,0,r,s,a) = 0} \qquad \forall\, \mathrm{ft} \neq \text{'standard'}, \forall\, \mathrm{r,s,a} \qquad (3)$$

Given the feeder stock from the previous year, the new feeders required for system expansion, and the proportions of new and enhanced feeders receiving PLRT and/or capacity upgrade, the feeder stock for the current year is determined. Note that the feeder stock at year zero is the feeder stock at the beginning of the analysis. At each year, the number of feeders in each category is updated from the previous year feeder stock. Feeders not at the end of their lifetime simply become one year older.

$$\mathrm{FN(ft,y,r,s,a) = FN(ft,y-1,r,s,a-1)} \qquad \forall\, \mathrm{ft,y,r,s,1<a\leq lifetime} \qquad (4)$$

New feeders are required in each year, region, and sector for system expansion. System expansion is assumed to accommodate half of the load growth in each region. The load that new feeders must meet is therefore one half of the load growth in that year. Note that the rest of the load growth is met by enhancement (either PLRT, capacity upgrade, or both) to current feeders.

$$NFL(y,r,s) = IPL(r,s)*[(1+gr(r))^{y} -(1+gr(r))^{y-1}]/2 \qquad \forall\, y,r,s \qquad (5)$$

The number of new feeders required to meet this load is the quotient of the new feeder load and the capacity of standard feeders.

$$NF(y,r,s) = NFL(y,r,s)/Capacity \qquad \forall\, y,r,s \qquad (6)$$

Standard feeders are added to the stock as the portion of system expansion that does not receive the PLRT.

$$FN(\text{'standard'},y,r,s,1) = NF(y,r,s)*TP\_NewStandard(y) \qquad \forall\, y,r,s \qquad (7)$$

PLRT enhanced feeders are added to the stock as the sum of the portion of system expansion that does receive PLRT and the portion of feeders at capacity that are enhanced by the PLRT.

$$\begin{aligned} FN(\text{'PLRT'},y,r,s,1) &= NF(y,r,s)*TP\_NewPLRT(y) \\ &+ FN(\text{'standard'},y-1,r,s,lifetime)*TP\_CurrentToPLRT(y) \qquad (8) \\ &\forall\, y,r,s \end{aligned}$$

Capacity upgraded feeders are added to the stock as the portion of feeders at capacity that receive a capacity upgrade as an enhancement.

$$\begin{aligned} &FN(\text{'upgrade'},y,r,s,1) = \\ &\quad FN(\text{'standard'},y-1,r,s,lifetime)*TP\_CurrentToUpgrade \qquad \forall\, y,r,s \qquad (9) \end{aligned}$$

Some feeders at capacity receive both the PLRT and a capacity upgrade.

$$\begin{aligned} &FN(\text{'upgrade\&PLRT'},y,r,s,1) = \\ &\quad FN(\text{'standard'},y-1,r,s,lifetime)*TP\_CurrentToBoth \qquad \forall\, y,r,s \qquad (10) \end{aligned}$$

Noncoincidence Analysis

After the inventory analysis determines the feeder stock for a given year, the noncoincidence analysis determines what the regional peak load offset due to PLRT prevalence is. The number of feeders with PLRT is the sum of standard feeders with PLRT and capacity upgraded feeders with PLRT of all ages.

$$NP(y,r,s) = \sum_{a=1}^{lifetime} [\, FN(\text{'PLRT'},y,r,s,a) + FN(\text{'upgrade\&PLRT'},y,r,s,a) \,] \qquad (11)$$
$$\forall\, y,r,s$$

The contribution of these feeders to the regional peak demand reduction is the product of the number of PLRT feeders, feeder capacity, sector effectiveness, and noncoincidence factor.

$$RR(y,r,s) = NP(y,r,s)*Capacity*SectorEffectiveness(s)*Noncoincidence(r) \quad \forall\, y,r,s \tag{12}$$

Finally, the regional peak load reduction attributable to PLRT penetration is the sum of regional peak load reduction contributions from the three sectors.

$$RRtotal(y,r) = \sum_{s} RR(y,r,s) \quad \forall\, y,r,s$$

(13* ARABIC |13})

APPENDIX C: ELECTRICITY RELIABILITY AND INFRASTRUCTURE SECURITY BENEFITS ESTIMATION

Appendix C-1

Information Package
For Use by

The National Panel on Estimating the Electricity Reliability and Security Benefits of the U.S. Department of Energy's Distributed Systems Integration R&D Program

Information Package
For Use by

The National Panel on Estimating the Electricity Reliability and Security Benefits of the U.S. Department of Energy's Distributed Systems Integration R&D Program[23]

This package provides information and market projections that serve as reference material for panel members who are estimating the electricity reliability and energy infrastructure security benefits of technologies anticipated from the Distributed Systems Integration (DSI) R&D program in the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability.

It is important for panel members to refer to this information so that all members base their estimates on the same set of assumptions and projections.

The information in this package is as follows:

1. Definitions of reliability and security,

2. DSI program metric – major technical goal(s) of the program, including a brief description of the program, and its expected outputs and outcomes,

3. DSI overview – description of the systems being (or proposed to be) developed,

4. Energy market projections from the National Energy Modeling System (NEMS)

   DSI TECHNOLOGIES ARE BEING MODELED IN NEMS BY SHIFTING THE LOAD PROFILES, REDUCING PEAK LOADS BY 20% IN SOME AREAS.

[23] The information in this package was compiled by staff of Oak Ridge National Laboratory, which is managed by UT-Battelle, LLC for the U.S. Department of Energy under contract DE-AC-05-00OR22725. The information is based *in part* on information provided by the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability. Although the information is thought to be accurate, there is no guarantee of its accuracy; and it does not necessarily represent the views of the Office of Electricity Delivery and Energy Reliability, the U.S. Department of Energy, UT-Battelle, or Oak Ridge National Laboratory.

1. Definitions

Reliability

The "reliability" of an electric power system is the degree to which it delivers power to consumers in the amount desired and within acceptable standards. The reliability of a system may be assessed with respect to its:

- Adequacy – The ability of the electric system to supply the aggregate electrical demand and energy requirements of consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements; and
- Operational Reliability[24] – The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

<u>Reliability Benefits of R&D</u>

The questions you answer will help us estimate the reliability benefits of the R&D. The "reliability benefits" of R&D are reliability-related cost reductions that can be attributed to new or improved technologies from the R&D. Specifically, reductions in any of the following costs are reliability benefits.

iv) <u>Outages</u>: Electrical outage costs reflect the frequency, duration, and magnitude (amount of power) of outages, the number and type of customers affected, mitigative measures (both supply and demand) that reduce the extent or effects of outages, the costs of these mitigative measures, and the costs of restoring service. Reductions in outage costs that can be attributed to improved technologies are of their reliability benefits.

v) <u>Power quality</u>: Power-quality disturbances are deviations from power being supplied as a sine wave with the amplitude and frequency given by national or system standards. Power-quality disturbances might affect the proper functioning of electronic and other sensitive equipment. Reductions in the costs of these disturbances that can be attributed to improved technologies are part of their reliability benefits.

vi) <u>Transmission congestion</u>: Transmission congestion costs are the difference between the cost of delivering electricity if there were no transmission constraints, which are the cause of the congestion, and the cost with the current (or anticipated) constrained system. Reductions in congestion costs that can be attributed to improved technologies are part of their reliability benefits.

[24] The North American Electric Reliability Council (NERC) formerly used the term "security," but recently changed to the use of "operational reliability" to reduce confusion among those outside the industry, who might think of "security" as being "homeland security" or "energy/oil security."

Costs of Outages, Power Quality Disturbances, and Transmission Congestion

Though interrelated elements of reliability, outages, power-quality disturbances, and congestion comprise three separate cost components.[25] There are no "official" estimates of their costs.

Previous estimates of current (not projected) costs are generally in the following range:

- Annual cost of outages in the U.S. – $22 billion to $135 billion
- Annual cost of power quality disturbances in the U.S. – $6 billion to $34 billion
- Annual cost of transmission congestion in the U.S. -- $150 million to $2.6 billion

These estimates are in year 2001 dollars. The estimates range considerably and, indeed, actual costs will vary considerably from year to year depending on the number and severity of outages, frequency of power quality disturbances, and amount of transmission congestion. Notwithstanding these variations, these estimates provide a reasonable order of magnitude of the *current* costs (in year 2001 dollars). *Future* costs could increase significantly or even decrease depending on changes in generation capacity, demand for electric power, transmission capacity, and improvements in technology.

Energy System Infrastructure Security

The (in)security of energy system infrastructure refers to its vulnerability to highly disruptive catastrophic events, and to the system's ability to respond and recover in such an event. Infrastructure includes both physical and cyber systems.

Energy System Infrastructure Security – Benefits of R&D

The questions you answer will help us gauge the energy system infrastructure security benefits of R&D ("security benefits"). The security benefits of R&D are improvements in the security-related state of the U.S. energy system infrastructure that can be attributed to new or improved technologies from the R&D.

The following three elements are used to describe the state of the infrastructure:

a) Vulnerability to attack or destruction: Vulnerability refers to the likelihood of a catastrophic event on a system. Catastrophic events include major terrorist attacks, cyber attacks, and major natural disasters. Vulnerability encompasses the likelihood of an event; the likelihood that an attack is successful; and the magnitude of the damage to the system. Reductions in vulnerability that can be attributed to new or improved technologies are an indicator of their security benefits.

[25] Electricity reliability standards and other system requirements dictate that an adequate level of reserves, both real and reactive, be maintained to ensure operational reliability. Reductions in the costs of providing these reserves, including any reduction in the level of reserves required for operational reliability, are classified as system efficiency benefits and *not* as reliability benefits.

b) Supply response: The ability of a system to respond and recover in a catastrophic event improves its security. Such capabilities could include providing stored energy, limiting the extent of damage, isolating part of the system from damage, or rapidly repairing infrastructure. Reductions in damages from what they would have been without these capabilities are an indicator of their security benefits.

c) Demand conditions and response: Changes in demand (load profiles) in a system prior to any event can reduce the extent of damage should an event occur. Also, the ability of a system to rapidly adjust demand can reduce the likelihood of cascading failures elsewhere in the system. Reductions in damages from what they would have been without these prior changes and without these demand-response capabilities are an indicator of their security benefits.

Costs of Catastrophic Events

Catastrophic events are very low probability but extremely high impact. Their immediate damages are in the billions of dollars, but their overall impacts are more far reaching. In this analysis, we do not attempt to attach dollar values to energy system infrastructure security. Instead, we will use the estimated reductions in vulnerability and damage that can be attributed to technological improvements as indicators of their benefits.

2. DSI Program Metric – A Summary of the Key Program Goals

Program: Distributed Systems Integration (DSI)

Funding: ***$xx*** million per year beginning in FY2008 to FY2015

Timeframe: Improvements achieved in 2015, relative to the year 2006

Program Description: This program is developing distribution system designs that will employ distributed energy technologies. These designs will be targeted specifically at reducing peak demands on feeder equipment components that would otherwise be subject to near-term replacement or expansion. The designs will address the issue of optimal distributed energy location and sizing relative to the circuit elements and loads, The optimal design will also be a function of the load mix, temporal consumption patterns, and size. The designs will take advantage of both the real and reactive power capabilities of DSI technologies. Multiple feeders will be identified with near-term load growth projections beyond their existing capacity. Working in concert with utility partners, multiple candidate sites will be selected. Detailed economic and technical evaluations will be made to compare the traditional circuit expansion options to the DSI-enhanced circuit design. Based on these evaluations, demonstration sites will be selected and DSI equipment installed. The DSI designs are expected to offer significant advantages relative to the traditional circuit expansion by means of their modular sizing, expeditious installation times, and controllability (this program element will complement the visualization and controls efforts). Specifically, it is expected that the controllable injection of real and reactive power at the feeder level will reduce local system loading by at least 20% and will reduce line losses at both the feeder and transmission levels.

Long-Term Goals: Demonstrate peak load reduction on distribution feeders with the implementation of distributed energy (DE) and energy management systems (EMS) at a cost competitive with a system/capacity upgrades (i.e., cost not to exceed $1,600 per kW in 2001 dollars).

	2008 – Baseline	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Percent reduction in peak load	0%	5%	10%	10%	15%	15%	15%	20%
Number of feeders analyzed/ demonstrated	0	1	2	2	1	2	2	1

Anticipated Outcomes: The system designs and demonstrations will lead to utility acceptance of DSI alternatives to circuit expansion. The use of these technologies will have several benefits: (a) energy efficiency, for example by reducing losses of electricity from transmission lines; (b) system efficiencies due to reduced loading and temperatures on substation equipment and wires; (c) improved reliability such as reduced outages due to the local availability of emergency power, and (d) greater energy infrastructure security, for example by reducing the extent of the transmission network at risk to terrorists.

Program: Distributed Systems Integration (DSI)
Rationale for Government Investment: The Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations includes specific recommendations that DOE expand its research programs on reliability related tools, and specifically calls for a study of obstacles to the economic deployment of demand response capability and distributed generation. The integration of distributed energy into feeder system design – DSI – represents a relative new concept and uncertain solution for the utility industry. The evolving and uncertain regulatory environment for all electric utilities makes it difficult for companies to justify costly investment in R&D into alternate system designs.

3. Distributed System Integration[26]

3.1 Program Overview

The DSI program plans to design, assess, and optimize integrated systems that use distributed energy technologies to reduce peak loads and to otherwise optimize distribution. The objective is to best utilize distributed energy technologies and designs such as microgrids to improve local and system reliability and infrastructure security.

The focus of the program is to be on the feeder-level application and benefits of integrated distributed generation and energy management systems. For example, one major thrust will be to assess the load/customer distribution on the feeder and the expected load growth, and to then select the optimal mix and integration of distributed generation equipment to serve those needs.

This equipment could include reciprocating engines, microturbines, fuel cells, and photovoltaics, and energy storage devices. Control equipment, especially control equipment designed to provide voltage support from the distributed generation unit, will also be tested (if a willing utility partner can be found). Monitoring equipment will be used to evaluate the impact of the distributed generation unit on local power quality and reliability. Other aspects of DSI, such as fuel flexibility or emissions control, might be included in the evaluation if appropriate customers are located on the selected feeders.

In summary, emphasis will be on systems design and integration of distributed generation and energy management technologies, and on the evaluation and optimization of these designs to best suit different situations.

3.2 Current Situation and the Motivation for Investment in Research, Development, Deployment, and Demonstration

Our nation's ability to deliver secure and reliable electricity is severely challenged by an aging electricity transmission and distribution system (the grid). The majority of the power delivery system was built on technology developed in the 1960s, 70s and 80s and is limited by the speed in which it can respond to disturbances. This limitation increases the vulnerability of the power system to a higher number of and greater spread of long-term outages. Slower response requires higher operating margins and causes greater system constraints, which results in higher costs that are passed on to consumers.

The current distribution system was designed and built to deliver peak electricity demand. This peak may be limited to just a few hours per year; nonetheless the system must be built to handle this peak. As load grows, utilities invest in new infrastructure to satisfy the new demand. Most utilities are regulated in a manner that encourages them to invest in new infrastructure, rather than to take actions that would encourage a reduction in demand. This

[26] This summary provides a broad description of the program, including its possible energy saving and environmental benefits. Panel members should *not* include energy savings and environmental benefits in their estimates of the reliability and energy system security impacts of the R&D program.

approach leads to economic inefficiencies. In recent years, there has been pressure on utilities to reduce costs. As a result, new distribution infrastructure has lagged investments in new infrastructure. Pockets of congestion, reduced reliability and high, volatile prices now exist throughout the country and are likely to continue without a technology solution.

3.3 Key Application of DSI Designs

Through the use of distributed energy and advanced energy management systems, the peak demand can be reduced on the distribution system. This reduction in peak demand will eliminate or defer the need for new transmission and distribution capacity, reduce congestion and decrease electricity prices and volatility. Dispersal of generation also increases reliability and reduced security vulnerabilities. The key technical barriers include low cost, communication and control that optimizes distributed energy resources (DER) with load. The practical use of distributed energy as a peak load reduction has been demonstrated in theory, but not in practice. Figure 1 illustrates this idea.

3.4 Technical Properties of Distributed Systems Integration Designs

Key technical attributes of DSI designs are that they provide:

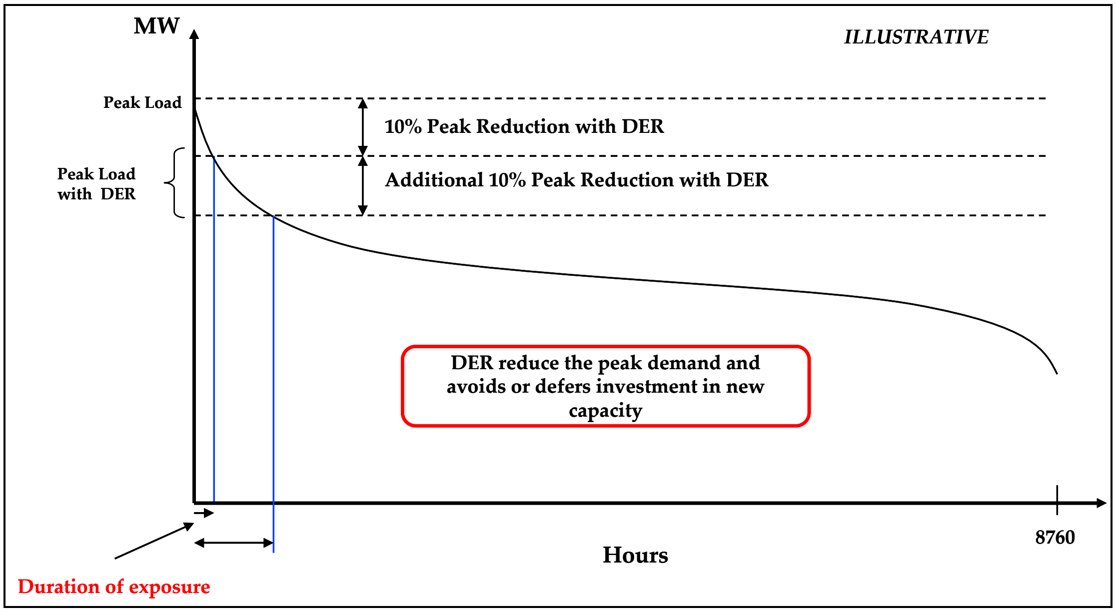
(1) Modularity: Load growth can be matched with right-sized installations. Traditional alternative utility expansion increments are, by their nature, “lumpy”, and lead to lower system utilization factors. This is especially valuable where growth rates are moderate to low.

(2) Efficiency: DSI, when used in a Combined Heat and Power system, can usefully harvest 70 to 85% of the energy present in the fuel. This should be compared to the ~30% efficiency for delivered central-station electricity.

(3) Active Control: An active power production system enables active control, unlike fixed resources such as wires, transformers, or capacity banks. The relative production of real and reactive power can be varied according to the dynamic system needs.

(4) Load Reduction: Local power provision reduces the loading on every upstream system component, including circuit lines, transformers, transmission lines, and generating plants. Local power can also be used as an emergency power supply.

Figure 1. Illustration of the Impact of Distributed Energy Resource on Peak Load



3.5 Technical Performance of the Next-Best Technology

(1) Voltage Support: The most commonly employed traditional technology for voltage support is the installation of capacity banks to inject reactive power and the most common control system for these capacitors is a simple time clock. The chief disadvantage of capacitors is their susceptibility to total voltage collapse because while the VAR needs increase with the square of the load, the capacitor effectiveness decreases with the square of the voltage. That is, the capacitors are at their lowest performance at those times when they are most needed.

(2) Meeting Local Load Growth: The traditional alternatives vary according to the rate of load growth and the local availability of alternative circuits. Where possible, large loads can be redirected onto other nearby circuits. This is often the lowest-cost option, but is usually a short-term solution. In the long run, the alternative is to install additional substation equipment and new feeder circuits. Depending on the topography and development state (i.e., urban vs. rural), the cost of such expansion can vary widely. Also, in the long term, additional transmission capacity will be required to serve the load growth, even if that additional capacity is only used 200-300 hours per year.

3.6 Market Potential

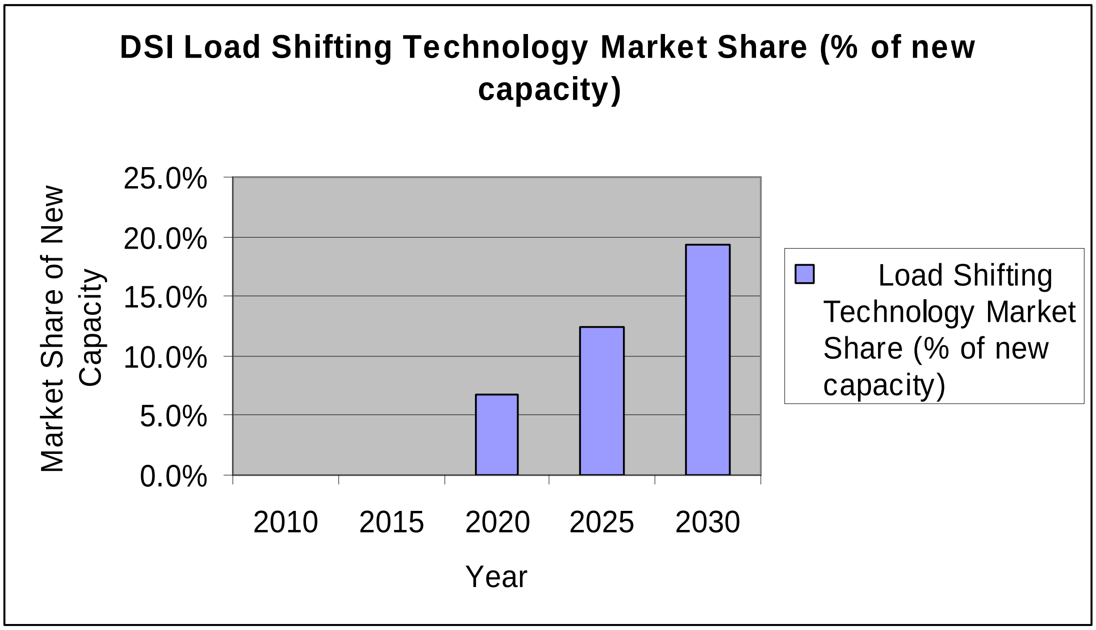
Previous work has shown that the cost of traditional circuit expansion options range from less than $100/kW to more than $1,200/kW. DE-augmented circuit expansion designs are expected to be especially attractive at those locations with higher alternative costs. The DE-integrated designs also offer values and capabilities unavailable with traditional expansion options, including reduced loads on upstream transmission lines and an element of active control to meet the needs of dynamic system conditions. The controlled injection of reactive power is expected to provide significant reduction in both transmission level and substation loads, thus offering an additional value stream.

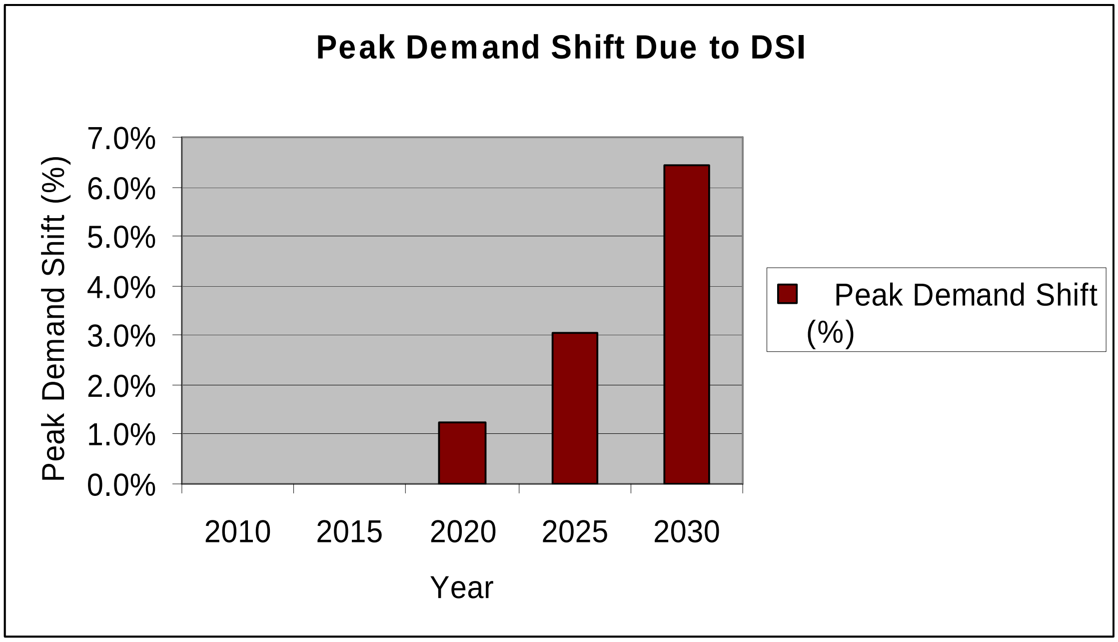
3.7 If There Were No DOE DSI Program

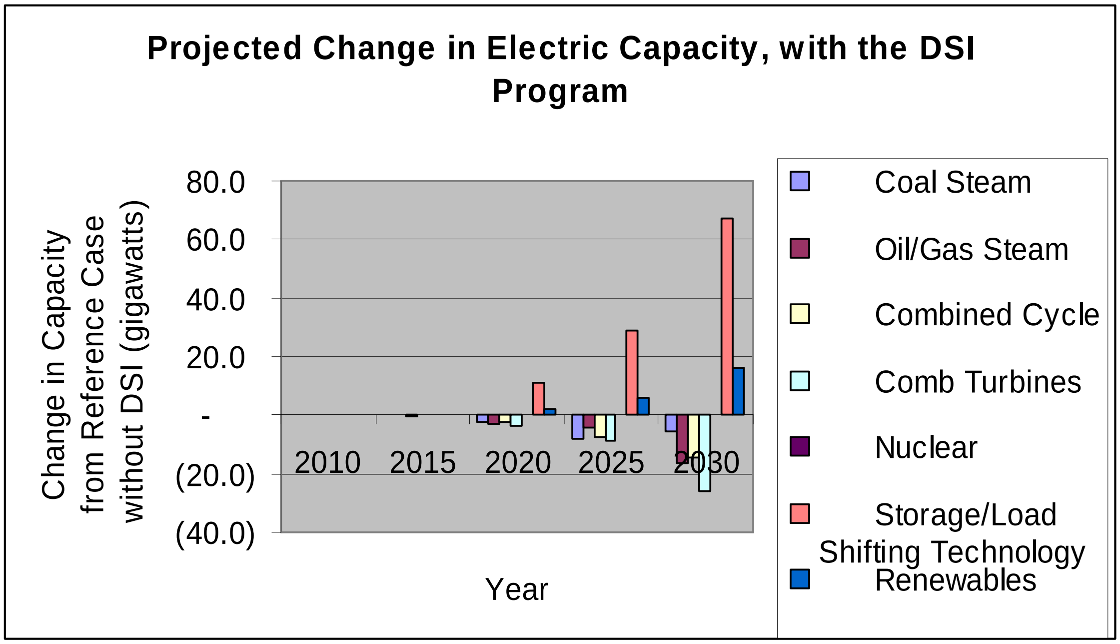
Considering the uncertain regulatory climate, prudent utilities will make only the minimum system investment necessary to serve short-term needs, and thus miss the opportunity to consider alternative distributed energy technologies with the long-term potential to improve system efficiency and reduce transmission constraints.

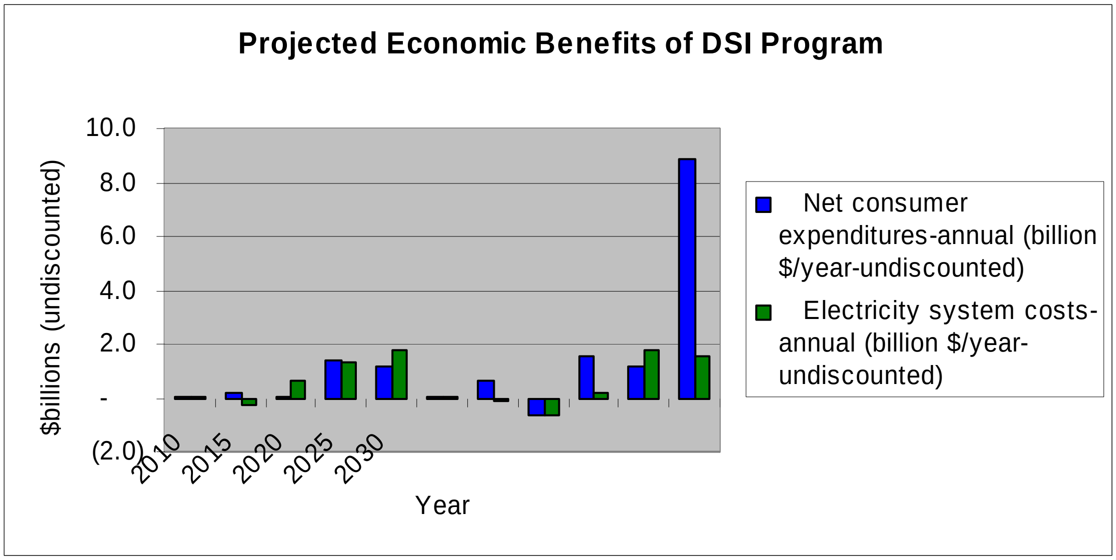
4. Energy Market Projections

The following projections were from the U.S. Department of Energy's National Energy Modeling System (NEMS), a large-scale integrated energy market model.




Peak Demand Shift Due to DSI
Peak Demand Shift (%)
7.0%
6.0%
5.0%
4.0%
3.0%
2.0%
1.0%
0.0%
2010
2015
2020
2025
2030
Year
Peak Demand Shift (%)


Projected Change in Electric Capacity, with the DSI Program
Change in Capacity from Reference Case without DSI (gigawatts)
80.0
60.0
40.0
20.0
-
(20.0)
(40.0)
2010
2015
2020
2025
2030
Year
Coal Steam
Oil/Gas Steam
Combined Cycle
Comb Turbines
Nuclear
Storage/Load Shifting Technology
Renewables


Projected Economic Benefits of DSI Program
10.0
8.0
6.0
4.0
2.0
-
(2.0)
$billions (undiscounted)
2010
2015
2020
2025
2030
Year
Net consumer expenditures-annual (billion $/year-undiscounted)
Electricity system costs-annual (billion $/year-undiscounted)

Appendix C-2

Information Package
For Use by

The National Panel on Estimating the Electricity Reliability and Security Benefits of the U.S. Department of Energy's High Temperature Superconductivity R&D Program

Information Package
For Use by

The National Panel on Estimating the Electricity Reliability and Security Benefits of the U.S. Department of Energy's High Temperature Superconductivity R&D Program[27]

This package provides information and market projections that serve as reference material for panel members who are estimating the electricity reliability and energy infrastructure security benefits of technologies anticipated from the High Temperature Superconductivity (HTS) R&D program in the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability.

It is important for panel members to refer to this information so that all members base their estimates on the same set of assumptions and projections.

The information in this package is as follows:

5. Definitions for electricity reliability and security of energy system infrastructure.

6. HTS program metric – major technical goal(s) of the program, including a brief description of the program, and its expected outputs and outcomes,

7. HTS technology overview – description of the technologies being (or proposed to be) developed,

8. HTS market projections

PLEASE USE THESE PROJECTIONS, EVEN THOUGH YOUR OWN MIGHT DIFFER, SO THAT ALL PANELISTS BASE THEIR ESTIMATES ON THIS SET OF PROJECTIONS.

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[27] The information in this package was compiled by staff of Oak Ridge National Laboratory, which is managed by UT-Battelle, LLC for the U.S. Department of Energy under contract DE-AC-05-00OR22725. The information is based *in part* on information provided by the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability. Although the information is thought to be accurate, there is no guarantee of its accuracy; and this information does not necessarily represent the views of the Office of Electricity Delivery and Energy Reliability, the U.S. Department of Energy, UT-Battelle, or Oak Ridge National Laboratory.

1. Definitions

Reliability

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- Adequacy – The ability of the electric system to supply the aggregate electrical demand and energy requirements of consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements; and
- Operational Reliability[28] – The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

<u>Reliability Benefits of R&D</u>

The questions you answer will help us estimate the reliability benefits of the R&D. The "reliability benefits" of R&D are reliability-related cost reductions that can be attributed to new or improved technologies from the R&D. Specifically, reductions in any of the following costs are reliability benefits.

vii) <u>Outages</u>: Electrical outage costs reflect the frequency, duration, and magnitude (amount of power) of outages, the number and type of customers affected, mitigative measures (both supply and demand) that reduce the extent or effects of outages, the costs of these mitigative measures, and the costs of restoring service. Reductions in outage costs that can be attributed to improved technologies are of their reliability benefits.

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ix) <u>Transmission congestion</u>: If differences in the delivered prices of electricity between regions are greater than the cost of operating the transmission system (or acquiring transmission services) plus the value of electricity loss from transmission lines, then there is transmission congestion along the path between these regions. Transmission congestion costs are the difference between the cost of delivering electricity if there were no transmission constraints, which are the cause of the congestion, and the cost with the current (or anticipated) constrained system. Reductions in congestion costs that can be attributed to improved technologies are part of their reliability benefits.

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Costs of Outages, Power Quality Disturbances, and Transmission Congestion

Though interrelated elements of reliability, outages, power-quality disturbances, and congestion comprise three separate cost components.[29] There are no "official" estimates of their costs.

The range of previous estimates of current (not projected) costs are in the following range:

- Annual cost of outages in the U.S. – $22 billion to $135 billion
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The (in)security of energy system infrastructure refers to its vulnerability to highly disruptive catastrophic events, and to the system's ability to respond and recover in such an event. Infrastructure includes both physical and cyber systems.

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Costs of Catastrophic Events

Catastrophic events are very low probability but extremely high impact. Their immediate damages are in the billions of dollars, but their overall impacts are more far reaching. In this analysis, we do not attempt to attach dollar values to energy system infrastructure security. Instead, we will use the estimated reductions in vulnerability and damage that can be attributed to technological improvements as indicators of their benefits.

2. HTS Program Metric – A Summary of the Key Program Goals and Anticipated Outcomes

Program: High Temperature Superconductivity (HTS)

Funding Request: $60 million per year beginning in FY2008 to FY2016

Timeframe: Improvements achieved in 2016, relative to the year 2006

Program Summary:
This program is developing superconducting ceramic products able to conduct very large quantities of electrical current with virtually zero resistance. These new materials have superconducting properties at temperatures of 77K, an achievable temperature. The goals of the program are to develop materials with improved properties, exploit those breakthroughs through the Second Generation Wire Initiative, develop prototype equipment and carry out demonstration projects, as well as develop test beds for these and other novel power technologies in an off-grid setting through the Power Delivery Research Initiative . The technical achievement will lead to commercially available equipment incorporating HTS technologies – (e.g., low-loss power cables, ~ 250 MVA HTS generators, 5,000 to 10,000 hp HTS motors). The added cost of using HTS material is expected to be well below the anticipated savings in energy loss reduction, increased efficiency and improved reliability. Specifically, it is expected that the saving on conductor cost may be between 1/3 to 2/3 by replacing conventional copper wires with high performance HTS conductors (on a kA-m basis).

Long-Term Goals: By 2016, reduce the footprint for new T&D infrastructure and reduce energy losses through the use of high-temperature superconducting wire.

1) HTS Wire: By 2020, develop prototype wire achieving 1,000,000 critical current- length (A-m) for second generation wire

	2005 – Baseline	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2014**	**2015**	**2020**
Critical Current-Length (A-m)	22,149 (107A x 207m)	30,000	40,000	50,000	50,000	70,000	70,000	100,000	500,000	800,000	1,000,000

2) HTS Coils: Maintain progress in achieving increasingly powerful coils for electric power applications such as transformers and generators: measured by magnetic field (Tesla) produced by test coil at a temperature of 65K

	2005 – Baseline	**2006**	**2007**	**2008**	**2009**	**2010**	**2012**	**2014**
Magnetic field (Tesla at 65K)	0.3	0.3	1.0	1.0	2.0	2.0	3.0	5.0

Anticipated Outcomes:
The technologies, test bed development, and demonstrations will lead to commercially available transformers, electric motors, generators, fault current limiters, and underground power cables made of HTS materials. The use of these technologies will have several benefits: (a) energy

Program: High Temperature Superconductivity (HTS)
efficiency, for example by reducing losses of electricity from transmission lines; (b) system efficiencies due to cables that have much greater carrying capacity; (c) improved reliability such as reduced outages due to the enhanced carrying capacity of transmission lines; (d) greater energy infrastructure security, for example by reducing the extent of the transmission network at risk to terrorists; and (e) environmental benefits such as reduced oil disposal concerns because of less use of oil in motors.
Rationale for Government Investment: The National Energy Policy Report to the President in 2001 cites the importance of HTS technology. However, HTS R&D is long-term and high risk. The payoffs are uncertain and, if realized, accrue over a long time horizon, making it difficult for the private sector to embark on these activities alone. The evolving and uncertain regulatory environment for electricity transmission markets makes it difficult for companies to justify costly investments in transmission-technology R&D.

3. HTS Technology Overview[30]

When electrical current flows through conventional conductors such as copper wires, energy is lost in the form of resistive heat. On the other hand, superconductors have the ability to conduct electricity without the loss of energy. This unique property makes superconductors attractive as the material to power our economy for this new century.

3.1 Current Situation and the Motivation for R&D

Our nation's ability to deliver secure and reliable electricity is severely challenged by an aging electricity transmission and distribution system (the grid). The majority of the power delivery system was built on technology developed in the 1960s, 70s and 80s and is limited by the speed in which it can respond to disturbances. This limitation increases the vulnerability of the power system to a higher number of and greater spread of long-term outages. Slower response requires higher operating margins and causes greater system constraints, which results in higher costs that are passed on to consumers.

The current distribution system is built to deliver the peak electricity demand. This peak may be limited to just a few hours per year; nonetheless the system must be built to handle this peak. This approach has led to pockets of grid congestion and exposes customers to high, volatile prices. While overall electricity efficiency (from generation to consumption) has steadily improved over the past two decades, little improvement has been made in reducing the energy losses in the T&D system. These losses increase dramatically as the system becomes more constrained.

Major reliability events and increased congestion in major transmission corridors and local distribution systems are costing the United States billions of dollars each year and jeopardize the safety and well-being of millions of Americans and U.S. industry. In addition, the grid is becoming increasingly vulnerable to disruption due to the escalating risk attacks. Because the electric grid provides the backbone for many critical infrastructures such as telecommunications, transportation, health care, and banking and finance, any disruption can have major consequences to the economy and public health and safety.

New transmission improvements are needed to maintain reliability, to ensure security, and to drive down electricity costs to consumers. Roadblocks to investing more in infrastructure have allowed infrastructure to age and become more constrained. First, regulatory uncertainty has prevented the private sector from investing in some transmission projects. Second, siting and permitting concerns slow or prevent new transmission lines from being built. Both these roadblocks drive up the costs of new infrastructure, which is ultimately passed on to consumers.

Through state-of-the-art technology and equipment enhancements**,** the capability of the transmission system can be significantly improved, affecting the performance and reliable

[30] This summary provides a broad description of the program, including its possible energy saving and environmental benefits. Panel members should *not* include energy savings and environmental benefits in their estimates of the reliability and energy system security impacts of the R&D program.

operation of the entire electricity system. This approach requires upfront investment in research and development.

3.2 Key Power Applications for HTS

HTS technology development is targeted primarily at four major applications:

- Motors greater than 500 horsepower
- Generators greater than 100 MVA
- Transformers greater than 20 MVA
- Transmission cable at intermediate- and distribution-level voltages.

Initial use of equipment based on superconductivity in the electric grid began in 2005 with the installation of 2 SuperVAR units – a type of superconducting generator – on the Tennessee Valley Authority's system to improve reliability. However, widespread use will happen gradually over the long-term with reliability improvements being a principal driver as was the case for TVA.

The U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability (OE) has been leading the national effort in this technology and has demonstrated the use of HTS cables in reliably delivering electrical service to three factories since 2000. Advanced superconducting cable designs will begin operation during FY 2006-2007 in the electric grids of three major utilities. In addition, other enabling power devices such as fault current limiters and energy storage units (e.g., superconducting magnetic energy storage (SMES), flywheels) may also benefit from HTS technology.

The FY 2008 base program will focus on second generation (2G) wire improvement as well as on developing coils needed for transformers, generators and other power equipment using 2G wire.

3.3 Technology Attributes

The high temperature superconducting (HTS) wire currently under development is the so-called second generation $YBa_2Cu_3O_x$ (YBCO) coated conductor. Compared to the first generation power-in-tube $(Bi,Pb)_2Sr_2Ca_2Cu_3O_x$ (BSCCO) wire, 2G conductors posses intrinsically superior performance at high temperatures and high fields, as well as offer the potential of lower manufacturing cost. Due to the proprietary nature of system cost and market potential of various applications, few information is available in open literature. As a result, information presented in this background supplement is based largely on "Analysis of Future Prices and Markets for High Temperature Superconductors" by J. Mulholland, T.P. Sheahen and B. McConnell [1] available at http://www.ornl.gov/sci/htsc/documents/pdf/Mulholland%20Report%20063003.pdf. Updated public information regarding specific application is included where appropriate. Widespread utilization of this technology in transmission and distribution power devices and systems could result in significant benefits to the national energy usage and security as well as the environment.

3.4 Technology Benefits

Superconducting power equipment has the potential to become a key 21st century technology for improving (a) reliability, (b) efficiency, and (c) reduced pollutant emissions.

(a) Increase in energy capacity and reliability: The most useful property of a 2G HTS wire is its high (engineering) current density. This translates to smaller size and weight of systems such as motors, generators and transformers. For the transmission grid, HTS technology could be used to form the backbone of a controllable very low impedance AC transmission network. In addition, this technology might also be used in very high power DC cables. Due to its lossless property, an HTS DC cable might carry 10x to 100x greater current than conventional Cu or Al cables. For fixed power in the range of 20 – 500 MVA, this allows the DC voltage to be reduced from 100-150 kV to 10's of kV. This can simplify the converter station, reduce its volume and cost, and increase the reliability of the network.

(b) Increase in energy savings: With reduced loss, substantial savings could be realized in the transmission and distribution of electrical power from the power plants to the consumers. Potential savings calculated in Ref [1] are benchmarked against 1999 values, and are listed in Table 1 for the four major applications. While the time horizon and amount of expected savings may vary due to the evolving 2G technology since the completion of this analysis in 2003, the fact that substantial energy savings may be possible through broad market penetration of the HTS technology remains unchanged.

Table 1. HTS Energy Savings (GWh)

Year	Motors	Transformers	Generators	Cables	Total
2009	0	0	2	1	3
2011	0	0	11	3	14
2013	1	0	44	13	58
2015	4	0	170	55	230
2017	15	2	556	200	770
2019	57	15	1,400	600	2,900
2021	150	94	2,700	1,300	4,300
2023	300	450	4,200	2,300	7,200
2025	470	1,200	5,800	3,300	11,000

(c) Decrease in pollutant emissions: Table 2 lists the projected reductions in carbon emissions (greenhouse gases), and in SO_x and NO_x. These projections correspond to the projected reductions in energy use listed in Table 1 (source: Ref [1]).

Table 2. Emission Reductions Attributable to HTS Devices

Year	Energy savings (GWh)	Carbon reduction (metric tons)	SO_x reduction (metric tons)	NO_x reduction (metric tons)
2009	3	490	6	3
2011	14	2,300	29	13
2013	58	9,200	110	52
2015	230	36,000	430	200
2017	770	121,000	1,400	660
2019	2,900	320,000	3,600	1,700
2021	4,300	660,000	7,100	3,500
2023	7,200	1,100,000	12,000	5,800
2025	11,000	1,600,000	16,900	8,400

3.5 Cost of HTS Component Relative to the Total Cost of the System

Conductor performance greatly influences the system design, and therefore the system cost. As such, the information is highly proprietary and system specific. Hence, any "prediction" of HTS component cost from persons other than the system manufacturer is highly speculative at best. However, one fact remains certain. HTS wire cost must be low to be competitive with conventional copper technology, and be a small fraction of the total cost of a system. In addition, for applications such as HTS cable, it was pointed out by a leading cable manufacturer that the definition of "system" might be expanding to include much broader materials/activities; the cost components being cable: 20%, other materials: 10%, cable access/installation: 20%, and civil works: 50%.

3.6 Size of Potential Market

Table 3 lists the potential market of the four major applications as estimated in Ref [1]. Recent information from a major motors manufacturer suggests that the worldwide potential market for HTS motors > 1,000 horsepower to be roughly $1 billion annually. Also, U.S. medium-power transformer market, which is addressable by HTS technology, is roughly 1,300 units annually. In addition, information provided by a leading cable manufacturer showed that the North American cable market for 2005 to be approximately $1 billion (installed system), of which $700 million may be addressable by the HTS cable (system) technology.

Table 3. Projected Market for HTS Devices (thousands of Dollars)

Year	Motors	Transformers	Generators	Cables	Total
2011	230	0	6,900	4,100	11,000
2013	960	0	25,000	14,000	40,000
2015	4,000	240	84,000	48,000	136,000
2017	15,000	1,500	230,000	140,000	380,000
2019	51,000	9,400	450,000	320,000	820,000
2021	110,000	56,000	590,000	490,000	1,200,000
2023	150,000	220,000	660,000	570,000	1,600,000
2025	160,000	390,000	680,000	590,000	1,800,000

4. Energy Market Projections

PLEASE USE THESE PROJECTIONS IF THEY ARE RELEVANT TO WHAT YOU ARE ESTIMATING.

In a recent National Energy Modeling System (NEMS) update for HTS technology, the inputs from various potential HTS device manufactures clearly showed that significant delay in market penetration as well as reduction in energy differential will occur if no R&D support is available from DOE (refer to the following graphs).

Figure M-1. Projected Market Penetration of HTS Large-Motors – Percentage of New Additions and Existing Replacements, With and Without the DOE R&D Program

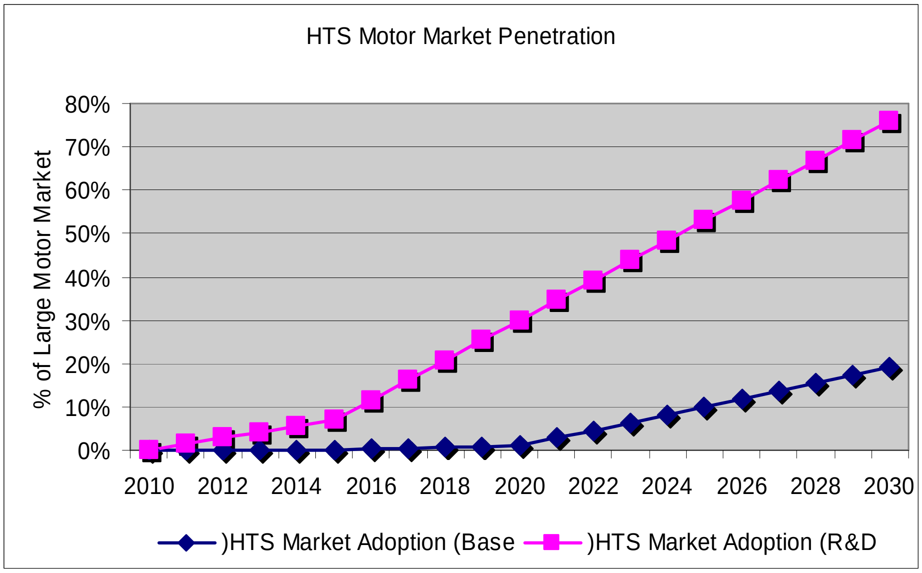


Figure M-2. Projected Market Penetration of HTS Large-Motors – Percentage of All Equipment in the Field, With and Without the DOE R&D Program

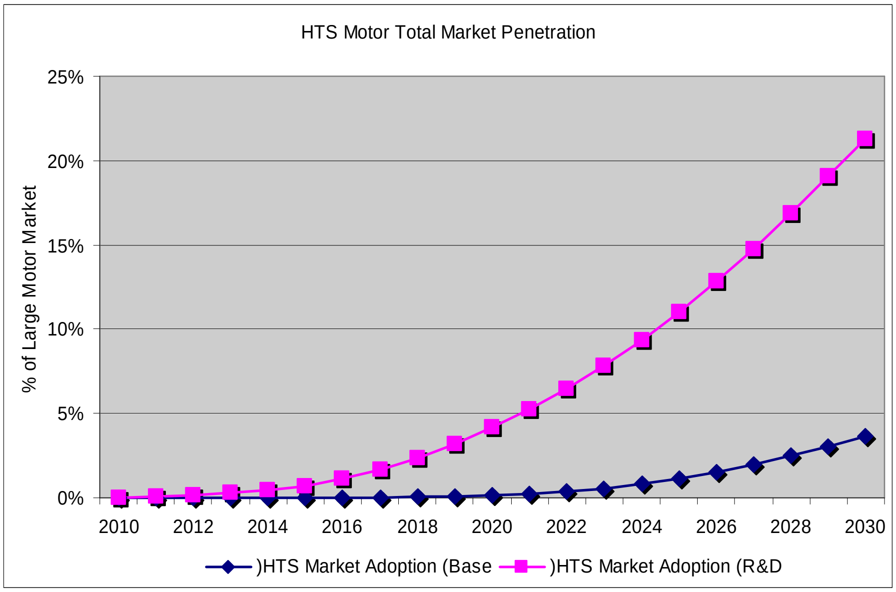


Figure M-3. Projected Efficiency Differential of HTS Large-Motors, With and Without the DOE R&D Program

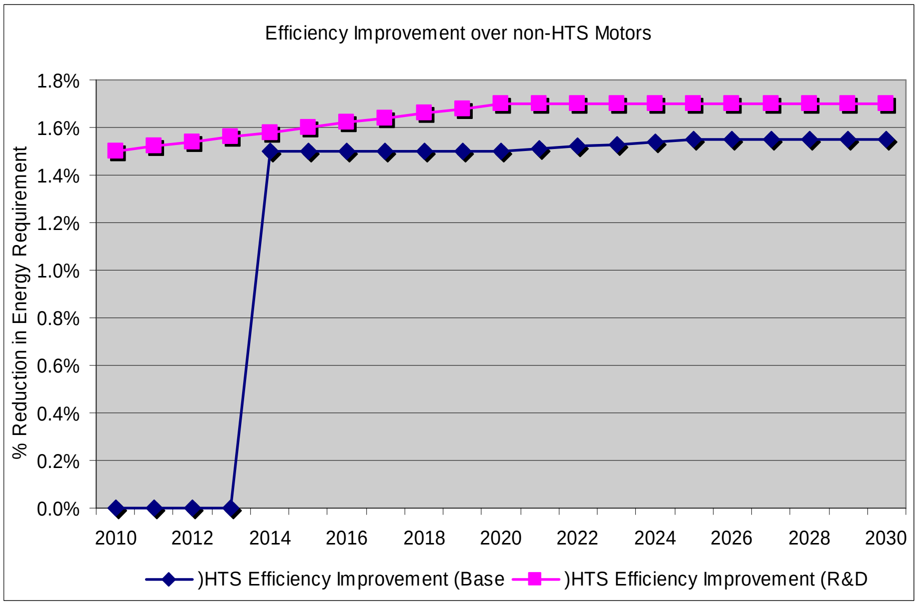


Figure M-4. Projected Cost Differential of HTS Large-Motors, With and Without the DOE R&D Program

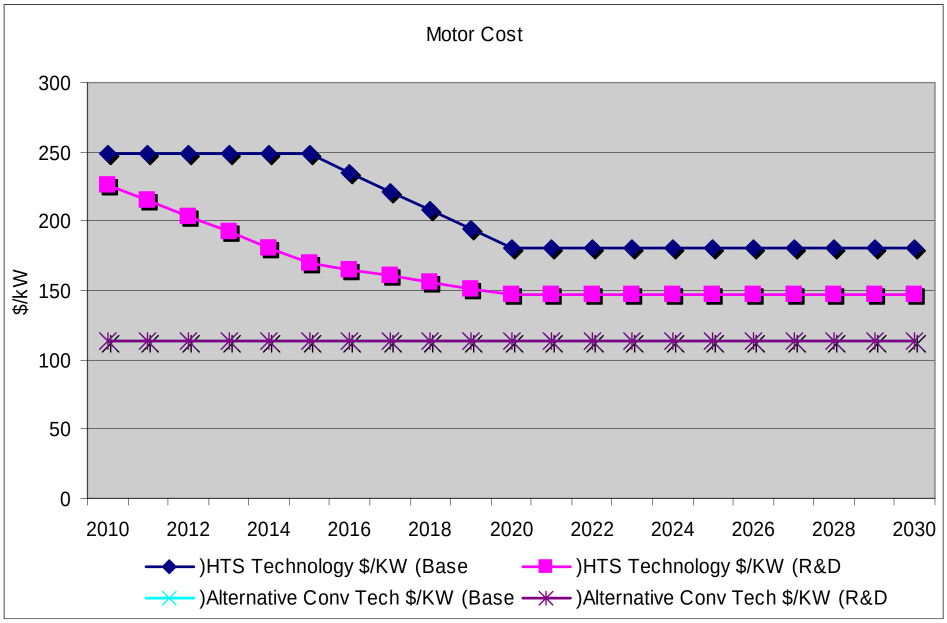


Figure T-1. Projected Market Penetration of HTS Transformers – Percentage of New Additions and Existing Replacements, With and Without the DOE R&D Program

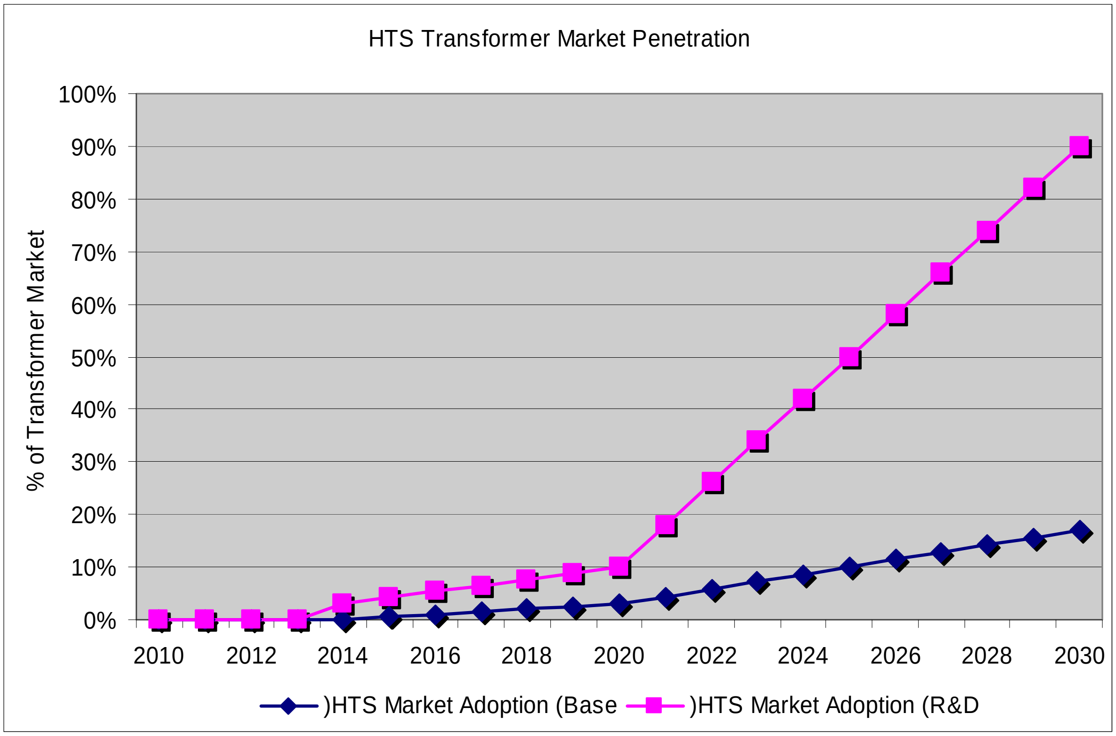


Figure T-2. Projected Market Penetration of HTS Transformers – Percentage of All Equipment in the Field, With and Without the DOE R&D Program

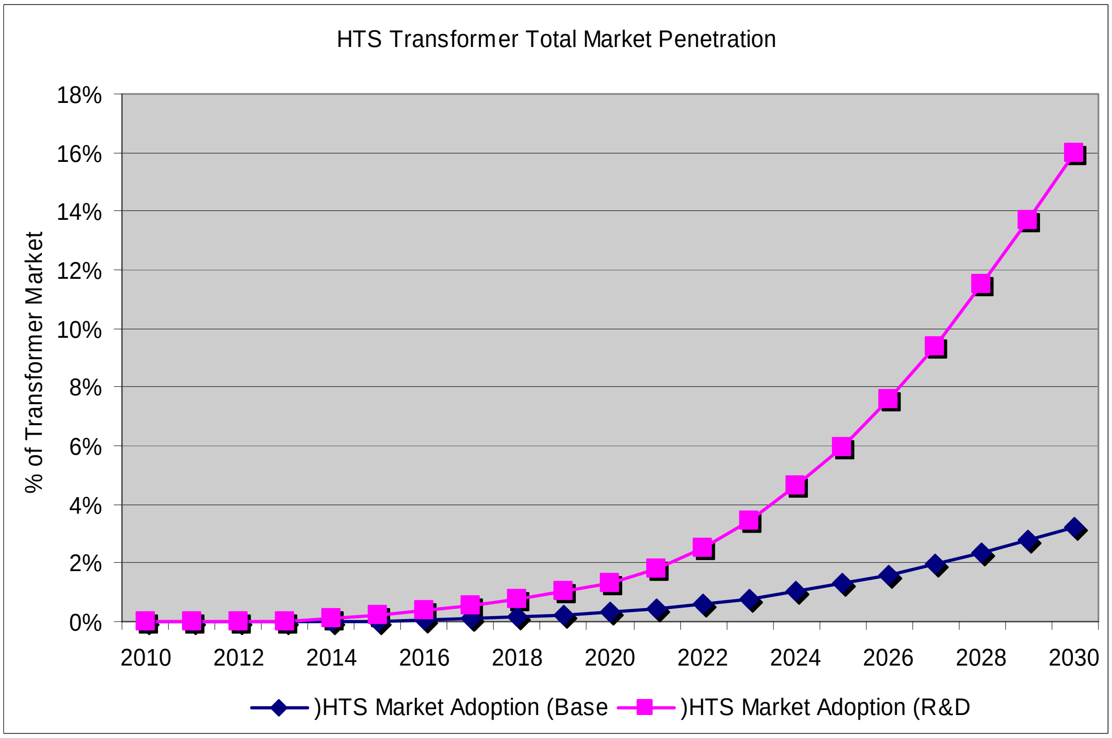


Figure T-3. Projected Efficiency Differential of HTS Transformers, With and Without the DOE R&D Program

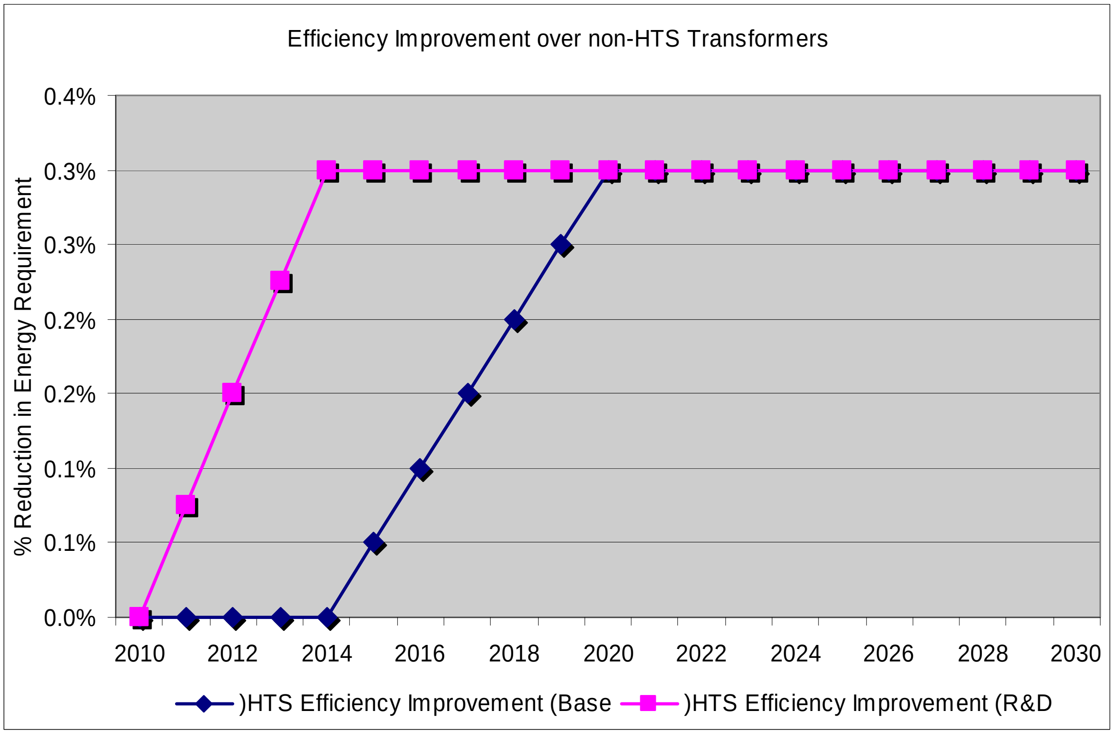


Figure T-4. Projected Cost Differential of HTS Transformers, With and Without the DOE R&D Program

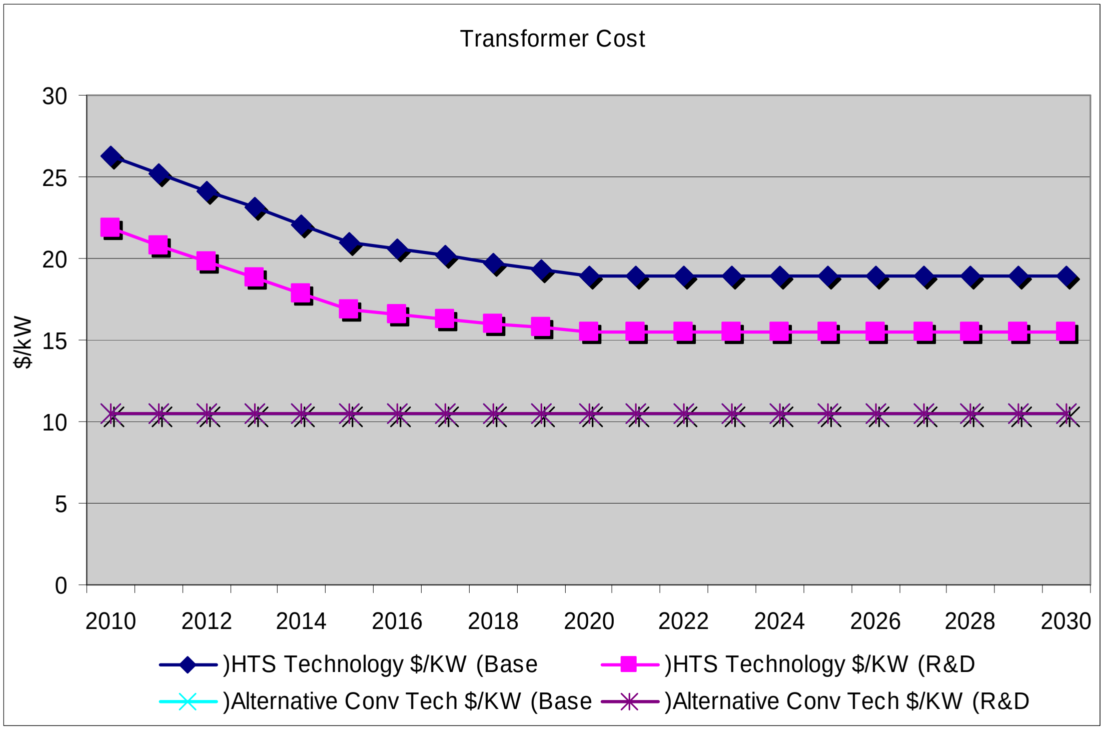


Figure G-1. Projected Market Penetration of HTS Generators – Percentage of New Additions and Existing Replacements, With and Without the DOE R&D Program

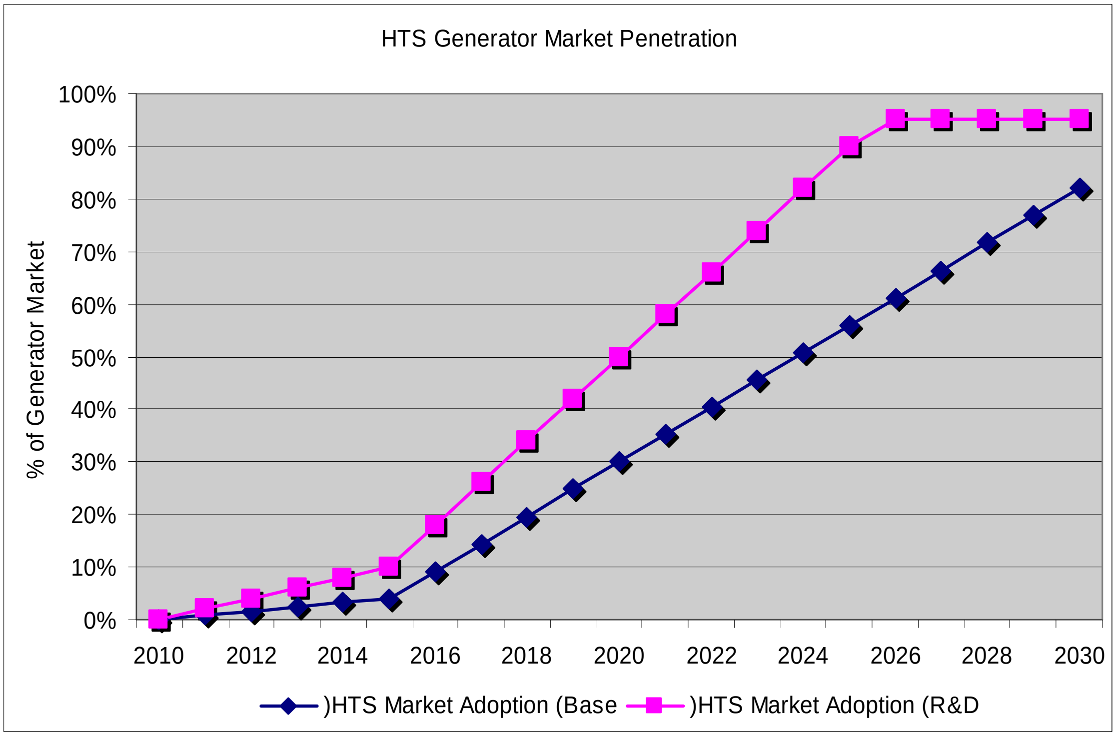


Figure G-2. Projected Market Penetration of HTS Generators – Percentage of All Equipment in the Field, With and Without the DOE R&D Program

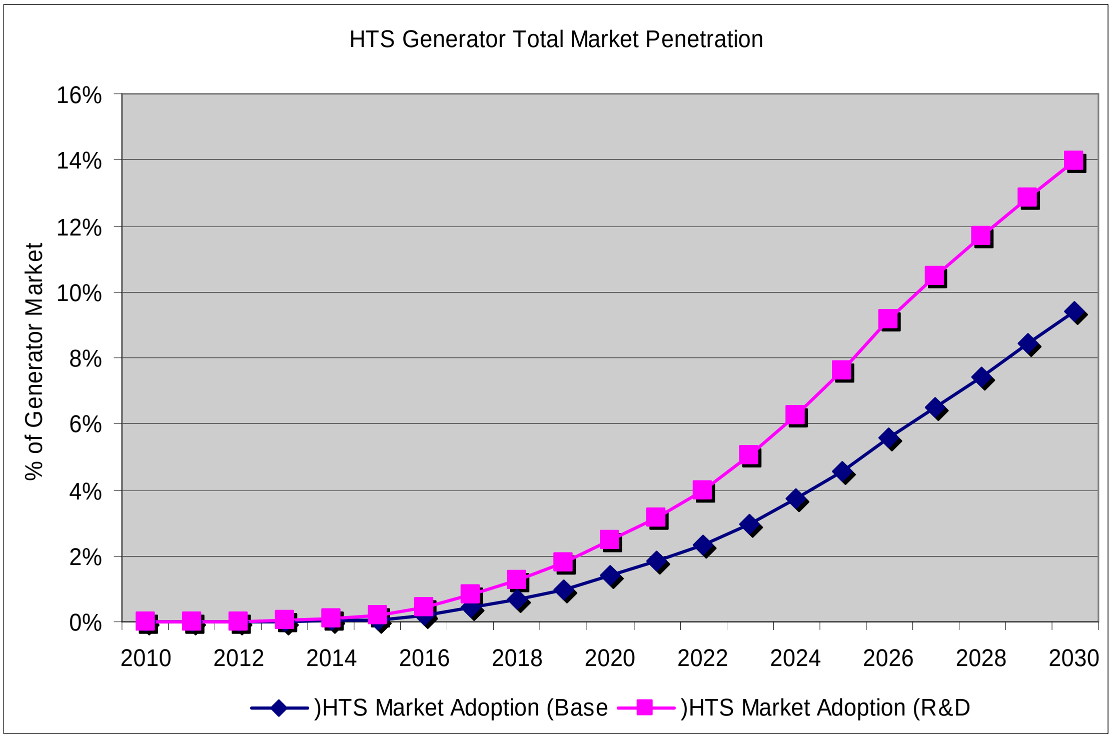


Figure G-3. Projected Efficiency Differential of HTS Generators, With and Without the DOE R&D Program

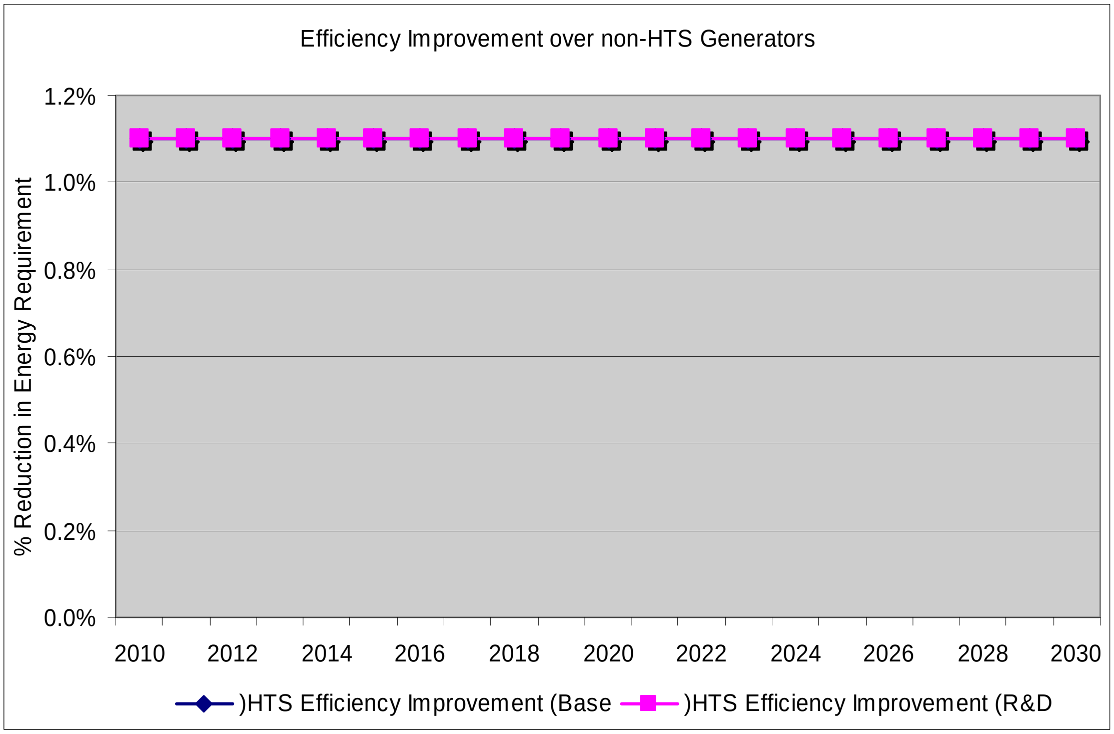


Figure G-4. Projected Cost Differential of HTS Generators, With and Without the DOE R&D Program

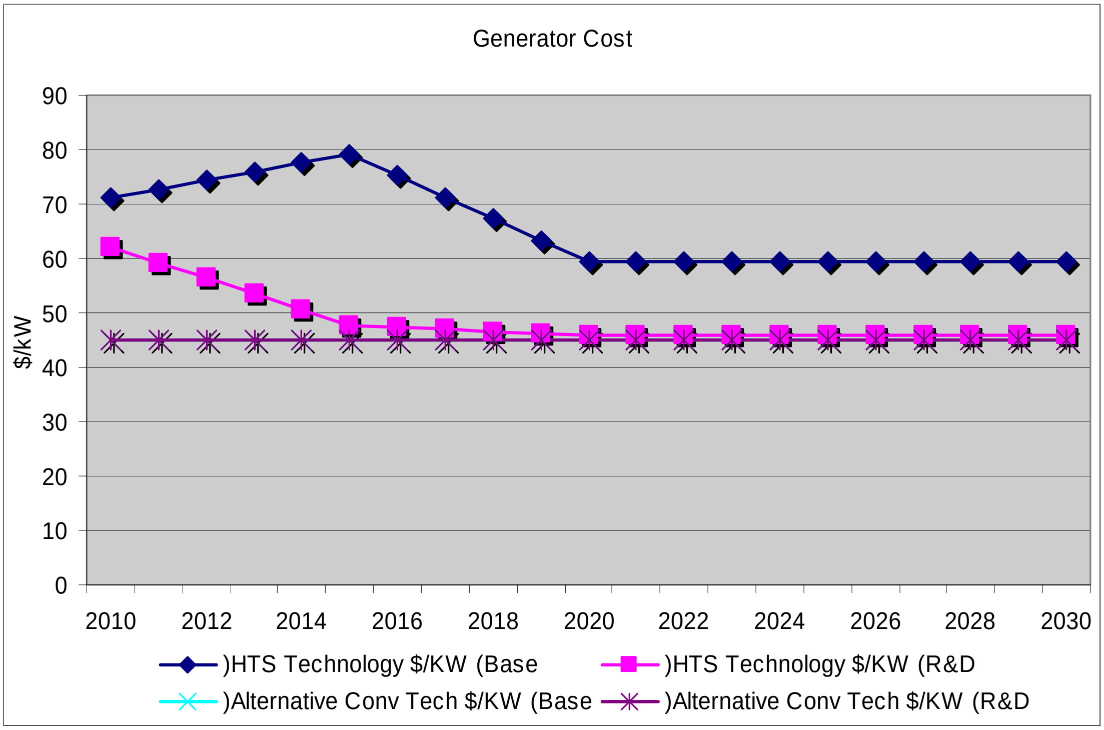


Figure C-1. Projected Market Penetration of HTS Cables – Percentage of New Additions and Existing Replacements, With and Without the DOE R&D Program

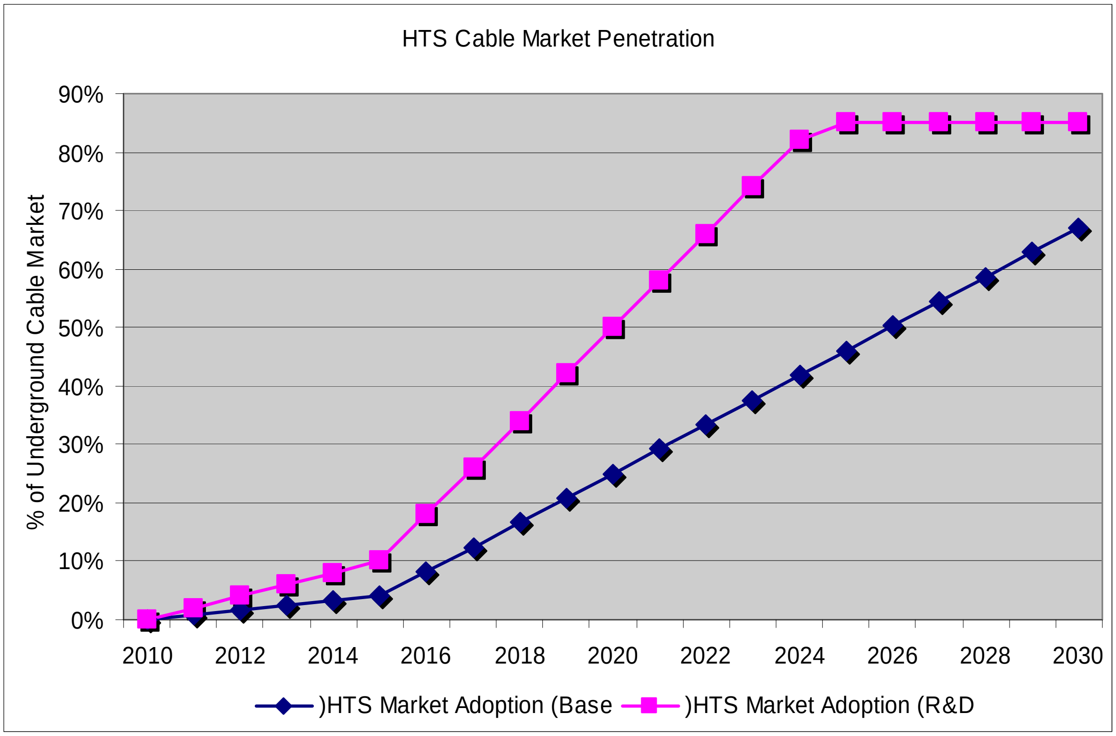


Figure C-2. Projected Market Penetration of HTS Cables – Percentage of All Equipment in the Field, With and Without the DOE R&D Program

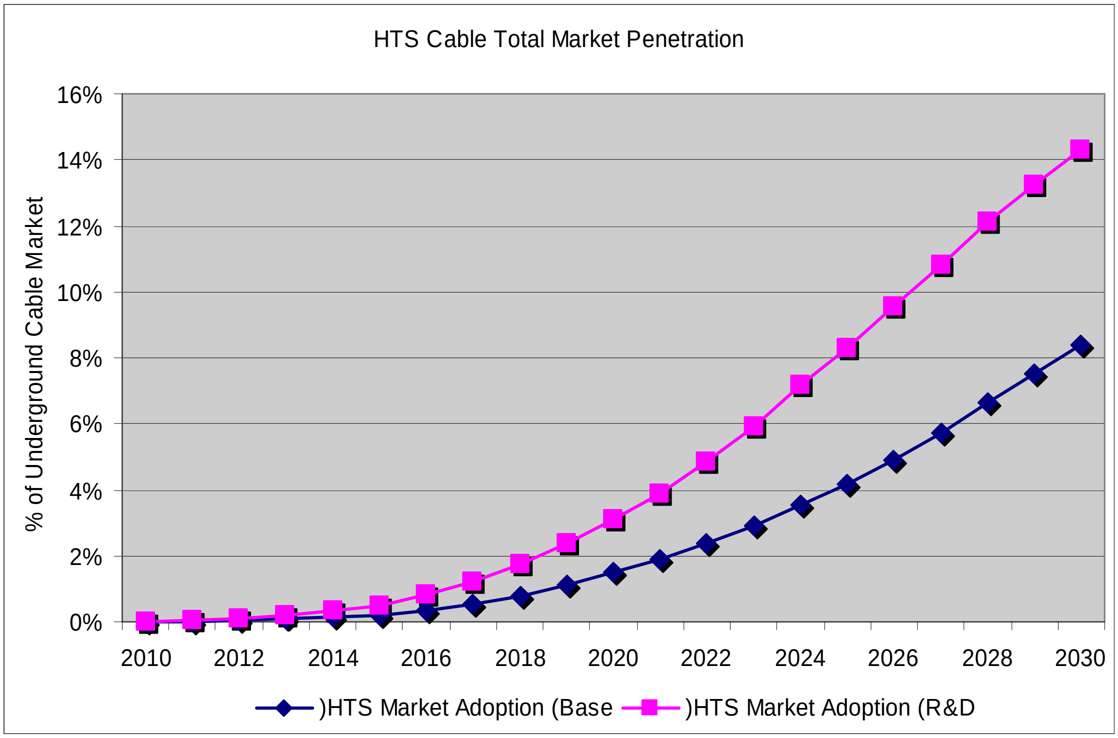


Figure C-3. Projected Efficiency Differential of HTS Cables, With and Without the DOE R&D Program

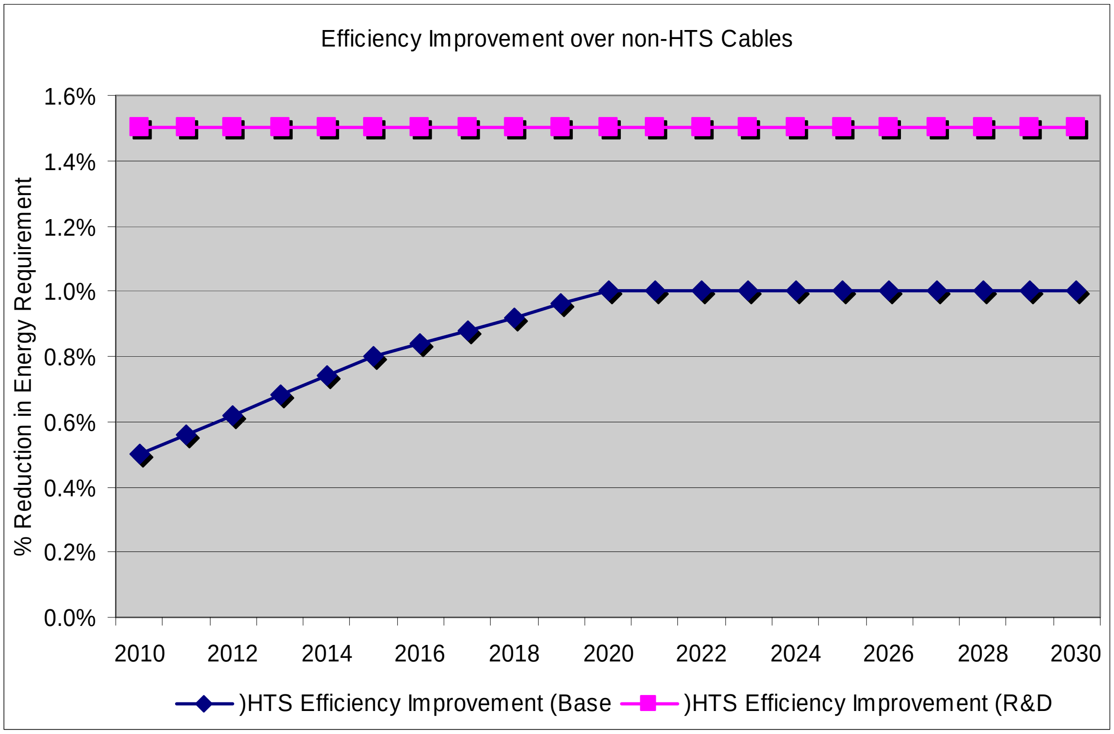
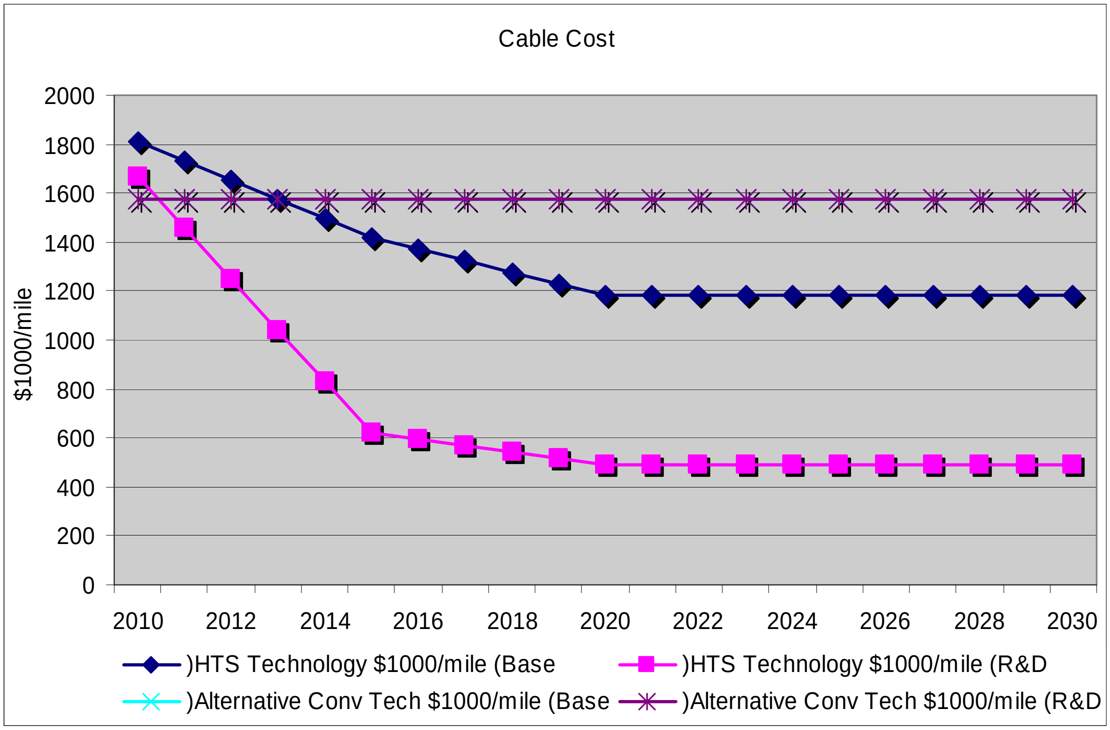
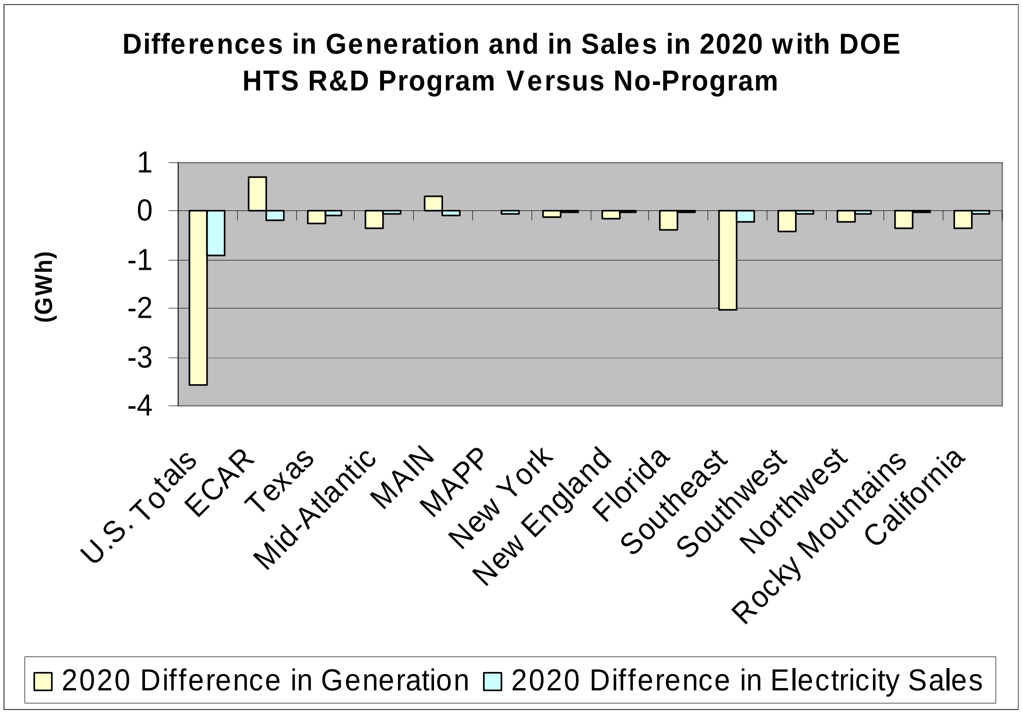


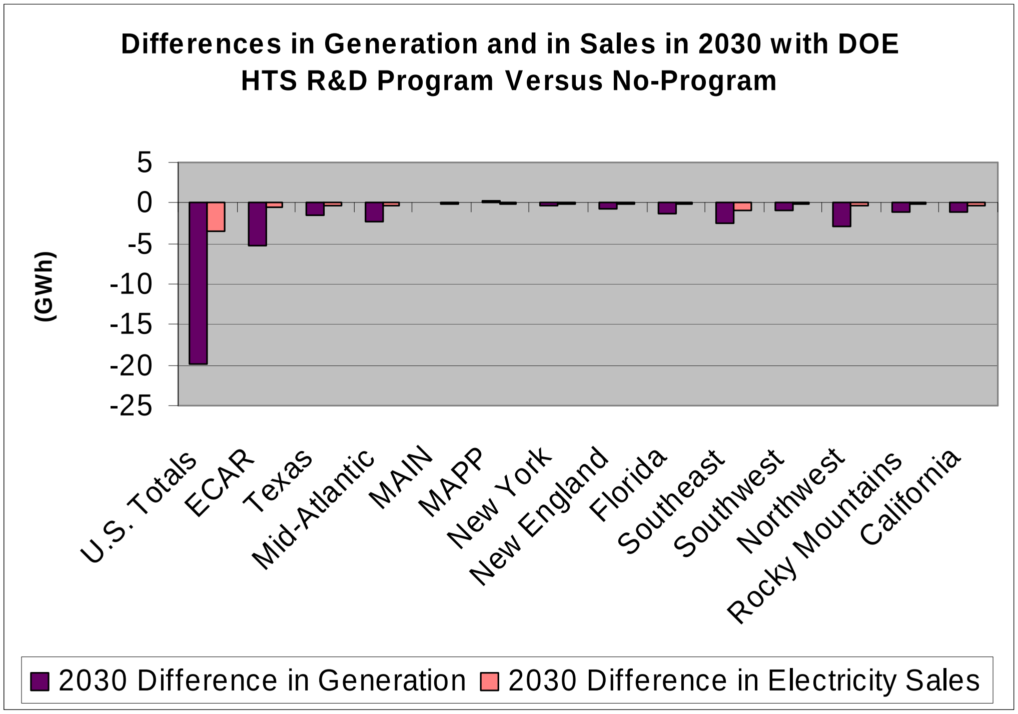
Figure C-4. Projected Cost Differential of HTS Cables, With and Without the DOE R&D Program



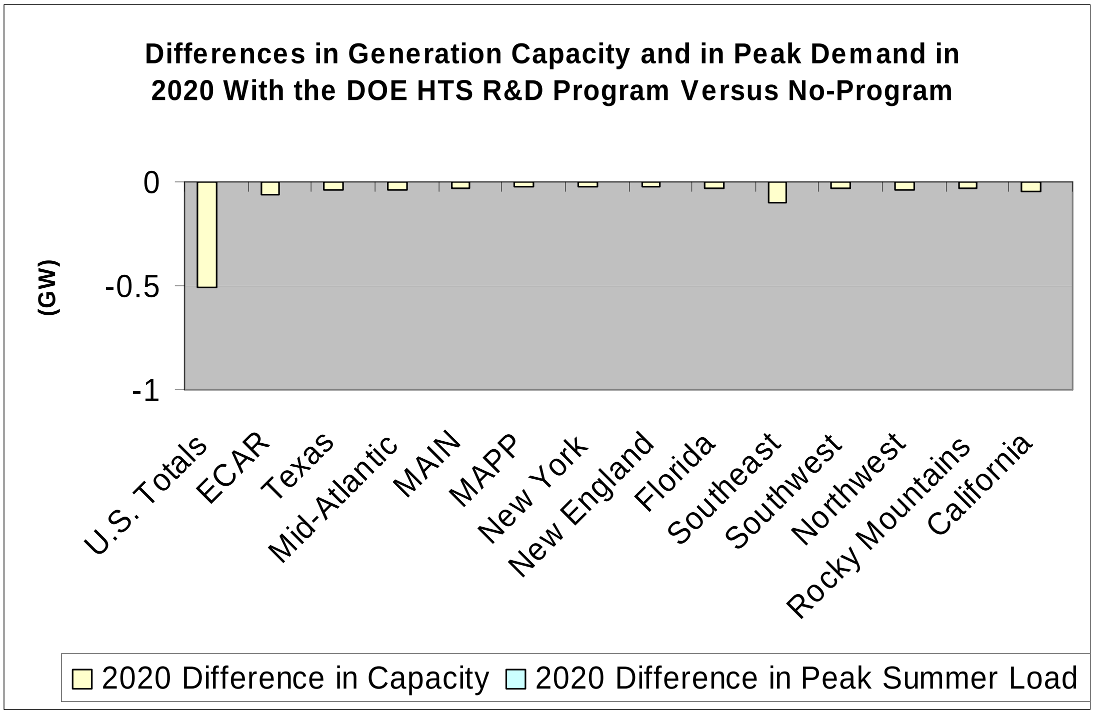
The following graphs are preliminary projections from the National Energy Modeling System (NEMS). Refer to these projections to the extent they are relevant to making your estimates.

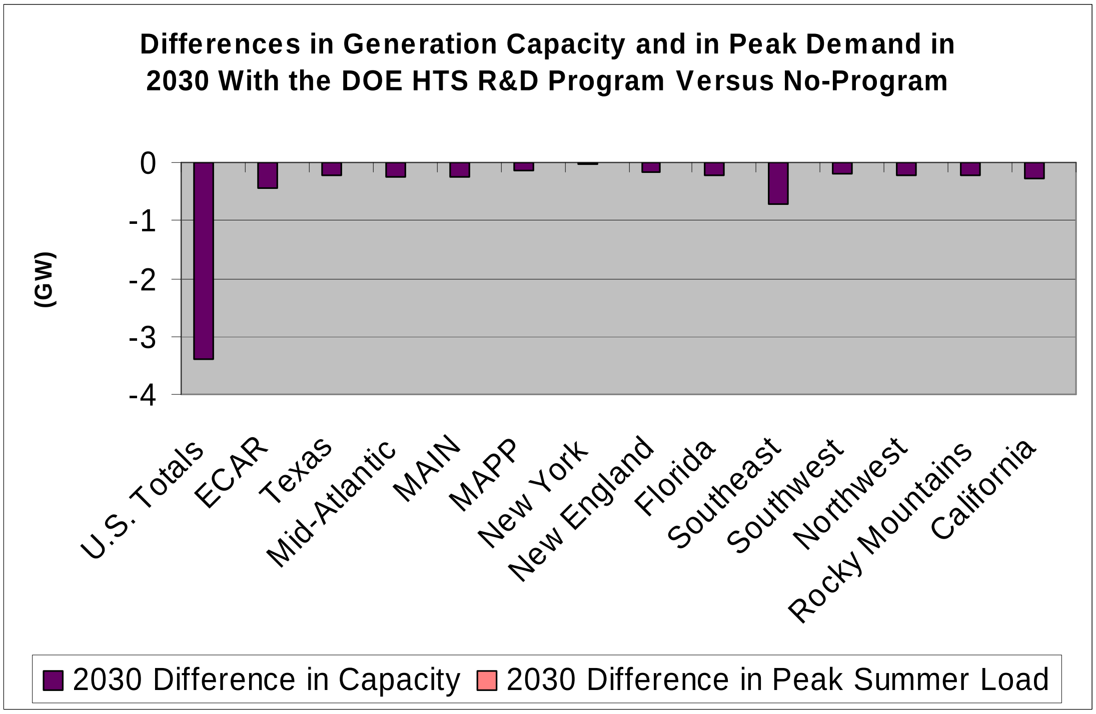
Generation and electricity sales are less with the DOE HTS R&D program, particularly generation.



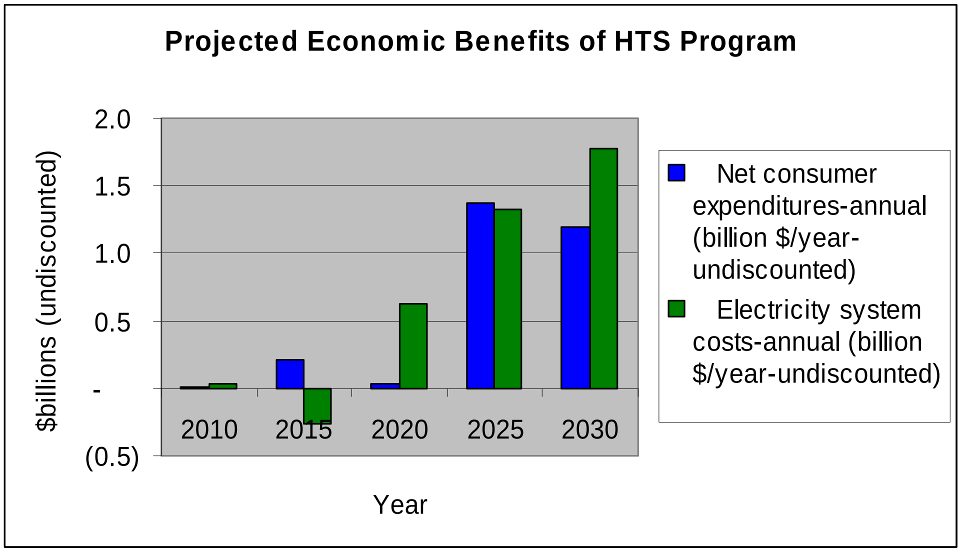

Differences in Generation and in Sales in 2030 with DOE HTS R&D Program Versus No-Program
(GWh)
5
0
-5
-10
-15
-20
-25
U.S. Totals
ECAR
Texas
Mid-Atlantic
MAIN
MAPP
New York
New England
Florida
Southeast
Southwest
Northwest
Rocky Mountains
California
2030 Difference in Generation
2030 Difference in Electricity Sales

If there is a DOE HTS R&D Program, less generation will be needed to meet demand (which is unchanged from the No-Program case).





The reduction in consumer expenditures on electricity and the reduction in electricity system costs are two (non-additive) measures of the economic benefits of the HTS program. The projected reduction in consumer expenditures on electricity is projected to be $1.8 billion less in 2030 (dollars are not discounted) compared to the No-Program case. Electricity system costs are projected to be less by almost $1.2 billion. The projections are updated from the May 2006 projections.



Appendix C-3

Information Package
For Use by

The National Panel on Estimating the Electricity Reliability and Security Benefits of the U.S. Department of Energy's Energy Storage and Power Electronics R&D Program

Information Package
For Use by

The National Panel on Estimating the Electricity Reliability and Security Benefits of the U.S. Department of Energy's Energy Storage and Power Electronics R&D Program[31]

This package provides information and market projections that serve as reference material for panel members who are estimating the electricity reliability and energy infrastructure security benefits of technologies anticipated from the Energy Storage and Power Electronics R&D program in the U.S. Department of Energy's (DOE's) Office of Electricity Delivery and Energy Reliability (OE).

It is important for panel members to refer to this information so that all members base their estimates on the same set of assumptions and projections.

The information in this package is as follows:

1. Definitions for reliability and security,

2. Program metric – major technical goal(s) of the program, including a brief description of the program, and its expected outputs and outcomes,

3. Program overview – description of the systems being (or proposed to be) developed, and

4. Energy market projections – projected energy supply and demand

   PLEASE USE THESE PROJECTIONS, EVEN THOUGH YOUR OWN MIGHT DIFFER, SO THAT ALL PANELISTS BASE THEIR ESTIMATES ON THIS SET OF PROJECTIONS.

[31] The information in this package was compiled by staff of Oak Ridge National Laboratory, which is managed by UT-Battelle, LLC for the U.S. Department of Energy under contract DE-AC-05-00OR22725. The information is based *in part* on information provided by the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability. Although the information is thought to be accurate, there is no guarantee of its accuracy; and it does not necessarily represent the views of the Office of Electricity Delivery and Energy Reliability, the U.S. Department of Energy, UT-Battelle, or Oak Ridge National Laboratory.

1. Definitions

Reliability

The "reliability" of an electric power system is the degree to which it delivers power to consumers in the amount desired and within acceptable standards. The reliability of a system may be assessed with respect to its:

- Adequacy – The ability of the electric system to supply the aggregate electrical demand and energy requirements of consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements; and
- Operational Reliability[32] – The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

<u>Reliability Benefits of R&D</u>

The questions you answer will help us estimate the reliability benefits of the R&D. The "reliability benefits" of R&D are reliability-related cost reductions that can be attributed to new or improved technologies from the R&D. Specifically, reductions in any of the following costs are reliability benefits.

x) <u>Outages</u>: Electrical outage costs reflect the frequency, duration, and magnitude (amount of power) of outages, the number and type of customers affected, mitigative measures (both supply and demand) that reduce the extent or effects of outages, the costs of these mitigative measures, and the costs of restoring service. Reductions in outage costs that can be attributed to improved technologies are of their reliability benefits.

xi) <u>Power quality</u>: Power-quality disturbances are deviations from power being supplied as a sine wave with the amplitude and frequency given by national or system standards. Power-quality disturbances might affect the proper functioning of electronic and other sensitive equipment. Reductions in the costs of these disturbances that can be attributed to improved technologies are part of their reliability benefits.

xii) <u>Transmission congestion</u>: Transmission congestion costs are the difference between the cost of delivering electricity if there were no transmission constraints, which are the cause of the congestion, and the cost with the current (or anticipated) constrained system. Reductions in congestion costs that can be attributed to improved technologies are part of their reliability benefits.

[32] The North American Electric Reliability Council (NERC) formerly used the term "security," but recently changed to the use of "operational reliability" to reduce confusion among those outside the industry, who might think of "security" as being "homeland security" or "energy/oil security."

Costs of Outages, Power Quality Disturbances, and Transmission Congestion

Though interrelated elements of reliability, outages, power-quality disturbances, and congestion comprise three separate cost components.[33] There are no "official" estimates of their costs.

The range of previous estimates of current (not projected) costs are generally in the following range:

- Annual cost of outages in the U.S. – $22 billion to $135 billion
- Annual cost of power quality disturbances in the U.S. – $6 billion to $34 billion
- Annual cost of transmission congestion in the U.S. -- $150 million to $2.6 billion

These estimates are in year 2001 dollars. The estimates range considerably and, indeed, actual costs will vary considerably from year to year depending on the number and severity of outages, frequency of power quality disturbances, and amount of transmission congestion. Notwithstanding these variations, these estimates provide a reasonable order of magnitude of the *current* costs (in year 2001 dollars). *Future* costs could increase significantly or even decrease depending on changes in generation capacity, demand for electric power, transmission capacity, and improvements in technology.

Energy System Infrastructure Security

The (in)security of energy system infrastructure refers to its vulnerability to highly disruptive catastrophic events, and to the system's ability to respond and recover in such an event. Infrastructure includes both physical and cyber systems.

Energy System Infrastructure Security – Benefits of R&D

The questions you answer will help us gauge the energy system infrastructure security benefits of R&D ("security benefits"). The security benefits of R&D are improvements in the security-related state of the U.S. energy system infrastructure that can be attributed to new or improved technologies from the R&D.

The following three elements are used to describe the state of the infrastructure:

g) Vulnerability to attack or destruction: Vulnerability refers to the likelihood of a catastrophic event on a system. Catastrophic events include major terrorist attacks, cyber attacks, and major natural disasters. Vulnerability encompasses the likelihood of an event; the likelihood that an attack is successful; and the magnitude of the damage to the system. Reductions in vulnerability that can be attributed to new or improved technologies are an indicator of their security benefits.

[33] Electricity reliability standards and other system requirements dictate that an adequate level of reserves, both real and reactive, be maintained to ensure operational reliability. Reductions in the costs of providing these reserves, including any reduction in the level of reserves required for operational reliability, are classified as system efficiency benefits and *not* as reliability benefits.

h) Supply response: The ability of a system to respond and recover in a catastrophic event improves its security. Such capabilities could include providing stored energy, limiting the extent of damage, isolating part of the system from damage, or rapidly repairing infrastructure. Reductions in damages from what they would have been without these capabilities are an indicator of their security benefits.

i) Demand conditions and response: Changes in demand (load profiles) in a system prior to any event can reduce the extent of damage should an event occur. Also, the ability of a system to rapidly adjust demand can reduce the likelihood of cascading failures elsewhere in the system. Reductions in damages from what they would have been without these prior changes and without these demand-response capabilities are an indicator of their security benefits.

Costs of Catastrophic Events

Catastrophic events are very low probability but extremely high impact. Their immediate damages are in the billions of dollars, but their overall impacts are more far reaching. In this analysis, we do not attempt to attach dollar values to energy system infrastructure security. Instead, we will use the estimated reductions in vulnerability and damage that can be attributed to technological improvements as indicators of their benefits.

2. Energy Storage and Power Electronics Program Metric – A Summary of the Key Program Goals and Anticipated Outcomes

Program: Energy Storage and Power Electronics
Funding: ***<u>$xx</u>*** million per year beginning in FY2008 to FY2015 **Timeframe:** Improvements achieved in 2015, relative to the year 2006
Program Description: Power electronics devices hold substantial promise for transforming the electric power system. High voltage power electronics allow precise and rapid switching of electric power to support long distance transmission. This speed and precision will allow the system to more rapidly respond to system disturbances and allow the system to operate with lower margins and fewer constraints, thereby reducing the need for additional infrastructure. One of the most basic power system devices is the switch. A top priority technology need is for power electronics switches with the capability for high voltage, high speed, with little or no cooling requirements, and a favorable cost-to-value relationship. New approaches or materials (silicon carbide, gallium nitride, or diamond) that are not currently used today in power electronics will be needed. Working in this voltage and current domain will require more research into the properties and suitability of advanced materials. There is interest in exploring new materials; "going beyond silicon." Diamond, gallium nitride and silicon-carbide are promising materials for use in power electronics.
Long-Term Goals: By 2025, demonstrate a prototype solid state switch with less than 1 millisecond response. When used in a breaker, these switches will not increase the cost of the system by more than 10%.

Program: Energy Storage and Power Electronics

Long-Term Goals (continued):

Performance Characteristics	2005 - Baseline	2008	2010	2012	2018	2025
Speed	Current mechanical breakers operate at 4-6 cycles (66 – 100 milli-seconds) Fuses operate in ¼ cycle (4 milli-seconds		5 milli-seconds	4 milli-seconds	2 milli-seconds	1 milli-seconds
Voltage/ Current	Silicon –based switches (fully controllable) 5000 volts and 10 amps	1200 volts/10 amps		10,000 volts/10 amps	20,000 volts/100 amps or 50,000 volts/>10 amps	20,000 volts/500 amps or 50,000 volts/>100 amps
Temperature Limits	Current silicon-based devices are limited to 150ºC			250ºC		400ºC

Anticipated Outcomes: R&D on Energy Storage and Power Electronics could lead to the following benefits:

- Reduced power quality disturbances — Activities using information technology, numerically controlled manufacturing, medical, and other precision equipment would benefit from reduced incidence of voltage sags.
- Enhancing reliability — New power electronic equipment can mitigate the effects of faults, spikes and instabilities making the electricity supply more secure, reducing the number of line trips. Power electronic systems can provide dynamic response to system contingencies. FACTS controllers can respond much faster than the conventional solutions such as mechanically switched devices.
- Reducing transmission congestion – Due to improved and lower cost FACTS controllers and HVDC terminals
- Preserving the environment — Some of the devices using these technologies are environmentally friendly. They contain no hazardous materials and produce no waste or pollutant. Increased penetration of wind energy due to lower cost for new transmission and transmission upgrade.

Rationale for Government Investment: R&D in advanced power electronics and materials is long-term and high risk. The payoffs are uncertain and, if realized, accrue over a long time horizon, making it difficult for the private sector to embark on these activities alone. The evolving and uncertain regulatory environment for electricity markets makes it difficult for companies to justify costly investments in this type of R&D

Program: Energy Storage and Power Electronics
because the financial markets for providing power-quality services might not be fully developed. Advanced power electronic components and systems for military applications are being developed under government sponsorship. R&D for Military applications is advancing the capabilities of many power electronic components but the military systems produced do not operate at voltage and power levels that will benefit the electric grid. Further research and development is necessary to extend the results of the military work to fit utility requirements. (see Fig. 1)

3. Energy Storage and Power Electronics – Program Overview[34]

3.1 Current Situation and the Motivation for Investment in Research, Development, Deployment, and Demonstration

Our nation's ability to deliver secure and reliable electricity is severely challenged by an aging electricity transmission and distribution system (the grid). This situation is exacerbated by the increasing demand for electricity which pushes the system to its operational limits. The majority of the power delivery system was built on technology developed in the 1960s, 70s and 80s and is limited by the speed in which it can respond to disturbances. This limitation increases the vulnerability of the power system to a higher number of and greater spread of long-term outages, as well as increased incidence of power-quality disturbances.

There has been and continues to be a substantial federal R&D investment in power electronics for military and transportation applications. However, utility applications are unique in their power requirements. For example; in automotive applications, size and weight are the key drivers for transportation. In contrast,OE will address the high voltage and high current applications. This will require additional focus on thermal management and high temperature packaging. Figure 1 illustrates OE's focus relative to other applications and R&D initiatives.

Figure 1. Area of Focus of Energy Storage and Power Electronics R&D Program

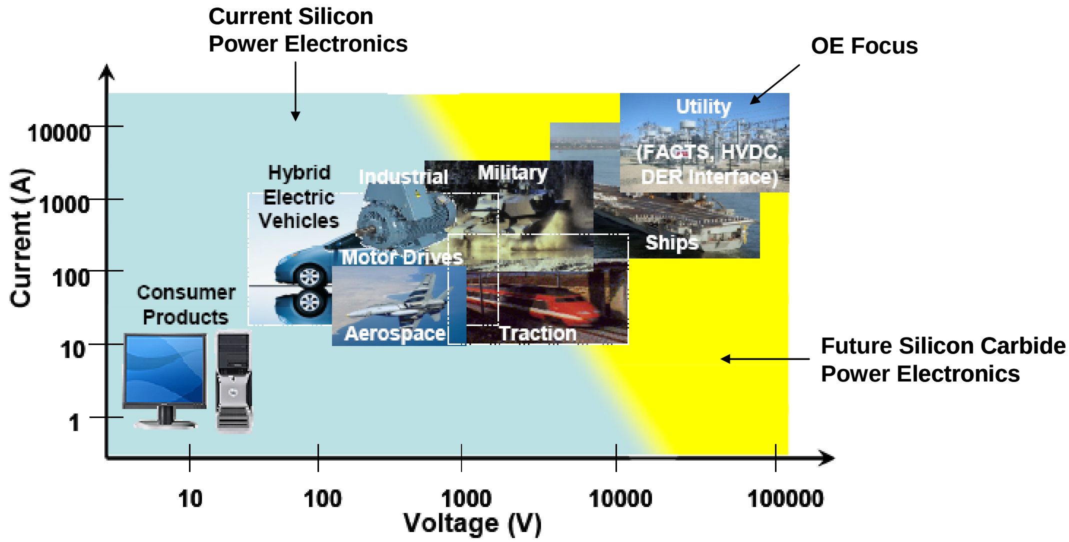


Fig. 1.2. Voltage and current rating for different power electronics application areas.

[34] This summary provides a broad description of the program, including its possible energy saving and environmental benefits. Panel members should *not* include energy savings and environmental benefits in their estimates of the reliability and energy system security impacts of the R&D program.

Advanced Materials Research for Power Electronics

Most present commercial power electronics devices (diodes, thyristors, IGBTs, MOSFETs, etc.) are silicon-based devices. The performance of these systems is approaching the theoretical limits of the fundamental material properties of silicon. The emergence of new power electronics devices based on wide band-gap semiconductor materials, such as silicon carbide, will likely result in substantial improvements in the performance of power electronics converter systems in terms of higher blocking voltages, efficiency, and reliability as well as reduced thermal requirements. Wide band-gap materials show great potential in this area, especially diamond and silicon carbide (SiC) Wide band-gap (WBG) power devices offer significant performance improvements.

Research areas for WBG devices include overcoming materials processing challenges, thermal management of devices, improving reliability and reducing costs of systems. Many WBG materials have low processing yields. For example, SiC have processing defects, called micropipes, that reduce the yields. Presently, the best available SiC wafers have less than one micropipe per square-cm, but they are much more expensive than the typical wafers with less than 10 micropipes per square-cm. High-temperature packaging issues also limit the utilization of WBG materials. Research is needed to develop new types of thermal interface materials that conduct heat more efficiently than conventional materials, improving overall performance and helping to meet cooling needs of future devices. For example, carbon nanotubes have excellent heat-conduction properties, which may offer solutions in this area. Nanotube-based interfaces can conduct several times more heat than conventional thermal interface materials at the same temperatures.

Advanced Materials Research for Energy Storage Systems

Energy storage devices combine several subsystems into systems capable of converting energy into the form needed to charge the storage device, the storage device itself, a device to extract the stored energy and convert it back into the form desired, a control system to coordinate the actions of the various components and a communication system to interface with the outside world. The energy conversion systems are typically power electronic Power Conversion Systems (PCS) capable of bi-directional energy conversion. The storage device itself can compromise many different forms: batteries, capacitors, electro-chemical capacitors, flywheels, water or compressed air stored with a high potential energy, and magnetic field. The DOE advanced material research for energy storage systems will focus on materials to improve the storage device itself and the PCS. The PCS research is discussed above. The storage device materials research will take advanced in material manufacturing methods, newly developed materials and newly developed materials with electrochemical properties suitable for the storage of energy. Advanced material manufacturing technologies such as nano-formed materials, offer the opportunity to custom engineer desirable properties into new or existing materials. Newly developed materials such as carbon nano-tubes have very large surface areas, can have customized electrostatic properties or possibly designed in electrochemical attributes to enhance the energy storage process. Newly developed ionic liquids will be explored for use as electrolyte solutions in either batteries or capacitors. These ionic liquids have the potential to increase the operating voltage of the device from the current nominal value of 2V up to 5 to 6V. Other potential opportunities exist in developing and exploiting new electrochemical couples for either flow batteries or more conventional stationary plate batteries. The goals of this research are to increase the energy density of storage devices, increase the lifetime of storage devices, decrease the maintenance required, and reduce the effective cost of these devices.

The program will pursue this research through contracts with Universities, private companies and through research programs at the nation's National Laboratories. The program will collaborate with the DOE Office of Science in this research strengthening the link from basic research through the eventual commercialization of the developed technologies.

3.2 Application of Power Electronics Technologies

A power electronics device performs many diverse functions and is the modern replacement for electromechanical devices. For example, Flexible Alternating Current Transmission System (FACTS), fault current limiters, and High Voltage Direct Current (HVDC) utilize power electronic technologies to provide solutions to upgrade the nation's electrical transmission system infrastructure. Applications specific to FACTs devices can be seen in the following tables [others not listed in these tables are DSTATCOM 9distributed STATCOMs), IPFC (interline power flow controllers, and SSSC (static synchronous series compensators)]. Technical benefits of FACTS devices include both dynamic and steady state applications for addressing grid issues. Conventional solutions (e.g. shunt reactor or shunt capacitor) do not provide the flexibility that the electric grid needs to improve reliability and security.

3.3 Technical Characteristics

Today, silicon (Si) -based power devices dominate the power electronics and power system applications. They offer many advantages to customers, but at the same time they suffer from limitations in their material properties. This opens a door for new materials to enter the power electronics field. Wide band-gap materials show great potential in this area, especially carbide (SiC) and chemical vapor decomposition of diamond tips in a vacuum for field effect devices. Figure 2 illustrates typical solutions associated with traditional technologies for enhancing power system control, conventional FACTS, and advanced FACTS.

In order for these technologies to be widely adopted throughout the utility industry, advances in solid-state devices and systems need to be realized. The components that make up the heart of FACTS technologies and HVDC systems require high blocking voltage to minimize series stacking and high temperature packaging at high voltage levels. They also need high switching frequency to lead to fast dynamic power processing ability, high quality power output and to minimize balance of plant components. Thus research and development breakthroughs are needed for wide-band gap materials.

Table 1. Dynamic Applications of FACTS

Issue	Type of System	Corrective Action	Conventional Solution	FACTS device
Transient Stability	A, B, D	Increase synchronizing torque	High-response exciter, series capacitor	TCSC, TSSC, UPFC
	A, D	Absorb kinetic energy	Braking resistor, fast valving (turbine)	TCBR, SMES, BESS
	B, C, D	Dynamic load flow control	HVDC	TCPAR, UPFC, TCSC
Dampening	A	Dampen 1 Hz oscillations	Exciter, Power system stabilizer (PSS),	SVC, TCSC, STATCOM
	B, D	Dampen low frequency oscillations	Power system stabilizer (PSS)	SVC, TCPAR, UPFC, NGH, TCSC, STATCOM
Post Contingency Voltage Control	A, B, D	Dynamic voltage support	-	SVC, STATCOM, UPFC,
		Dynamic flow control	-	SVC, UPFC, TCPAR
		Dynamic voltage support and flow control	-	SVC, UPFC, TCSC
	A, B, C, D	Reduce impact of contingency	parallel lines	SVC, TCSC, STATCOM, UPFC
Voltage Stability	B, C, D	Reactive Support	shunt capacitor, shunt reactor	SVC, STATCOM, UPFC
		Network control actions	LTC, reclosing, HVDC controls	UPFC, TCSC, STATCOM
		Generation control	High-response exciter	-
		Load control	Under-voltage load shedding Demand-Side Management Programs	-

Legend for Table 1:

A. Remote generation — B. Interconnected areas
C. Tightly meshed network — D. Loosely meshed network
BESS – battery energy storage system — UPPC – Unified power flow controller
HVDC – High-voltage direct current — SVC – Static Var compensator
LTC – Transformer-load tap changer — TCPAR – Thyristor-controlled phase-angle regulator
NGH -- Hingorani Damper — TCSC – Thyristor-controlled series capacitor
PAR – Phase-angle regulator — TCVL – Thyristor-controlled voltage limiter
SCCL – Superconducting current limiter — TSBR – Thyristor-switched braking resistor

Table 2. Steady State Applications of FACTS

Issue	Problem	Corrective Action	Conventional solution	FACTS device
Voltage limits	Low voltage at heavy load	Supply reactive power	Shunt capacitor, Series capacitor	SVC, TCSC, STATCOM
	High voltage at light load	Remove reactive power supply	Switch EHV line and/or shunt capacitor	SVC, TCSC, STATCOM
		Absorb reactive power	Switch shunt capacitor, shunt reactor	SVC, STATCOM
	High voltage following outage	Absorb reactive power	Add shunt reactor	SVC, STATCOM
		Protect equipment	Add arrestor	SVC
	Low voltage following outage	Supply reactive power	Switch shunt capacitor, reactor, series capacitor	SVC, STATCOM
		Prevent overload	Series reactor, PAR	TCPAR, TCSC
	Low voltage and overload	Supply reactive power and limit overload	Combination of two or more devices	TCSC, UPFC, STATCOM, SVC
Thermal limits	Line or transformer overload	Reduce overload	Add line or transformer	TCSC, UPFC, TCPAR
			Add series reactor	SVC, TCSC
	Tripping of parallel circuit (line)	Limit circuit (line) loading	Add series reactor, capacitor	UPFC, TCSC
Loop flows	Parallel line load sharing	Adjust series reactance	Add series capacitor/reactor	UPFC, TCSC
		Adjust phase angle	Add PAR	TCPAR, UPFC
	Post-fault sharing	Rearrange network or use “Thermal limit” actions	PAR, Series Capacitor/Reactor	TCSC, UPFC, SVC, TCPAR
	Flow direction reversal	Adjust phase angle	PAR	TCPAR, UPFC
Short circuit levels	Excessive breaker fault current	Limit short circuit current	Add series reactor, new circuit breaker	SCCL, UPFC, TCSC
		Change circuit breaker	Add new circuit breaker	
		Rearrange network	Split bus	
Subsynchronous resonance	Potential turbine /generator shaft damage	Mitigate oscillations	series compensation	NGH, TCSC

Legend for Table 2.

NGH = Hingorani Damper
PAR = Phase-Angle-Regulator
SCCL = Super-Conducting Current Limiter
SVC = Static Var Compensator
STATCOM = Static Compensator
TCPAR = Thyristor Controlled Phase-Angle Regulator
TCSC = Thyristor Controlled Series Capacitor
TCVL = Thyristor Controlled Voltage Limiter
TSBR = Thyristor Switched Braking Resistor
TSSC = Thyristor Switched Series Capacitor
UPFC = Unified Power Flow Controller

The technical characteristics of wide band gap materials include:

- WBG unipolar devices are thinner, and they have lower on-resistances.
- WBG-based power devices have higher breakdown voltages because of their higher electric breakdown field. This will reduce or maybe eliminate the need for series connection of devices and the voltage balancing circuits.
- Most WBG materials have a higher thermal conductivity and can operate at higher temperatures.
- Forward and reverse characteristics of WBG power devices vary only slightly with temperature and time; therefore, they are more reliable.
- WBG-based bipolar devices have excellent reverse recovery characteristics.

Because of low switching losses, WBG-based devices can operate at higher frequencies.

3.4 Value of the Technologies

Widespread deployment of Energy Storage and Power Electronics technologies could achieve the following:

- Increasing transmission capacity—by increasing the damping factor and transient stability limit so that the power transmission stability limit is close to its thermal limit.
  - Increasing the real power capacity of existing systems: up to 40% increase in capacity can be realized.
  - Enhancing necessary grid expansion where required—reducing transmission line construction. Frequently, adding new transmission lines to meet increasing electricity demand is limited by economical and environmental constraints. FACTS controllers and HVDC lines help to meet these requirements with the existing transmission systems.
- Improving controllability—power electronics can control power flow and regulation of voltages in the power grid by stretching the “laws of physics” on the power system.
  - Power naturally flows from high impedance to low, but FACTS devices help to control the power flow under the operator’s consideration.
  - Additionally, technologies can facilitate non-synchronous grid interconnections; e.g. HVDC can connect two grids with different frequencies.

3.5 Possible Benefits

Because of their technical characteristics and value in varied applications, R&D on energy storage and power electronics could lead to technologies that provide the following benefits:

- Reducing power quality disturbances — Information technology, medical, and other precision equipment are adversely affected by significant variations in voltage. Increased transmission capacity and controllability of voltages will reduce voltage sags. A voltage sag occurs when voltage is significantly (e.g., > 10%) below the nominal system voltage for an extended time (e.g., > one cycle). These represent over 98% of all power quality problems according to the Electric Power Research Institute Distribution Power Quality Study. Momentary outages are the next most common occurrence, followed by long-term outages.

- Enhancing reliability — Transmission system reliability is affected by many different factors. Although FACTS devices cannot prevent faults, they can mitigate the effects of faults and make electricity supply more secure by reducing the number of line trips. Power electronic systems can provide dynamic response to system contingencies. FACTS controllers can respond much faster than the conventional solutions such as mechanical switch.
- Preserving the environment — FACTS controllers are environmentally friendly. They contain no hazardous materials and produce no waste or pollutant.

3.6 Potential Size of this Market

Presently, approximately 30% of all electric power generated utilizes power electronics somewhere between the point of generation and its end use. Most power electronics uses today are for improved control of loads such as variable-speed drives for motors that drive fans, pumps, and compressors or in switching power supplies found throughout most consumer products. By 2030, it is expected that perhaps as much as 80% of all electric power will use power electronics somewhere between generation and consumption, with the greatest gains being made in variable- speed drives for medium-voltage (4.16 to 15 kV) motors, utility applications such as FACTS or high-voltage HVDC converter stations, or in the interface required between utilities and distributed energy resources such as microturbines, fuel cells, wind, solar cells, or energy storage devices.

Electric power production in the 21st century could very well see dramatic changes in both the physical infrastructure and the control and information architecture. A shift could take place from a relatively few large, concentrated generation centers and the transmission of electricity over mostly a high-voltage ac grid to a more diverse and dispersed generation infrastructure. The advent of high-power electronic modules could continue to encourage the use of more dc transmission and make the prospects for interfacing dc power sources such as fuel cells and photovoltaics more easily achievable.

3.7 Cost Comparisons

Conventional solutions are normally less expensive than FACTS devices–but limited in their dynamic performance. Usually a FACTS Controllers can solve several problems, which would otherwise need to be solved by several different conventional solutions. Table 3 provides costs of voltage control equipment and compares conventional, thyristor-based technology with advanced, converter-based technologies.

For example, capacitor banks are installed in a substation to provide voltage support for the grid. Capacitor banks range from $1 million (this is a relatively high number, normally, is $10-$15/kvar) for 50 Mvar at 115 kV to $5 million for 200 Mvar at 500 kV; adding additional capacitors costs $500,000 or more, depending on the voltage and the Mvar added. Capacitor banks and switches have minimal maintenance costs. There are approximately 5,000 switched shunt capacitors in the North American power system, with about 170,000 Mvar of capacity. Switched capacitors cannot smoothly adjust their var output because they rely on mechanical switches and take between one-tenth of a second and one second to operate.

In contrast, static var compensators (SVCs) use electronic switches, called thyristors, switching capacitors and controlling inductors. Static synchronous compensators (STATCOMs) supply or absorb reactive power using semiconductor electronic switches called Gate Turn Off thyristors, where there is no need for physical capacitors and/or inductors. Both SVCs and STATCOMs automatically switch to regulate voltage on a line. SVCs are usually large footprint installations in substations and STATCOMs are relatively smaller footprint installation, 30%-40% less than a comparable SVC. In the 115-230 kV range, SVCs typically operate in ranges of 0-100 Mvar inductive and 100-200 Mvar capacitive, and cost is $30-$40/kvar At higher voltages, SVCs range from 300 Mvar inductive to 500 Mvar capacitive, and cost at the higher end of $/kvar. Smaller SVCs can change output in a few milliseconds. Larger SVCs can make small changes quickly, but may take a few seconds to make larger changes. Output from SVCs can be varied continuously – they do not require the discharge time needed for switched capacitor banks. SVCs have some of the same problems as capacitors during voltage drops in that their maximum capacitive support drops with the square of the power system voltage. STATCOMs respond independently of transmission voltage and, therefore, provide better reactive support capability than SVCs for preventing voltage collapse. STATCOMs also are more compact than SVCs, requiring less footprint space in a substation. DSTATCOMS are distributed STATCOMS that are IGBT based, currently costing >$150kVAr capacitance.

Table 3. Cost Comparisons of Voltage Control Equipment

Table 1: **Characteristics of Voltage-Control Equipment**

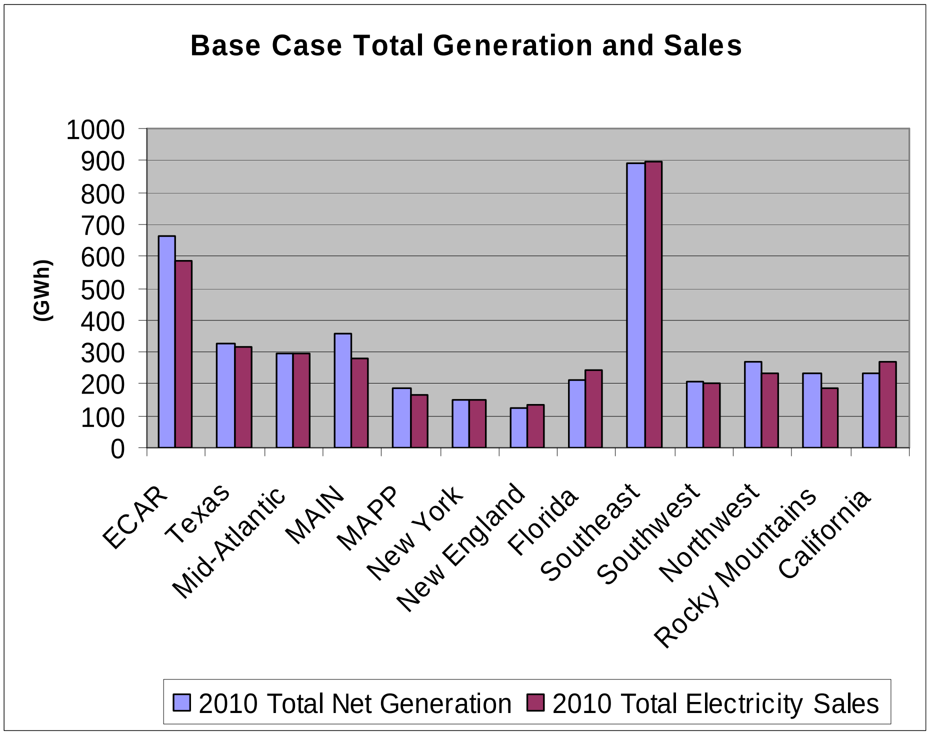
Equipment type	Speed of response	Voltage Support			Costs		
		Ability	Availability	Disruption	Capital (per kvar)	Operating	Opportunity
Generator	Fast	Excellent, additional short-term capacity	Low	Low	Difficult to separate	High	Yes
Synchronous Condenser	Fast	Excellent, additional short-term capacity	Low	Low	\$30-35	High	No
Capacitor	Slow	Poor, drops with V^2	High	High	\$8-10	Very low	No
Static VAr Compensator	Fast	Poor, drops with V^2	High	Low	\$45-50	Moderate.	No
STATCOM	Fast	Fair, drops with V	High	Low	\$50-55	Moderate	No
Distributed Generation	Fast	Fair, drops with V	Low	Low	Difficult to separate	High	Yes

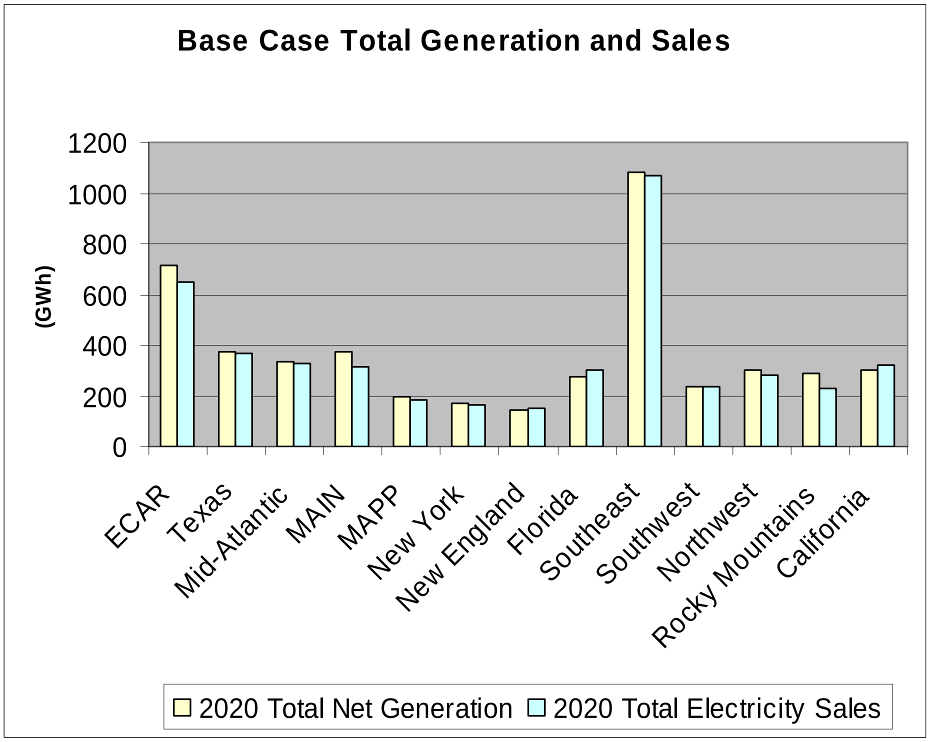
Source: *B. Kirby and E. Hirst 1997, Ancillary-Service Details: Voltage Control, ORNL/CON-453, Oak Ridge National Laboratory, Oak Ridge TN, December*

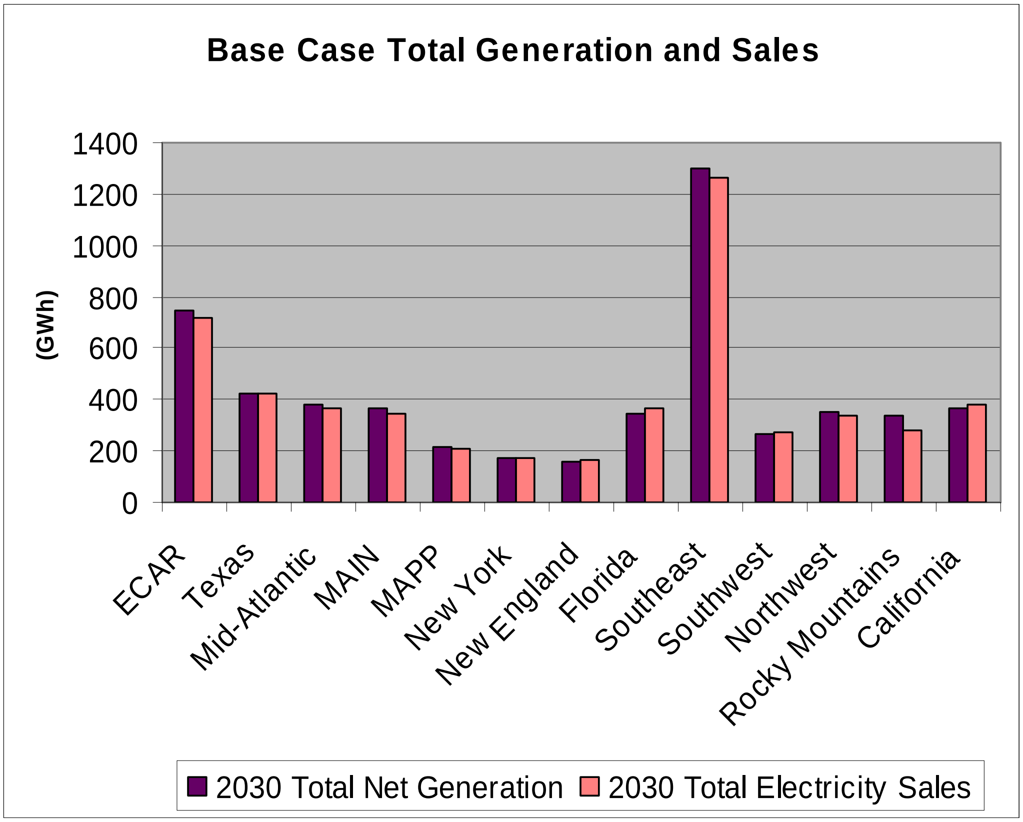
Note to Table 3: These 1997 cost estimates quoted might not be representative of today's prices. Also, costs for devices like synchronous condensers and STATCOMS are based on the devices' full dynamic range. If only a portion of that range is required the cost per kVar will be higher.

4. Energy Market Projections

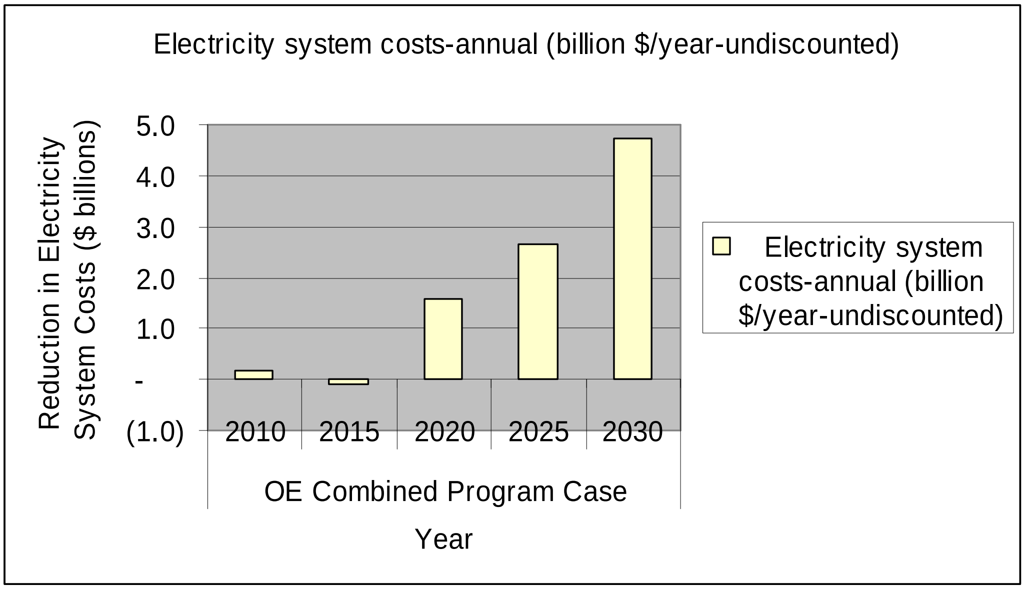
The following graphs are projections from the National Energy Modeling System (NEMS) – May 2006. Refer to these projections to the extent they are relevant to making your estimates.







Projected Economic Benefits of the DSI and HTS Programs Combined (Electricity System Cost Reduction)



Appendix C-4

Information Package
For Use by

The National Panel on Estimating the Electricity Reliability and Security Benefits of the U.S. Department of Energy's <u>Visualization and Controls</u> R&D Program

Information Package
For Use by

The National Panel on Estimating the Electricity Reliability and Security Benefits of the U.S. Department of Energy's Visualization and Controls R&D Program[35]

This package provides information and market projections that serve as reference material for panel members who are estimating the electricity reliability and energy infrastructure security benefits of technologies anticipated from the Visualization and Controls R&D program in the U.S. Department of Energy's (DOE's) Office of Electricity Delivery and Energy Reliability (OE).

It is important for panel members to refer to this information so that all members base their estimates on the same set of assumptions and projections.

The information in this package is as follows:

9. Definitions for reliability and security.

10. Program metric – major technical goal(s) of the program, including a brief description of the program, and its expected outputs and outcomes,

11. Technology overview – description of the technologies being (or proposed to be) developed, and

12. Energy market projections – energy supply and demand projections for the U.S.

    PLEASE USE THESE PROJECTIONS, EVEN THOUGH YOUR OWN MIGHT DIFFER, SO THAT ALL PANELISTS BASE THEIR ESTIMATES ON THIS SET OF PROJECTIONS.

[35] The information in this package was compiled by staff of Oak Ridge National Laboratory, which is managed by UT-Battelle, LLC for the U.S. Department of Energy under contract DE-AC-05-00OR22725. The information is based *in part* on information provided by the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability. Although the information is thought to be accurate, there is no guarantee of its accuracy; and it does not necessarily represent the views of the Office of Electricity Delivery and Energy Reliability, the U.S. Department of Energy, UT-Battelle, or Oak Ridge National Laboratory.

1. Definitions

Reliability

The "reliability" of an electric power system is the degree to which it delivers power to consumers in the amount desired and within acceptable standards. The reliability of a system may be assessed with respect to its:

- Adequacy – The ability of the electric system to supply the aggregate electrical demand and energy requirements of consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements; and
- Operational Reliability[36] – The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

Reliability Benefits of R&D

The questions you answer will help us estimate the reliability benefits of the R&D. The "reliability benefits" of R&D are reliability-related cost reductions that can be attributed to new or improved technologies from the R&D. Specifically, reductions in any of the following costs are reliability benefits.

xiii) Outages: Electrical outage costs reflect the frequency, duration, and magnitude (amount of power) of outages, the number and type of customers affected, mitigative measures (both supply and demand) that reduce the extent or effects of outages, the costs of these mitigative measures, and the costs of restoring service. Reductions in outage costs that can be attributed to improved technologies are of their reliability benefits.

xiv) Power quality: Power-quality disturbances are deviations from power being supplied as a sine wave with the amplitude and frequency given by national or system standards. Power-quality disturbances might affect the proper functioning of electronic and other sensitive equipment. Reductions in the costs of these disturbances that can be attributed to improved technologies are part of their reliability benefits.

xv) Transmission congestion: Transmission congestion costs are the difference between the cost of delivering electricity if there were no transmission constraints, which are the cause of the congestion, and the cost with the current (or anticipated) constrained system. Reductions in congestion costs that can be attributed to improved technologies are part of their reliability benefits.

[36] The North American Electric Reliability Council (NERC) formerly used the term "security," but recently changed to the use of "operational reliability" to reduce confusion among those outside the industry, who might think of "security" as being "homeland security" or "energy/oil security."

Costs of Outages, Power Quality Disturbances, and Transmission Congestion

Though interrelated elements of reliability, outages, power-quality disturbances, and congestion comprise three separate cost components.[37] There are no "official" estimates of their costs.

The range of previous estimates of current (not projected) costs are generally in the following range:

- Annual cost of outages in the U.S. – $22 billion to $135 billion
- Annual cost of power quality disturbances in the U.S. – $6 billion to $34 billion
- Annual cost of transmission congestion in the U.S. -- $150 million to $2.6 billion

These estimates are in year 2001 dollars. The estimates range considerably and, indeed, actual costs will vary considerably from year to year depending on the number and severity of outages, frequency of power quality disturbances, and amount of transmission congestion. Notwithstanding these variations, these estimates provide a reasonable order of magnitude of the *current* costs (in year 2001 dollars). *Future* costs could increase significantly or even decrease depending on changes in generation capacity, demand for electric power, transmission capacity, and improvements in technology.

Energy System Infrastructure Security

The (in)security of energy system infrastructure refers to its vulnerability to highly disruptive catastrophic events, and to the system's ability to respond and recover in such an event. Infrastructure includes both physical and cyber systems.

Energy System Infrastructure Security – Benefits of R&D

The questions you answer will help us gauge the energy system infrastructure security benefits of R&D ("security benefits"). The security benefits of R&D are improvements in the security-related state of the U.S. energy system infrastructure that can be attributed to new or improved technologies from the R&D.

The following three elements are used to describe the state of the infrastructure:

j) Vulnerability to attack or destruction: Vulnerability refers to the likelihood of a catastrophic event on a system. Catastrophic events include major terrorist attacks, cyber attacks, and major natural disasters. Vulnerability encompasses the likelihood of an event; the likelihood that an attack is successful; and the magnitude of the damage to the system. Reductions in vulnerability that can be attributed to new or improved technologies are an indicator of their security benefits.

[37] Electricity reliability standards and other system requirements dictate that an adequate level of reserves, both real and reactive, be maintained to ensure operational reliability. Reductions in the costs of providing these reserves, including any reduction in the level of reserves required for operational reliability, are classified as system efficiency benefits and *not* as reliability benefits.

k) Supply response: The ability of a system to respond and recover in a catastrophic event improves its security. Such capabilities could include providing stored energy, limiting the extent of damage, isolating part of the system from damage, or rapidly repairing infrastructure. Reductions in damages from what they would have been without these capabilities are an indicator of their security benefits.

l) Demand conditions and response: Changes in demand (load profiles) in a system prior to any event can reduce the extent of damage should an event occur. Also, the ability of a system to rapidly adjust demand can reduce the likelihood of cascading failures elsewhere in the system. Reductions in damages from what they would have been without these prior changes and without these demand-response capabilities are an indicator of their security benefits.

Costs of Catastrophic Events

Catastrophic events are very low probability but extremely high impact. Their immediate damages are in the billions of dollars, but their overall impacts are more far reaching. In this analysis, we do not attempt to attach dollar values to energy system infrastructure security. Instead, we will use the estimated reductions in vulnerability and damage that can be attributed to technological improvements as indicators of their benefits.

2. Visualization and Controls Program Metric – A Summary of the Key Program Goals and Anticipated Outcomes

Program: Visualization and Controls

Funding Request: XXX million per year beginning in FY2008 to FY2014

Timeframe: Improvements achieved in 2014, relative to the year 2006

Program Summary: The Visualization and Controls (V&C) program will develop tools/algorithms that will:

- Improve the response time of the transmission system to system disturbances to reduce the number and spread of outages
- Reduce the operating margins by allowing the system to operate closer to its loading limits by sensing deterioration of system conditions and enabling faster response
- Harden the transmission system's digital control, communications and computing systems

Long-Term Goals: By 2014, develop tools and algorithms to enable an automatic, smart, real-time switchable network for transmission system operations that enables secure and reliable grid operations, controls major regions of the grid, and is hardened against cyber attacks. OE will maintain the capability to test three SCADA systems per year.

		2002 – Baseline	2003	2005	2008	2009	2010	2011	2012	2014
Capabilities	Tools	Predictive Modeling	One Real-time Data Collection Tool	One Real-time Data Collection Tool		One Diagnostics/ Operator Cuing Tool	One Diagnostics/ Operator Cuing Tool	Two Diagnostics/ Operator Cuing Tool	One Diagnostics/ Operator Cuing Tool	One Automation System
	Evidence	Offline Analysis	Area Control Error Real Time Monitoring System (frequency and area control error (ACE))	Wide Area Phasor Measurement(real and reactive power flow)		Dynamic Security Assessment (real-time assessment of voltage levels)	Electro-mechanical Grid Stability Alarm (analysis of characteristic power oscillations)	Security Evaluation Tool (analysis of cyber vulnerabilities) Contingency Evaluation Tool (analysis of system to withstand contingencies)	Operator Cueing Presentation (decision support tools)	Automatic System Reconfiguration, (reactive power control, interruptible load, adaptive islanding)
Coverage	Sensors	Approximately 50 Phasor Measurement Unit (PMUs) in Western Interconnect		50 Phasor Measurement Unit (PMUs) in Eastern Interconnect	Implement 50 additional sensors	Implement 50 additional sensors		Demonstrate 50 sensors at distribution voltage	Demonstrate 50 sensors at distribution voltage	Demonstrate 50 sensors at distribution voltage

Anticipated Outcomes: The V&C Program expects to develop advanced software and hardware that will lead to improved, commercially available monitoring devices and visualization tools, state estimation software, system modeling and simulation tools, fault current limiters. These technologies will significantly improve electricity reliability by reducing outages, improving power quality, and reducing transmission congestion; and enhance cyber security by improving grid status monitoring and response with better communications and control technologies.

Program: Visualization and Controls
Rationale for Government Investment: The program is engaged in technologies to improve reliability because the market for reliability services is still relatively new and evolving. As such, the private sector is expected to under-invest in R&D because of the uncertainty about the return on its investments. Aspects of reliability and cyber security also have public goods aspects to them and are thus appropriate areas for government involvement. In terms of cyber security, the National Research Council identified *"protecting energy distribution services by improving the security of SCADA systems"* as a key technical initiatives for making the Nation safer. This and other reports led the White House to declare that *"securing DCS/SCADA is a national priority"* in *The National Strategy to Secure Cyberspace* (February 2003).

3. Visualization and Controls: Technology Overview

3.1 Current Situation and the Motivation for R&D

The current transmission system was built on technology developed in the 1960s, 70s and 80s and is limited by the speed with which it can respond to disturbances. This limitation increases the vulnerability of the power system to a higher number of and greater spread of long-term outages. Slower response requires higher operating margins and causes greater system constraints, which results in higher costs that are passed on to consumers. The increasing use of communications and control technology throughout the transmission and distribution system makes it even more vulnerable. The faster, wider and deeper use of communications and control, while necessary to improve reliability, also opens the transmission more to security vulnerabilities particularly from cyber attacks.

Control systems are vital to the reliable operation of the grid. However, these systems are becoming more vulnerable to malicious cyber attacks due to the increased adoption of standardized technologies with known vulnerabilities and the increased connectivity to the internet. The need to improve control system security is well recognized by both the private and public sectors. The National Research Council identified *"protecting energy distribution services by improving the security of SCADA systems"* as one of the fourteen most important technical initiatives for making the Nation safer. This and other reports led the White House to declare that *"securing DCS/SCADA is a national priority"* in *The National Strategy to Secure Cyberspace* (February 2003).

While the private sector is best equipped to protect these systems, GAO noted in their report on *Cybersecurity of Control Systems* that businesses are reluctant to spend money to secure control systems because of the expense, personnel required and the perception of a low threat. Vendors will not develop more secure systems unless they perceive a robust end-user market and have clear system requirements to design to. Even if more secure control systems are developed, there is no consistent way to test their potential vulnerabilities. To help address these issues, the *National Strategy to Secure Cyberspace* recommended that DOE work in partnership with industry and develop adequate test beds and new technologies such as low latency link encryption, key management, and grid status monitoring.

OE is also responsible for the energy infrastructure security in accordance with Homeland Security Presidential Directive (HSPD) 7. In this role, OE focuses on communications and controls specific to the energy infrastructure and coordinates with DHS to ensure there is no overlap in efforts. While asset owners see the benefit in sharing information with one another to develop lessons learned, they are reluctant to share specific, sensitive information. OE plays the facilitation role of the unbiased, neutral body that can collect information from utilities and develop lessons learned while maintaining the sensitivity of the information.

3.2 Visualization and Controls (V&C): Program Initiatives

Prior to the OE V&C program, system operators used off-line models to assess reliable operation of the system under predicted loading and contingencies conditions; real-time sensing and visualization of parameters were not done. A real-time monitoring, visualization and control system based on time-synchronized measurements of frequency, voltage and current on the electric transmission system will provide immediate benefits from initial visualization screens that display the status of the transmission system over a wide area in real time. However, to take full advantage of this technology, new software applications must be developed that are fed with these measurements to calculate the “health” of the grid in real time. OE’s approach is to first develop the capabilities for real-time data collection and begin to build a baseline for system performance. Over time, researchers will be able to compare system operation to this baseline. This will allow for new diagnostics and operator cuing tools to be developed and will lead ultimately to automatic operation. OE works closely with industry through technical working groups that are developing the applications and will demonstrate proof of concept tools and algorithms (in operating or simulated environments) with increasing capabilities over time:

Predictive Modeling → Real-time Data Collection → Diagnostics/Operator Cuing → Automation

Implementing new control schemes will require a minimal area of coverage. Currently real-time data collection is limited to approximately 100 sensors throughout the country. OE will work with industry to increase first the breadth of coverage by increasing the number of sensors and then the depth by deploying distribution level sensors. Sensors included in the deployment could include: phase measurement units (PMUs); upgrade of existing digital fault recorders with GPS-synchronization, or as PMUs; Intelligent Electronic Devices (IED) in the substation that can provide information redundancy, like time-synchronized circuit breaker monitors; or sensors for dynamic line loading conditions (sag monitors).

3.3 Technology Development

Visualization and Controls technologies focus on improving the reliability and security of transmission and distribution operations by improving system and reliability operators' ability to "observe" the system. Information systems, including advanced sensors, and control devices will reduce the decision time required to react to disturbances on the grid, improve communications among system operators across jurisdictional boundaries, improve security and improve recovery (through standard control technologies including transformers, sensors, communications equipment, and fault current limiters.) Predictive modeling capabilities along with development of other tools will enable faster responses and mitigation of contingencies. With the advancements and implementation of information systems throughout the grid, cyber security will be essential. A significant thrust of V&C's technology development activities is to harden the transmission system's digital control, communications and computing systems.

Monitoring Devices & Visualization Tools

The ability to have grid "situational awareness" across the electric grid is considered a key to maintaining high levels of reliability. In order to monitor the health of the grid and its dynamic state, high-fidelity real-time synchronized grid monitoring instruments, called Phasor Measurement Unit (PMU), have been installed in the Western Interconnection and are being installed throughout the Eastern Interconnection (EI). Aggregation of PMUs with phasor data concentrators (PDC, one utility), super PDCs (several utilities), and real-time operations tools that use this data can give wide-area views and online analysis of the power grid on a wide-area basis. Online real-time monitoring and operations tools and analyses are being developed in addition to post-disturbance or event analysis tools (software and hardware) to enable better planning, operations, modeling and improved reliability over the power grid are also being developed.

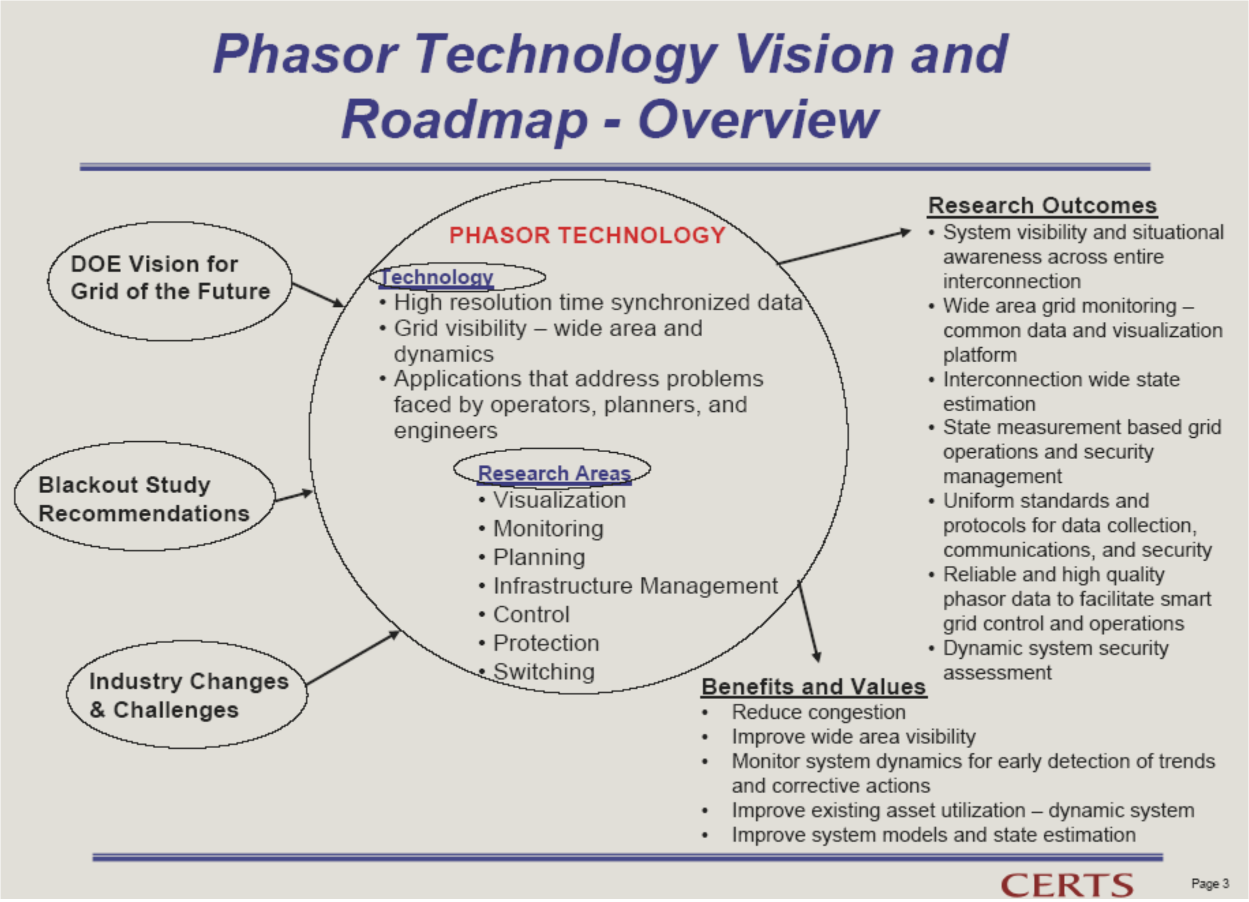
Phasors (phasor magnitude and angle) are GPS time-synchronized measurements from the high-speed sampling of instantaneous voltage and current of the power grid that provide more data than traditional systems. Phasor Data Concentrators (PDC) receive and correlate time-tagged phasor data from PMUs throughout the system to create a wide area dataset. GPS (accuracy to 1 microsec) time synchronized high speed measurements are essential for real-time & wide-area monitoring of transmission lines and inter-ties. If a disturbance is detected, the entire data set is recorded in synchronism; this allows the data to be overlaid regardless of communication latencies. Widespread deployment of theses technologies can help detect disturbances and provide advance warnings to prevent widespread outages. Online operations tools using this new real-time data are very much in their infancy. The PMUs give a whole new and complete picture of system dynamics, and understanding the dynamic modes of the EI is the first issue at hand. However, the limited number of PMUs that are currently installed in the EI only gives a small glimpse of system dynamics. It can also provide post disturbance analysis and validation of both steady-state and dynamic grid models. Future applications include: simultaneous visualization of grid operations, weather/lightning, and other environmental data; enhanced grid state estimation; adaptive control and protection systems; advanced contingency analysis to rapidly consider N-2 to N-X contingencies and produce data bases for decision making; and dynamic system rating and power flow control via Flexible AC Transmission Systems (FACTS) devices, dynamic volt/var observability, real time dispatch of a distribution level voltage schedule, and control.

As illustrated in Figure 1, phasor technology R&D and deployment will create a robust, secure, synchronized data measurement and communication infrastructure that will improve planning, operation and reliability by providing:

- a comprehensive wide-area view of the system
- rapid assessment of system conditions

- improved system models for steady-state and dynamic analysis, and
- enhanced post-disturbance analysis.

Figure 1. Phasor Technology Vision and Roadmap



State Estimation

The best power system control centers in the country are evolving to encompass larger and larger areas of the grid. In order to observe the entire eastern and western interconnections, real-time data throughout each interconnection is needed. Currently, state estimator software programs use Supervisory Control And Data Acquisition Systems (SCADA) data (2 to 5 second data) along with network models to determine the estimated state of the grid. State estimations are usually run every 1 to 5 minutes. The incorporation of PMU data into State Estimators (SEs) offers the ability to improve the accuracy, robustness (ability to converge on a solution) and model correctness of existing state estimators. Also, current SEs are used separately by each utility or ISO, and PMU data offer the capability to integrate the SEs being used by each so that they are more accurate and precise. This is especially true for the models of the external buses for an SE, and why the system model is the least detailed and accurate. However, simply obtaining real-time data and having a faster and more accurate SE does not provide improvements on the grid on their own. Action needs to be taken in the way of real-time controls. In order to react, certain steps can be useful in improving the grid reliability such as running a state estimator to true-up the data against a model of the system (state estimation), running a full set of contingency analysis (line/generator trips, etc.), and returning the results to each of the control centers across the entire grid. All of this needs to be repeated every few seconds.

The real-time data collection and analysis tasks are daunting but are reasonably well understood. There is also an acknowledged need for more sophisticated visualization tools that allow system operators to better understand the large-scale health of the power system and what may be required to ensure that system integrity is maintained. Current industry practice provides excellent tools for operators to address local problems in detail. They do this continuously. Tools that provide operators with the ability to recognize wide-scale, interconnection-threatening conditions are in their infancy. Tools that help operators cope with large-scale events as they occur do not exist. Advanced control centers are pushing the state of the art in commercial data communications and computation but the largest still handle less than 10% of the interconnected power system and computational requirements increase quite dramatically as you analyze larger systems.

Modeling & Simulation

Modeling and simulation tools will be available to help improve reliability of the nation's grid. In order to achieve this vision, data management capabilities will be critical. Data compression, data quality, on-line data analysis, storage and retrieval are all important factors.

- Non-linear systems analysis – models that are customized for individual grid analysis applications that include the degree of non-linear representation required
- Simulation – Combine advanced models and high-speed computing to support planning and grid/market interaction analysis
- Offline analytical methods for analyzing and processing large numbers of contingencies efficiently
- Design Criteria Human Factors – visualization

Fault Current Limiters

In recent years, the power grids are bearing larger loads with no substantial upgrade in the power system pushing up the loading on existing transmission capacity, shrinking operating margins and raising fault-current levels. This has driven the need for a device that can operate with little to no power loss and limit fault currents to a manageable level. In the normal mode, the novel fault current limiter offers little to no impedance to limit losses due to its use while in situations of faults, it switches into high impedance mode to limit the fault current. This is the basic principles of Ohm's law being put into effect: a higher impedance will result in a smaller current. The resourceful placement of inductors also limits the fault current in the transient response as it is impossible to change the current through an inductor instantaneously. The inductor will also resist extreme changes in the current and thus aid in limiting the amount of fault current.

3.4 Market Applications for the Technologies

The major applications of these technologies are with regional transmission organizations (RTOs), independent system operators (ISOs), and control areas. Significant benefits are to be realized by utilities and ISOs. Software and hardware vendors are expected to participate at all levels. Eventually, relatively inexpensive instrumentation and communications systems will become available in the market. Figure 2 is an illustration of some of the various market and operational elements that would benefits from these technologies.

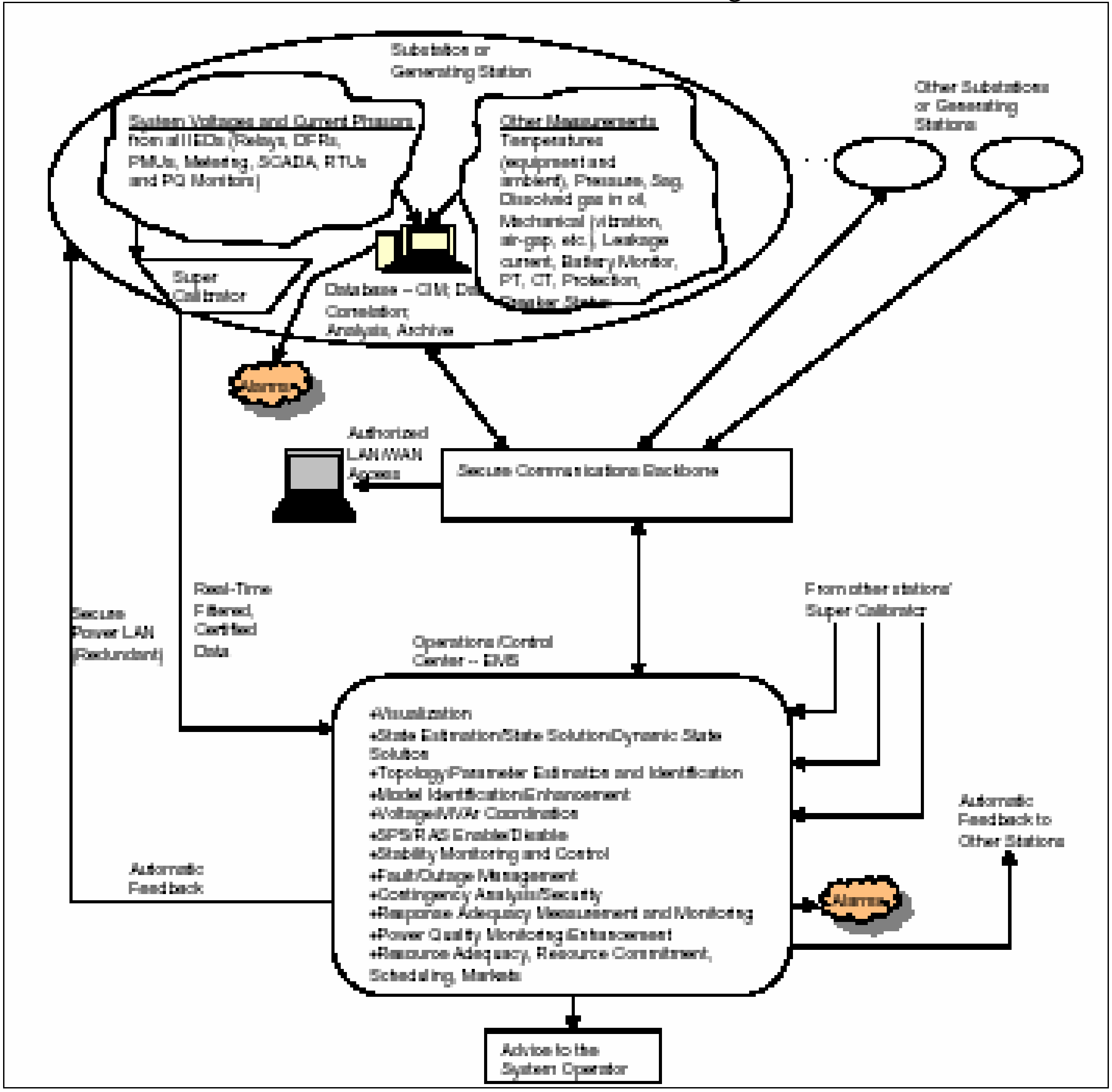
3.5 Size of Potential Market

Sensors and monitors will be located at major substations and large generating stations to start, and later expanded to less significant substations and generating stations as the technology comes down in cost and in the complexity of installation and setup. In the Eastern Interconnect Project, around 35 PMUs are currently installed with the hope to grow that number to 50 by the end of this year. Over 350 real time measurement units will be installed in the phase III effort. There are over 14,000 high voltage substations, so the market size potential is not close to being realized.

3.6 Comparisons to Current Technologies

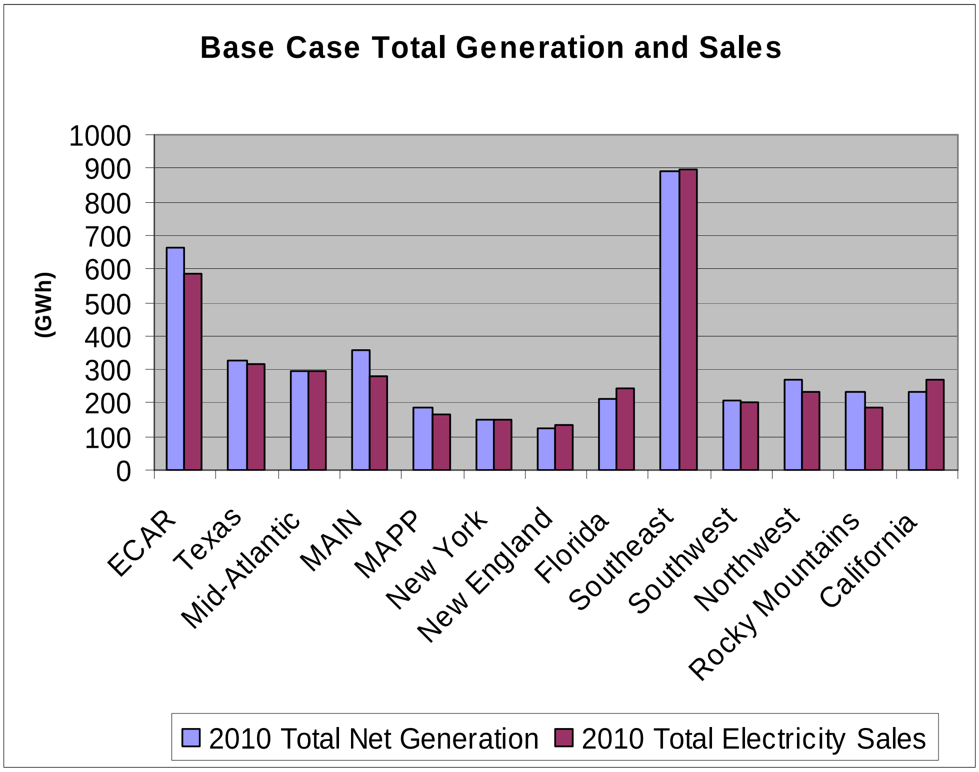
Current technology is not available that offers wide-area situational awareness of the electric grid. Any additional monitoring devices, analytical models and visualization tools will be an added cost in order to overcome this technical limitation. The electric power grid represents billions of dollars of capital investment. Millions of dollars are required each year to maintain and repair equipment. A major blackout can not only cause major equipment failures but also result in direct and indirect costs associated with the loss of electric power to industrial, commercial, and residential customers. The current state of the art is the use of SCADA to provide data measurements in the seconds time-frame, which is not precisely time-synchronized and which was never designed to provide real-time control capabilities. The State Estimators use the SCADA in combination with grid models to determine the state of the system every 1 to 5 minutes. These SCADA systems have been around since the 1970's and are expensive to install and maintain and replace, but offer significant benefits in terms of observing and analyzing the grid. PMU-based technology is the next level of data acquisition and control and can provide significant benefits that both compliment existing SCADA as well as provide separate and unique benefits. The cost of PMU technology due to its development phase is still high but is coming down closer to market expectations as the use of the technology grows and its benefits continue to grow and has its communication and performance requirements are standardized. However at the present and for the near future, the technology is still too expensive to be use in mass quantity by any one utility. Most are installing one to a few units to learn more about the technology which is still very much an R&D project.

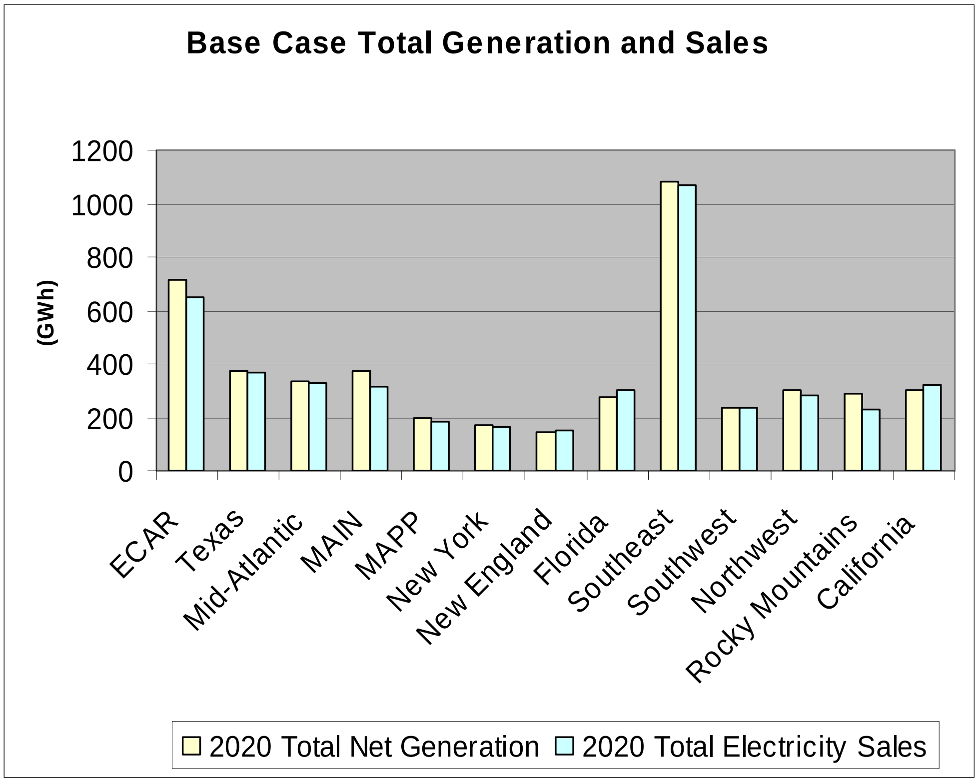
Figure 2. Illustration of Various System Elements that Could Benefit from V&C Technologies

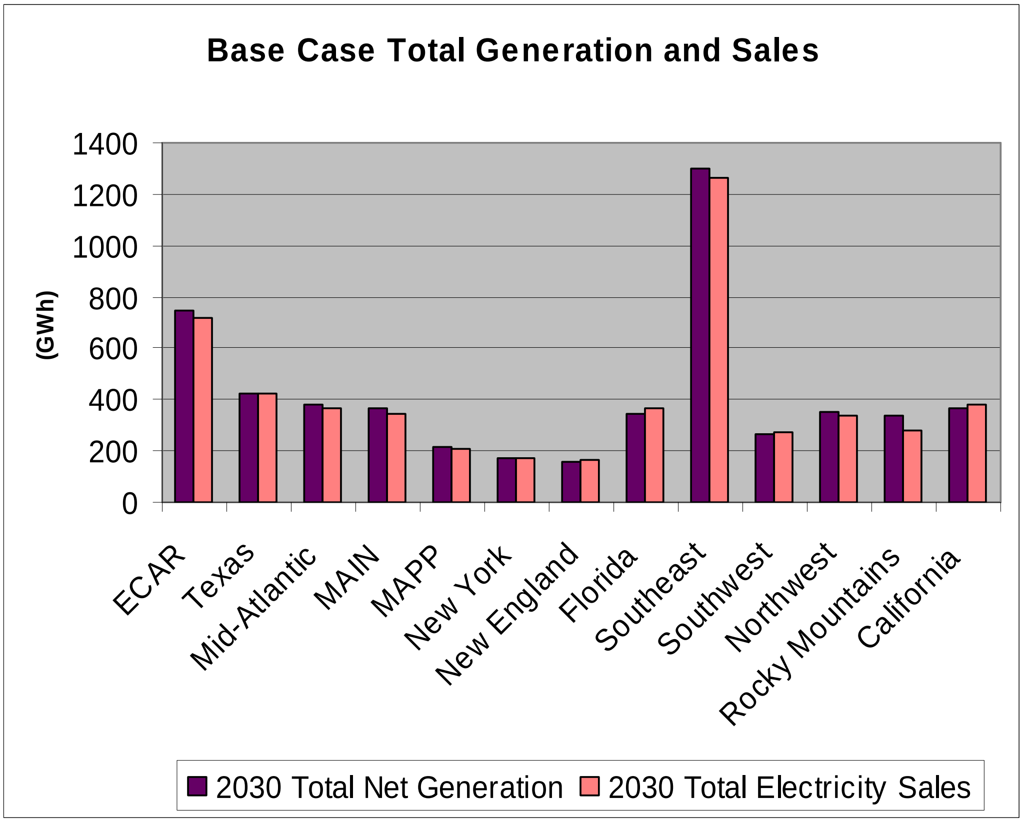


4. Energy Market Projections

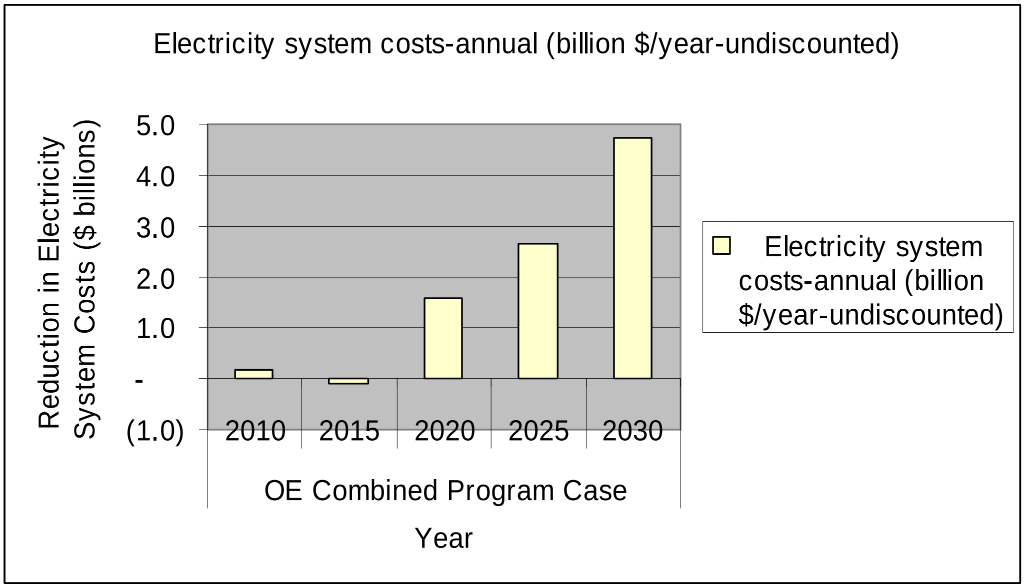
The following graphs are projections from the National Energy Modeling System (NEMS) – May 2006. Refer to these projections to the extent they are relevant to making your estimates.




Base Case Total Generation and Sales
(GWh)
1200
1000
800
600
400
200
0
ECAR
Texas
Mid-Atlantic
MAIN
MAPP
New York
New England
Florida
Southeast
Southwest
Northwest
Rocky Mountains
California
2020 Total Net Generation
2020 Total Electricity Sales


Base Case Total Generation and Sales
(GWh)
1400
1200
1000
800
600
400
200
0
ECAR
Texas
Mid-Atlantic
MAIN
MAPP
New York
New England
Florida
Southeast
Southwest
Northwest
Rocky Mountains
California
2030 Total Net Generation
2030 Total Electricity Sales

Projected Economic Benefits of the DSI and HTS Programs Combined (Electricity System Cost Reduction)



Appendix C-5

List of Panel Members

National Panel on Estimating the Reliability and Security Benefits of the U.S. Department of Energy's Distributed Systems Integration R&D Program

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National Panel on Estimating the Reliability and Security Benefits of the U.S. Department of Energy's *High Temperature Superconductivity* R&D Program

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Vice President, Electric Industry Affairs
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National Panel on Estimating the Reliability and Security Benefits of the U.S. Department of Energy's *Energy Storage and Power Electronics* R&D Program

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Sandia National Laboratory

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Electrivation

James P. Crane
Research and Development Manager
Exelon Energy Delivery

Michael R. Ingram
Senior Manager, Transmission Technologies
Tennessee Valley Authority

Dale Krummen
Transmission Staff Engineer
American Electric Power

Robert H. Lasseter
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University of Wisconsin

Neil Kirby
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AREVA T&D Inc

David Nichols
Rolls Royce

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Vijay Vittal
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National Panel on Estimating the Reliability and Security Benefits of the U.S. Department of Energy's *Visualization and Controls* R&D Program

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David Hawkins
Lead Industry Relations Representative
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Appendix C-6

Questions asked of Panel Members (example is for the High Temperature Superconductivity panel)

Benefits of R&D to Develop New or Improved Technologies that Improve Electricity Reliability and/or the Security of Energy System Infrastructure

Technology R&D Program: **_High Temperature Superconductivity_**

Name of Panel Member:
Title:
Organization:
E-mail:

Disclosure – Do you or your organization receive U.S. Department of Energy or National Laboratory funding?

Information and Instructions:

Thank you for serving on the "National Panel on Estimating the Reliability and Security Benefits of the U.S. Department of Energy's High Temperature Superconductivity R&D Program." This program is supporting development of domestic manufacturing capability for second-generation high temperature superconducting wires for widespread use in advanced electric power equipment.

We request your estimates of the future improvements in electricity reliability and energy system security that will result from technologies developed in connection with this program:

- Provide one set of estimates assuming there will be such a program in the U.S. Department of Energy (DOE) and another set assuming there will not be a program (with high temperature superconductivity (HTS) advances due solely to private sector and other non-U.S. DOE R&D).

- To reflect the uncertainty in such estimates, provide a High or 95-th percentile estimate, a Mid or 50-th percentile estimate, and a Low or 5th-percentile estimate. The **High, Mid, and Low** estimates of cost reductions attributable to R&D should **all be based on the Mid-Estimate Market Penetration** of the technology/system.

Before making your estimates, carefully review the estimates and reasoning of the other members of this panel from the previous round(s) and the program summary information, all of which are provided separately. It might be helpful to compare your estimates for this R&D program (i.e., your estimates on the following pages) to your estimates for all four R&D programs combined (which you are providing in a separate attachment). **If the estimates of individual panels *add* to cost or damage reductions that are close to 100%, then either the new technologies/systems will in fact eliminate all outages, etc., or one or more panels' estimates are too high, or one or more technologies/systems are redundant or competing for the same market.**

Suggested Steps:

We suggest that you develop your estimates in the following steps:

1. Review the information provided separately. It describes the DOE program's technical goals, the technologies or designs to be developed, and broad energy market projections.

2. Review the previous estimates and reasoning of the other members of this panel.

3. Estimate the Mid case without any DOE programs (does not apply to questions 3 and 7). Positive percentages mean that private sector R&D (but without any DOE program) will lead to high temperature superconductivity technologies that reduce the costs of outages, power quality disturbances, etc. relative to what they would otherwise be.

4. Estimate the Mid case with the DOE program. If you think that the DOE program will have a net benefit, then the percentages should be greater than the corresponding percentages in the "No DOE R&D" column.

5. Provide estimates for the Low and High cases that are keyed to your Mid estimates. The values in the High columns should be greater than the corresponding values in the Mid columns, and similarly the Low column values should be less. Your estimates should reflect the technical risks in achieving the R&D goals, market uncertainties, and other (e.g., regulatory) uncertainties.

6. In questions 3 to 6, base your Low and High (as well as your Mid) estimates of the % reductions on the Mid-estimate of market penetration.

Meaning of "% Reductions":

i) The % reductions are relative to what the costs will be using best-available current technology/designs, if there will be no future R&D at all (neither government, universities, nor industry) on the technology/design areas that the DOE program(s) is focusing on.

ii) Very small values of % reduction in the No-DOE columns of the tables mean that private sector advances in HTS designs will have very small effect on stemming outage and other costs because of their limited market penetration or effectiveness. Conversely, very large values of % reductions mean very large impacts.

iii) The difference between corresponding "With DOE" and "No DOE" numbers directly reflects the incremental impact of the DOE program.

iv) The % reductions in the "With DOE" case stem from technologies/designs developed in some connection with the DOE program, not from every technology of that type

v) % reductions should always be positive numbers, or zero. In the first round, some panelists had negative numbers to reflect their assessment that congestion, transmission congestion, etc. costs will increase in the future regardless of advances in technology. But the % reduction numbers are relative to the projected costs so that the numbers should always be non-negative.

vi) Costs and cost reductions are in constant dollars, adjusted for inflation.

vii) The % reductions are relative to the total cost (e.g., of outages) to the nation, not just relative to where the technology/system is deployed. If the market penetration is low, then one would expect low % reductions in outage, power quality disturbance, and transmission congestion costs, and in security-related benefits.

viii) The % reductions in costs, etc. are all (even the Low and High ones) based on your Mid-level estimate of market penetration. Greater levels of market penetration normally lead to larger impacts (i.e., greater reductions in costs).

Contacts for Information: *General*: Russell Lee, E-mail: leerm@ornl.gov
Technical: Dominic F. Lee, E-mail: leedf@ornl.gov

Instructions on Return of Your Estimates:

Answer the questions directly in this Word file in the spaces highlighted in color.[38] When you are finished, rename this file by appending your last name (e.g., Panel Member's Estimates_HTS_02_Smith.doc).

Return completed material by **Monday, July 10, 2006** to both Russell Lee and Gbadebo Oladosu:

leerm@ornl.gov; oladosuga@ornl.gov

[38] Panel members will be listed and the results of the panel's estimates will be provided in a publicly available report. Your estimates or comments will not be attributed by name either in this report or in the exchange of information among panel members (e.g., you will be referred to as Panel Member H-01).

Panel Member's Estimates:

1. Market Penetration. Provide Low and High estimates of the market penetration of high temperature superconductivity technologies for electricity delivery and reliability, *as a percentage of all equipment in the field* (Note: These percentages are consistent with the projections of market penetration as a percentage of new sales and replacements (which were previously used in this table). The latter are graphed in Section 4 of the HTS Program description).

The estimates should be for the "bundle" of all HTS technologies being developed by the DOE program, not just the technology with which you are most familiar. DO NOT CHANGE ANY VALUES ALREADY IN THE TABLE (IN THE GRAY CELLS).

Table 1. Average ***Market Penetration*** of HTS Technologies
as a Percentage of all Equipment in the Field

Year	Low		Mid		High	
	No DOE R&D	**With DOE R&D**	**No DOE R&D**	**With DOE R&D**	**No DOE R&D**	**With DOE R&D**
2010	%	%	0%	0%	%	%
2015	%	%	0.07%	0.4%	%	%
2020	%	%	0.5%	2.5%	%	%
2030	%	%	6%	16%	%	%

Comment 1. The reasoning behind your estimates:

2. Outage Reductions.[39] Given the Mid-estimates of market penetration, estimate the percent reduction in the total cost of electrical outages in the U.S. that can be attributed to HTS technological advances.[40]

Table 2. *% **Reduction in Total Electrical Outage Costs in the U.S.***
*(Based on **Mid**-Estimate of Market Penetration)*

Year	Low		Mid		High	
	No DOE R&D	**With DOE R&D**	**No DOE R&D**	**With DOE R&D**	**No DOE R&D**	**With DOE R&D**
2010	%	%	%	%	%	%
2015	%	%	%	%	%	%
2020	%	%	%	%	%	%
2030	%	%	%	%	%	%

Comment 2. The reasoning behind your estimates:

[39] Not including outages from terrorist attacks, wars, major natural disasters, or other catastrophic destruction.

[40] If technologies will be available at the same time and will perform the same as those if there were no DOE program, then all estimates in each pair of columns in Table 2 will be the same. Each percentage value must be less than 100%.

3. <u>Components of Outage Cost-Reduction</u>. Given the Mid-estimates of market penetration with the DOE program, estimate the <u>portion</u> of the reduced outage costs that you attribute to an expected reduction in: (a) the number of outages, (b) average duration of outages, and (c) number of customers affected per outage.

Table 3. ***Relative Contribution to Reduction in Outage Costs***

Reason for Reduction in Outage Cost	Contribution to Total Cost Reduction
(a) Reduced number of outages	%
(b) Reduced average duration of an outage	%
(c) Reduced average number of residential customers, or reduced size of commercial or industrial customers, affected by an outage	%
Above three add up to:	100%

Comment 3. The reasoning behind your estimates:

4. <u>Reductions in Power-Quality Disturbances</u>. Power-quality disturbances are deviations from power being supplied as a sine wave with the amplitude and frequency given by national or system standards. Estimate the percent <u>reduction</u> in the total <u>cost of power-quality events</u> in the U.S. that can be attributed to HTS technological advances.[41]

Table 4. ***% Reduction in Total Cost of Power-Quality Disturbances in the U.S.***
*(Based on **Mid**-Estimate of Market Penetration)*

Year	Low		Mid		High	
	No DOE R&D	**With DOE R&D**	**No DOE R&D**	**With DOE R&D**	**No DOE R&D**	**With DOE R&D**
2010	%	%	%	%	%	%
2015	%	%	%	%	%	%
2020	%	%	%	%	%	%
2030	%	%	%	%	%	%

Comment 4. The reasoning behind your estimates:

[41] If technologies will be available at the same time and will perform the same as those if there were no DOE program, then all estimates in each pair of columns in Table 4 will be the same. Each percentage value must be less than 100%.

5. <u>Reductions in Transmission Congestion</u>. Transmission congestion costs are the difference between the cost of delivering electricity if there were no transmission constraints, which are the cause of the congestion, and the cost with the current (or anticipated) constrained system. Estimate the percent <u>reduction in the total cost of transmission congestion</u> in the U.S. that can be attributed to HTS technological advances.[42]

Table 5. ***% Reduction in Total Transmission Congestion Costs in the U.S.***
*(Based on **Mid**-Estimate of Market Penetration)*

Year	Low		Mid		High	
	No DOE R&D	With DOE R&D	No DOE R&D	With DOE R&D	No DOE R&D	With DOE R&D
2010	%	%	%	%	%	%
2015	%	%	%	%	%	%
2020	%	%	%	%	%	%
2030	%	%	%	%	%	%

Comment 5. The reasoning behind your estimates:

6. <u>Security of Energy System Infrastructure</u>. The (in)security of energy system infrastructure refers to its vulnerability to highly disruptive catastrophic events, and to the system's ability to respond and recover in such an event.[43] Estimate the percent <u>reduction</u> in each of the following factors that can be attributed to HTS technological advances.[44]

Table 6a. *% **Reduction in Likelihood** of a Catastrophic Event on U.S. Energy System Infrastructure due to **Improved HTS Technologies***
*(Based on **Mid**-Estimate of Market Penetration)*

Year	Low		Mid		High	
	No DOE R&D	With DOE R&D	No DOE R&D	With DOE R&D	No DOE R&D	With DOE R&D
2010	%	%	%	%	%	%
2015	%	%	%	%	%	%
2020	%	%	%	%	%	%
2030	%	%	%	%	%	%

Comment 6a. The reasoning behind your estimates:

[42] If optimized system designs will be available at the same time and will perform the same as those if there were no DOE program, then all estimates in each pair of columns in the table will be the same. Each percentage value must be less than 100%.

[43] Examples of such events include major terrorist attacks, cyber attacks, and major natural disasters.

[44] Each percentage value in Tables 6a-c must be less than 100%.

Table 6b. ***Given an Attack or Destructive Event,*** *% Mitigation of the Damage, by Using Improved HTS Technologies and Systems that Provide Replacement Power or that Isolate Electricity* ***Supply***[45]
(Based on ***Mid****-Estimate of Market Penetration)*

Year	Low		Mid		High	
	No DOE R&D	**With DOE R&D**	**No DOE R&D**	**With DOE R&D**	**No DOE R&D**	**With DOE R&D**
2010	%	%	%	%	%	%
2015	%	%	%	%	%	%
2020	%	%	%	%	%	%
2030	%	%	%	%	%	%

Comment 6b. The reasoning behind your estimates:

Table 6c. ***Given an Attack or Destructive Event,*** *% Reduction in What the Damage Would have Been, by Using HTS Technologies and Systems to Reduce or Shift Energy* ***Demand***[46]
(Based on ***Mid****-Estimate of Market Penetration)*

Year	Low		Mid		High	
	No DOE R&D	**With DOE R&D**	**No DOE R&D**	**With DOE R&D**	**No DOE R&D**	**With DOE R&D**
2010	%	%	%	%	%	%
2015	%	%	%	%	%	%
2020	%	%	%	%	%	%
2030	%	%	%	%	%	%

Comment 6c. The reasoning behind your estimates:

[45] Given that the disruptive event occurs. Each estimate must be less than 100%.

[46] Given that the disruptive event has occurred and that back-up or replacement supply is deployed. The reduced demand could either be prior to any event occurring (e.g., due to greater energy or system efficiency), or (possibly elsewhere in the system) in response to the event. Each estimate must be less than 100%.

7. **<u>Reliability Projections</u>**. Provide your mid-level estimate of the percentage increase in the future costs of outages, power quality disturbances, and transmission congestion in the U.S., relative to the current levels in the year 2005, **assuming <u>no</u> future R&D of <u>any type</u>**.

Table 7. *Mid-Level % Difference in* ***Costs in the Future*** *Relative to Today's Costs (In Constant Dollars – Do* ***Not*** *Include Any Inflation)*[47]

Year	Outages	Power Quality Disturbances	Transmission Congestion
2010	%	%	%
2015	%	%	%
2020	%	%	%
2030	%	%	%

Comment 7. The reasoning behind your estimates:

Thank you.

[47] A value of 0% in a given year means that annual costs increase at the general rate of inflation. A positive percentage means that the annual costs are greater than current costs by that percentage, even after adjusting for inflation. A negative percentage means that costs have decreased, after adjusting for inflation. For example, "25%" means 25% greater than the cost in 2005; 100% means double the cost in 2005; etc.