Barriers to Industrial Energy Efficiency

A Study Pursuant to Section 7 of the
American Energy Manufacturing Technical Corrections Act

June 2015

U.S. DEPARTMENT OF ENERGY

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Statutory Requirement

American Energy Manufacturing Technical Corrections Act

Public Law 112-210

Section 7. Reducing Barriers to the Deployment of Industrial Energy Efficiency

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(a) Definitions – In this section:

1) Industrial Energy Efficiency – The term "industrial energy efficiency" means the energy efficiency derived from commercial technologies and measures to improve energy efficiency or to generate or transmit electric power and heat, including electric motor efficiency improvements, demand response, direct or indirect combined heat and power, and waste heat recovery.

2) Industrial Sector – The term "industrial sector" means any subsector of the manufacturing sector (as defined in North American Industry Classification System codes 31-33 (as in effect on the date of enactment of this Act)) establishments of which have, or could have, thermal host facilities with electricity requirements met in whole, or in part, by on-site electricity generation, including direct and indirect combined heat and power or waste recovery.

(b) Report on the Deployment of Industrial Energy Efficiency

1) In General – Not later than 2 years after the date of enactment of this Act, the Secretary shall submit to the Committee on Energy and Commerce of the House of Representatives and the Committee on Energy and Natural Resources of the Senate a report describing:

(A) the results of the study conducted under paragraph (2); and

(B) recommendations and guidance developed under paragraph (3).

2) Study —The Secretary, in coordination with the industrial sector and other stakeholders, shall conduct a study of the following:

(A) The legal, regulatory, and economic barriers to the deployment of industrial energy efficiency in all electricity markets (including organized wholesale electricity markets, and regulated electricity markets), including, as applicable, the following:

(i) Transmission and distribution interconnection requirements.

(ii) Standby, back-up, and maintenance fees (including demand ratchets).

(iii) Exit fees.

(iv) Life of contract demand ratchets.

(v) Net metering.

(vi) Calculation of avoided cost rates.

(vii) Power purchase agreements.

(viii) Energy market structures.

(ix) Capacity market structures.

(x) Other barriers as may be identified by the Secretary, in coordination with the industrial sector and other stakeholders.

(B) Examples of—

(i) successful State and Federal policies that resulted in greater use of industrial energy efficiency;

(ii) successful private initiatives that resulted in greater use of industrial energy efficiency; and

(iii) cost-effective policies used by foreign countries to foster industrial energy efficiency.

(C) The estimated economic benefits to the national economy of providing the industrial sector with Federal energy efficiency matching grants of $5,000,000,000 for 5- and 10-year periods, including benefits relating to—

(i) estimated energy and emission reductions;

(ii) direct and indirect jobs saved or created;

(iii) direct and indirect capital investment;

(iv) the gross domestic product; and

(v) trade balance impacts.

(D) The estimated energy savings available from increased use of recycled material in energy-intensive manufacturing processes.

3) *Recommendations and Guidance —The Secretary, in coordination with the industrial sector and other stakeholders, shall develop policy recommendations regarding the*

deployment of industrial energy efficiency, including proposed regulatory guidance to States and relevant Federal agencies to address barriers to deployment.

Executive Summary

Industry[1] accounted for approximately one-third of the United States' total primary energy consumption in 2012. The potential cost-effective energy savings in U.S industry is large—amounting to approximately 6,420 trillion British thermal units of primary energy (including combined heat and power), according to a comprehensive 2009 analysis by McKinsey & Company.[2] Congress recognized that there are a host of barriers limiting greater industrial energy efficiency. This study has been prepared in response to Section 7 of the American Energy Manufacturing Technical Corrections Act (Act), which directs the Secretary of Energy to conduct a study, in coordination with the industrial sector and other stakeholders, of barriers to the deployment of industrial energy efficiency.

The Act defines the term "industrial energy efficiency" to mean energy efficiency derived from commercial technologies and measures that improve energy efficiency, or technologies that generate or transmit electric power and heat. Examples of industrial energy efficiency provided in the Act include electric motor efficiency improvements, demand response, direct or indirect combined heat and power, and waste heat recovery. The Act defines the term "industrial sector" to mean any subsector of the manufacturing sector as defined in North American Industry Classification System (NAICS) codes 31–33.

In addition to studying barriers to deployment of industrial energy efficiency, Congress directed the Secretary of Energy to include the following:

- Examples of State and Federal policies, private initiatives, and foreign policies that foster greater use of industrial energy efficiency.
- Estimated economic benefits to the national economy of a $5 billion Federal matching grant program that supports the industrial sector.
- Estimated energy savings from increased use of recycled materials in energy-intensive manufacturing processes.

This study examines industrial energy efficiency technologies and measures divided into three categories:

[1] The Energy Information Administration defines "industry" to include manufacturing (NAICS codes 31- 33); agriculture, forestry, fishing, and hunting (NAICS code 11); mining, including oil and gas extraction (NAICS code 21); and construction (NAICS code 23). The Act defines "industry" more narrowly to include only manufacturing (NAICS codes 31-33).

[2] McKinsey & Company, 2009. Unlocking Energy Efficiency in the U.S. Economy, page 76.

- Industrial end-use energy efficiency
- Industrial demand response
- Industrial combined heat and power (CHP)[3]

The study is organized as follows:

- Executive Summary
- Chapter 1 – Introduction
- Chapter 2 – Energy Consumption Trends
- Chapter 3 – Barriers to Industrial End-Use Energy Efficiency
- Chapter 4 – Barriers to Industrial Demand Response
- Chapter 5 – Barriers to Industrial Combined Heat and Power
- Chapter 6 – Economic Benefits of Energy Efficiency Grants
- Chapter 7 – Energy Savings from Increased Recycling
- Appendices[4]

Chapters 3, 4, and 5 include examples of successful State, Federal and international polices and private initiatives that foster greater use of industrial energy efficiency.

Stakeholder Input

This study results from a collaboration of DOE with nearly 50 experts from industry, combined heat and power operators, environmental stewardship organizations, associations of state governmental agencies, and federal governmental agencies. Contributions from stakeholders significantly improved the depth and breadth of the study.

Background on the Industrial Sector

The manufacturing sector is an important segment of the U.S. economy and is responsible for driving a significant amount of economic activity. Metrics that highlight the importance of manufacturing in the United States include (2013 data unless noted otherwise):

- Contributed $2.08 trillion, or about 12.5 percent, to U.S. gross domestic product.

[3] Within the context of this study, the topic of waste heat recovery is limited to waste heat to power and is included with combined heat and power.
[4] Appendices include stakeholders that collaborated with DOE (Appendix A) and supporting material for Chapter 6, including IMPLAN modeling (Appendices B-F).

- Supported more than 17.4 million jobs.
- Created high paying jobs—in 2012, compensation for manufacturing jobs was more than 25 percent higher than the average compensation for all U.S. jobs.

Data from the Energy Information Administration (EIA) shows that the industrial sector accounts for the largest share of energy consumption in the United States. In 2012, the United States consumed approximately 95 quads of energy, with the industrial sector accounting for 30.6 quads, or 32 percent of the total. Of this 32 percent, manufacturers accounted for 74 percent of energy consumption, equal to 22.6 quads, or 24% of all energy use in the United States.

EIA forecasts that total energy consumption will grow to about 102 quads in 2025, with nearly all of the growth coming from the industrial sector. From 2012 to 2025, energy consumption in the industrial sector is forecast to increase from 30.6 quads to 37.4 quads – a 22% increase. In 2025, energy use in the industrial sector is expected to exceed 36% of total energy consumption in the United States.

Given the scale of energy consumption in the industrial sector, and particularly the manufacturing segment, industrial energy efficiency improvements can have a significant impact on reducing the amount of energy consumed in the United States. The industrial sector has achieved substantial reductions in energy consumption as a result of implementing energy-efficient technologies and practices. Energy intensity—the amount of energy required for a fixed amount of manufacturing output—declined 40 percent between 1991 and 2006. While the industrial sector has shown significant progress in energy efficiency, studies suggest that the industry can move forward at an even faster pace, reducing energy consumption by 15 to 32 percent below 2025 forecast values.

Several Federal policies emphasize the importance of industrial energy efficiency and set aggressive goals for further adoption of energy-efficient technologies and practices. For example, Executive Order 13624 (signed August 30, 2012) sets a goal of 40 GW of additional combined heat and power capacity by 2020 and directs DOE to expand its Better Plants program, which partners with industry to achieve greater savings through efficiency. Given the scale of domestic manufacturing, improvements in the efficient use of energy in this sector is expected to have a significant impact on achieving Federal energy and climate goals, while improving U.S. manufacturing competitiveness.

Study Results

Barriers to Industrial Energy Efficiency and Successful Examples and Opportunities to Overcome Barriers

The industrial sector has shown steady progress in improving energy efficiency over the past few decades. As illustrated by the sidebar examples in Chapters 3, 4, and 5, many manufacturing plants in the industrial sector have been leaders in adopting advanced technologies and implementing innovative practices that have improved energy efficiency. While much progress has been achieved, this study identified 42 barriers that can be addressed to accelerate industrial energy efficiency. There may be additional barriers and successful examples not captured in this document, and the barriers discussed in this document should not be viewed as fully exhaustive.

There is a concentration of barriers and successful examples related to State utility regulations, including issues such as:

- Aligning utility and customer incentives with achievement of greater energy efficiency.
- Establishing energy savings targets.
- Increasing outreach for end-use energy efficiency, demand response, and CHP programs.

Of the 42 barriers identified, 15 correspond to end-use energy efficiency, 11 to demand response, and 16 to combined heat and power. The barriers are divided into three groups: economic and financial, regulatory, and informational. There are 15 economic and financial barriers, 18 regulatory barriers, and 9 informational barriers (breakdown shown in **Table 1**).

Table 1. Summary of Barriers

Group	Type of Industrial Energy Efficiency			Total
	End-use Efficiency	Demand Response	CHP	
Economic & Financial	6	3	6	**15**
Regulatory	5	5	8	**18**
Informational	4	3	2	**9**
Total	**15**	**11**	**16**	**42**

Successful examples and opportunities to overcome the barriers listed in **Table 1** were identified. There is overlap in some cases between barriers and related successful examples, and in these cases a single action can address multiple barriers.

Economic Benefits of Federal Matching Grants

Key assumptions used for the economic benefits analysis include (full list of assumptions in Chapter 6):

- $5 billion of Federal matching grants allocated equally over 10 years (i.e., $500 million per year).
- Participant cost share of 80 percent for base case. With this assumption, the total funding pool is $25 billion, or $2.5 billion per year.
- 50 percent of funds allocated for combined heat and power projects, and 50 percent of funds used to support energy efficiency and demand response projects.
- All funds used for deployment (no funds allocated for research and development).

The results of the analysis indicate that a $5 billion Federal matching grant program implemented over a 10-year period will:

- Help support up to 9,700 to 11,200 jobs per year for the life of the program.
- Help manufacturers save $3.3 to $3.6 billion per year in energy costs by Year 5 of the grant program, and $6.7 to $7.1 billion per year by Year 10 of the grant program.

The results shown above correspond to a base case scenario with 80 percent participant cost share. An alternative scenario was evaluated based on 50 percent participant cost share. In general, the economic benefits derived from the 50 percent cost share scenario are lower compared to the 80 percent scenario because Federal grant funds are leveraged at a lower level in the 50 percent scenario.

Energy Savings from Recycling

The potential energy savings from increased recycling using currently deployed technologies were evaluated as requested for five energy-intensive industries: paper, aluminum, glass, steel, and plastics. These industries have the potential to use significant quantities of recycled materials. The analysis was limited to primary recycling (also called closed-loop recycling), where recycled products are mechanically reprocessed into a product with properties equivalent to the original product.[5] Increasing the amount of recycled material used as feedstock for manufacturing processes can significantly reduce energy consumption for energy-intensive manufacturers.

Two recycling scenarios were evaluated: modest and aggressive. These scenarios assume only currently deployed technologies. The modest scenario assumed that recycling rates remain well within the boundaries of existing technology and material availability limitations, and the aggressive scenario pushed these boundaries. It is important to note that the recycling rate

[5] This study was limited to focus only on MSW sources of waste materials since data are abundant. Useful data on recycling and recovery from other sources of waste materials (e.g., construction and debris) are not available and so were excluded from the study.

assumptions for the moderate and aggressive scenarios are not based on industry data. Rather, the authors of the study considered data on current recycling rates and the technical recycling limits, and developed the recycling rate assumptions for the scenarios within those ranges of data.

The recycling analysis included a breakdown of three types of plastics with a high potential for increased recycling:

- *Polyethylene terephthalate (PET).* PET is used for soft drinks packaging (PET bottles) and synthetic fibers.
- *High-density polyethylene (HDPE).* HDPE is used to make plastic jugs.
- *Low-density polyethylene (LDPE)/linear low-density polyethylene (LLDPE).* LDPE is used for plastic bags, and LLDPE is used for stretch wrap.

The recycling analysis shows that the following three manufacturing sectors have the potential to increase energy savings by more than 10 percent in at least one of the two scenarios:[6]

- Plastics (PET): 32 percent savings in aggressive scenario; 17 percent savings in modest scenario
- Steel: 15 percent savings in aggressive scenario; 6 percent savings in modest scenario
- Aluminum: 12 percent savings in aggressive scenario; 3 percent savings in modest scenario

While PET manufacturing shows the highest energy savings percentage (32 percent in aggressive scenario), the total energy savings are greatest for the steel industry because the amount of energy used for steel production is greater than the amount of energy needed for plastics production. For the steel industry, energy savings are estimated at 118 TBtu for the aggressive scenario, and 43 TBtu under the modest scenario. In terms of total energy savings, the steel industry is followed by paper, plastics (PET, HDPE, and LDPE/LLDPE combined), aluminum, and glass.

[6] The other sectors show positive energy savings below 10% in both the aggressive and modest scenarios.

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Acronyms and Abbreviations

ACEEE	American Council for an Energy-Efficient Economy
AEO	Annual Energy Outlook
AER	Annual Energy Review
AMI	Advanced Metering Infrastructure
APS	Alternative Portfolio Standard
ARRA	American Recovery and Reinvestment Act of 2009
BACT	Best Available Control Technology
BAU	Business as Usual
BGE	Baltimore Gas and Electric
BOF	Basic Oxygen Furnace
Btu	British Thermal Unit
CHP	Combined Heat and Power
CPF	Carbon Price Floor
CPP	Critical Peak Pricing
CEPS	Clean Energy Portfolio Standard
CSP	Curtailment Service Provider
DG	Distributed Generation
DISCO	Distribution Company
DOE	U.S. Department of Energy
DSIRE	Database of State Incentives for Renewables & Efficiency
DSM	Demand Side Management
EAF	Electric Arc Furnace
EERS	Energy Efficiency Resource Standard
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
EO	Executive Order
FERC	Federal Energy Regulatory Commission
FIT	Feed-in-Tariff
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GW	Gigawatt
HB	House Bill
HDPE	High Density Polyethylene
HVAC	Heating, Ventilating, and Air Conditioning
IAC	Industrial Assessment Center
IEE	Industrial Energy Efficiency

IEEP	Industrial Energy Efficiency Program
IOU	Investor-Owned Utility
IRP	Integrated Resource Plan
IRR	Internal Rate of Return
IRS	Internal Revenue Service
ISO	Independent System Operator
ITC	Investment Tax Credit
kW	Kilowatt
LAER	Lowest Achievable Emissions Reduction
LDPE	Low Density Polyethylene
LLDPE	Linear Low Density Polyethylene
LGIA	Large Generator Interconnection Agreement
LGIP	Large Generator Interconnection Procedures
MACRS	Modified Accelerated Cost-Recovery System
MACT	Maximum Achievable Control Technology
MADRI	Mid-Atlantic Distributed Resources
MECS	Manufacturing Energy Consumption Survey
MLP	Master Limited Partnership
MSW	Municipal Solid Waste
M&V	Measurement and Verification
MW	Megawatt
MWh	Megawatt-hours
NAESB	North American Energy Standards Board
NAICS	North American Industry Classification System
NPV	Net Present Value
NSR	New Source Review
NYSERDA	New York State Energy Research and Development Authority
O&M	Operation and Maintenance
PBF	Public Benefits Fund
PBR	Permit-by-Rule
PE	Polyethylene
PET	Polyethylene Terephthalate
PP	Polypropylene
PPA	Power Purchase Agreement
PS	Polystyrene
PSD	Prevention of Significant Deterioration
PTC	Production Tax Credit
PURPA	Public Utility Regulatory Policies Act

PVC	Polyvinyl Chloride
QF	Qualifying Facility
REIT	Real Estate Investment Trust
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
RTP	Real-Time Pricing
SBC	Systems Benefit Charge
SEEP	Supplier Energy Efficiency Program
SEMP	Strategic Energy Management Plan
SEP	Superior Energy Performance
SGIA	Small Generator Interconnection Agreement
SGIP	Small Generator Interconnection Procedures
TAP	Technical Assistance Partnership
T&D	Transmission and Distribution
TOU	Times of Use
TWh	Terawatt-hour
WHP	Waste Heat to Power
UBC	Used Beverage Can

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1. Introduction

1.1 Statutory Requirement

This study has been prepared pursuant to Section 7 of the *American Energy Manufacturing Technical Corrections Act*, (Pub. L. 112-210) which was signed into law on December 18, 2012. This Act directs the U.S. Department of Energy (DOE) to undertake a study "in coordination with the industrial sector and other stakeholders" on barriers to industrial energy efficiency.[1]

1.2 Description of the Manufacturing Sector

The Act defines the industrial sector to be manufacturing subsectors as described in North American Industry Classification System (NAICS) codes 31–33.[2] For perspective, NAICS codes consist of two to six digits based on the structure shown in **Table 2**. There are 20 two-digit NAICS sector codes as shown in **Table 3**. This table also shows the 21 three-digit subsector codes that comprise the manufacturing sector.

Table 2. Structure for NAICS Codes

Number of Digits	Description
2	Sector
3	Subsector
4	Group
5	Industry
6	Country-specific (United States, Canada, Mexico)

The manufacturing sector (NAICS 31–33) is broadly defined to include business establishments that use mechanical, physical, or chemical processes to create new products. Business establishments in the manufacturing sector are frequently called plants, factories, or mills, and cover a wide size of operations, ranging from small bakeries to integrated steel mills. The key distinction between manufacturing business establishments (NAICS 31–33) and businesses in other NAICS sectors is that manufacturers (NAICS 31–33) transform raw materials into new products.

Manufacturing subsectors are shown in **Table 3** (NAICS codes 31–33). Businesses are grouped into subsectors based on similarities in production processes, production equipment, and/or employee skills.

Table 3. NAICS Sector Codes and Manufacturing Subsector Codes

Two Digit Sector Codes

Code	Description
11	Agriculture, Forestry, Fishing and Hunting
21	Mining
22	Utilities
23	Construction
31-33	**Manufacturing**
42	Wholesale Trade
44-45	Retail Trade
48-49	Transportation and Warehousing
51	Information
52	Finance and Insurance
53	Real Estate Rental and Leasing
54	Professional, Scientific, and Technical Services
55	Management of Companies and Enterprises
56	Administrative and Support and Waste Management and Remediation Services
61	Educational Services
62	Health Care and Social Assistance
71	Arts, Entertainment, and Recreation
72	Accommodation and Food Services
81	Other Services (except Public Administration)
92	Public Administration

Three Digit Manufacturing Subsector Codes

Code	Description
311	Food Manufacturing
312	Beverage and Tobacco Product Manufacturing
313	Textile Mills
314	Textile Product Mills
315	Apparel Manufacturing
316	Leather and Allied Product Manufacturing
321	Wood Product Manufacturing
322	Paper Manufacturing
323	Printing and Related Support Activities
324	Petroleum and Coal Products Manufacturing
325	Chemical Manufacturing
326	Plastics and Rubber Products Manufacturing
327	Nonmetallic Mineral Product Manufacturing
331	Primary Metal Manufacturing
332	Fabricated Metal Product Manufacturing
333	Machinery Manufacturing
334	Computer and Electronic Product Manufacturing
335	Electrical Equipment, Appliance, and Component Manufacturing
336	Transportation Equipment Manufacturing
337	Furniture and Related Product Manufacturing
339	Miscellaneous Manufacturing

The manufacturing sector is an important segment of the U.S. economy and is responsible for driving a significant amount of economic activity. A 2013 report from the Alliance to Save Energy highlights the importance of manufacturing in the United States (based on data for 2013 unless noted otherwise):[3]

- Contributed $2.08 trillion, or about 12.5 percent, to U.S. gross domestic product.
- Supported more than 17.4 million jobs.
- Created high paying jobs—in 2012, compensation for manufacturing jobs was more than 25 percent higher than the average compensation for all U.S. jobs.

Federal policies continue to emphasize the importance of industrial energy efficiency and set aggressive goals for further adoption of energy-efficient technologies and practices.[4,5] Given the scale of domestic manufacturing, improvements in energy efficiency in this sector will have a significant impact on achieving Federal energy and climate goals.

1.3 Benefits of Industrial Energy Efficiency

The Act calls for a study of barriers to industrial energy efficiency. As barriers are examined, it is critical to identify what actions can be considered by states, Federal agencies, and private entities, to address these barriers, with the goal of capturing well-documented benefits[6] from increased deployment of industrial energy efficiency. It is also important to note successful examples of successful state and federal policies, private initiatives and international policies that resulted in greater use of industrial energy efficiency.

To help organize the analysis of barriers in this study, the topic is divided into three groups:

- Industrial End-Use Energy Efficiency
- Industrial Demand Response
- Industrial Combined Heat and Power (CHP)

Benefits for these three groups are discussed from two perspectives:

- Benefits to individual U.S. businesses (e.g., a manufacturing site that implements an energy efficiency improvement)
- Benefits to the nation

1.3.1 Industrial End-Use Energy Efficiency

Industrial end-use energy efficiency includes a broad range of energy-efficient technologies and management practices that can be implemented in the manufacturing sector to reduce energy consumption per unit of production. Examples that illustrate the diversity of technologies and practices include advanced electric motors and drives, energy-efficient lamps and lighting controls, recovery of waste heat, modernization or replacement of process equipment, and implementation of strategic energy management[7] systems that promote continuous energy efficiency improvement.

Benefits for U.S. businesses:

- *Reduced energy costs.* Industrial end-use energy efficiency can provide economic benefits by reducing energy costs for businesses by using less electricity or fuel per unit of production.[8]

- *Reduced emission control costs.* Industrial end-use efficiency measures provide a low-cost approach for reducing emissions. The Environmental Protection Agency (EPA) estimates that if the energy efficiency of industrial facilities[9] improved by 10 percent, companies could save $20 billion per year and reduce greenhouse gas (GHG) emissions equivalent to the electricity consumption of 22 million homes.[10]
- *Enhanced competitiveness.* Energy efficiency helps reduce energy costs and exposure to volatile energy prices, thereby reducing production costs and improving competitiveness.
- *Co-benefits such as reduced material loss, improved product quality, and reduced water consumption.* Industrial end-use energy efficiency often yields co-benefits beyond direct energy savings, and these co-benefits can have significant value to businesses.

Benefits for the nation:

- *Lower product costs for consumers.* Energy efficiency can reduce the cost of goods for American families and businesses by reducing the cost of manufacturing goods. Enhanced energy efficiency means that it takes less energy to manufacture products and these savings can be passed along to consumers.
- *Increased job growth.* The production and installation of energy-efficient technologies supports job growth based on American technology and skilled American labor. The American Council for an Energy-Efficient Economy (ACEEE) analysis indicates jobs are created from two primary effects: first, construction jobs are supported when an energy efficiency measure is implemented, and second, subsequent jobs are supported through energy cost savings that result from implementation.[11] For the manufacturing sector, a $1 million investment in an energy efficiency project with a 2-year payback is estimated to create 6.5 net jobs during the first year, plus 3½ net jobs in subsequent years over the life of the energy efficiency measure that is installed.[12]
- *Lower electricity costs associated with reduced electric grid infrastructure expenses.* Improved end-use efficiency reduces the amount of electricity that needs to be delivered through the electric grid. This reduction relieves stress on the electric grid and may help avoid or defer transmission and distribution (T&D) investments. Savings in electric grid investments benefit all electricity customers by avoiding increases in electricity rates.[13]
- *Increased health benefits from reduced criteria air pollutant and GHG emissions.* Reduced energy use through end-use efficiency can lead to lower-criteria air pollutant emissions, providing health benefits for society. End-use efficiency also lowers GHG

emissions associated with electric and thermal production for use on-site, which are linked to climate change.

1.3.2 Industrial Demand Response

Demand response yields a temporary change in energy usage driven by a price signal or incentive payment. Traditional demand response programs are used in the electric sector to reduce electricity usage during periods of high electricity demand (e.g., a hot summer afternoon) or when electric grid reliability may be compromised.[14] Modernization of grid communications and control technologies are creating additional opportunities for demand side resources to provide ancillary services such as regulation service and load following.[15] There are three primary ways for a manufacturing plant to respond to a demand response event:[16]

- Reduce electricity consumption
- Shift electricity usage
- Generate on-site power with standby generators or CHP

Benefits for U.S. businesses:

- *Reduces customer bills by reducing customer demand during peak periods.* Demand response can reduce on-peak energy costs, thereby decreasing the overall cost of production.[17] For example, industrial customers participating in demand response programs can switch their peak electricity usage to non-peak times when prices are lower or ramp up on-site generation (if available) during times of peak demand.
- *Produces revenue from incentive payments for demand response participation.* Demand response can provide industrial participants with payments that can be used for additional energy efficiency projects.
- *Enhances competitiveness*. Demand response helps reduce energy costs and exposure to volatile energy prices, thereby reducing production costs and improving competitiveness.

Benefits for the nation:

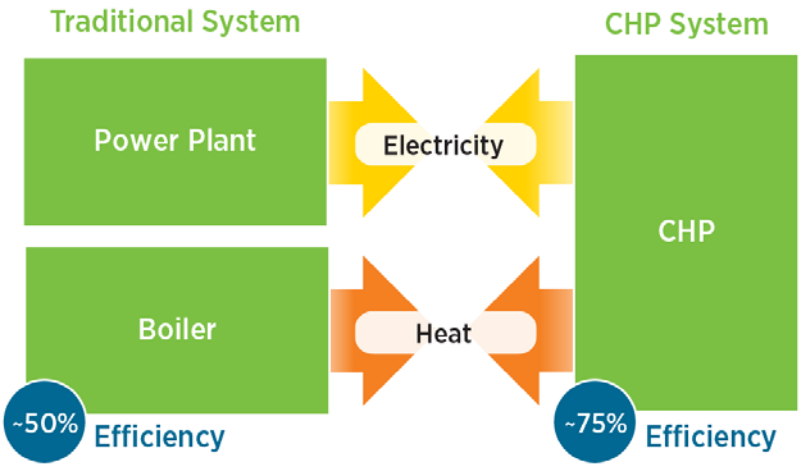
- *Avoid or defer construction of new generation plants.* Demand response can help defer or eliminate the need to build new power generation plants to meet peak power requirements.

- *Avoid or defer transmission and distribution (T&D) system upgrades.* In addition to reducing the need for new generation plants, demand response also reduces the need for new or upgraded T&D assets.
- *Promotes optimal dispatch of generation resources.* Demand response reduces grid peaks and can help fill "valleys" through load shifting. By smoothing electricity delivered from the grid, demand response can help maximize utilization of grid assets, including renewable energy.
- *Improves grid reliability and resiliency.* Demand response can enhance energy reliability because there is less stress on the grid during peak times, reducing the likelihood of voltage sags and power quality issues.
- *Enables grid integration of intermittent renewable resources.* State renewable portfolio standards and other incentives are driving the adoption of intermittent wind and solar technologies. As a result, flexible demand response can be used to absorb intermittent renewables through technologies that enable two-way communication and automated controls.
- *Contributes to job growth.* Demand response often requires certain infrastructure to be manufactured, installed, and maintained, such as additional metering, interconnection, or distribution hardware. The manufacture and installation of such technologies uses local labor and technology, which supports the U.S. economy.[18]

1.3.3 Industrial Combined Heat and Power

Combined heat and power simultaneously generates electric power and useful thermal energy from a single fuel source. Instead of purchasing grid electricity and burning fuel in an on-site furnace or boiler to produce thermal energy, a manufacturing plant can use a CHP system to provide both electricity and thermal energy from a single energy-efficient technology located on-site. A typical topping cycle CHP system consists of a gas turbine or reciprocating engine (these types of technologies that convert fuels to electrical or mechanical energy in CHP systems are referred to as prime movers) integrated with an electrical generator and a thermal recovery system. The CHP system produces electricity and recovers thermal energy that can be used for process heating, hot water heating, space heating, or space cooling. **Figure 1** shows a typical industrial CHP system that offsets the need for grid electricity and the need for steam or hot water that would otherwise be produced from an on-site boiler. When electricity and thermal energy are provided separately, the overall energy efficiency is in the range of 45–50 percent.[19] While efficiencies vary for CHP installations based on site specific parameters, it is reasonable to expect that a typical topping-cycle CHP system will operate at 65–80 percent efficiency (75 percent shown in figure).[20,21]

Figure 1. Efficiency Comparison between CHP and Conventional Generation [22]



Source: Efficiencies adapted from "Combined Heat and Power: A Clean Energy Solution"[23] *and information published by the U.S. Environmental Protection Agency's Combined Heat and Power Partnership*[24]

Benefits for U.S. businesses:

- *Reduces energy costs for the user.* Properly engineered CHP systems may reduce energy costs because the cost of fuel consumed to operate the CHP system can be less than the cost of purchased grid electricity plus the cost of fuel and operation of an on-site boiler or furnace, or because waste heat is being used instead of fuel.[25]
- *Reduces risk of electric grid disruptions and enhances energy reliability.* On-site CHP may provide an alternative source of electricity generation during grid outages leading to enhanced power reliability. Many CHP systems continued to operate following grid outages caused by natural disasters, including Hurricane Katrina, Hurricane Sandy and Hurricane Irene.[26]
- *Provides stability in the face of uncertain electricity prices.* CHP systems can help reduce energy costs and exposure to volatile electricity prices.

Benefits for the nation:

- *Improves U.S. industrial competitiveness.* CHP systems may help reduce industrial energy costs, thereby reducing production costs and improving competitiveness.
- *Offers a low-cost alternative for overall energy needs, including for new electricity generation capacity.* CHP may provide lower energy costs for users by displacing higher-priced purchased electricity and boiler fuel with lower-cost self-generated power and recovered thermal energy. Such on-site generation may also avoid T&D losses

associated with electricity purchased from the grid, and may defer or eliminate the need for new T&D investment.

- *Provides an immediate path to lower emissions of GHG and air pollutants through increased overall energy efficiency.* CHP systems typically reduce carbon dioxide (CO_2) emissions and criteria air pollutants, including emissions of nitrogen oxides (NO_X), sulfur dioxides (SO_2), and carbon monoxide (CO) emissions, through increased efficiency due to the simultaneous generation of electric power and useful thermal energy on-site from a single fuel source.[27] Achieving the President's August 2012 goal of 40 GW of new, cost-effective CHP by 2020 is expected to reduce CO_2 emissions by 150 million metric tons of CO_2 annually—equivalent to the emissions from over 25 million cars.[28]
- *Reduces need for new T&D infrastructure and enhances power grid security.* CHP systems are located on-site or adjacent to the facility they serve. On-site generation may avoid T&D losses associated with electricity purchased from the grid and can defer or eliminate the need for new T&D investment.
- *Uses abundant, clean domestic energy sources*. Currently, 72 percent of existing CHP capacity is fueled by natural gas, and the clean burning and low-carbon aspects of natural gas will likely make it a preferred fuel for future CHP growth.[29] Additionally, EPA estimates that there are 6 to 8 GW of potential waste heat to power projects that could use recovered thermal energy instead of a fuel source.[30]
- *Uses highly skilled American labor and American technology.* Similar to other efficiency measures, CHP systems provides jobs and other benefits to the overall economy—manufacturing, installing, and maintaining CHP systems uses highly skilled American labor.[31]
- *Supports energy infrastructure reliability and resiliency.* CHP systems may reduce demand on the electricity delivery system, thus reducing stress on the grid and reducing the likelihood of voltage sags and power quality issues. Grid resilience strategies must also consider options to improve grid flexibility and control, which include greater use of CHP and distributed generation.[32] In addition, CHP can help keep critical infrastructure (e.g., hospitals, emergency shelters, police and fire stations, and other public buildings) operational by providing electricity, heating, and cooling during storm and other grid disruption events.[33]

1.4 Challenging Market Factors

Many factors affect the implementation of industrial energy efficiency. Some factors, such as technology performance or cost, are unique to specific measures or particular types of products that are manufactured. Other factors are broader and apply to all manufacturing sectors. Two

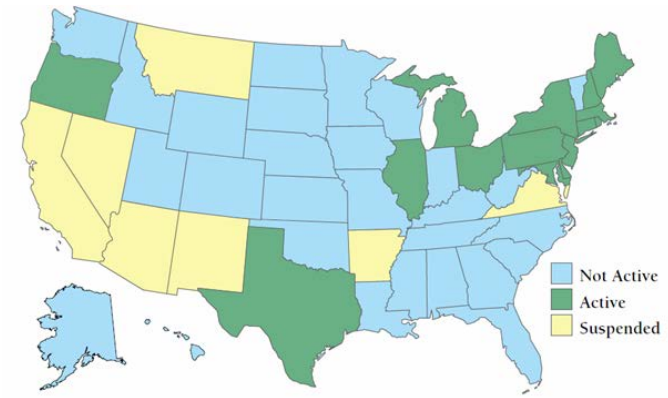
of these broad factors include the regulatory structure of electricity markets and the wide range of industrial facility sizes.

1.4.1 Electricity Markets

The structure of electricity markets evolved during the 20th century to include investor-owned utilities (IOUs) and consumer-owned utilities. IOUs are also referred to as private utilities and are owned by investors or shareholders. Consumer-owned utilities are also called public utilities and can be owned by government bodies (e.g., a municipality) or consumer groups, such as public utility districts or rural electric cooperatives. Most utilities in the United States, whether public or private, are monopolies. In the case of IOUs and some consumer-owned utilities, state utility regulatory commissions provide regulatory oversight.[34] By the mid-1990s, many IOUs had grown to be large companies that owned electric generating facilities and distribution services (also known as "vertically integrated" utilities).[35]

Driven by state legislation and regulatory actions aimed at retail market restructuring, as well as Federal regulatory actions affecting wholesale markets (e.g., Federal Energy Regulatory Commission [FERC] Ruling 888), the utility industry was restructured starting in the mid-1990s (see **Figure 2** for map of restructuring activity by state). In states that restructured, retail markets were opened to competitive power suppliers and IOUs divested most or all of their generating facilities to wholesale generating companies. While state restructuring policies differ, most state utility regulatory agencies in restructured states have retained regulatory oversight over only the IOUs' distribution functions, even though many IOU parent companies continue to own and operate generation in competitive wholesale markets.

Figure 2. Status of Electricity Restructuring Activity by State (as of 2010)[36]



Note: "Active" means that a state has restructured its electric industry, and that state rulemakings and other more minor activities related to the restructuring process are ongoing. "Not Active" means that a state has not undertaken any significant steps to restructure its electric industry. "Suspended" means that a state started the process to restructure its electric industry, but never completed the process.

Source: EIA and RAP, 2011

Depending on specific state and regional regulatory actions, the business models for distribution-only utilities and vertically integrated utilities can be very different, and these differences can affect the treatment of industrial energy efficiency.

In states that did not create retail competition, utilities recover construction costs for generation, transmission, and distribution assets through rates approved by a state utility regulatory commission. State utility regulatory commissions have an obligation to electricity consumers to keep rates at reasonable levels, while ensuring universal and reliable electricity service and reasonable rates of return to franchised IOUs.[37]

In states with restructured retail competition, IOUs typically no longer own generating assets, instead purchasing electricity supplies from wholesale markets on behalf of customers and distributing power sold to retail customers by independent power marketers. Wholesale markets are typically managed by Independent System Operators (ISOs), though ISO structures vary greatly from region to region.[38]

A principal issue for utilities and their regulators, in both restructured and traditionally-regulated states, is that energy efficiency, including CHP, reduces electricity sales. Because fixed costs are often recovered by utilities through volumetric rates, lost sales can reduce fixed-cost recovery, as well as return on assets for utilities. For energy efficiency, this issue is typically addressed through a mix of cost-recovery mechanisms, and can include incentives for achieving state-mandated energy efficiency goals.[39]

There are differences in how utilities view cost recovery for energy efficiency measures and on-site generation technologies, such as industrial CHP. For energy efficiency measures, a utility will typically see a relatively smooth and gradual reduction in electricity sales spread across many energy efficiency program participants. For an industrial CHP project, however, a utility may see a sudden and significant decrease in electricity sales concentrated at a single customer site. This type of change can contribute to stranded costs associated with feeders, substations, and other T&D assets that were installed by the utility to serve the business district where the CHP customer is located. These utility investments often drive the utility to apply specific fees or tariffs to CHP customers.[40]

1.4.2 Diversity in Customer Size

Industrial customers are diverse in size with different needs and capabilities, and this diversity impacts how they adopt energy efficiency technologies and practices. For example, a small facility and/or company may not have the resources to hire the technical staff necessary to identify or implement efficiency measures. Small facilities may not meet minimum load size requirements to participate in wholesale demand response markets or may not have enough

load reduction potential to attract Curtailment Service Providers (CSPs), who would otherwise seek to aggregate their loads for participation in demand response markets.

Policies may be targeted for specific industrial customer sizes. Standardized or streamlined procedures (e.g., interconnection) for CHP may only be available for certain size projects and required equipment may not be commensurate with the size and potential impact of smaller generators (e.g., 5 MW or less).[41,42]

Customer size also affects how utility energy efficiency programs are designed. For instance, if industrial customers in a given state are dominated by large energy-intensive manufacturers (e.g., chemical, paper, and iron and steel plants), utility energy efficiency programs may be directed toward specialized technical services, custom project incentives, and relatively large capital-intensive process improvements for these industries. Smaller, less energy-intensive customers may be more effectively served by simpler and more prescriptive energy efficiency programs that focus on common end-uses such as motors, lighting, steam, and compressed air. Regardless of how an energy efficiency program is structured, the utility customer that is considering an energy efficiency expense will ultimately determine if the capital expense required for the project is economically justified.

1.5 Stakeholder Participation and Study Organization

Nearly 50 stakeholder experts in the industrial energy field collaborated with DOE during the development of this study. Stakeholders represented a wide spectrum of interests and provided valuable insights from diverse perspectives. Appendix A contains a list of these stakeholders.

This study consists of the following sections:

- Executive Summary
- Chapter 1—Introduction
- Chapter 2—Energy Consumption Trends
- Chapter 3—Barriers to Industrial End-Use Energy Efficiency
- Chapter 4—Barriers to Industrial Demand Response
- Chapter 5—Barriers to Industrial Combined Heat and Power
- Chapter 6—Economic Benefits of Energy Efficiency Grants
- Chapter 7—Energy Savings from Increased Recycling
- Appendices
    - A – Collaboration Stakeholders

- B – Results of 50 Percent Cost Share Scenario
- C – Details for End-Use Energy Efficiency and Demand Response
- D – Details for Combined Heat and Power
- E – IMPLAN Background
- F – Calculation of Electricity Energy Savings and CO_2 Reductions

Energy consumption trends for the United States, with a focus on industrial manufacturing, are discussed in Chapter 2.

Barriers are discussed in Chapters 3, 4, and 5. Interspersed throughout the discussion of barriers are examples of state, Federal, private, and international programs and policies that have proven successful in increasing energy efficiency in the industrial sector.

Economic benefits are analyzed in Chapter 6. This analysis examines impacts that would result from $5 billion of grant funding.

Recycling is examined in Chapter 7. This analysis is focused on energy reductions that could be achieved from increased recycling in energy-intensive manufacturing industries.

For the barriers discussed in Chapters 3, 4, and 5, it is important to note that there is overlap between some barriers as they can be applicable to multiple energy efficiency groups. For example, internal competition for capital is discussed as a barrier for both end-use energy efficiency and CHP. In this study, most barriers are discussed under a single energy efficiency group. The categorization of a particular barrier to a single energy efficiency group is based on factors that include where stakeholder group members frequently associated the barrier, and how the barrier is frequently discussed in reference material cited in this study.

Endnotes

[1] DOE recognizes that barriers to deployment of industrial energy efficiency involve complex, often controversial, issues. The intent of this study is not to judge barriers. Rather, the objective is to identify and discuss barriers that impede deployment of energy efficiency in the industrial sector and analyze policies that have effectively addressed these barriers.

[2] U.S. Census Bureau. Web link.

[3] National Association of Manufacturers, 2014. "Facts About Manufacturing in the United States," Web link.

[4] The President's Climate Action Plan, 2013. Web link.

[5] Executive Order 13624, 2012. "Accelerating Investment in Industrial Energy Efficiency," Web link. This Executive Order identifies industrial energy efficiency as a priority and sets a national goal of 40 GW of new, cost-effective CHP in the United States by 2020.

[6] Many reports discuss the benefits of energy efficiency. Seven reports that discuss benefits in the industrial sector include (1) McKinsey, 2009. "Unlocking Energy Efficiency in the U.S. Economy." (2) U.S. Environmental Protection Agency (EPA), 2007. "Energy Trends in Selected Manufacturing Sectors: Opportunities and Challenges for Environmentally Preferable Energy Outcomes." (3) U.S. Department of Energy (DOE), 2006. "Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the United States Congress." (4) Regulatory Assistance Project (RAP), 2013. "Demand Response as a Power System Resource." (5) U.S. Department of Energy and U.S. Environmental Protection Agency, 2012. "Combined Heat and Power: A Clean Energy Solution." (6) American Council for an Energy-Efficient Economy, 2013. "How Electric Utilities Can Find Value in CHP." (7) American Gas Association, 2013. "The Opportunity for CHP in the United States."

[7] DOE defines strategic energy management as a long-term, continual improvement approach to efficiency that includes goals, tracking, and reporting. Web link. The Consortium for Energy Efficiency defines strategic energy management as a continuous improvement approach to reducing energy intensity over time, characterized by demonstrated customer commitment, planning and implementation, and systemic measurement. Web link.

[8] U.S. Department of Energy, January 2006. "Save Energy Now in Your Motor-Driven Systems," Web link.

[9] U.S. Environmental Protection Agency, 2014. "ENERGY STAR Challenge for Industry," Web link. This EPA program requires industrial participants to commit to a goal of reducing energy intensity by 10 percent within 5 years. EPA defines "industrial" for this program to be NAICS codes 31–33 and 21. This definition of "industrial" is broader than that used for the Act, which includes only NAICS code 31–33.

[10] U.S. Environmental Protection Agency, 2010. "ENERGY STAR Helps Auto Plants Improve Energy Efficiency," Web link.

[11] American Council for an Energy-Efficient Economy, 2011. "How Does Energy Efficiency Create Jobs?" Web link.

[12] First year jobs assume the energy savings occur in first year (6½ net jobs = 3 jobs from construction plus 3½ jobs supported through energy savings).

[13] Regulatory Assistance Project, 2012. "U.S. Experience with Efficiency as a Transmission and Distribution System Resource."

[14] Federal Energy Regulatory Commission, October 2013. "Reports on Demand Response & Advanced Metering," Web link.

[15] Doug Hurley, Paul Peterson, and Melissa Whited, May 2013, "Demand Response as a Power System Resource," Synapse Energy Economics and Regulatory Assistance Project, Web link .

[16] National Action Plan for Energy Efficiency. 2010. "Coordination of Energy Efficiency and Demand Response," Web link.

[17] U.S. Department of Energy, 2006. "Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them," Web link.

[18] Several reports discuss job creation. Four reports include the following: (1) The California Energy Commission notes that one of the benefits of demand response is job creation in the technology and service industries. Web link. (2) Whitehouse Council on Environmental Quality, 2013. "Leading the Effort to Cut Energy Waste," Web link. (3) Smart Grid Today, January 2010. "DRSG Members Tell 200 House Members About Smart Grid Jobs," Web link. (4) Berkeley National Laboratory. March 2011. "Open Automated Demand Response (OADR) Deployments Retain and Create Jobs," Web link.

[19] Ibid.

[20] Bottoming cycle CHP systems can have, in some cases, lower efficiencies than the CHP system efficiency noted of 65 to 80 percent.

[21] Environmental Protection Agency, 2008. "Catalog of CHP Technologies," Web link. The efficiency of a CHP system varies based several factors, including the type of prime mover used. This reference provides efficiencies for several types of CHP systems.

[22] American Gas Association, 2013. "The Opportunity for CHP in the United States," prepared by ICF International. This report shows an efficiency of 49 percent for conventional generation (power plant and on-site boiler) due to recent increases in power plant efficiency and decreases in T&D losses.

[23] U.S. Department of Energy and U.S. Environmental Protection Agency, 2012. "Combined Heat and Power: A Clean Energy Solution," Figure 1, page 7, Web link.

[24] U.S. Environmental Protection Agency, Combined Heat and Power Partnership, Efficiency Benefits, online data, Web link.

[25] U.S. Department of Energy and U.S. Environmental Protection Agency, 2012. "Combined Heat and Power: A Clean Energy Solution," Web link.

[26] ICF International, 2013. "Combined Heat and Power: Enabling Resilient Energy Infrastructure for Critical Facilities," prepared for Oak Ridge National Laboratory, Web link.

[27] U.S. Environmental Protection Agency, October 2008. "Combined Heat and Power Energy Savings and Energy Reliability for Data Centers," Web link.

[28] U.S. Department of Energy and U.S. Environmental Protection Agency, 2012. "Combined Heat and Power: A Clean Energy Solution," Web link.

[29] Ibid.

[30] "Waste Heat to Power Systems," EPA CHP Partnership, May 2012.

[31] Baer, P., et al., 2013. "The Job Generation Impacts of Expanding Industrial Cogeneration," Web link.

[32] Executive Office of the President. Economic Benefits of Increasing Electric Grid Resilience to Weather Outages. 2013. Web link.

[33] U.S. Department of Energy, U.S. Department of Housing and Urban Development, and U.S. Environmental Protection Agency, September 2013. "Guide to Using Combined Heat and Power for Enhancing Reliability and Resiliency in Buildings," Web link.

[34] In most, but not all states, municipal utilities and public utility districts are not subject to any economic regulation by the state utility regulator.

[35] Regulatory Assistance Project, 2011. "Electricity Regulation in the U.S.: A Guide," Web link.

[36] Ibid. Chart included on EIA Web site and also in Regulatory Assistance Project (RAP), 2011, "Electricity Regulation in the U.S.: A Guide," page 14, Figure 4-3, Web link and also Web link.

[37] Regulatory Assistance Project, 2011. "Electricity Regulation in the U.S.: A Guide," Web link.

[38] ISO/RTO Council, 2005. "The Value of Independent Regional Grid Operators," Web link.

[39] National Action Plan for Energy Efficiency, "Aligning Utility Incentives with Investment in Energy Efficiency," 2007, Web link. The "throughput incentive" or lost margin recovery issue is the effect on utility financial margins caused by the energy efficiency–produced drop in sales. Utilities incur both fixed and variable costs. Fixed costs include a return of (depreciation) and a return on (interest plus earnings) capital (a utility's physical infrastructure), as well as property taxes and certain operation and maintenance (O&M) costs. These costs do not vary as a function of sales in the short run. However, most utility rate designs attempt to recover a portion of these fixed costs through volumetric prices—a price per kilowatt-hour or per therm. These prices are based on an estimate of sales: price = revenue requirement / sales. If actual sales are either higher or lower than the level estimated when prices are set, revenues will be higher or lower. All else being equal, if an energy efficiency program reduces sales, it reduces revenues proportionately, but fixed costs do not change. Less revenue, therefore, means that the utility is at some risk for not recovering all of its fixed costs. Ultimately, the drop in revenue will impact the utility's earnings for an investor-owned utility or net operating margin for publicly and cooperatively owned utilities.

[40] State and Local Energy Efficiency (SEE) Action Network, 2013. "Guide to the Successful Implementation of State Combined Heat and Power (CHP)," Web link.

[41] In this study, "small" is defined to be < 5 MW, "medium" to be 5–20 MW, and "large" to be > 20 MW.

[42] State and Local Energy Efficiency (SEE) Action Network, 2013. "Guide to the Successful Implementation of State Combined Heat and Power (CHP)," Web link.

2. Energy Consumption Trends

This chapter presents energy consumption trends in the United States with the intent of providing context for the magnitude of benefits that might be captured by accelerating the pace of improved industrial energy efficiency and identifying the sectors and applications with the greatest energy efficiency opportunities.

2.1 All Sectors

2.1.1 Definitions of Energy Consumption

The Energy Information Administration (EIA) divides energy consumption into four major end-use sectors: industrial, commercial, residential, and transportation. Further, it presents energy consumption data in three forms:

- *Primary energy.* Primary energy is defined to be energy where it first occurs in an energy balance, before conversion to other forms of energy. For example, coal is a form of primary energy used to produce electricity. Electricity is not considered primary energy. Natural gas is a form of primary energy that is used to produce electricity and also consumed directly by end-users.
- *Delivered energy.* Delivered energy includes primary energy used directly by end-users and electricity delivered to end-users. Delivered energy is the amount of energy consumed at the point of use. In practical terms, delivered energy is the amount of energy purchased by an industrial site.
- *End-use energy.* End-use energy is delivered energy plus electricity system losses that occur during transmission and distribution. Electricity losses are allocated to each end-use sector in proportion to the amount of electricity consumed by each sector.

Table 4 shows energy consumption values consistent with the preceding definitions. To reiterate, delivered energy is the consumption of energy at the site level (point of use). Total end-use energy represents the total consumption of energy for each sector, including electricity losses that occur during transmission and distribution.

Table 4. 2012 Energy Consumption by Sector, TBtu

Sector	Primary Energy (A)	Electricity Retail Sales to Sector (B)	Delivered Energy (C=A+B)	Electricity System Losses (D)	Total End-Use Energy (E=C+D)
Industrial	20,435	3,363	23,798	6,814	30,612
Residential	5,931	4,690	10,620	9,501	20,122
Commercial	3,770	4,528	8,298	9,174	17,472

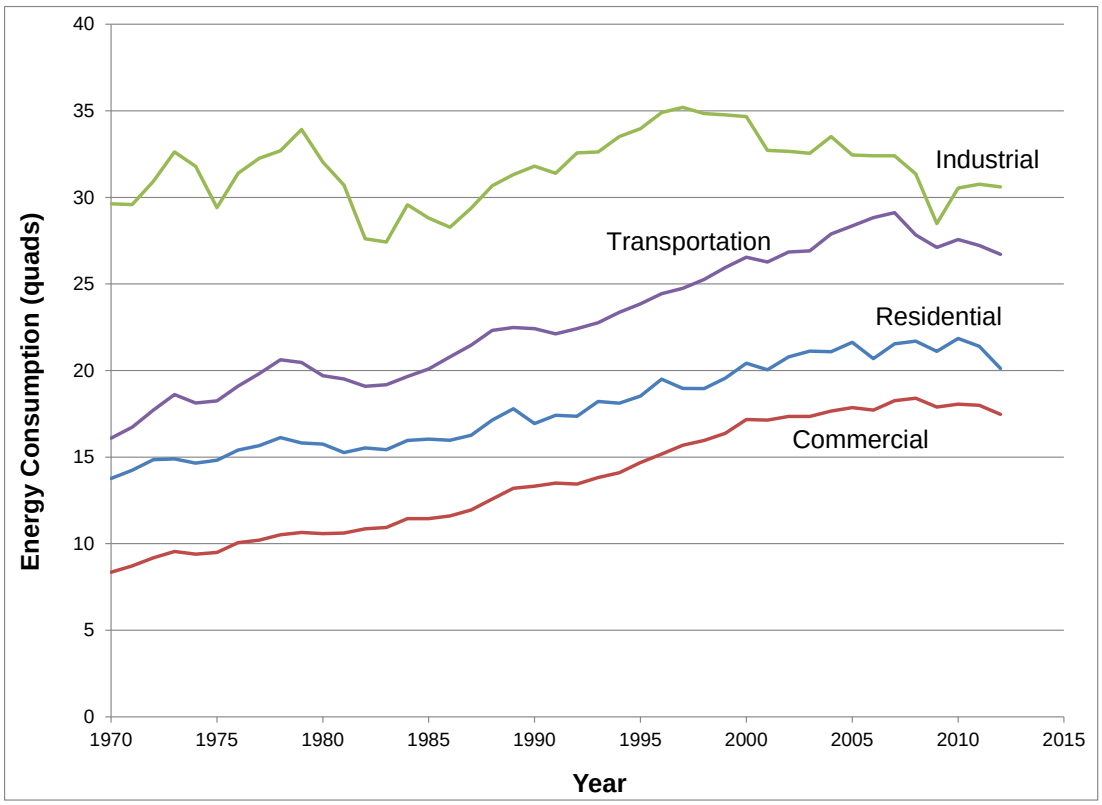
Sector	Primary Energy (A)	Electricity Retail Sales to Sector (B)	Delivered Energy (C=A+B)	Electricity System Losses (D)	Total End-Use Energy (E=C+D)
Transportation	26,634	25	26,659	51	26,710
Total	**56,770**	**12,606**	**69,376**	**25,540**	**94,916**

Source: EIA MER, 2013

2.1.2 Total End-Use Energy Consumption

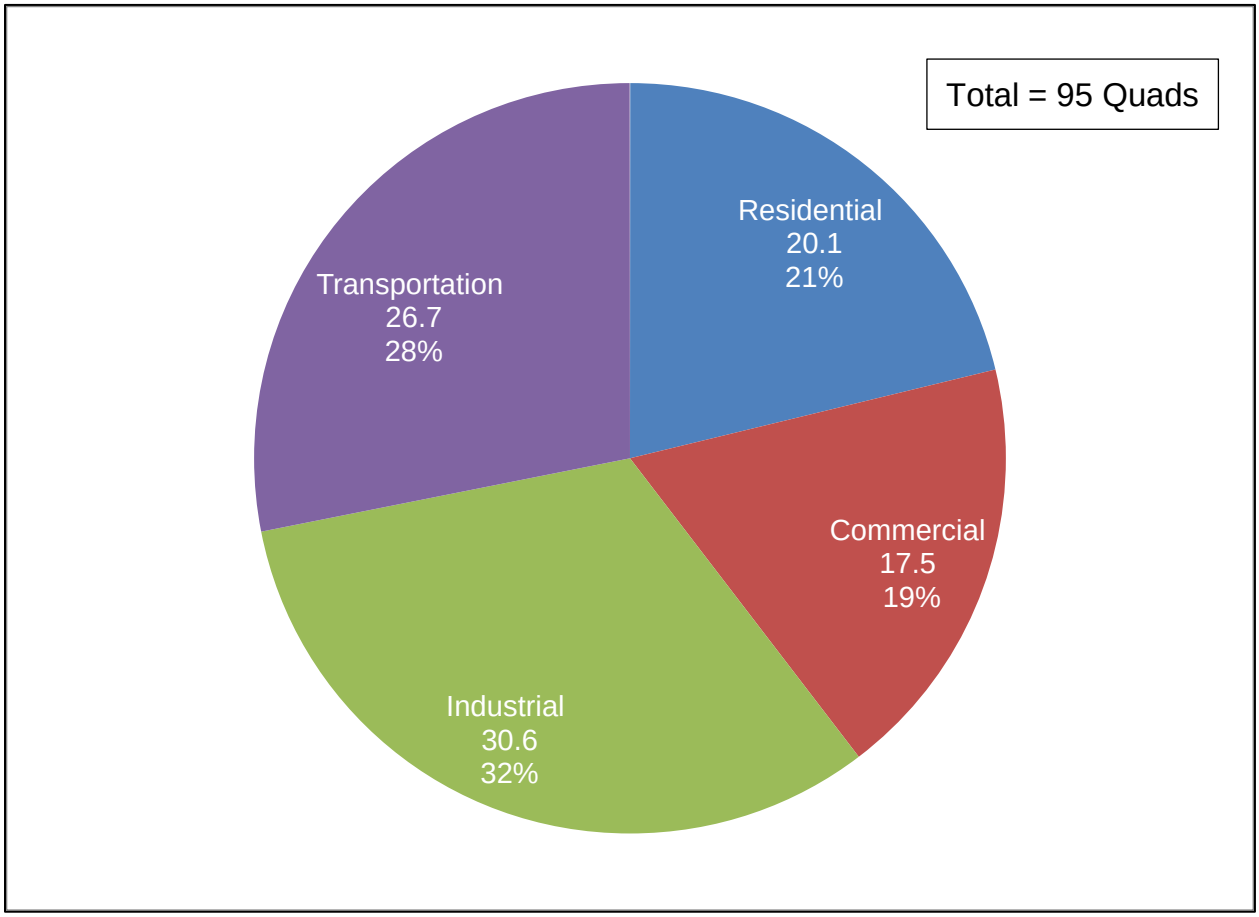
The industrial sector includes manufacturing (NAICS 31–33), agriculture (NAICS 11), mining (NAICS 21), and construction (NAICS 23) establishments. In terms of total end-use energy (as defined above), the industrial sector is the largest consuming sector in the United States, followed by transportation, residential, and commercial sectors, respectively. **Figure 3** shows total end-use energy consumption in the United States over the past four decades. The figure shows that while transportation, residential, and commercial sectors are all increasing, the industrial sector trend is less defined. For the industrial sector, energy consumption peaked at approximately 35 quadrillion Btu (quads) in the mid to late 1990s, and then declined to approximately 29 quads in 2009.[1] After 2009, energy consumption increased and has remained between 30 and 31 quads. In 2012, the industrial sector accounted for 30.6 quads of energy consumption, or 32 percent of all energy used in the United States (see **Figure 4**).

Figure 3. Total End-Use Energy Consumption Trends by Sector (1970–2012)



Source: EIA, 2013

Figure 4. Total End-Use Energy Consumption by Sector (2012, Quads)



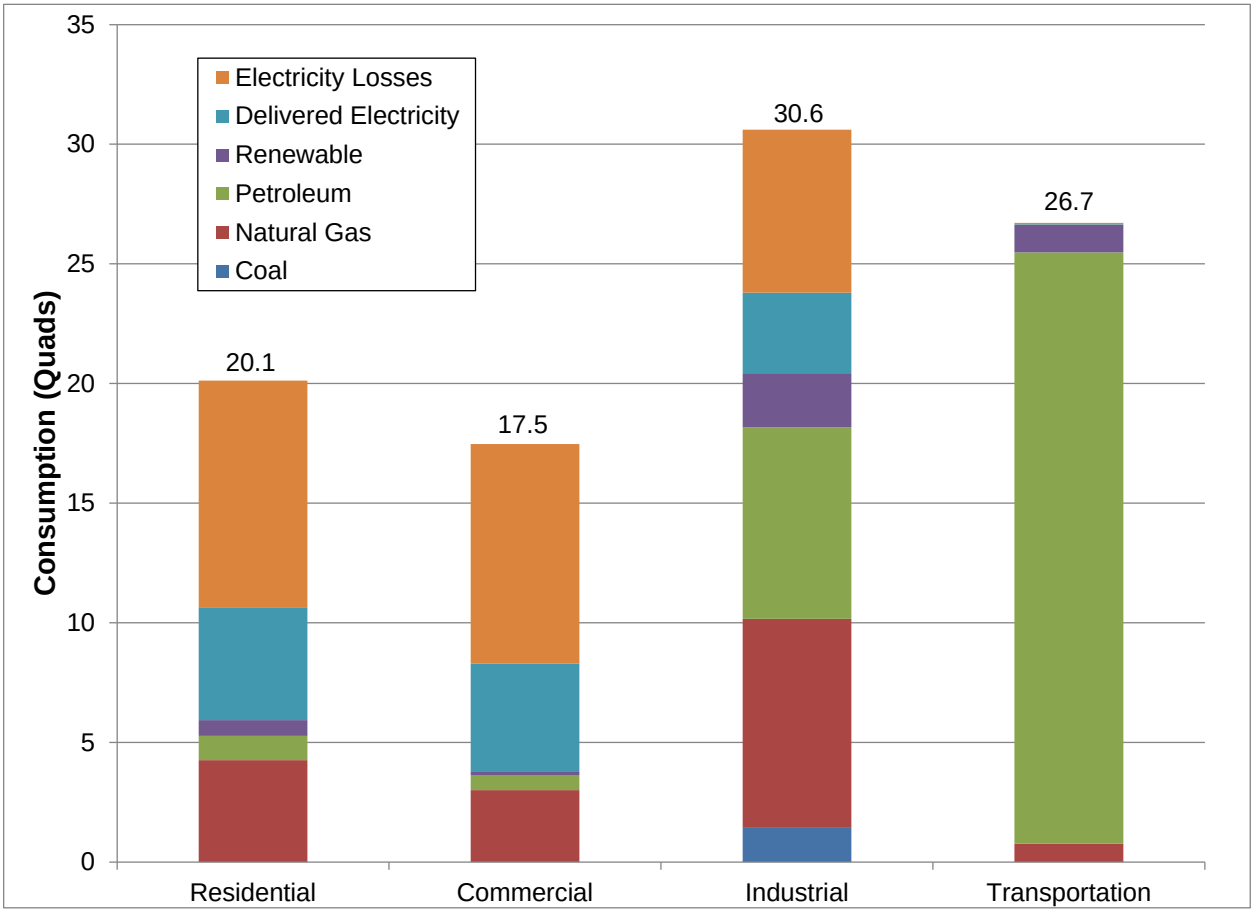
Source: EIA, 2013

Figure 5 shows a breakdown of energy sources for each end-use sector. The total consumption in each of the four sectors is composed of primary energy (natural gas, petroleum, coal, and renewables), delivered electricity (also referred to as electricity sales), and energy losses associated with electricity consumption. The industrial sector includes a diverse set of manufacturing processes, and this diversity is reflected in the range of primary energy sources used in the industrial sector. The transportation sector is dominated by petroleum consumption, which is used to refine gasoline, diesel fuel, and other transportation fuels. Natural gas consumed in the transportation sector is used primarily for gas pipeline compressors. The residential and commercial sectors consume mostly natural gas and electricity along with small amounts of petroleum and renewable energy.

As indicated in **Figure 5**, the residential, commercial, and industrial sectors all have significant electricity losses. These losses reflect energy that is lost during the conversion of primary energy to electricity, and in the transmission and distribution of electricity. For perspective, data from EIA show that the efficiency of delivered grid electricity in 2012 was 34 percent

(includes conversion losses at generation plants and T&D losses).[2] In the EIA energy accounting framework, electricity losses are allocated to end-use sectors based on electricity consumption in these sectors.

Figure 5. End-Use Energy Consumption by Sector and Source (2012 Data)

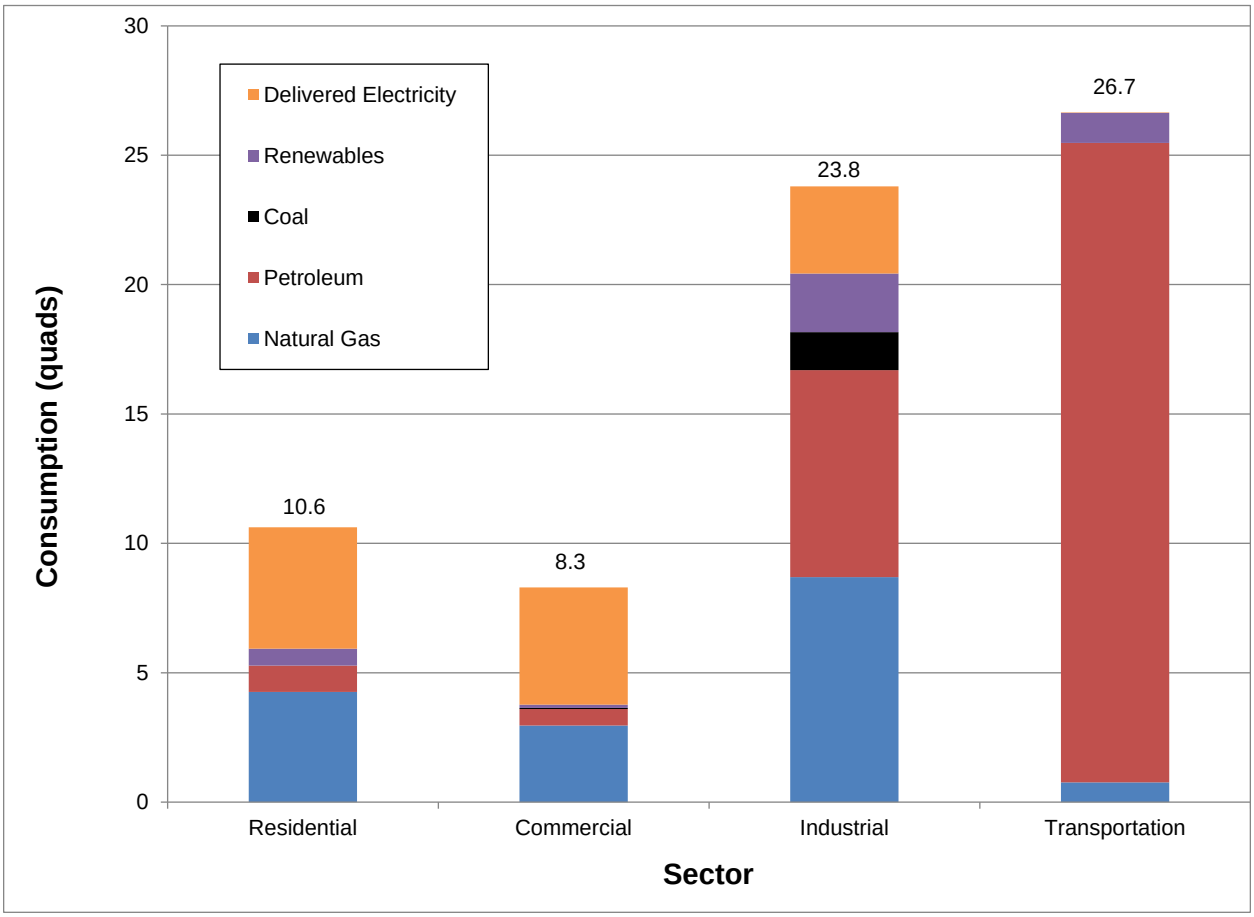


Source: EIA, 2013

2.1.3 Delivered Energy Consumption

Another way of looking at energy consumption is at the point of use, or what is considered delivered energy consumption. **Figure 6** shows delivered energy consumption by sector in 2012. The only difference between **Figure 5** and **Figure 6** is that **Figure 6** does not include electricity losses (electricity losses are the top segment of the bar chart in **Figure 5**). **Figure 6** shows that the transportation sector consumes the most energy (26.7 quads), most of which is petroleum. The industrial sector has the second largest delivered energy consumption (23.8 quads), followed by the residential sector (10.6 quads) and the commercial sector (8.3 quads). As indicated in **Figure 6**, the industrial sector uses a diverse mix of energy, including natural gas, petroleum, coal, renewables, and electricity.

Figure 6. Delivered Energy Consumption by Sector and Source (2012 Data)

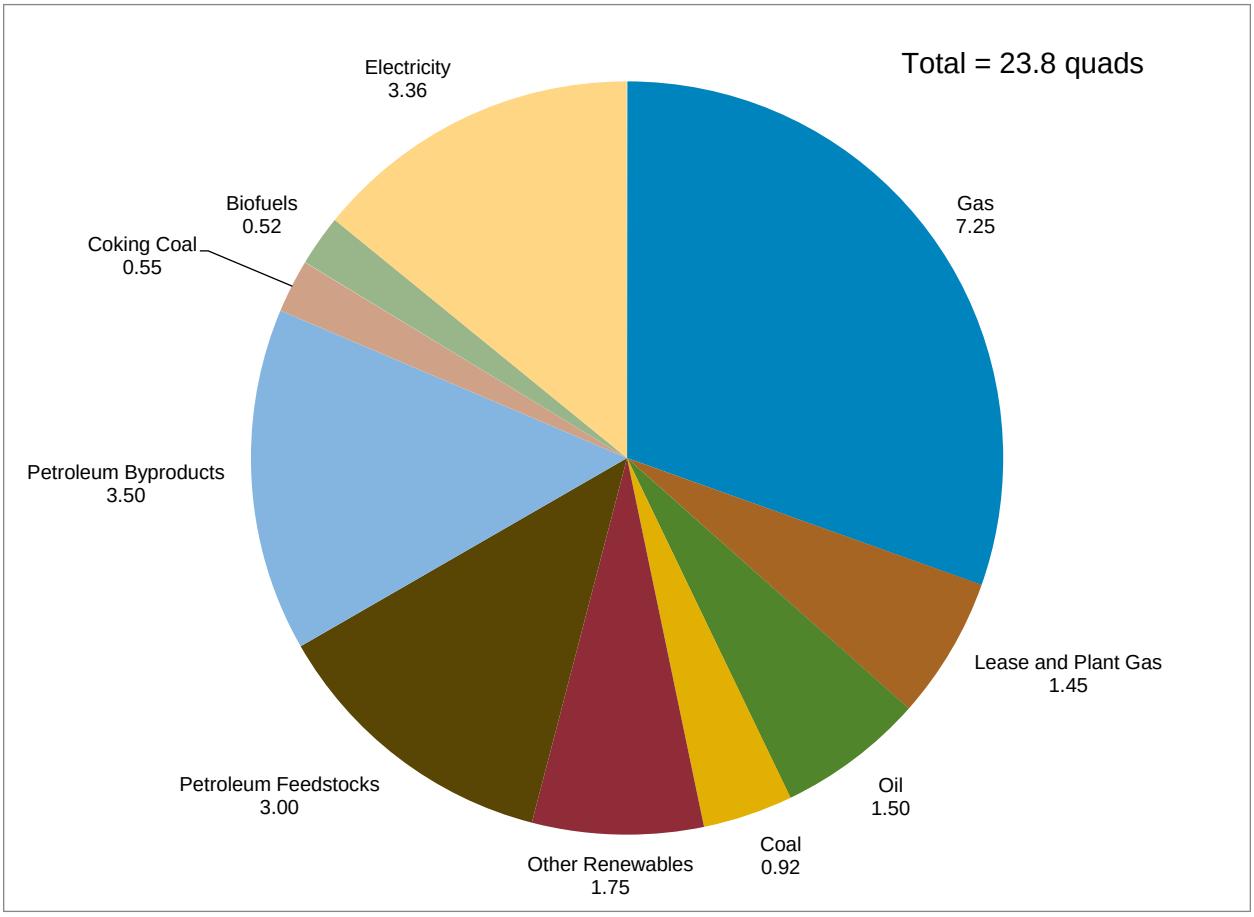


Source: EIA, 2013

Although most of the energy consumed in industry is for heat (e.g., for process heaters, boilers) and power, a significant fraction of the energy consumed in the industrial sector is used for non-fuel purposes (e.g., feedstocks). Observations concerning industrial energy consumption in 2012 include (see **Figure 7**):

- Almost 20 percent of natural gas is lease and plant gas—gas used in the production and processing of natural gas before it reaches consumers.
- Only 20 percent of petroleum is purchased for use as fuel—feedstocks and byproducts comprise the balance. Feedstocks consist primarily of liquid petroleum gas (LPG), and naphtha derivatives, while byproducts are fuels (e.g., still gas and petroleum coke) recovered from refinery processes.[3]
- Over one-third of coal is used for coke production (used in steel production).

Figure 7. Delivered Energy Consumption Breakdown in the Industrial Sector (2012 Data)



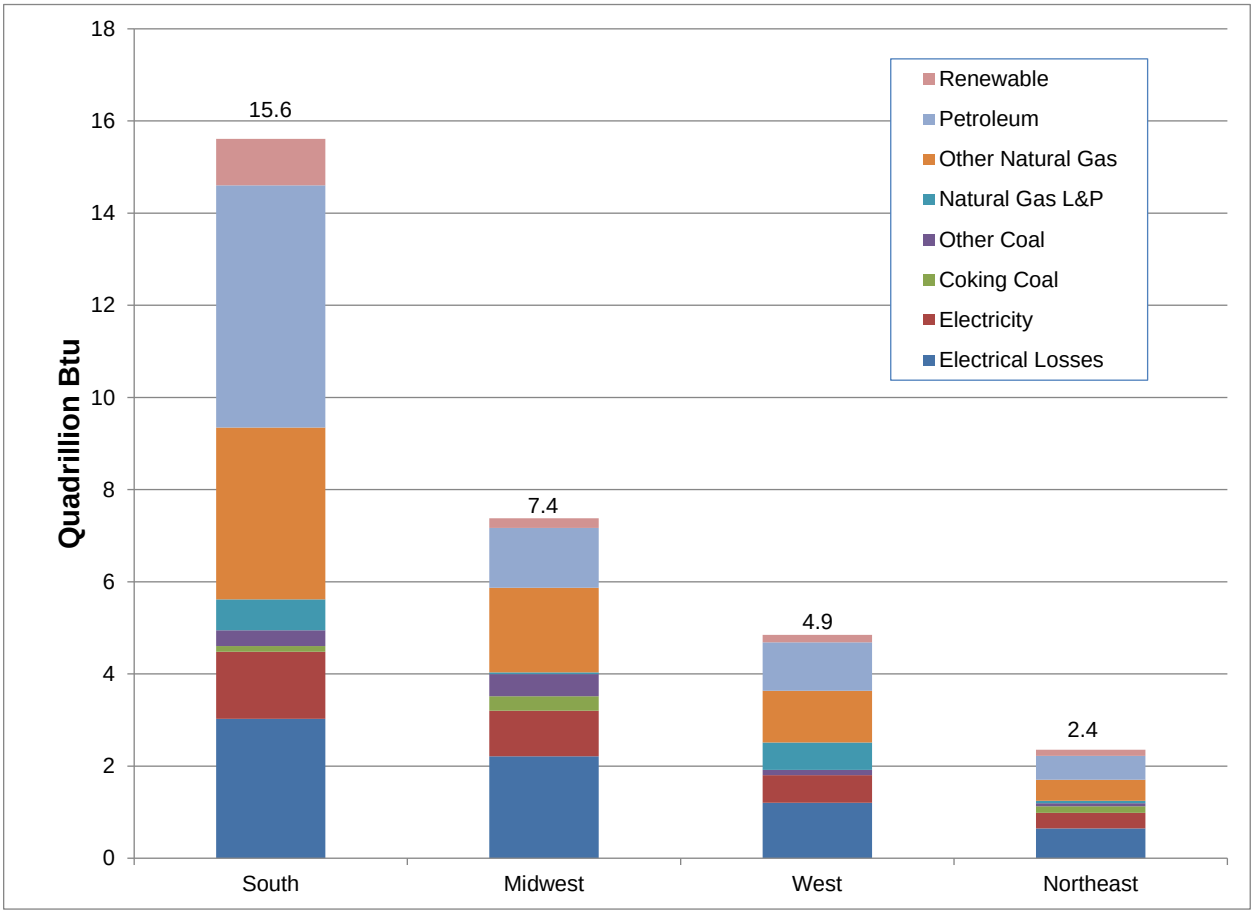
Source: EIA, MER, Annual Energy Outlook 2014, Early Release, Reference Case

Figure 8 shows the regional distribution (by census region) of industrial energy consumption for 2011.[4,5] The South region represents the largest share of industrial energy consumption (including electricity losses) at 15.6 quads, or 52 percent of the total industrial sector energy consumption. The Midwest region has the second largest share of industrial energy demand at 7.4 quads (24 percent), followed by the West region at almost 5 quads (16 percent) and the Northeast at 2.4 quads (8 percent). A breakdown of total industrial energy consumption in these four regions is as follows:

- **South**—This region consumes 67 percent of total industrial renewable energy, 65 percent of total industrial petroleum, over half of total natural gas, 43 percent of total electricity, and 29 percent of total coal.
- **Midwest**—This region consumes nearly 50 percent of total coal, 30 percent of total electricity, 22 percent of total natural gas, 16 percent of total petroleum, and 14 percent of total renewable energy.

- **West**—This region consumes 20 percent of total natural gas, 18 percent of total electricity, 13 percent of total petroleum, 11 percent of total renewable, and 7 percent of total coal use.
- **Northeast—**This region consumes 13 percent of total coal, 10 percent of total electricity, 9 percent of total renewable energy, 6 percent of total natural gas, and 6 percent of total petroleum use.

Figure 8. Energy Consumption Regional Breakdown in the Industrial Sector (2011 Data)[6]



Source: EIA, State Energy Database System, 2013

2.2 Manufacturing Sector

The industrial energy consumption values discussed in **Section 3.1** include the manufacturing sector (NAICS 31–33) plus the agriculture (NAICS 11), mining (NAICS 21), and construction (NAICS 23) sectors. The latter three sectors—NAICS 11, 21, and 23—account for a small amount of energy compared to manufacturing industries (NAICS 31–33); mostly fuel for on- and off-road vehicles. Based on the most recent Manufacturing Energy Consumption Survey (MECS),[7]

the manufacturing sector (NAICS 31–33) accounted for about 74 percent (17.5 quads) of industrial delivered energy consumption in 2010 (23.6 quads of delivered energy consumed in industrial sector in 2010). MECS is the only comprehensive survey on energy consumption by manufacturers. The most recent MECS data is for 2010 as it is completed every 4 years. Therefore, this section refers only to 2010 energy consumption, and specifically to delivered energy, not total end-use energy.

Table 5 shows energy consumption for all 21 manufacturing industry subsectors (i.e., three-digit NAICS codes). The top six consuming subsectors are petroleum and coal products (324), chemicals (325), paper (322), primary metals (331), food (311), and non-metallic mineral products (327).[8] These six subsectors accounted for about 16.7 quads of energy consumption in 2010, which is slightly under 90 percent of all energy consumed in the manufacturing sector in 2010 (see **Figure 9**).

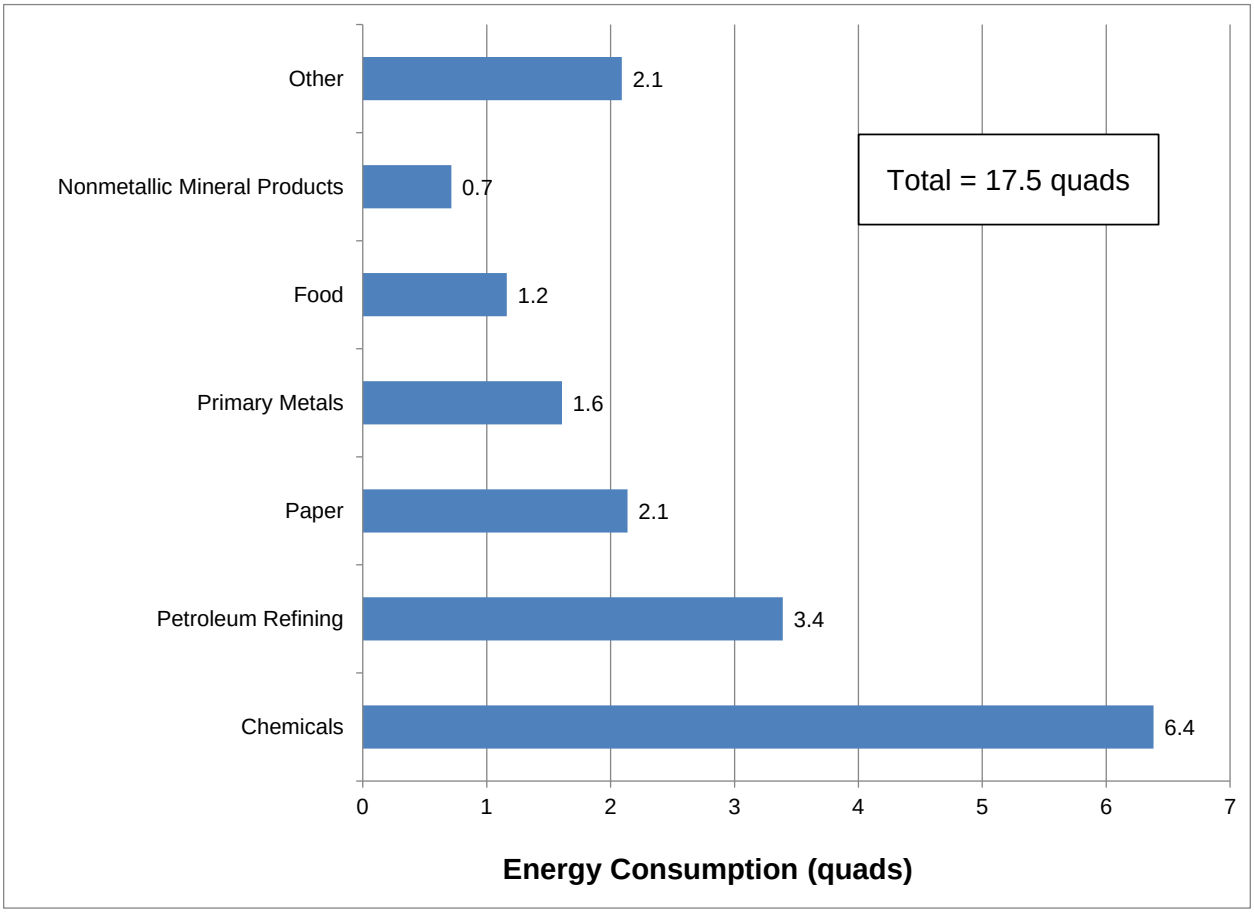
Table 5. Delivered Energy Consumption by Manufacturing Subsector (2010 Data)

NAICS Code	Subsector	Energy Consumption (quads)
325	Chemicals	6.38
324	Petroleum and Coal Products	3.39
322	Paper	2.14
331	Primary Metals	1.61
311	Food	1.16
327	Non-metallic Mineral Products	0.72
321	Wood Products	0.47
332	Fabricated Metal Products	0.30
336	Transportation Equipment	0.28
326	Plastics and Rubber Products	0.28
333	Machinery	0.15
334	Computer and Electronic Products	0.15
313	Textile Mills	0.10
335	Electrical Equip., Appliances, and Components	0.09
312	Beverage and Tobacco Products	0.09
323	Printing and Related Support	0.08
339	Miscellaneous	0.04
337	Furniture and Related Products	0.04
314	Textile Product Mills	0.02
315	Apparel	0.01
316	Leather and Allied Products	0.00
Total for NAICS 31-33		**17.48**

Source: MECS 2010; ICF Estimates

Note: Total may differ due to rounding.

Figure 9. Energy Consumption by Manufacturing Subsector (2010 Data)[9]



Source: MECS, 2010; ICF Estimates

As shown in **Table 6**, the industrial sector, particularly the manufacturing sector, consumes a variety of fuels. Natural gas and petroleum are the main fuels consumed in the manufacturing sector, followed by electricity, other (which includes biomass, such as pulping liquor and wood), and coal, respectively. While natural gas is primarily used as a fuel for process heating, boilers, and CHP, petroleum is used mainly as a feedstock to make chemical products. Electricity is used mainly for machine drive and electrolytic processes. Other fuels are usually burned in boilers and process heaters.

Table 6. Delivered Energy Consumption by Energy Source (2010 Data)

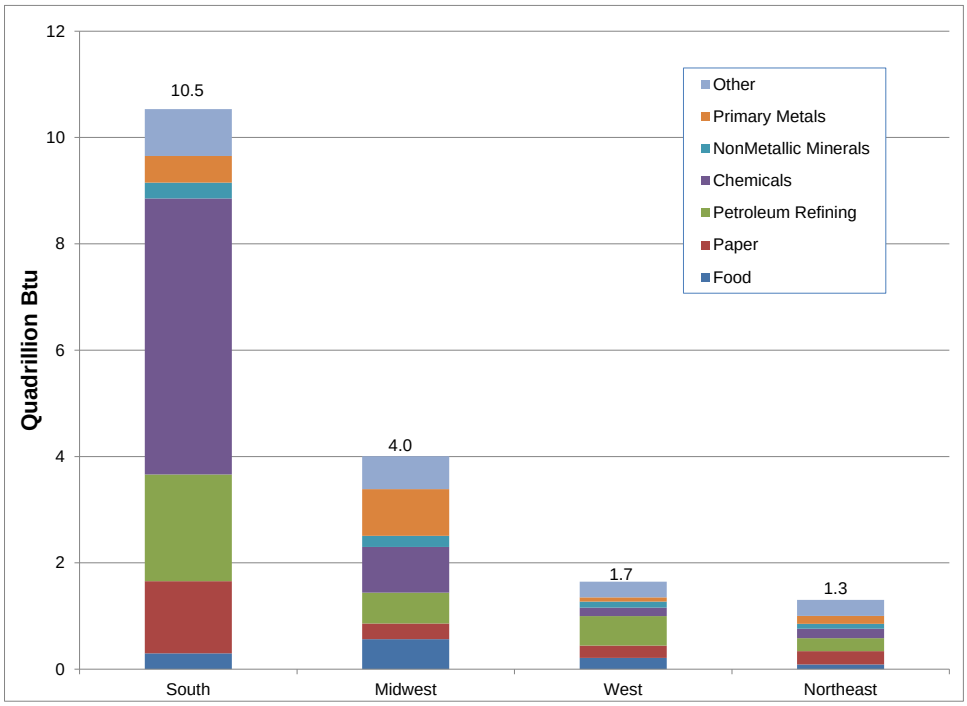
Energy Source	Consumption (quads)
Electricity	2.44
Petroleum	5.47
Residual Oil	*0.17*
Distillate	*0.14*
LPG/NGL[10]	*1.53*
Petrochemical Feedstocks	*1.22*
Byproduct fuels	*2.18*
Other Petroleum	*0.24*
Natural Gas	5.72
Coal	1.57
Other	2.29
Biomass	*1.45*
Other Petroleum	*0.84*
Total	**17.48**

Source: MECS, 2010; ICF Estimates

Figure 10 and **Figure 11** show energy consumption by census region and manufacturing industry subgroup for 2010 based on the MECS data set. Like the regional results for total industry, manufacturing energy consumption is dominated by the South region, which accounts for 60 percent of total manufacturing energy consumption, or 10.5 quads. The Midwest region, which has the second largest manufacturing energy consumption, accounts for 23 percent (4 quads) of total manufacturing energy use, followed by the West region at 9 percent (1.7 quads) and the Northeast at 7 percent (1.3 quads). Characteristics that distinguish these regions include:

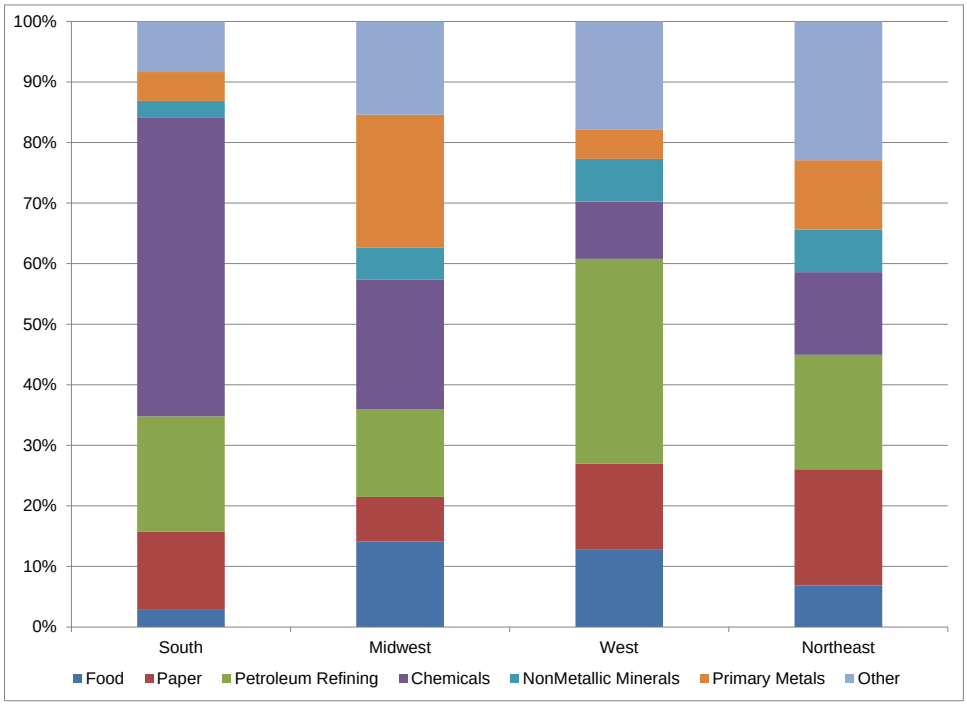
- **South —**The chemical industry consumes almost half of total consumption in the region, followed by the refining industry, which consumes 19 percent, and the paper industry, which consumes 13 percent. These three industries account for 81 percent of total manufacturing energy consumption in the region.
- **Midwest—**This region is characterized by a large presence of primary metals and chemical industries that collectively represent 43 percent of the region's energy consumption.
- **West—**This region is dominated by petroleum refining, paper, and food industries. These three industries combined account for over 60 percent of manufacturing energy use in the region.
- **Northeast—**In this region, paper and petroleum refining industries are the largest consumers among energy-intensive industries, each representing almost 20 percent of total energy use.

Figure 10. Energy Consumption by Region and Manufacturing Subsector (Quads, 2010)



Source: MECS, 2010; ICF Estimates

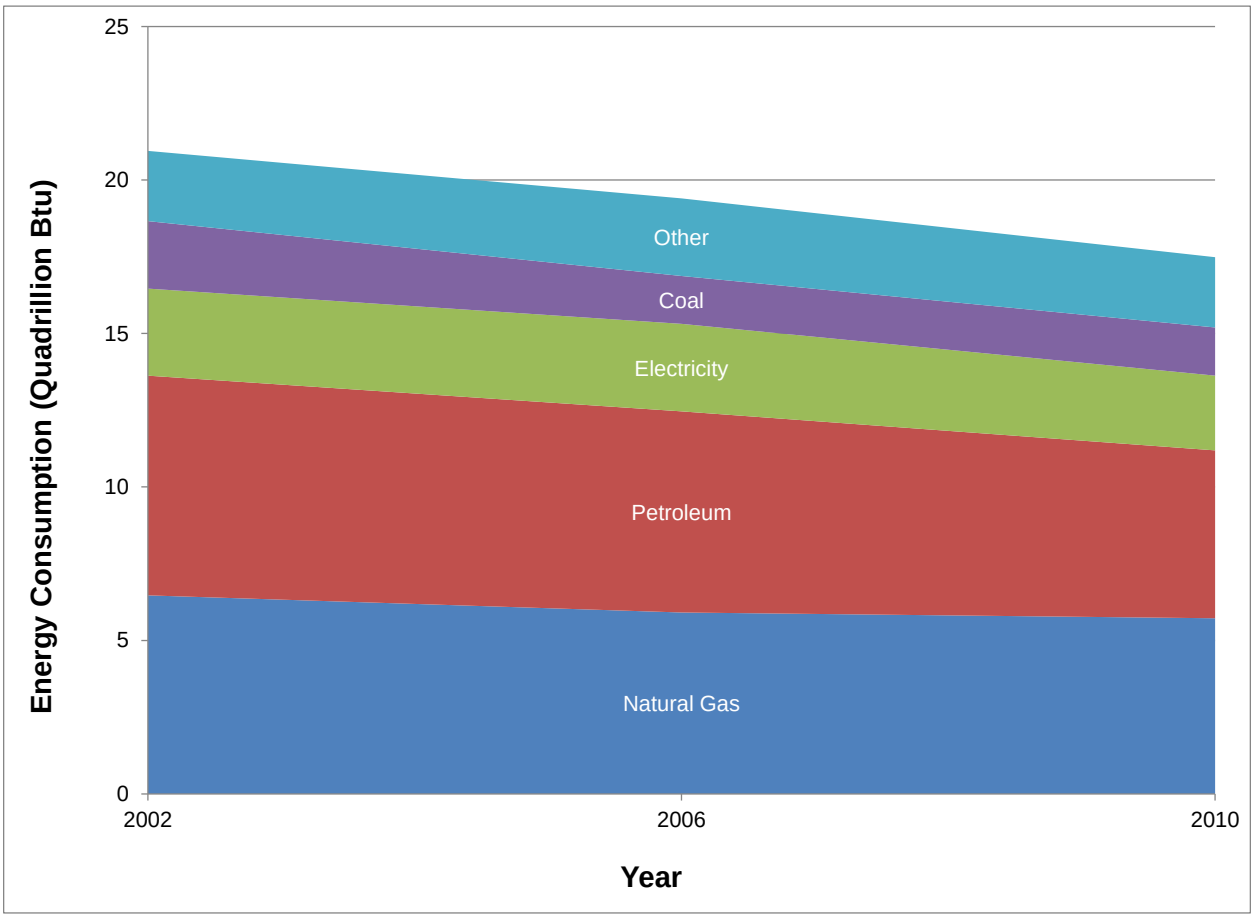
Figure 11. Energy Consumption by Region and Manufacturing Subsector (%, 2010)



Source: MECS, 2010; ICF Estimates

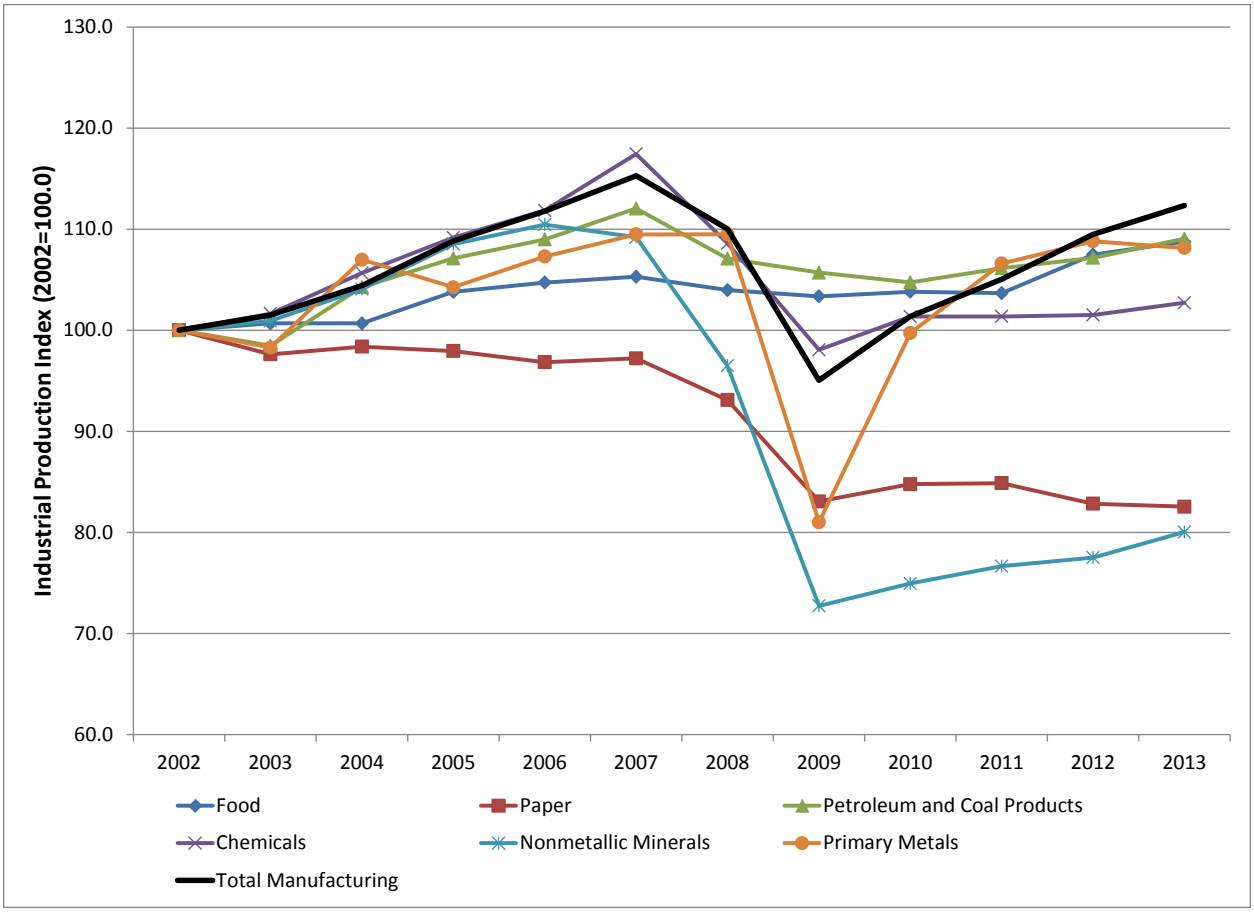
Energy consumption in the manufacturing sector has been trending downward in recent years. Between 2002 and 2010, energy consumption in the manufacturing sector decreased from 20.9 to 17.5 quads, or about 17 percent (see **Figure 12**).[11] A closer look at industrial production trends for energy-intensive industries is shown in **Figure 13**. This figure shows that production increased in each of the energy-intensive industries, except paper, from 2002 to 2007. From 2007 to 2009, production levels dropped for all energy-intensive industries, with the largest declines occurring in the non-metallic minerals, primary metals, and paper industries as the entire United States experienced an economic recession. From 2010 to 2013, industrial production has slowly rebounded and trended upward for all the energy-intensive industries, except paper.

Figure 12. Manufacturing Energy Consumption by Fuel Type, 2002–2010



Source: MECS 2010, 2006, 2002; ICF Estimates

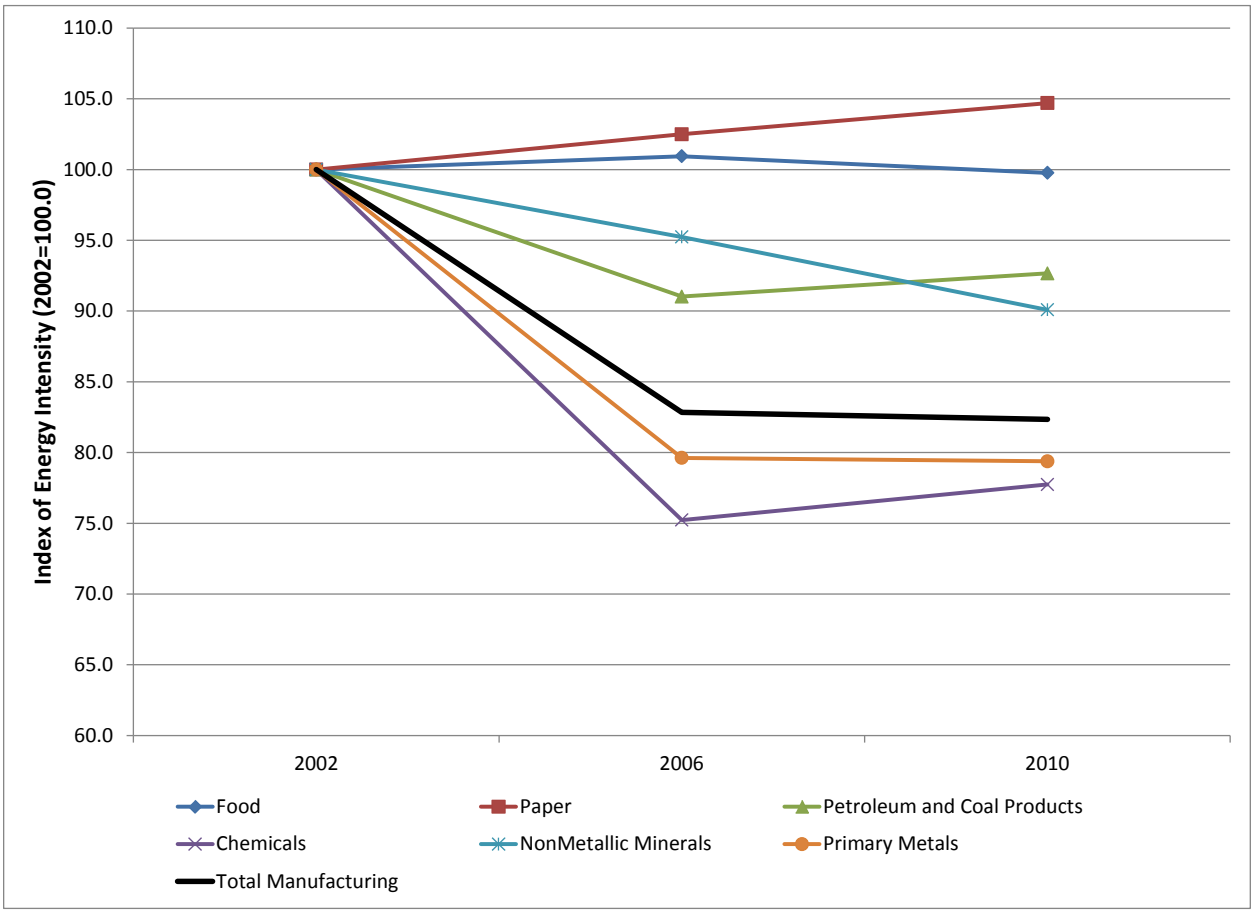
Figure 13. Manufacturing Production by Subsector, 2002–2013



Source: Federal Reserve Board, Industrial Production Indices, 2014

Figure 14 shows energy intensity trends from 2002 to 2010 for energy-intensive industries. The figure shows that there were large reductions in energy intensity in most industries from 2002 to 2006. The chemical and primary metals industries had the largest drop in energy intensity from 2002 to 2006, at over 20 percent. A variety of factors could have driven these reductions, including changes in industry mix (e.g., faster growth of lower energy-intensive industries), investments in more energy-efficient technologies, and retirements of older plants and equipment. From 2006 to 2010, energy intensities in most industries have remained largely unchanged. Two exceptions are the paper industry (increase in energy intensity) and the non-metallic minerals industry (decrease in energy intensity).

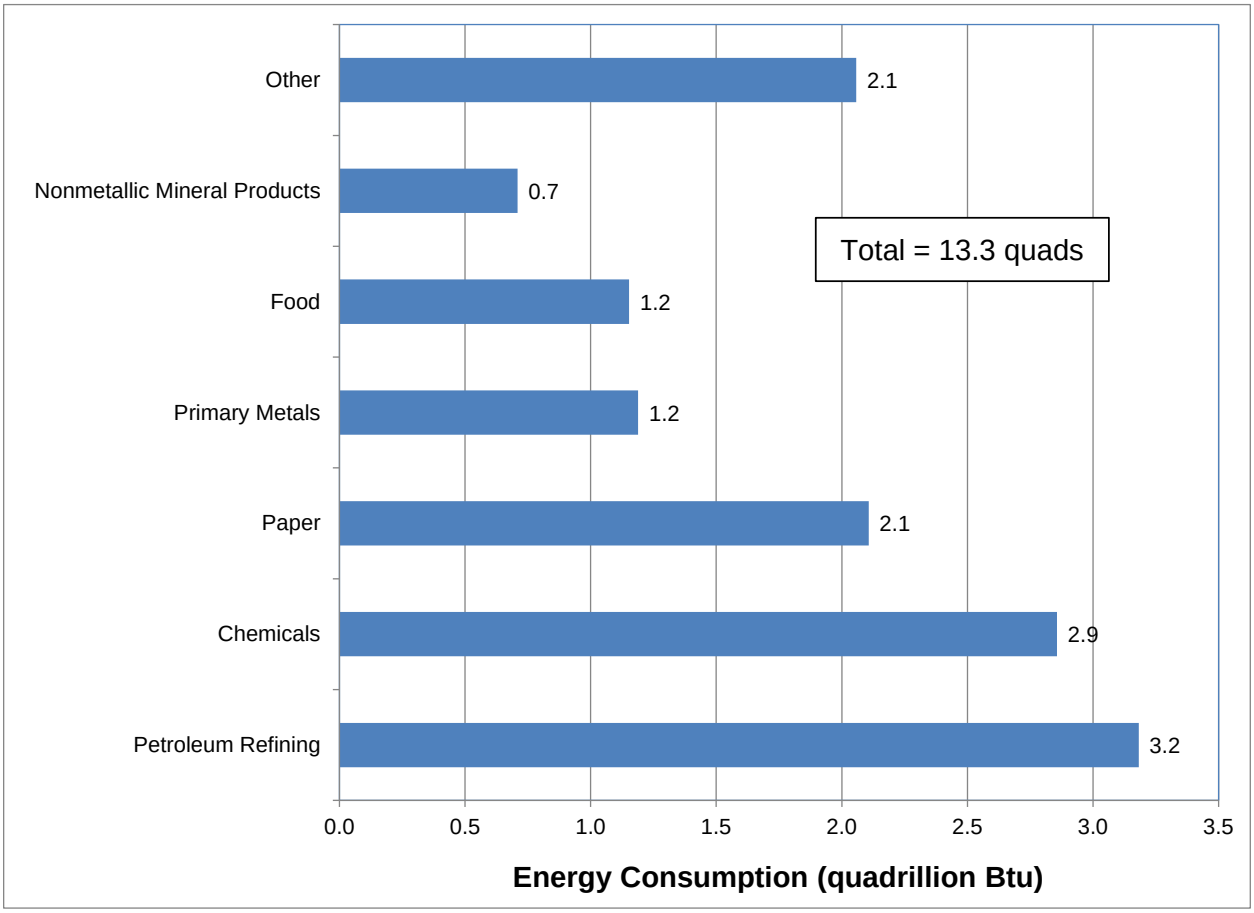
Figure 14. Manufacturing Delivered Energy Intensity by Subsector, 2002–2010



Source: Energy consumption from MECS, 2010 and ICF Estimates. Industrial Production from Federal Reserve Board, Industrial Production Indices, 2014.

Energy use in industry consists of energy for heat and power, and energy as raw material or feedstocks. The use of feedstocks is for the manufacture of petrochemical products such as ethylene, propylene, ammonia, and methanol. Feedstock consumption in 2010 was 4.2 quads. The bigger application of energy is for heat and power at 13.3 quads. **Figure 15** shows energy consumption for heat and power in 2010 for the six manufacturing subsectors with the highest energy consumption. Similar to the trends for total energy consumption (**Figure 9**), the largest consuming subsectors are petroleum and coal products (NAICS 324), chemicals (NAICS 325), paper (NAICS 322), primary metals (NAICS 331), food (NAICS 311), and non-metallic minerals (327). Collectively, these six subsectors accounted for approximately 85 percent of consumption for heat and power in the manufacturing sector in 2010.

Figure 15. Energy Consumption for Heat and Power by Sector (2010 Data)



Source: MECS, 2010; ICF Estimates

2.3 End-Use Applications

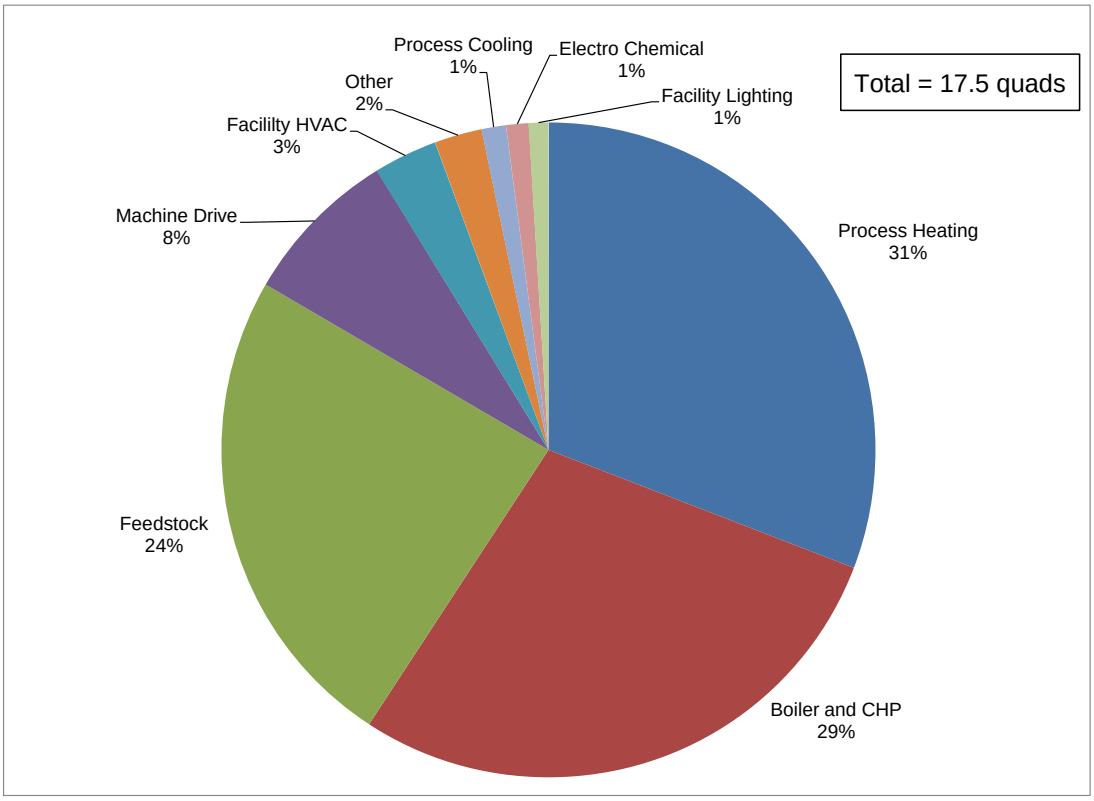
Energy is used in the manufacturing sector to meet diverse needs, such as driving motors; producing steam; fueling furnaces, kilns, and ovens; refrigerating warehouses; as well as serving basic plant needs, such as lighting, space heating, and space cooling. **Table 7** and **Figure 16** show a breakdown of energy consumption by end-use in the manufacturing sector for 2010.[12] The table shows that the largest application of energy in manufacturing is process heating, followed by boilers and CHP, and feedstocks. These three applications account for 83 percent of total energy use.

Table 7. Manufacturing Energy Consumption by Application (2010 data)

End-Use	Energy Consumption (quads)		
	Electricity	Fuels	Total
Process Heating	0.30	5.09	5.40
Boiler and CHP	0.03	4.93	4.96
Feedstock	0.00	4.23	4.23
Machine Drive	1.21	0.16	1.36
Facility HVAC	0.23	0.32	0.55
Other	0.12	0.29	0.41
Process Cooling	0.19	0.03	0.21
Electro-Chemical	0.19	0.00	0.19
Facility Lighting	0.17	0.00	0.17
Total	**2.44**	**15.05**	**17.48**

Source: MECS, 2010; ICF Estimates

Figure 16. Manufacturing Energy Consumption by Application (2010 Data)

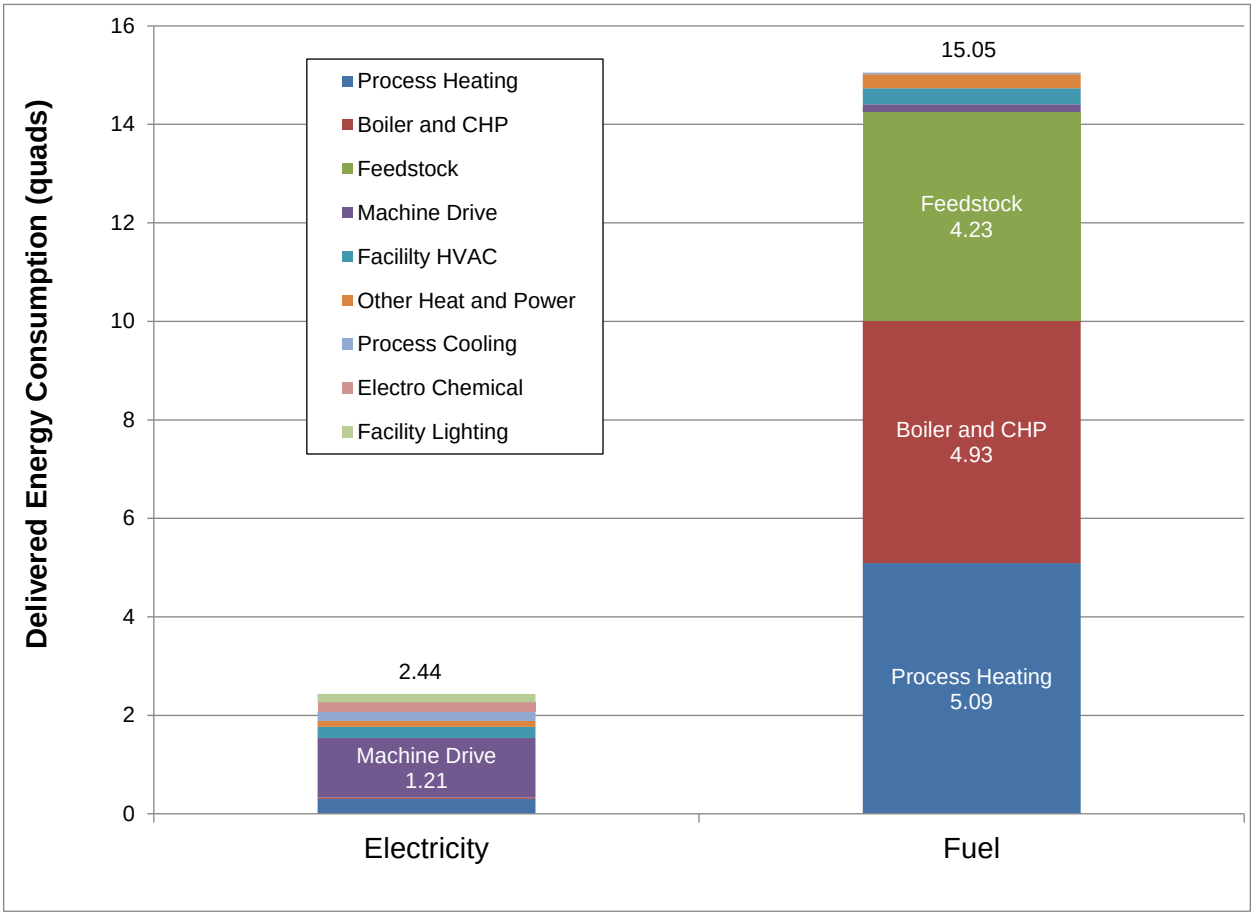


Source: MECS, 2010; ICF Estimates

Figure 17 shows energy consumption for electricity and fuel (non-electric) by end-use application. The figure shows that the uses of electricity vary greatly from fuels. Electricity use is primarily for machine drives, accounting for almost half of total electricity use in manufacturing. The rest are for electrolytic processes, space cooling, and lighting. Fuels have

different uses in manufacturing, but primarily for steam generation (boilers and CHP), process heating, and feedstocks.

Figure 17. Manufacturing Energy Consumption by End-Use Application (2010 Data)

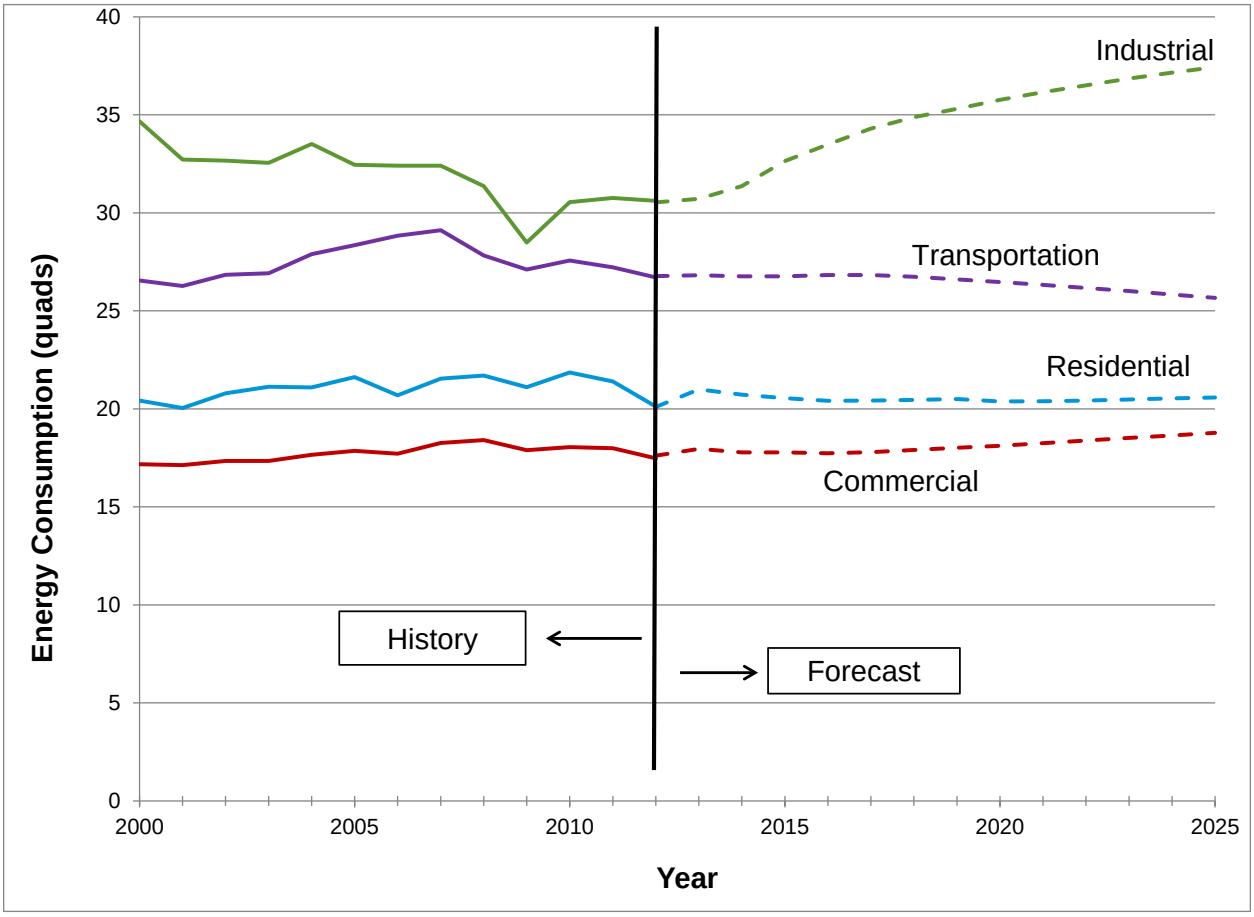


Source: MECS, 2010; ICF Estimates

2.4 Growth Forecast

As indicated in **Section 2.1**, the United States consumed approximately 95 quads of energy in 2012, with the industrial sector accounting for the largest share—30.6 quads, or 32 percent of the total. EIA forecasts that total energy consumption will grow to about 102 quads in 2025, with nearly all of the growth coming from the industrial sector (see **Figure 18**).[13] From 2012 to 2025, energy consumption in the industrial sector is forecast to increase from 30.6 quads to 37.4 quads – a 20 percent increase. In 2025, energy consumption in the industrial sector is expected to exceed 36% of total U.S. energy consumption. From 2012 to 2025, the average annual growth rate for total energy consumption in the industrial sector is forecast to be 1.6 percent, compared to 0.2 percent in the residential sector, 0.5 percent in the commercial sector, and negative 0.3 percent in the transportation sector.[14]

Figure 18. Energy Consumption Forecast



Source: EIA

The forecast growth in the industrial sector is driven, in part, by increased shale gas production and lower natural gas prices.[15] This optimistic picture for domestic gas supplies is expected to stimulate manufacturing output and energy consumption. Energy-intensive industries, such as chemicals and primary metals, are forecast to have the highest energy consumption growth rates, although energy consumption growth is expected across nearly all manufacturing subsectors. As energy use grows in the manufacturing sector over the next decade and beyond, there will likely be capital investments in new plant construction and existing plant renovations. For example, in 2013, the American Chemistry Council reported that up to $100 billion may be invested in the U.S. chemical industry by 2025 to expand production capacity by nearly 90 million tons.[16] This period of capital investments in manufacturing plants presents an excellent opportunity to invest in energy efficiency improvements.

Endnotes

[1] U.S. Energy Information Administration, 2013. "Monthly Energy Review," December 2013, Table 2.1, Energy Consumption by Sector, Web link .

[2] U.S. Energy Information Administration, 2012. "Electricity Flow, 2012," Online data, Web link.

[3] The EIA State Energy Data System defines LPG to include ethane (including ethylene), propane (including propylene), normal butane (including butylene), butane-propane mixtures, ethane-propane mixtures, and isobutane. In this case, LPG includes natural gas liquids (NGLs), which are ethane, propane, and butane. NGLs in the industrial sector are primarily used as feedstocks for olefin production.

[4] Data source: EIA, State Energy Data System. Latest available data for which state data are complete is 2011.

[5] There are four Census Regions: *Northeast*: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont, New Jersey, New York, and Pennsylvania; *Midwest*: Illinois, Indiana, Michigan, Ohio, Wisconsin, Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, and South Dakota; *South*: Delaware, District of Columbia, Florida, Georgia, Maryland, North Carolina, South Carolina, Virginia, West Virginia, Alabama, Kentucky, Mississippi, Tennessee, Arkansas, Louisiana, Oklahoma, and Texas; and *West*: Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Utah, Wyoming, Alaska, California, Hawaii, Oregon, and Washington.

[6] U.S. Energy Information Administration, "State Energy Data System (SEDS), 2013." The state information data is reported for 2011, which is the most recent year available from SEDS.

[7] Energy Information Administration, 2010. "Manufacturing Energy Consumption Survey (MECS)," Table 1.2, First Use of Energy for All Purposes (fuel and nonfuel), Web link.

[8] Nonmetallic mineral products include glass and cement.

[9] Ibid.

[10] The EIA MECS defines LPG and NGL as with EIA SEDS (see previous footnote). LPG includes a group of hydrocarbons such as ethane, ethylene, propane, propylene, normal butane, butylene, ethane-propane mixtures, propane-butane mixtures, and isobutane produced at refineries or natural gas processing plants, including plants that fractionate raw natural gas plant liquids. NGLs are a group of hydrocarbon such as ethane, propane, and butane. As such, NGL is a subset of LPG.

[11] U.S. Energy Information Administration, 2013. "Manufacturing Energy Consumption Data Show Large Reductions in Both Manufacturing Energy Use and the Energy Intensity of Manufacturing Activity Between 2002 and 2010," Web link.

[12] Energy Information Administration, 2010. "Manufacturing Energy Consumption Survey (MECS)," Table 5.2, End-Uses of Fuel Consumption, Web link.

[13] Energy Information Administration, 2013. "Annual Energy Outlook (AEO) 2014—Early Release," Reference Case, Web link , Table 2, Energy Consumption by Sector and Source.

[14] Annual growth rates calculated by ICF based on reference case energy consumption values in EIA AEO 2014.

[15] Energy Information Administration, 2013. "Annual Energy Outlook (AEO) 2014—Early Release," Reference Case, Web link.

[16] American Chemistry Council, 2013. Press release discussing a report from IHS, Web link.

3. Barriers to Industrial End-Use Energy Efficiency

3.1 Background

"Energy efficiency" is broadly defined as using less energy to provide the same or improved level of service or manufacturing output.[1] In the industrial sector, energy efficiency can be achieved across a diverse range of technologies and practices. For example:

- *Motors.* Retrofit existing motors (pumps, fans, compressors, motor-driven process equipment) with variable speed drives; replace aging motors with modern, more efficient motors.
- *Steam systems.* Retrofit existing boilers with economizers; improve steam trap maintenance; upgrade, or add, insulation to distribution systems.
- *Plant buildings.* Upgrade lighting (lamps and controls); improve maintenance for heating, ventilation, and air conditioning (HVAC) equipment.
- *Process equipment.* Enhance process monitoring through the use of sensors and controls for ovens, kilns, furnaces, and other energy-intensive equipment; improve maintenance procedures or schedules for process equipment.
- *Systematic energy management systems.* Adopt management practices and systems that optimize energy use across plant locations; use enhanced data collection to inform management decisions that will help drive down energy use; share results at all organizational levels to emphasize the importance of achieving energy savings goals.[2]

The magnitude of benefits from implementing energy efficiency in the industrial sector varies by specific technology or practice. In general, these benefits may include:[3]

Benefits for U.S. businesses:

- Reduced energy costs.
- Reduced emissions control costs.
- Enhanced competitiveness.
- Co-benefits, such as reduced material loss, improved product quality, and reduced water consumption.

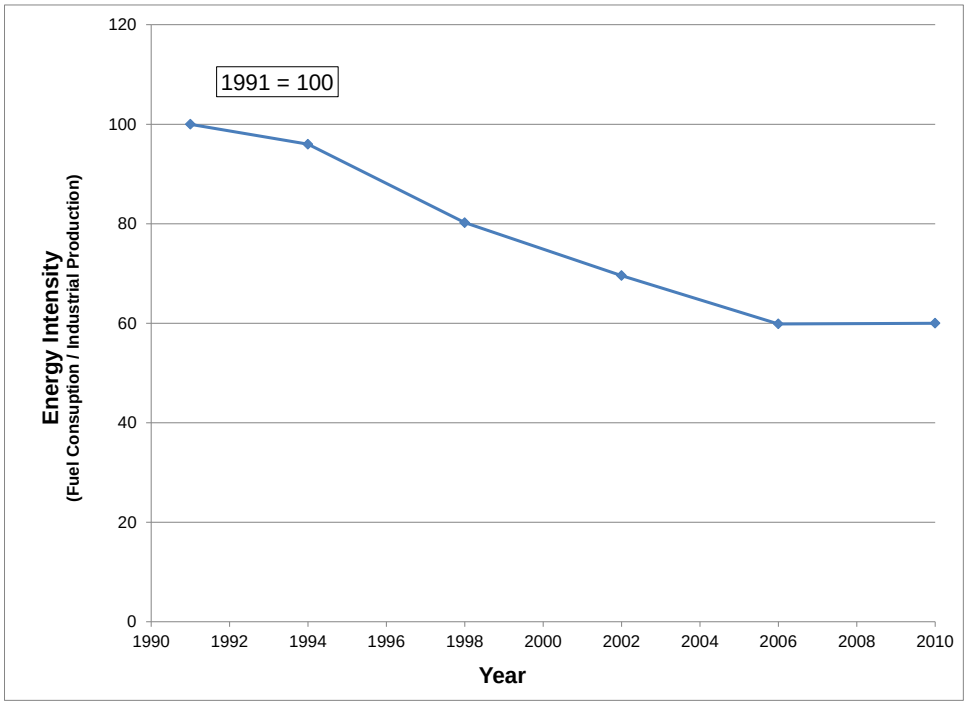
Benefits for the nation:

- Lower product costs for consumers.

- Increased job growth.
- Lower electricity costs associated with reduced electric grid infrastructure expenses.
- Increased health benefits from reduced criteria pollutant and greenhouse gas emissions.

The industrial sector has achieved significant progress in energy efficiency. One measure of this progress is energy intensity, which is the ratio of energy consumed to manufacturing output. As indicated in **Figure 19**, the energy intensity in the manufacturing sector declined by approximately 40 percent from 1991 to 2006 (based on the ratio of energy consumed to industrial production). Energy intensity remained unchanged from 2006 through 2010—a period marked by economic recession in the United States.

Figure 19. Manufacturing Sector Energy Intensity



Source: 1) Fuel consumption (numerator) from EIA MECS 2010, 2006, 2002, 1994, and 1991[4]
2) Industrial production (denominator) from Federal Reserve Board[5]

The structure of the utility industry and state policies has influenced advancements in industrial energy efficiency. In the mid to late 1990s, the utility sector was restructured in several states, and one consequence was that utilities in some restructured states reduced funding for end-use energy efficiency programs.[6] State and regional organizations filled part of the energy efficiency funding gap, but overall, investments in energy efficiency remained relatively low following restructuring.[7] In the past 5 to 10 years, utilities have shown a renewed interest in energy efficiency, in part due to state policies that have been established requiring energy savings through energy efficiency resource standards[8] .[9] An energy efficiency resource standard

(EERS) sets energy savings targets, usually as a percentage of retail electric sales that increase over time.[10] As utilities strive to meet aggressive EERS targets, they are beginning to focus on achieving additional energy savings from end-use efficiency in the industrial sector.[11] In addition, Federal standards continue to raise minimum efficiency levels for many common measures, such as lighting and HVAC equipment used in residential and commercial sectors, as well as electric motors, pumps and fans used in the industrial sector.[12] While higher standards improve overall energy efficiency, these higher standards tend to reduce the remaining potential for new energy savings from energy efficiency programs in the residential and commercial sectors.[13] For these reasons, and the reasons listed in the following bullets, utilities are increasingly turning to the industrial sector to help meet significant efficiency goals:[14]

- Industrial energy efficiency programs are often more cost-effective compared to residential and commercial energy efficiency programs.[15] Industrial energy efficiency measures can be half the cost (measured in dollars per unit of energy saved) compared to energy efficiency measures implemented in homes or buildings.[16] In most electricity markets, delivery of reliable energy efficiency resources to meet electrical energy consumption costs between 15 and 50 percent of the cost of power from new central station generation.[17] The cost of energy saved through ratepayer energy efficiency programs ranges from $0.021[18] to $0.025 per kWh, compared to conventional energy supply side options typically costing $0.07 to 0.15 per kWh.[19]
- Resurgence in the U.S. industrial sector, including re-shoring,[20] has brought new awareness to the potential for energy efficiency to help the competitive position of returning and/or expanding manufacturing plants.[21]

The opportunity for energy efficiency cuts across manufacturers that produce relatively high energy-intensive products, as well as manufacturers that produce lower energy-intensive products. For relatively high energy-intensive products, energy costs are a significant percentage of total costs, and lowering energy costs through increased end-use efficiency can have a substantial impact on reducing the cost of manufactured products. For example, in the steel industry, energy accounts for about 15 percent of product cost, and in the glass industry energy accounts for 8 to 12 percent of product cost.[22] The industrial gases industry supplies oxygen to both of these industries and energy can account for up to 80 percent of its product cost, so those impacts can ripple throughout the supply chain. For lower energy-intensive products, such as computer assembly, furniture manufacturing, and transportation equipment manufacturing, the opportunity to save energy may be smaller, but the savings are still important. For both energy-intensive and less energy-intensive manufacturers, improvements in energy efficiency can help improve competitiveness and increase corporate profit margins.

While the industrial sector has shown progress in energy efficiency, recent studies suggest that even greater levels of energy efficiency can be achieved. For perspective, EIA forecasts that energy consumption in the industrial sector will grow from 30.6 quads in 2012 to over 37 quads by 2025.[23] Three recent studies suggest that accelerated adoption of energy efficiency technologies and practices in the industrial sector could reduce energy consumption by 15 to 32 percent compared to 2025 forecast values:

- *American Council for an Energy-Efficient Economy: 15 to 24 percent energy savings.* A 2012 study, ACEEE looked at historical energy intensity trends in the industrial sector and compared these trends to an EIA reference case (AEO 2011).[24] The EIA reference showed an approximate 1 percent per year decline in energy intensity in the industrial sector from 2010 to 2050. ACEEE noted that leading firms such as 3M, Alcoa, Dow, and United Technologies Corporation have achieved sustained reductions significantly beyond this level for many years (see sidebar on Alcoa).[25] ACEEE calculated energy savings that would be derived from energy intensity levels that decline at 2 percent and 2.75 percent per year. These calculations showed that energy consumption in the industrial sector could be reduced 15 to 24 percent by 2025, and 36 to 51 percent by 2050.[26]

> ***Alcoa's Participation in DOE's Better Plants Challenge and Energy Intensity Targets***
>
> Alcoa is a participant in DOE's Better Plants Challenge. With DOE, Alcoa set a goal in 2010 to reduce energy intensity by 25 percent by 2020 across 28 plants and 30 million square feet. In partnership with the Better Plants Challenge, Alcoa has achieved a 15 percent energy intensity improvement from its baseline 2005 levels. Alcoa is sharing with DOE and the public the strategies it has put in place to improve energy efficiency, including an initiative to link performance-based compensation to energy savings for executives and other company employees.
>
> *Source: U.S. Department of Energy, Better Buildings Challenge. Web link.*

- *McKinsey: 25 percent energy savings.* In a 2009 study, McKinsey estimated that the industrial sector could reduce its overall energy consumption by 18 percent in 2020[27] compared to a business as usual (BAU) scenario developed by EIA for the Annual Energy Outlook.[28] Extrapolated to 2025, this energy savings reduction is 25 percent compared to BAU. In the McKinsey study, all energy savings are derived from end-use energy efficiency measures that have a positive net present value (NPV), but are not realized in the baseline.

- *National Research Council: 21 to 32 percent energy savings.* In a 2009 report, the National Research Council estimated industrial energy savings to be 14 to 22 percent[29] in 2020 compared to a BAU scenario developed by EIA for the Annual Energy Outlook.[30] Extrapolated to 2025, these energy savings increase to 21 to 32 percent. In the National Research Council report, the savings are based on cost-effective technologies, which are

generally defined to be technologies that provide an internal rate of return (IRR) of 10 percent or higher.[31]

3.2 Barriers

Manufacturers in the industrial sector have shown progress in using energy more efficiently. However, barriers impede greater adoption of energy efficiency in the industrial sector. Barriers are discussed in three categories: (1) economic and financial, (2) regulatory, and (3) informational.

3.2.1 Economic and Financial Barriers

Significant economic and financial barriers to industrial end-use energy efficiency include:

- *Internal competition for capital.* Manufacturers often have limited capital available for end-use efficiency projects and frequently require very short payback periods (one to three years).
- *Corporate tax structures.* U.S. tax policies, such as depreciation periods, the treatment of energy bills, and other provisions can be a deterrent.
- *Program planning cycles.* There can be a mismatch between industrial planning cycles and utility and state energy efficiency program cycles, which can hinder industrial sites from moving forward with an energy efficiency project.
- *Split incentives.* Companies often split costs and benefits for energy efficiency projects between business units, which complicates decision-making.
- *Failure to recognize non-energy benefits of efficiency.* Not considering non-energy or co-benefits of an end-use energy efficiency project weakens the business case.
- *Energy price trends.* Volatile energy prices can create uncertainty in investment returns, leading to delayed decisions on energy efficiency projects.

Internal Competition for Capital

Manufacturers have limited capital for investments in new equipment, process upgrades, and plant improvements, and energy efficiency projects need to compete for this capital.[32] In a 2010 survey, respondents from a number of industry sectors (e.g., health care, manufacturing, finance, consulting, retail, and government) in the United States and Canada cited capital availability as their top barrier to investing in energy efficiency.[33] This survey indicated that decision-makers in the industrial sector typically expect capital investments to have short payback periods of 1 to 3 years.[34] In interviews, 44 percent of energy managers indicated that they need a payback of less than 3 years for energy efficiency projects, and other evidence suggests that under difficult economic conditions companies may look for a payback period of

18 months or less.[35] Short payback periods were also identified in a 2013 report by the Alliance to Save Energy.[36] In this report, payback and return on investment expectations were evaluated for three different types of investors. If the capital was being provided by an internal capital equipment budget, the payback period was in the range of 1–3 years (see **Table 8**) as opposed to longer payback periods for other types of investors (up to 30 years for funding from government sources).

Even when end-use energy efficiency projects do meet corporate investment thresholds, manufacturers may still not go ahead with such projects if they do not have a direct connection with the company's core business. For example, the ability to increase production is often viewed more favorably than being able to produce a product/good with less energy, even if the economic impacts are equal for both alternatives.

Some companies have taken proactive steps to encourage evaluation of energy efficiency projects. One example is Walmart (see sidebar), which works with suppliers to identify attractive projects. Another example is Cummins (see sidebar below), which has an internal capital fund devoted to energy efficiency improvements.

Another barrier associated with capital constraints is that financing an energy efficiency project can also impact a manufacturer's credit rating

Walmart Supplier Energy Efficiency Program (SEEP)

Walmart established the SEEP program to help encourage end-use efficiency investments in their supply chain. The SEEP program is structured as follows:

1. Walmart has an ongoing dialogue with manufacturers to discuss energy efficiency improvements. Upgrades are generally focused on building technologies (e.g., lighting, HVAC, water heating, and energy management systems or controls).
2. If a particular manufacturer shows interest in an energy efficiency upgrade, Walmart and the manufacturer will discuss the expected financial performance for the upgrade (e.g., payback or IRR).
3. If the outcome of Step 2 is positive, an energy audit will be performed. Walmart pays for the energy audit if the manufacturer invests in energy efficiency equipment based on the results of the audit. If the supplier takes no action, the supplier pays for the audit.
4. If the manufacturer decides to make an investment in energy efficiency, Walmart helps the manufacturer obtain competitive bids for the projects.

An example of a successful SEEP project is at VonDrehle Corporation, a U.S. paper manufacturer located in Hickory, NC. Walmart paid for an energy audit at a VonDrehle site. Following the audit, Walmart helped VonDrehle obtain bids for lighting upgrades that were subsequently implemented on 50 percent of the lights at the VonDrehle facility. VonDrehle paid for the lighting upgrades, which save an estimated $37,000 a year, resulting in a payback of less than 4 years.

Source: Institute for Industrial Productivity. Web link.

because the carrying cost of the project is included on the company's balance sheet. With this barrier in mind, some utilities have started offering alternative financing structures:

- In Wisconsin, Alliant Energy's Shared Savings Program operates as a type of on-bill financing program to encourage customers to take on major energy efficiency investments such as CHP that they may not have pursued due to capital constraints. Alliant now earns a rate of return on its Shared Savings portfolio equivalent to what it receives from its investments in more traditional assets.[37]
- Minnesota Power provides industrial users in northeastern Minnesota with on-bill financing for energy efficiency projects.[38]

Table 8. Investment Expectations

Class of Investor	Payback (years)	Return-on-Investment (annual %)
Government Agency	7-30	3-10
Outside Investor	3-7	10-25
Internal Capital Equipment Budget	1-3	25-100

Source: Adapted from ASE, 2013

Cummins' Internal Capital Fund to Support Energy Efficiency

Cummins, Inc., designs, manufactures, distributes, and services engines and related technologies, including fuel systems, emissions solutions, and power-generation systems. The company is a partner in DOE's Better Buildings Better Plants program, and committed to reducing energy intensity by 25 percent in 2016 compared to 2005. Cummins has already reduced the energy intensity of its facilities by almost 34 percent from 2005 to 2012 by targeting high-return opportunities. The company has an internal capital fund devoted to these high-return efficiency projects and has allocated $20.7 million in capital over 2013–2015 to install submeters, expand control systems, and upgrade or replace inefficient equipment. Additionally, Cummins was recognized by EPA with a Climate Leadership Award in 2012 due in part to this internal capital fund that helped create dedicated, annual funding for energy efficiency improvements.

Source: Cummins. Web link.

Corporate Tax Structure

The U.S. Internal Revenue Service (IRS) tax structure may discourage investments in end-use efficiency. Most business expenses, including energy costs, qualify as a tax deduction. Most types of property, including machinery and equipment investments, can be depreciated over time. The depreciation periods allowed by the IRS vary depending on several factors, including the type of asset and the expected life of the asset. In the IRS tax code, depreciation periods

can be long, often exceeding the asset life.[39] Long depreciation periods can serve as a disincentive to replace existing equipment—which may be old and inefficient—until the existing equipment is fully depreciated.[40] Additionally, energy bills are treated as a business expense and can be subtracted from taxable income. This tax provision subsidizes energy costs, which reduces the incentive for businesses to reduce energy costs.[41] An example of a successful accelerated depreciation program is the Netherlands VAMIL program (see sidebar).[42]

Netherlands Energy Efficiency Tax Incentives

When corporations buy capital assets, the value of the assets is depreciated over time. If depreciation is accelerated, there are corporate tax advantages. To help stimulate capital expenditures on energy efficiency, the Netherlands adopted the Random Depreciation of Environmental Investments Measure (VAMIL) in 1991, which offers accelerated depreciation for certain energy efficient assets. VAMIL allows for up to 75 percent depreciation of investment costs during the first year, compared to 20 percent over a minimum of 5 years for other capital expenditures in the Netherlands. Maximum investment costs are 25 million euros per asset (equivalent of to $32 million U.S. dollars). VAMIL saves companies an estimated 3–8 percent of the total investment costs for energy efficient equipment. In 2012, VAMIL provided 33 million euros worth of tax exemptions.

Source: Institute for Industrial Productivity. Web link.

Program Planning Cycles

There can be a mismatch between planning cycles used in the industrial sector and energy efficiency programs offered by utilities.[43] Decision-makers at industrial plants often have a planning horizon of 4–7 years for major plant upgrades,[44] although the timing varies considerably between companies and manufacturing sectors.[45] Utility energy efficiency programs are typically announced for 1- to 3-year periods,[46] and the type of energy efficiency incentives may change between program cycles. The relatively short timeframe and long-term uncertainty in utility energy efficiency programs can make it difficult for industrial customers to incorporate the value of utility energy efficiency incentives in long-term plans. If energy efficiency projects are not captured in long-term manufacturing plant upgrade plans, these energy efficiency projects may be overlooked.

Split Incentives

Companies often split responsibility for plant operations, energy bills, and investment decisions across different organizational/business units. In some corporate structures, energy managers are not asked to review energy bills nor do they receive recognition for reducing energy costs (this is not the case for J.R. Simplot—see sidebar).[47] A procurement manager may be motivated to minimize first costs[48] and minimizing operational costs through reduced energy consumption may not be a priority.[49] These “split-incentive” barriers can inhibit energy efficiency projects.

Failure to Recognize Non-energy Benefits

Another barrier to the increased adoption of industrial end-use efficiency is that co-benefits, such as reduced maintenance and reduced material use, are often not included when a project is under consideration. Valuing non-energy benefits, such as the societal benefits of industrial energy efficiency, reduced water use, and reduced emissions, can be important.[50] For example, energy efficiency can help enhance grid reliability because there is less demand on the grid; energy efficiency contributes to improved air quality because of reduced emissions associated with lower electricity generation. While somewhat less tangible, studies have shown that energy efficiency projects can improve employee satisfaction and help companies improve their corporate image.[51] Valuing the full range of benefits for an industrial energy efficiency project can improve the implementation rate.

Valuing non-energy benefits, such as the societal benefits of industrial energy efficiency, can be important.[52] As described above, at a national level, energy efficiency can result in lower product costs for customers, increased job growth, lower electricity costs associated with reduced grid infrastructure expenses, and increased health benefits from reduced exposure to criteria pollutant and greenhouse gas emissions. Studies from ACEEE and RAP have found that non-energy benefits from industrial energy efficiency projects can be as high as or even higher than the energy cost saving benefits resulting from the project.[53] A recent State and Local Energy Efficiency Action Network (SEE Action) study found that due to the complications associated with quantifying non-energy benefits, it may be most practical for administrators to focus on only the key non-energy benefits most amenable to quantification. This study points out that some state programs incorporate a relatively large

J.R. Simplot
Executives Promote Energy Efficiency and Recognize Accomplishments

The J.R. Simplot Company is one of the largest privately held food and agribusiness companies in the country. Cognizant of the "split-incentive" problem, the company now trains employees in best practices and has adopted an Energy Champions program. The Energy Champion has responsibilities for energy efficiency and works with an on-site energy efficiency team.

To further promote energy savings and cooperation in reducing energy consumption, the CEO hands out annual awards for energy efficiency:

- Energy Efficiency Plant of the Year
- Energy Champion of the Year
- Energy Employee of the Year

In 2009, J.R. Simplot joined the Better Plants Challenge, and since then more than 10 of J.R. Simplot's plants have reduced energy intensity more than 5 percent, and 4 plants have reduced energy intensity by 25 percent. A corporate energy manager noted that by simply applying behavioral changes, one plant was able to realize a 3 percent reduction in energy consumption in 1 year with no capital expenditures.

Source: Sturtevant, D. Web link.

range of non-energy benefits such as the New York State Energy Research and Development Authority (NYSERDA), Massachusetts, and Bonneville Power Authority.[54] These states can serve as useful models for other states trying to determine appropriate quantification methods for non-energy benefits.

To further illustrate the value of quantifying non-energy benefits, the inclusion of co-benefits in the analysis of an energy efficiency measure, such as improved product quality and reduced water consumption, can increase the internal rate of return for a project, decrease the payback period, thereby making investments more likely. For the Energy Trust of Oregon, water savings are a common non-energy benefit that is quantified and is considered straightforward as compared to other non-energy benefits such as improving safety and employee morale.[55] State organizations have also piloted explicit consideration of co-benefits as part of the energy efficiency cost calculation. A study sponsored by ACEEE in 2012 summarizes state policies that incorporate the assessment of non-energy benefits.[56]

Non-energy benefits such as lower emissions can be recognized through state policies, such as Energy Efficiency Resource Standards and emissions reduction programs. Twenty-five states already have policies in place that establish energy savings goals.[57] Some emission reduction programs—including the Regional Greenhouse Gas Initiative and California's cap-and-trade program—already recognize the emissions benefits of energy efficiency across ten states.[58] Successful examples of recognizing the non-energy benefits include:

- Regional Greenhouse Gas Initiative (RGGI) Energy Efficiency Funding—Because of energy efficiency programs funded by CO_2 allowance revenue, electricity consumers located in northeastern states participating in the Regional Greenhouse Gas Initiative (ME, NH, VT, MA, NY, CT, RI, MD, DE) saved over $1 billion in energy costs. In addition, the RGGI program in combination with market responses and state clean energy policies have helped RGGI states reduce CO_2 emissions 40 percent since 2005.[59] Over a three-year study period, the average industrial customer saved over $2,500 each.[60] Manufacturers who have participated in energy efficiency programming funded by the allowance revenue have also experienced significant additional cost savings (RGGI, 2012).
- Energy Efficiency Resource Standards—An EERS can be a significant driver of increased energy efficiency. As of July 2013, twenty-five states have policies in place that establish energy savings targets. Massachusetts and Vermont have the highest EERS targets at 2.5 percent savings annually.[61]
- China 1,000 Enterprises Program—this program launched in 2006 seeks to reduce the energy consumption of the one thousand largest industrial enterprises in China. The

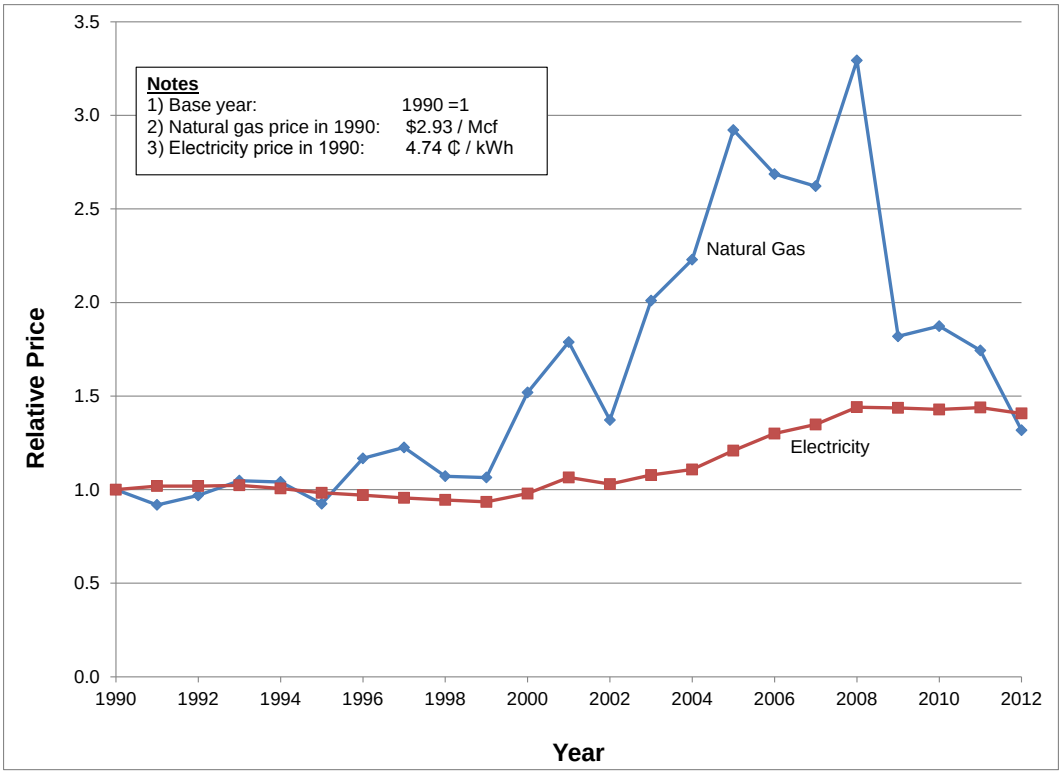
program set a goal of reducing energy consumption by 100 million tons of coal equivalent by the end of 2010 and set energy consumption targets for each enterprise. Achievement of the energy saving targets is part of the provincial government evaluation system in which the responsible government officials are evaluated annually on whether the energy consumption targets are met. Regions and enterprises that do not meet the targets are not granted rewards or honorary titles. In addition, officials are not promoted without meeting the energy conservation goals.[62] China's National Development and Reform Commission (NDRC) announced that the program had exceeded that goal 2 years early—by the end of 2008, the program had saved 106 million tons coal equivalent, resulting in avoiding 265 million metric tons of CO_2 emissions.[63]

- India Perform Achieve Trade (PAT) Program—This is a trading scheme aimed to reduce energy consumption in industries across India using market oriented mechanisms. The program covers the following sectors: thermal power plants, cement, iron and steel, aluminum, fertilizers, pulp and paper, chlor-alkali, and textiles. Experts estimate that if PAT is successful, it alone could help India meet half of its emissions intensity targets announced at Copenhagen, i.e., a reduction of 20–25 percent reduction by 2020, based on a 2005 baseline.[64]
- Australia Industry reporting program—The Energy Efficiency Opportunities (EEO) Program was an Australian Government initiative encouraging large energy-using businesses to increase their energy efficiency by improving the identification, evaluation, and implementation of cost-effective energy saving opportunities. The program was mandatory for organizations that use over 0.5 petajoules (PJ) of energy annually and may be undertaken voluntarily by medium energy users.[65]
- South Korea Emissions Trading Scheme (ETS)—South Korea announced in 2012 that it will cap approximately 70 percent of the country's GHG emissions. The cap aims to cut emissions by 236 $MtCO_2e$, or 29%, by 2020 via emissions reductions from the industrial sector (83 $MtCO_2e$). The trading scheme is set to begin in 2015, and will cover facilities producing more than 25,000 tons of greenhouse gas emissions—expected to be around 450 of the country's largest emitters.[66] In addition, under their green growth strategy, the country has allocated KRW $2.5 trillion towards industrial energy efficiency measures.[67]

Energy Price Trends

Volatile energy prices can create uncertainty and dampen interest in an energy efficiency project. As indicated in **Figure 20**, natural gas prices increased significantly from 2000 through 2008. Since 2009, natural gas prices have generally been declining, with the exception of some volatility due to extreme weather conditions and transmission capacity (e.g., natural gas price spikes that occurred in the winter of 2014).[68] The expectation for natural prices to remain at low levels in the midterm (EIA projects Henry Hub spot prices to remain annually below $5/MMBtu through 2022)[69] could reduce motivation for industrial plants to implement energy efficiency projects, particularly industrial plants with short-term planning horizons. To the extent that forecast prices for natural gas remain low, industrial customers may perceive the economic value of investments in efficiency to be relatively low.[70]

Figure 20. Natural Gas and Electricity Price Changes in the Industrial Sector



Source: EIA, Monthly Energy Review, December 2013

3.2.2 Regulatory Barriers

There is significant activity at the state and Federal level to reduce regulatory barriers to energy efficiency. These efforts are leading to positive changes, but barriers still exist, including:

- *Utility business model.* The structure of utility cost recovery and lost revenue mechanisms can reduce a utility's interest in promoting industrial energy efficiency projects.
- *Industrial participation in ratepayer-funded energy efficiency programs.* Opt-out programs or loosely defined self-direct programs allow industrial customers to not participate in traditional energy efficiency programs.
- *Failure to recognize all energy and non-energy benefits of efficiency*. There can be unrecognized energy benefits and non-energy societal benefits associated with improving energy efficiency. If these benefits are omitted from the cost-effectiveness calculations for industrial energy efficiency programs, there can be under-procurement of industrial energy efficiency resources.
- *Energy resource planning.* Not requiring cost-effective energy efficiency to be considered as part of the integrated resource planning (IRP) process can slow the evolution or expansion of industrial energy efficiency programs.
- *Environmental permitting.* Uncertainty, complexity, and costs associated with permitting processes such as New Source Review (NSR) can deter facilities from moving forward with energy efficiency projects.

Utility Business Model

The traditional business model for regulated utilities can limit investments in end-use efficiency. In traditionally regulated electricity markets, utilities recover fixed program costs and earn revenue by selling energy, with the cost of building new power plants and transmission and distribution infrastructure recovered through energy sales.[71] Another key way that utilities earn revenue is from asset investments—for example, if regulators set the rate of return higher than the utilities' cost of capital, then utilities have a much greater incentive to invest in new capacity.[72] To elaborate, if a utility can raise capital at a cost of 9 percent, but can earn 11 percent returns on all invested capital, then it will deliver gains to its investors by adding capacity.[73] In this business model, traditionally regulated utilities may be discouraged from offering programs to help customers significantly reduce energy consumption and the need for new capacity.[74,75,76]

Electric rates are typically approved by the state utility regulatory agencies. These agencies seek to achieve "just and reasonable" rates for customers and "just and reasonable" returns for investors. Utilities face three primary financial concerns relative to customer energy efficiency programs: (1) recovery of program costs; (2) removal of the "through-put" incentive (profits linked to increased energy sales); and (3) providing earnings opportunities for shareholders comparable to alternative utility investments.[77] To address utility financial concerns, utility models that align customer and utility incentives have progressed in some states.[78] For example, state utility regulatory agencies may allow for energy efficiency program costs to be treated as "expenses" in utility rate cases, in other words, utilities can recover these expenses in the same manners as other costs such as employee salaries and administrative expenses.[79] In these cases, regulatory agencies balance the benefits of energy efficiency, and cost recovery and lost revenue needs of utilities.

Some state utility regulatory agencies have reviewed and modified the regulatory framework to address these concerns.[80] The state utility regulators working with utilities can adjust the "through-put" incentive to ensure utilities and customers are aligned to support greater investment in energy efficiency. Modification of these regulations may encourage utilities to promote and expand energy efficiency programs, while still allowing them to earn a fair rate of return on investments.

Industrial Participation in Ratepayer-Funded Energy Efficiency Programs

The costs of running energy efficiency programs are often recovered by a fee (also known as a rider) on ratepayer (customer) bills or by an amount embedded in the rate structure. Some state utility regulatory agencies allow large energy customers to opt-out of paying this rider or paying into a public benefits fund (PBF), a systems benefit charge (SBC), or other state fund that is used to offer ratepayer-funded energy efficiency programs.[81] States that offer opt-outs from energy efficiency programs often do so based on legislative mandates or because they believe the suite of utility-run energy efficiency programs, covering such items as lighting and HVAC, are not as helpful to the large industrial customers based on the investments they would need to make to be more energy efficient. In some cases, opt-out programs do provide opportunities for customers to optimize energy efficiency—it allows large customers to tailor energy efficiency investments to their specific need. However, opt-out provisions can also lead to fragmented industrial energy efficiency programs across a state or utility territory. Allowing industrial facilities to opt-out of energy efficiency programs can also burden smaller customers by placing a disproportionate share of costs on them, while still providing benefits to non-participating customers.[82]

Self-direct programs allow large industrial customers, and in some cases large commercial customers, to direct how funds are spent for energy efficiency improvements at their facility, instead of contributing funds into a larger energy efficiency program intended to benefit multiple energy users.[83,84] There are many variations in how self-direct programs are designed, including designs intended to improve the efficient use of both natural gas and electricity (see sidebar on Utah's proposed self-direct program).[85] In some cases, self-direct programs are perceived as unfairly allowing large customers out of their obligation to support regional energy efficiency goals or energy resource planning.[86] Opt-out programs—and in some cases self-direct programs (if there are no stringent verification or enforcement provisions)—can hinder improvements in industrial end-use efficiency.

To encourage greater participation in energy efficiency programs, experts have found that states can facilitate collaborations between utilities and their industrial customers to ensure the programs offered to the industrial customers are beneficial. States can also consider removing industrial opt-out provisions where they exist. For self-direct programs, states can craft programs that ensure measurement and verification requirements that result in verified energy savings and help achieve state energy efficiency policy goals. States can assess their policies to ensure they are structured to maximize cost-effective energy efficiency and that the customers receive benefits from the programs.[87,88]Natural gas utilities recover energy efficiency program costs similarly to electric utilities, including through an adder to delivery charges. Approximately 40 percent of U.S. industrial customers have separate purchasing agreements with wholesale gas suppliers or third-party marketers for natural gas, and these agreements account for about 88 percent of the natural gas volume

Utah Proposes to Combine Electric Public Benefits Fund with Voluntary Natural Gas Program

An innovative approach for funding natural gas savings programs is being proposed by the Utah Association of Energy Users. Self-direct programs typically allow large customers that would otherwise be required to contribute to an energy efficiency fund to use this money directly for energy efficiency improvements. In this proposed self-direct case, the Utah Association is suggesting that gas utilities ask large industrial customers to voluntarily pay between 1 and 3 percent of their gas expenses into a demand side management fund. Another distinctive feature is that the funds could then be combined with contributions they already make to electric public benefit funds (PBFs). Oftentimes, natural gas and electric PBFs are kept separate. Participating manufacturers in this program would then be allowed to self-direct funds to cover either electric or gas energy efficiency opportunities. This approach would allow implementation of larger and more effective programs with the flexibility to deliver both electricity and gas savings.

Source: State and Local Energy Efficiency Action Network. Web link.

delivered by U.S. utilities to industrial customers. Industrial customers that acquire natural gas from a source other than the local gas utility do not typically pay energy efficiency surcharges and are not served by ratepayer-funded energy efficiency programs. The industrial sector is the second largest end-use consumer of natural gas—26 percent of total U.S. end-use gas consumption.[89] Although some end-use customers implement energy savings programs on their own, most customer participation is through gas utility–administered programs, and not having industrial customers participate in energy efficiency programs represents a significant missed opportunity in gas-saving programs.[90,91]

To address lost savings, states can consider how to enable greater industrial participation in natural gas and electric utility energy efficiency programs. The State and Local Energy Efficiency Action Network found that state regulators can direct large industrial customers to contribute to revolving energy efficiency funds, usually in the range of 1 to 3 percent of their energy expenditures.[92] These program funds can be combined with other ratepayer-funded programs to assist with customer energy efficiency projects. This change would add more resources to these programs and facilitate additional programs targeted to deliver gas and electric savings.

Failure to Recognize All Energy and Non-energy Benefits

A 2013 report from the Regulatory Assistance Project identified 12 distinct sources of cost-reducing benefits associated with energy efficiency, and 7 different sources of non-energy societal benefits.[93] Benefits include avoided capacity costs (generation capacity, transmission capacity, distribution capacity), reduced line losses, reduced fuel price volatility, reduced cost of compliance with portfolio standard requirements, and reduced reserve margin requirements. A failure to account for all of the energy and non-energy benefits of efficiency results in an under-valuation of energy efficiency resources relative to supply side resources, and thus under-procurement of energy efficiency resource. Capturing the full energy value of efficiency will lead to more favorable industrial energy efficiency regulation and policies.

Energy Resource Planning

Integrated resource planning is used by utilities to identify options for meeting forecast energy demand based on balancing several factors, including legislative requirements, state utility regulatory agency guidelines, and environmental concerns. An integrated resource plan (IRP) often requires electric utilities to consider multiple options in addition to building new power plants or procuring more supply, including the development and application of energy efficiency programs.[94] Including end-use energy efficiency in an IRP could provide an incentive to expand these efforts.

An IRP may be a tool for encouraging industrial end-use efficiency and other forms of efficiency.[95] Under the traditional planning process, energy efficiency and other demand side resources[96] may be overlooked with planning focused solely on supply side resources.[97] Although many states have an IRP process, most do not have policies that require full consideration of demand side resources, including end-use energy efficiency measures.[98] A recent report found that in 2009, only six states had active policies in place that required full consideration of demand side resources, not just in electric generation planning, but also in electric transmission and distribution planning as well as natural gas planning.[99]

Planners can consider including a robust evaluation of both cost-effective supply- and demand-side resources to efficiently meet demand.[100] States can also conduct planning exercises and include end-use energy efficiency as a resource.[101, 102] Example successful approaches include:

- CHP/ WHP and other forms of end-use efficiency must be included in Integrated Resource Plans in Massachusetts, Connecticut, and in certain other states.[103]
- South Korea CHP/District Energy Optimization Plan—South Korea's Integrated Energy Supply Act integrates district heating networks into the construction of new urban developments. This is an efficient and cost-effective way to create guaranteed heat loads that allow successful commercial and industrial development and operation of CHP plants.[104]
- UK Department of Energy & Climate Change Digest of Energy Statistics 2013—Chapter 7: Combined Heat & Power—This document sets out the contributions made by combined heat and power to the United Kingdom's energy requirements.[105] A "Good Quality" CHP project, with installed capacity >1 MWe, must achieve 10 per cent primary energy savings compared with the EU reference values (established in Energy Efficiency Directive (2012/27/EU)) for separate generation of heat and power i.e. via a boiler and power station. Good Quality CHP capacity increased by nearly 3 per cent between 2011 and 2012 from 5,970 MWe to 6,136 MWe. Good Quality CHP is also eligible for certain UK incentives such as tax breaks and renewable energy credits.[106]

A related type of energy planning is with ISOs/RTOs. In some regions, the grid operator may not have access to a complete accounting for existing or planned energy efficiency resources. ISOs/RTOs that rely on capacity markets for planning may overlook some energy efficiency resources in the market, or energy efficiency resources that are under development or planned. As with IRPs at the utility level, regional grid planners can account for all existing and planned end-use energy efficiency measures, as well as all generation and transmission resources. ISOs/RTOs can work closely with states and utilities to ensure proper accounting of existing end-use energy efficiency resources. An example successful policy includes the following:

- In 2012, ISO-New England applied a revised energy efficiency forecast in its annual 10-year Regional System Plan (RSP, or Plan). The forecast allows the ISO for the first time to account for expected energy efficiency resources for the full ten years of the Plan. Prior to the development of this revised forecast methodology, the ISO's 10-year Plan used only the three years of energy efficiency resources that had cleared in the annual Forward Capacity Market (FCM) auctions. As a result, the ISO's treatment of energy efficiency was overly conservative. The revised energy efficiency forecast allows each annual Plan to more accurately fulfil its purpose: "to determine the resources and transmission facilities needed to maintain reliable and economic operation of New England's bulk electric power system over a ten-year horizon."[107]

Environmental Permitting

EPA's New Source Review (NSR) permitting programs, which are administered by states, can be a real or perceived hindrance to industrial end-use energy efficiency projects.[108] NSR permitting is triggered by construction of new major sources of air pollution or major sources that are being significantly modified.[109,110] The goal of the NSR program is to ensure that emission increases from these new and modified facilities are reduced to the maximum degree possible using demonstrated control technology, and that they do not cause or contribute to an air quality violation. Some industries have argued that the NSR permitting process can be costly and lengthy, and the outcome can be uncertain. With these obstacles, industrial plants may be reluctant to move forward with an end-use energy efficiency project if this action could trigger NSR permitting requirements. Despite recent changes[111] in NSR permitting procedures, some manufacturers avoid plant upgrades, including energy efficiency improvements, due to the risk of triggering NSR permitting.

Recent analyses of the EPA proposed Clean Power Plan by various organizations have found that the regulations may impose a significant risk that regulated units will trigger NSR as they make modifications to reduce their emissions.[112,113] These analyses suggest that EPA consider developing a streamlined NSR review process to avoid penalizing a source for improving efficiency and that under such an approach, the EPA can establish screening tools to confirm that already well-controlled sources or sources whose "net emissions increases" will stay below attainment significance thresholds comply with NSR. The Government Accountability Office (GAO) studied the NSR process in 2012 and found that the EPA does not maintain complete or centralized information on NSR permits and without this information it is difficult to determine how state and local permitting agencies vary from EPA in their interpretation of NSR requirements.[114] The GAO study concludes that specific federal EPA offices along with regional EPA offices and state and local permitting agencies can consider ways to better review and

improve NSR implementation, primarily by centralizing information to ensure that U.S. EPA NSR guidance is followed in a consistent manner.[115]

3.2.3 Informational Barriers

To make informed decisions about end-use efficiency measures, manufacturers need accurate and complete information on project benefits, as well as available resources to assist them in considering efficiency opportunities and investing in them. Implementation of end-use efficiency projects can be delayed if relevant information is not readily available, difficult to comprehend, subject to change or if resources are not available to hire outside expertise. Key informational barriers include:

- *Adoption of systematic energy management system.* Failure of many industrial and manufacturing companies and facilities to adopt a structured, systematic energy management system that drives continual improvement of energy performance.
- *Awareness of incentives and risk.* Lack of knowledge of available Federal, state and utility incentives for end-use efficiency measures can lead to missed opportunities.
- *Metering and energy consumption data.* Lack of disaggregated energy consumption data, such as process unit and equipment-level energy consumption data, and tools to evaluate such data, can prevent identification and evaluation of opportunities.
- *In-house technical expertise.* Lack of in-house technical expertise or the resources to hire outside technical staff for the development and operation of end-use efficiency projects can hinder deployment.

Adoption of Systematic Energy Management System

Many manufacturing plants have not adopted a structured, systematic energy management system to drive continual improvement of energy performance, including identification of long-term energy savings opportunities. Energy efficiency projects are often focused on single-technologies, or one-time solutions, such as installing new lighting or new electric motors. In contrast, an organization-wide structured, systematic energy management approach that sets long-term energy savings goals and uses rigorous tracking and reporting systems can drive greater savings, reach across entire building portfolios, and institutionalize such practices to sustain long-term savings.[116] Results reported by Nissan (see sidebar on Nissan's success story); Bonneville Power Administration, Energy Trust of Oregon and Puget Sound Energy show that systematic energy management systems achieve 5 to 25 percent energy savings in commercial and industrial applications.[117]

The Department of Energy's Superior Energy Management (Program (SEP) seeks to help companies adopt systematic energy management systems. The SEP is a certification and recognition program for facilities demonstrating energy management excellence and sustained energy savings. As of 2013, forty industrial facilities were participating in the SEP program, in which facilities implement an energy management system based on the Internal Standards Organization (ISO) 50001 standard, and pursue third-party verification of their energy performance improvements. SEP certification provides industrial facilities recognition for implementing a business process for continually improving energy performance and achievement of established energy performance improvement targets.[118] SEP-certified facilities have achieved annual savings of $87,000 to $984,000 using no-cost or low-cost operational measures. SEP-certified facilities also typically achieve a 10% reduction in energy costs within 18 months of SEP implementation, and paybacks of less than two years in facilities with energy costs greater than $1.5 million annually.[119]

Nissan Improves Energy Performance at Tennessee Facility by Over 7 Percent

Nissan worked with the U.S. Energy Department to implement an energy management system that meets all requirements of Superior Energy Performance (SEP) and ISO 50001. At its vehicle assembly plant in Smyrna, Tennessee, the company established an energy baseline and assessed opportunities to save energy within its major energy-using systems. Implementing the recommended projects and a systematic energy management system improved the facility's energy performance by about 7.2 percent.

Collectively, the capital and operations projects implemented at the plant are saving Nissan $1.2 million and 250 billion Btu (264,000 GJ) per year. Annual cost savings attributable solely to implementing SEP (annual savings minus those persisting from pre-SEP actions) total $938,000. Nissan invested $331,000 to implement SEP (including internal staff time), resulting in a payback period of just four months.

Source: Nissan. Web link.

Awareness of Incentives and Risks

Lack of awareness, both at industrial plants and financial institutions that might fund energy efficiency projects, can lead to missed opportunities. For industrial plants, it is important that decision-makers are aware of available incentives that can reduce the capital cost of an energy efficiency project, thereby improving the economic viability of the project. Significant outreach using case studies of successful projects and other information is often necessary to raise awareness and increase participation.[120]

Federal and state agencies conduct outreach on their industrial energy efficiency programs to help further awareness of available incentives, including those with third-party measurement

and verification (M&V) protocols that provide greater certainty of the energy savings. Example successful policies and/or programs include:

- International Energy Agency (IEA) Cogeneration and District Energy—this report, released in 2009, was designed to provide policy makers with a practical reference of "best practice" CHP policy examples from around the world. The report provides a technical introduction of CHP and district heating and cooling, and describes its global status and potential.[121] This report can help policy makers develop successful CHP incentive programs and regulations.
- ENERGY STAR for Industry—ENERGY STAR for Industry is a voluntary EPA program that helps businesses develop or refine their corporate energy management programs. ENERGY STAR industrial assistance includes energy management guidance, benchmarking and tracking tools, and recognition for energy performance achievements. EPA recognized 15 companies with ENERGY STAR Industrial Awards in 2013. Over 3,000 companies and organizations have joined the ENERGY STAR partnership. Since the year 2000, the ENERGY STAR program has helped save over 1,883 $MMTCO_2e$. A record number of industrial sites committed to the ENERGY STAR Challenge for Industry, and 75 met or exceeded their targets in 2012 by achieving a 10 percent reduction in energy intensity, saving 14.7 TBtu in energy.
- The Western Governors' Association (WGA) has a number of initiatives focused on industrial energy efficiency. In 2011, WGA convened a stakeholder group to address obstacles for industrial energy efficiency projects in the West. The stakeholder group released a report entitled *Building a Stronger Western Economy with Greater Industrial Energy Efficiency*, and released a subsequent policy resolution which recommends that WGA staff coordinate with state energy offices to identify industrial energy efficiency opportunities and to share best practices on programs that produce the greatest energy savings.[122]

In some cases, industrial plants may seek outside financing for energy efficiency projects. In the industrial sector, energy efficiency projects can be complex and financial institutions may not have a sufficient level of knowledge to evaluate risks for these projects. If the risk is difficult to evaluate, financial institutions may be reluctant to loan capital for an energy efficiency project.[123] Some energy efficiency programs have begun to leverage partnerships among private financial institutions, energy efficient equipment manufacturers, and others as a way to bring awareness to programs and to increase participation (see sidebar on the AlabamaSAVES loan program).[124]

In addition to financial partnerships, energy efficiency potential studies can be beneficial, helping identify significant opportunities for energy savings. The EPA cited several studies in its Clean Energy-Environment Guide to Action[125], finding that such studies can identify untapped opportunities for savings and encourage policy development and program implementation.[126] Overall, studies identified economic potential in the ranges of 13 to 27 percent for electricity, and 21 to 35 percent for gas. One of the studies cited by EPA is a Southwest Energy Efficiency Project (SWEEP) study in 2002. This SWEEP study found that investing about $9 billion (in 2000 dollars) in efficiency measures from 2003 to 2020 would reap total economic benefits of $37 billion for the Southwest region.[127] Federal and state agencies along with regional organizations can ensure that technical and economic potential studies for energy efficiency are performed to identify current and future market opportunities resulting from incentive programs for energy efficiency. ACEEE identifies these benefits, stating that a study could support a number of state or utility needs for designing efficiency policies and programs, such as setting energy savings goals, incorporating energy efficiency into the integrated resource planning (IRP) process, or determining funding levels for efficiency programs and policies.[128]

AlabamaSAVES Loan Program Provides Project Funding for the Industrial Sector

The AlabamaSAVES loan program was launched in 2010 and is targeted specifically for industrial businesses. The program provides low-interest loans of up to 100 percent of project costs up to $4 million. This program partners with Bank of America, Philips Lighting, Metrus Energy, and Efficiency Finance to provide private sector leveraging of funds and program outreach. Using existing sales and marketing channels and supplier networks with Alabama industries and contractors, these private partners are helping to drive increased participation in the program.

Since awarding the first loan in June 2011 through September 2013, AlabamaSAVES has approved more than $20 million in loans for energy upgrades. Alabama businesses are saving $5.1 million in estimated annual energy costs because of this financing program.

Source: National Association of State Energy Officials. Web link.; Energy Manager Today. Web link.

Metering and Energy Consumption Data

The lack of disaggregated energy consumption data, particularly submetered data for energy-intensive industrial processes, and lack of analytic capabilities to analyze large volumes of energy consumption data, can impede identification and evaluation of opportunities.[129] Energy metering at some industrial facilities is limited to the gas and electric meters installed by the local utility for billing purposes,[130] and there may be only a single electric meter and a single gas meter for an entire manufacturing plant. Cost-effective submetering of production lines and energy-intensive equipment can significantly improve the accuracy of estimating expected

energy savings from end-use energy efficiency measures that may be under consideration (see sidebar on submetered data).[131,132]

In-House Technical Expertise

The lack of technical expertise or lack of available staff to devote to energy efficiency or energy management can also hinder development of end-use efficiency.[133] Some industrial facilities, particularly small and mid-sized companies, lack in-house engineering expertise and can benefit from assistance identifying and then selecting energy efficiency solutions. Technical assistance can assist these companies with moving projects forward.[134]

Submetered Data Can Help Business Units Drive Innovation in Energy Efficiency

Some organizations, such as 3M and PPG Industries, have begun to allocate energy costs to individual business units and/or production lines based on submetered energy data. The goal is to give business units more visibility and accountability for their energy consumption, and ultimately get these business units to drive energy efficiency improvements. The Electric Power Research Institute (EPRI) found that allocating energy costs to specific business units or production lines can reduce energy consumption by 5–10 percent.

Source: Howe, B. Web link.

Bonneville Power Administration (BPA) evaluated industrial energy efficiency barriers, and found that industrial managers did not always know about energy efficiency technologies or how to implement and evaluate these measures. BPA provides assistance to industrial customers to help identify and implement energy efficiency measures (see description of the Energy Smart Industrial program).[135] BPA also found that it is critical to have support and understanding at all levels of the company—from executive management to plant staff—to successfully move high-impact energy efficiency projects forward.

There are a number of resources available to help provide manufacturers with technical assistance. DOE has a number of programs devoted to helping provide manufacturers with technical support.

Bonneville's Energy Smart Industrial (ESI) Program Provides On-site Technical Expertise

Bonneville Power Administration's ESI program was launched in October 2009. The program is considered a "one-stop shopping" program for industrial incentives because a variety of support is available—including assistance for custom projects, program-related administrative support, and technical assistance. There are several main subprograms under the ESI framework, including the Energy Project Manager Program where BPA funds a position for an engineer at an industrial facility. The ESI program placed 23 energy project managers working in 32 separate industrial facilities by the end of 2011. The ESI program was recognized by ACEEE in 2013 as an "exemplary program" under their "Industrial and Large Customer Programs."

Source: U.S Department of Energy. Web link.

For example, the Better Plants program and the Industrial Assessment Centers program seek to improve industrial energy performance. The DOE Better Plants program partners with the U.S. manufacturing sector to encourage companies to voluntarily commit to reducing energy intensity by 25 percent over 10 years. In addition to the economic and environmental benefits associated with achieving energy efficiency improvements, partners also receive national recognition from DOE, as well as technical support. Technical support includes help in establishing and analyzing key energy use data, identifying energy efficient technologies, and implementing energy saving projects.[136]

DOE's Industrial Assessment Centers (IACs) provide energy assessments of small and medium-sized industrial facilities conducted by engineering faculty with upper class and graduate students from a participating university. Assessments have identified nearly $542 million in energy savings and nearly 3.6 million metric tons in CO_2 emissions reductions since 2006.[137] Overall, these assessments have helped save over 530 trillion BTUs of energy – enough to meet the energy needs of 5.5 million American homes and have helped manufacturers save more than $5.6 billion in energy costs.[138]

In addition to DOE, The National Institute of Standards and Technology's Manufacturing Extension Partnership (MEP) program also helps provide technical assistance to manufacturers. The MEP program is an initiative through the Department of Commerce that works with small and mid-size U.S. businesses to retain jobs, increase profits, and become more efficient. MEP technical experts currently focus on technology acceleration, supplier development, sustainability, workforce and continuous improvement.[139] According to NIST, MEP centers have responded to approximately 490,000 requests for assistance since the program's inception.[140] In a survey of clients using the centers during FY2011, NIST found that companies reported $2.5 billion in new sales, $4.1 billion in retained sales, $900 million in cost savings and the creation or retention of 61,139 jobs.[141]

Lastly, the EPA's ENERGY STAR for Industry program also works with manufacturing companies to help them implement and approve energy management practices. ENERGY STAR works with selected manufacturing sectors to provide sector-specific information and guidance on improving plant energy performance, including tools to benchmark plant performance and could be further expanded to help provide manufacturers with additional performance guidance and technical assistance.[142]

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4. Barriers to Industrial Demand Response

4.1 Background

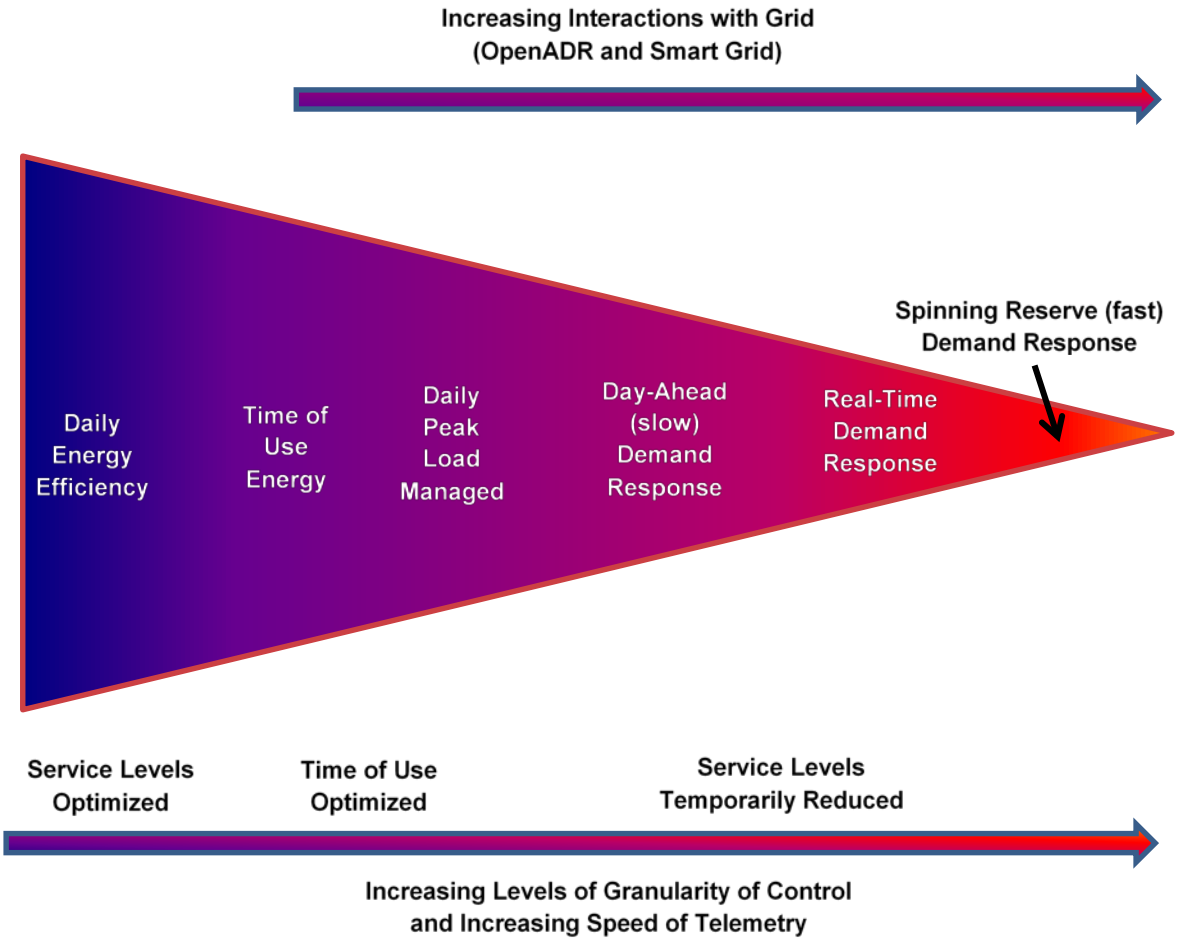
Demand response is defined as:[1]

> *Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.*

In the past, traditional demand response programs were focused on reducing electricity use during peak time periods (e.g., a hot summer afternoon). In recent years, technology advancements and new electricity market structures have allowed a greater level of communication and interaction between electricity consumers and utilities, and the definition of demand response has evolved from a focus on reductions in electricity demand to now include changes in electricity demand.

The relationship between demand response and energy efficiency can be viewed as a continuum as illustrated in **Figure 21** (based on information from the National Action Plan for Energy Efficiency and the Demand Response Research Center).[2,3] Energy efficiency measures are shown on the left-hand side of **Figure 21**. Moving from left to right on the continuum involves shorter timescales and captures practices that are considered demand response, including not only management of daily peak loads but also management of reserves and regulation. Historically, energy efficiency measures have been installed to provide ongoing energy savings and have not typically been controlled based on price signals or incentive payments. Demand response is a demand side resource like energy efficiency, but the fundamental difference between demand response and energy efficiency is that demand response implies an action taken in the short term in response to a signal (e.g., a price change).

Figure 21. Conceptual Relationship of Energy Efficiency and Demand Response



Source: Adapted from Demand Response Research Center

Demand response programs provide a range of benefits to both industrial customers and the nation. Key benefits that can be derived from demand response programs include:

Benefits for U.S. businesses:

- Reduces customer bills by reducing customer demand during peak periods (e.g., lower customer demand charges)
- Produces revenue from incentive payments for demand response participation
- Enhances competitiveness

Benefits for the nation:

- Defers or avoids construction of new generation plants
- Defers or avoids upgrades to transmission and distribution lines
- Promotes optimal dispatch of generation resources
- Improves grid reliability and resiliency
- Enables grid integration of intermittent renewable resources (e.g., wind and solar, see sidebar)[4]
- Contributes to job growth[5,6,7,8]

Flexible Demand Response Resources Help Support a Changing Electric Grid

The resource mix and fuels used to generate electricity in the United States is changing. For example, state renewable portfolio standards are driving the adoption of intermittent wind and solar technologies. These changes are creating an increased need for flexible demand response resources. Smart grid technologies that enable two-way communication and automated control have made it financially attractive to link a larger amount of flexible demand response resources with wholesale power markets.

Source: National Action Plan for Energy Efficiency. Web link.

Demand response programs can be offered to customers directly from local utilities or independent system operators/regional transmission organizations (ISOs/RTOs) where permitted. Customers may also have options in certain regions to work with intermediaries known as aggregators, or curtailment service providers (CSPs). CSPs provide value by aggregating flexible loads of multiple electricity customers and making this flexible load available to wholesale power markets (see sidebar).

CSP Role in Enabling Demand Response

CSPs aggregate load and serve as an intermediary between electricity consumers and ISOs/RTOs. CSPs can be particularly helpful to small customers that seek to participate in demand response programs.

Experience and expertise allow CSPs to assess the potential demand response participation for specific locations and to continuously reevaluate that potential in response to dynamic prices in ISO/RTO markets.

CSPs typically incur the expense of building and maintaining electronic applications that enable registration, dispatch, and settlement of demand response in wholesale power markets. The impact of CSPs can be significant. For example, CSPs now provide approximately 70 percent of the registered demand response megawatts in PJM's market.

Source: North American Standards Board (NAESB). Web link.

There are several ways of altering electricity use for demand response participation:[9]

- Customers can shift their electricity usage to a time other than the demand response period. For example, an industrial facility could shift production to evening, overnight, or weekend

operation when demand for grid electricity is typically lower compared to weekday operation. Another example is a refrigerated warehouse that overcools during the night, which results in a lower need for electricity during the day.

- Customers can reduce their electricity consumption. For example, a manufacturing plant could curtail production.
- Customer electricity consumption can be adjusted with a high degree of granularity (see sidebar on Alcoa).[10]
- Customers can self-generate electricity using standby generators or CHP.

Alcoa's Demand Response Program

Alcoa's aluminum plant in Warrick, IN, has a 570 MW on-site generation system that supplies electricity to an aluminum smelter and a rigid packing facility. Historically, Alcoa provided emergency shutdown capability to the Midwest Independent System Operator (MISO) and expanded demand response participation in 2009. Alcoa now provides MISO with up to 70 MWs of direct load control—MISO remotely controls 70 MW of smelter load in real time.

The demand response program is generating revenue of $15,000 to $120,000 per day when demand response events are called, and Alcoa expects to reduce their total energy costs by up to 10 percent. The revenue from this demand response program has helped Alcoa improve their manufacturing competiveness.

Source: Alcoa. Web link.

Demand response can be either "dispatchable" or "non-dispatchable."[11] Dispatchable demand response is also referred to as "incentive" demand response. Most dispatchable resources can be characterized as reliable, verifiable, and capable of responding to a utility or RTO/ISO request.[12] Examples of dispatchable demand response include:

- Utility control of customer equipment for short time periods.
- Directed reductions in return for lower rates (also called curtailable or interruptible rates).
- Programs offered by utilities and ISOs/RTOs that compensate customers for reduced demand when directed.
- Bidding of customer demand reductions into energy and ancillary services markets.

Non-dispatchable demand response refers to the use of retail rate designs to influence electricity consumption. Non-dispatchable demand response is also referred to as "price-based" demand response and includes dynamic electricity rates that change with power demand—higher rates during high-demand periods, and lower rates during low-demand periods. Non-dispatchable demand response is initiated by customer action, which can be

preprogrammed or automated. For example, Walmart has an automatic energy management system at several store locations that responds to preprogrammed strategy. An advanced metering system is used to shut down or lower store loads in order to comply with emergency events.[13]

Table 9 shows common event-based dispatchable and price-based non-dispatchable demand response programs. In general, more customers throughout the United States fall into dispatchable incentive-based programs compared to non-dispatchable price-based programs.[14] Many smaller, mass market customers may be participating in the price-based programs, while a smaller number of larger customers are in the incentive-based programs.

Table 9. Common Types of Demand Response Programs[15]

Description of Dispatchable and Non-dispatchable Demand Response Options		
Dispatchable Options		
Reliability	**Capacity**	**Direct load control or Direct Load Control Management:** Customers receive incentive payments for allowing the utility a degree of control over certain equipment (e.g., allow system operators to remotely shut down or cycle a customer's electrical equipment). Demand response resources typically have the ability to follow loads up or down. For example, an electric chiller can be cycled to reduce demand for electricity during a direct load control event. Following the direct load control event, the chiller may consume more electricity to make up for lost chilled water production.
		Interruptible/curtailable rates: Electric consumption subject to curtailment or interruption under tariffs or contracts that provide a rate discount or bill credit for agreeing to reduce load during system contingencies. In some instances, the demand reduction may be effected by action of the System Operator (remote tripping) after notice to the customer in accordance with contractual provisions.
		Critical peak pricing with load control: Demand side management that combines direct load control with a pre-specified high price for use during designated critical peak periods, which may be triggered by system contingencies or high wholesale market prices.
		Load as a capacity resource: Demand side resources that commit to making pre-specified load reductions when system contingencies arise.
	Reserves	**Spinning reserves:** Demand side resource that is synchronized and ready to provide solutions for energy supply and demand imbalance within the first few minutes of an emergency event.
		Non-spinning reserves: Demand side resource that may not be immediately available but may provide solutions for energy supply and demand imbalance after a delay of 10 minutes or more.
	Energy—Voluntary	**Emergency demand response programs:** Customers receive incentive payments for load reductions when needed to ensure reliability.
Economic	**Energy—Price**	**Demand bidding/buyback programs:** These programs allow customers to offer load reductions at a price at which they are willing to be curtailed, or to identify how much load they would be willing to curtail at posted prices.

Description of Dispatchable and Non-dispatchable Demand Response Options	
Non-dispatchable Options	
Time-Sensitive Pricing	**Time of use (TOU) rates:** Rates with fixed-price blocks that differ by time of day.
	Critical peak pricing: Rate and/or price structure that include a pre-specified, extra high rate that is triggered by the utility and is in effect for a limited number of hours or days. The total number of critical peak periods is typically capped for a calendar year.
	Peak time rebates: Customers earn a rebate by reducing energy use from a baseline during a specified number of hours or days. Like critical peak pricing, the number of critical peak days is usually capped for a calendar year and is linked to conditions such as system reliability concerns or very high supply prices.
	Real-time pricing (RTP) rates: Rates vary continually (typically hourly) in response to wholesale market prices. Customer electricity demand typically moves up or down in response to price signals.

Source: Adapted by ICF from the National Action Plan for Energy Efficiency,[16] information from Synapse Energy Economics and the Regulatory Assistance Project,[17] and the North American Electric Reliability Corporation[18]

The electricity reduction impact is also greater and more predictable with incentive-based dispatchable programs. For example, in 2012, incentive-based demand response programs provided 55,796 MW of reported peak load reduction and price-based demand response programs provided 10,555 MW of reported peak load reduction.[19]

In the past several years, there has been significant activity related to the design and regulation of event-based, or dispatchable, demand response. In 2008, FERC passed Order Number 719,[20] which provides guidance on how demand response resources can be bid into wholesale markets (see sidebar). Industrial

FERC Order Number 719

FERC issued Order Number 719, "Wholesale Competition in Regions with Organized Electric Markets," in October 2008. One of the goals of this final rule is to improve the operation of wholesale markets in the area of demand response and market pricing during periods of operating reserve shortage.

To address discrepancies in the treatment of demand response as compared to supply side resources, Order Number 719 requires each RTO or ISO to accept bids from demand response resources, on a basis comparable to other resources for ancillary services that are acquired in a competitive bidding process if the following criteria are met:

(1) Resource is technically capable of providing the ancillary service.
(2) Customer is capable of submitting a bid under the generally applicable bidding rules at or below the market-clearing price, unless the laws or regulations of the relevant regulatory authority do not permit a retail customer to participate.

Order Number 719 also permits an aggregator of retail demand response to bid the combined demand response directly into organized markets, unless this is not permitted by the laws or regulations of the relevant electric retail regulatory authority.

Source: Federal Energy Regulatory Commission. Web link.

customers, either directly or through aggregators, can participate in dispatchable demand response in different types of wholesale electricity markets, including:[21]

- *Energy Markets.* Demand response participants offer to reduce consumption usually in day-ahead auctions or on a real-time basis and receive the energy market price as a payment for the reduction if the demand response participant's bid is less than the market clearing price.
- *Capacity or Forward Capacity Markets.* New and existing demand response resources bid into grid operator capacity auctions stating that they will reduce demand by a specified amount in future years, ensuring resource adequacy. These providers typically have to curtail their load on short notice (e.g., 30 minutes to 2 hours) and receive capacity payments.
- *Ancillary Service Markets.* Those services necessary to support the transmission of electric power from seller to purchaser, given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system.[22] In the past, ancillary services have been provided solely by generators but have been opened more recently to demand response resources.[23] Demand response providers typically have to curtail on very short notice (30 minutes or less) to participate in ancillary service markets. Examples of ancillary services include frequency regulation,[24] spinning reserves,[25] and non-spinning reserves.[26]

EnerNOC Demand Response Enables Energy Efficiency Improvements

EnerNOC, a software company that provides applications to track energy use, in their assessment of results from food processing and cold storage facility customers, found that payments from demand response participation help offset high energy bills and also help fund energy efficiency projects or capital improvements that can further decrease costs.

Great Lakes Cold Storage provides frozen and refrigerated warehousing and distribution services from its two facilities located in Solon, OH, and Cranberry Township, PA. EnerNOC worked with Great Lakes to design an energy reduction plan. Both facilities reduce lighting, adjust refrigeration equipment, and shut down other loads during demand response dispatches. These actions temporarily reduce demand at both facilities by 1.6 MW, enabling the company to receive $33,000 in annual payments from EnerNOC. Great Lakes uses the savings it achieves from better energy management to pay for other energy efficiency upgrades at its facilities, such as installing 300 more efficient lighting fixtures. The company is also looking into installing new doors at its Solon facility as a way to increase energy savings.

Source: EnerNOC. Web link.

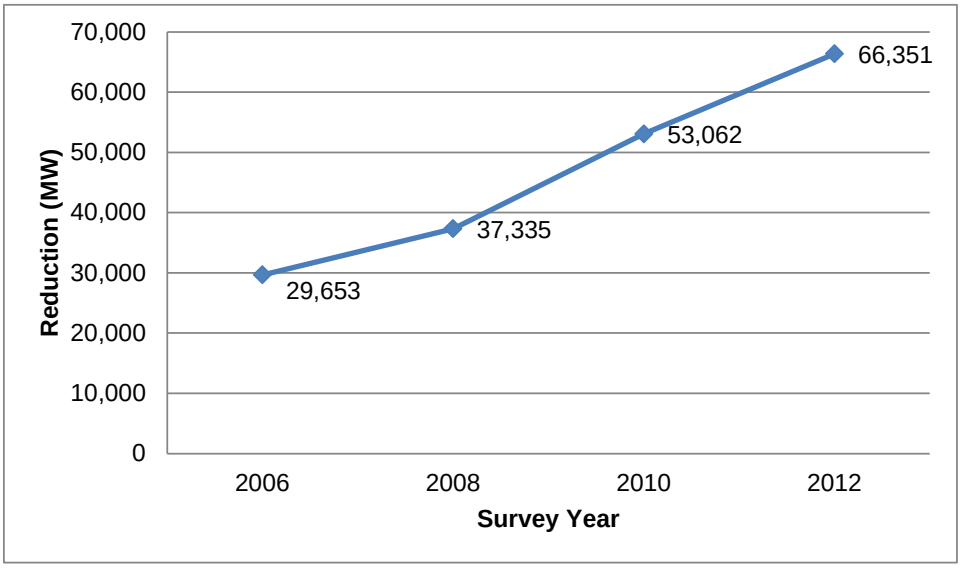
Every manufacturing location may not have the attributes or load flexibility necessary to participate in all types of demand response programs. Utilities and ISOs/RTOs often rely on aggregators or CSPs to market demand response programs to potential participants, evaluate the customer's potential wholesale market participation, enroll customers, manage curtailment events, and calculate payments or penalties for participants.[27] Aggregators can make it easier for industrial customers to participate in demand response programs by reducing the burden of understanding participation requirements and interfacing with the electric utility or ISO/RTO. Aggregators can also enable participation of smaller industrial and commercial customers that would otherwise not be eligible to participate due to the size of their load.

Revenue earned by participating in demand response programs can also be used to finance additional energy efficiency improvements at the participating manufacturing facility (see sidebar on EnerNOC).[28,29] Some CSPs state that demand response provides the opportunity to get a "foot in the door" with customers, and that a number of customers have used money from participating in demand response programs to fund energy efficiency projects. In addition, some CSPs have expanded beyond just demand response, acquiring companies that provide energy efficiency services as well. For instance, some CSPs have begun to monitor and analyze energy use from larger customers as a way of both providing demand response service and identifying energy efficiency opportunities.

Large industrial customers that meet minimum electric load limits can participate directly in utility ISO/RTO demand response programs or use the services of an aggregator. Direct participation requires more in-house labor to manage demand response activity, but financial payments may be larger because aggregator fees are avoided.

Participation in incentive- and price-based demand response programs is continuing to grow. A FERC survey found that reported potential peak reduction in the United States in 2011 was 66,351 MW. As shown in **Figure 22**, reported potential peak demand reduction has more than doubled over the past 6 years.

Figure 22. U.S. Potential Peak Reduction[30]



Source: FERC, 2012—Demand Response Survey

4.2 Barriers

While demand response is growing, key barriers to the increased use of demand response continue to exist. These barriers are discussed in three categories: (1) economic and financial, (2) regulatory, and (3) informational.

4.2.1 Economic and Financial Barriers

Economic and financial barriers to greater industrial use of demand response may include:

- *Limited number of customers on time-based rates.* Participation in demand response programs can be limited if customers are not on time-based rates.
- *Lack of sufficient financial incentives.* Some demand response programs may not provide a sufficient financial incentive to encourage participation.
- *Failure to fully account for demand response benefits.* Valuing the benefits of demand response, and determining how to attribute the benefits, can be complex.

Limited Number of Customers on Time-Based Rates[31]

The majority of retail customers are on retail tariffs that do not reflect time variations in the cost of electricity, diminishing the economic value of demand response actions taken by retail customers. Time-based rates have been shown to advance the development of new technologies and demand response programs. Recognizing that the use of time-based rates is somewhat limited, DOE issued American Recovery and Reinvestment Act (ARRA) funds to a

number of utilities to conduct pricing experiments and implement time-based rates. Utilities that received ARRA funding, such as Oklahoma Gas and Electric, Marblehead Municipal Lighting Department, Sioux Valley Energy, and the Sacramento Municipal Utility District, have shown that time-based rates can be used to empower customers and reduce system peak demands.[32] Cement makers praise the Texas demand response program, which links consumer credits or rebates to real time market prices for electricity.

Lack of Sufficient Financial Incentives

Based on the program and customer class, demand response programs may not provide a sufficient incentive to encourage participation. For many manufacturers, the cost of disrupting production can be quite high compared to the value of incentives paid for participation in a demand response program. In some cases, manufacturers are not likely to risk a negative impact on production output or product quality to receive a payment for participation in a demand response program. In these cases, where industrial plant managers balance the value of using electricity in the context of energy prices and conclude that it does not make sense to reduce or change usage, then an efficient outcome has been achieved for both the industrial site and the electricity market.

Failure to Fully Account for Demand Response Benefits

There is often disagreement on what components should be included in a benefits analysis of demand response. One of the main benefits associated with demand response is a reduction in wholesale price electricity costs. Nevertheless, there is uncertainty in how long to account for this benefit—only over the short term or as a mid- to-long-term benefit.[33] To help resolve this issue, DOE and FERC participated in the National Forum on the National Action Plan on Demand Response and helped develop a comprehensive examination of demand response cost-effectiveness.[34]

There are also issues concerning the value of avoided costs. A financial benefit of demand response is avoided generating capacity cost, and there is disagreement over what should be used as the avoided capacity price. In California, the full cost of a peaking plant is derated to account for revenues that it will earn through sales to the market, as well as to account for a lack of certainty that a demand response program will effectively reduce demand at the time of system peak.[35] There is still disagreement as to how this adjustment should be calculated. Another example is the amount and prices of avoided T&D capacity from demand response that can be challenging to determine. California has developed demand response cost-effectiveness tests,[36,37] but there are no widespread standards on valuing avoided T&D due to demand response.

The result of not accounting for all the value that demand response provides (dispatchable and non-dispatchable) can lead to a lower incentive payment or time-of-use rate for customers that respond to a demand response event. Undervalued payments may fail to attract the attention of industrial customers, thereby reducing participation in demand response programs.

To address cost-effectiveness of wholesale demand response, FERC enacted Order Number 745 in 2011 to provide guidance on the compensation of demand response in organized RTO and ISO energy and ancillary service markets. This order required that when a demand response resource participating in ISO/RTO organized energy market had the capability to balance supply and demand as an alternative to a generation resource, and when that dispatch was cost-effective as determined by a net benefits test, the demand resource must be compensated for the service it provided at the locational marginal price (LMP).

FERC Order 745 has been attributed to significant increases in demand response. In the 6 months from the time PJM implemented Order 745, economic energy reduction increased by 800 percent.[38] In May 2014, FERC Order Number 745 was vacated by the DC Court of Appeals.[39,40,41,42] The DC Court ruled that Order Number 745 was a direct regulation of the retail market and outside of FERC's statutory authority. FERC only has jurisdiction over the sale of electric energy at wholesale in interstate commerce. This ruling may lead RTOs and ISOs to alter demand response eligibility provisions in energy markets.

4.2.2 Regulatory Barriers

Potential regulatory barriers to demand response are grouped as follows:

- *Utility cost recovery structure.* The traditional regulatory model can discourage demand response if utility revenue is linked to financial returns derived from building new infrastructure.
- *Program requirements and aggregation.* Some potential participants in demand response programs are deterred due to numerous program requirements and terms that vary significantly, or aggregation rules that limit smaller industrial facilities.
- *Lack of standardized measurement and verification.* Absence of standard measurement and verification procedures can negatively impact demand response contract settlement, operational planning, and long-term resource planning.
- *Electricity market structures that limit demand response.* Some electricity markets focus on supply side resources, and demand response may not be allowed to participate in certain markets, or there may be other barriers to participation.

- *Inclusion in state energy efficiency resource standards.* Not including demand response in EERS programs may limit growth.

Utility Cost Recovery Structure

Cost recovery structures can provide a disincentive for utilities to develop and promote demand response programs. A well-designed demand response program may reduce the need to build new infrastructure. Regulated utilities are typically allowed to earn a rate of return on new infrastructure that is approved by regulators. If the need for new infrastructure is avoided, utilities will forego the financial returns associated with this avoided infrastructure.[43]

In addition to earning revenue from the construction of new assets, utilities earn much of their revenue through electricity sales to customers. A well-designed demand response program will reduce electricity consumption during peak periods. If this reduced electricity use is not shifted to an off-peak time, then overall electricity sales decline. If the utility business model has not been adjusted to align utility and customer interests, then the decline electricity sales will impact utility revenues.

Program Requirements and Aggregation

Market and operational rules in both wholesale and retail markets, such as minimum size requirements and prohibitions regarding demand response aggregator participation, also restrict participation in demand response programs. In some regions, third-party aggregators are prevented from enrolling demand response providers due to utility opposition and/or state utility regulatory concerns about consumer impacts and benefits.[44]

To participate, aggregators are often required to negotiate with each distribution utility or respond to multiple utility competitive bids. For instance, in the Midwest, distribution utilities will not voluntarily allow aggregators to solicit their customers to participate; the utility instead retains the authority to dispatch load resources. In other states, state utility regulators have rules that prevent aggregators from enrolling customers without the permission of the local utility.[45]

States can review requirements of their demand response requirements and procedures to ensure adequate participation by multiple segments of energy consumers in effective programs. In some regions, third-party aggregators are prevented from enrolling demand response providers, or there are other system size, certification, or operational limitations that deter greater industrial customer participation in demand response programs.[46,47]

California has an effective state policy in place to help address this barrier. California's three investor owned utilities have demand response programs, that specifically engage large commercial and industrial customers. In 2011, on average, 107 MW per hour of demand resources were bid or self-provided to the California ISO. Automated demand response (ADR) is used to send businesses demand response signals and implement load reductions automatically through facility control systems. The 2013 California Integrated Energy Policy Report (IEPR) identifies demand response and energy efficiency as key priorities in the state. California has also conducted research on how to address barriers to demand response within the state, issuing a study in 2009.[48]

Lack of Standardized Measurement and Verification

Measurement and verification procedures for demand response can vary widely across utilities, states, and ISOs/RTOs. This inconsistency can negatively impact demand response contract settlement, operational planning, and long-term resource planning. Without standard demand response measurement and verification procedures across all jurisdictions, the benefits of demand response can be unclear and inconsistent, making it difficult to accurately assess demand response programs.

An absence of standard protocols complicates participation for companies that operate in multiple states by increasing their cost of participation, therefore reducing their motivation to pursue demand response opportunities. The use of CSPs minimizes some of these costs due to economies of scale, but the CSPs must be willing to bear additional transaction costs due to multiple standards across jurisdictions. To help address this barrier, the North American Energy Standards Board (NAESB) developed voluntary Phase I Demand Response Measurement and Verification standards in 2010 and then in 2012 (see sidebar on FERC Order 676-G).[49] The goals of NAESB's M&V standards are to provide a common framework to help facilitate market transparency, accountability to promote accurate performance measurement

FERC Order Number 676-G

Standards for Business Practices and Communication Protocols for Utilities

NAESB developed voluntary Phase I Demand Response Measurement and Verification standards in 2010 and Phase II standards in 2012. The Phase II standards were incorporated into FERC's Order No. 676-G issued in 2013. These standards only apply to wholesale markets administered by RTOs and ISOs.

Order 676-G incorporates NAESB's updated business practice standards to categorize various products and services for demand response and energy efficiency and to support the measurement and verification of these products and services in organized wholesale electric markets. The standards are intended to make it easier for demand response and energy efficiency providers to participate in organized wholesale electric markets, while also reducing costs for these providers.

Source: Troutman Sanders. Web link.

of demand response resources by system operators, and to help develop uniform and consistent methods across all wholesale markets.[50] State agencies can examine how to codify NAESB guidance into retail measurement and verification standards for state demand response programs.[51] NAESB also developed and approved voluntary retail demand response measurement and verification standards. Since these standards are not within FERC jurisdiction, they were not the subject of a FERC rulemaking.

Electricity Market Structures that Limit Demand Response

Electricity markets, both wholesale and retail, have often focused on supply side resources. This focus may limit demand response participation in certain markets. For example, there may be restrictions on what type of resource can bid demand response into the market.[52] Wholesale electricity markets have certain rules that were developed with generators in mind, not necessarily demand response resources. For example, RTO and ISO tariffs often specify minimum run times (or bidding parameters) for generators, but do not commonly establish maximum run times (or bidding parameters), which could encourage greater use of demand response resources.[53] However, there are some positive examples: in PJM, limited demand response can only be called 10 times per summer for a maximum of 6 consecutive hours. Most demand response participants want to know how long they will need to respond to a demand response event, especially large industrial customers that may need to alter their operational plans. Other issues involve a limited ability to participate. The full value of demand response programs may not be captured unless a manufacturer is being able to participate in a number of markets such as capacity, energy, and ancillary services (see sidebar on ERCOT).[54,55]

Demand Response and Capacity Market Could Provide Benefits to ERCOT

The Electricity Reliability Council of Texas (ERCOT) is concerned about future supply constraints and does not have a capacity market. Peak demand has grown approximately 10 percent over the past decade in Texas, and hot weather during a 2011 heat wave caused peak demand to spike to a new high. Studies have shown that implementing a capacity market in ERCOT that allows for demand response participation could help increase grid reliability and lower electricity costs for consumers.

Source: The Brattle Group. Web link.

Inclusion in State Energy Efficiency Resource Standards

At present, 25 states have enacted long-term (3+ years) EERSs.[56] This type of standard typically sets long-term mandatory energy savings targets for utilities and efficiency program administrators and in some cases, states set separate tiers/targets for peak savings from demand response.[57] EERS programs that allow for demand response as an eligible activity, in a

separate tier/target from that established for energy efficiency (see sidebar on Arizona), can encourage utilities to expand or enhance their demand response program offerings as a way of helping meet the targets. These programs can also encourage utilities to provide a greater financial reward for those customers that participate in demand response. Several other states specifically call out demand response as eligible for helping meet their energy savings targets and have explicit MW reduction requirements.[58]

Arizona's Energy Efficiency Resource Standard

The Arizona Corporation Commission established a mandatory EERS in 2010. The rules apply to investor-owned utilities (IOUs) that have annual revenue of $5 million or more. By 2020, IOUs must achieve a cumulative savings equal to 22 percent of the previous year's electric sales. Electric distribution cooperatives have to propose an annual goal to achieve at least 75 percent of the savings requirement.

There are a variety of eligible measures for utilities to meet their savings targets, including peak demand reductions. Utilities can count their peak demand reductions from demand response and load management programs toward meeting the target. The total amount of savings that can come from peak demand reductions is limited to 2 percent in 2020 (about 9 percent of the total requirement of 22 percent).

4.2.3 Informational Barriers

To make an informed decision to participate in demand response, customers must be able to understand existing programs, the cost and benefits of participation, and the effect on industrial processes. Informational barriers include:

- *Knowledge and resource availability.* Lack of knowledge of federal, state, and utility incentives for demand response programs and lack of an understanding of programs can result in low participation. In addition, insufficient in-house technical expertise can also hinder participation (see sidebar on FERC actions to address these issues).

FERC's National Action Plan on Demand Response

FERC developed the National Action Plan on Demand Response as directed by Section 529 of the Energy Independence and Security Act of 2007. The National Action Plan identifies the following:

- Requirements for technical assistance to the states so that they can maximize the amount of demand response.
- Requirements for a national communications program to provide customer education and support.
- Analytical tools, model regulatory provisions, contracts, and other support materials for demand response.

Source: FERC. Web link.

- *Lack of widespread adoption of interoperability and open standards.* Many different devices and systems need to communicate in a robust demand response program. Demand response programs are hindered if technologies from different vendors do not

interoperate seamlessly. Several types of interoperability standards have been established such as SEP 2.0,[59] OpenADR,[60] and Green Button,[61] and they are being adopted in the market. However, more widespread use of open standards is necessary to align communication across devices.

- *Administrative burden.* The amount of time and effort required to participate in a demand response program can be a deterrent, particularly for smaller industrial companies.

Knowledge and Resource Availability

Industrial customers, and specifically facility energy managers, must be well informed of Federal, state, and utility incentives for demand response if participation is likely to occur.

Improved outreach on demand response programs is one way of increasing customer awareness and participation in existing programs. Joint education campaigns by utilities, regulators, and grid operators can assist in this effort; especially in areas where peak load relief is most necessary. The pathway for customers to participate should also be clear and easy to follow. For example, PJM offers a fact sheet for consumers, reference materials, and instructions for identifying a CSP who will act as an agent (see sidebar on Pennsylvania).[62]

In addition, facility managers have limited time to evaluate energy cost reduction alternatives. While demand response may offer opportunities to reduce energy costs, it can be a time-consuming process to accurately

Pennsylvania's Demand Response Targets and the Role of CSPs

Pennsylvania enacted Act 129 in 2008, which requires Pennsylvania electric utilities with more than 100,000 customers to reduce kWh consumption in Phase I of the program by 3 percent of projected June 2009–May 2010 electricity consumption by May 31, 2013, and also to reduce peak demand 4.5 percent, as measured by June 2007–May 2008 peak demand, by May 31, 2013. The target is met through a mix of dispatchable demand response and energy efficiency programs. All of the utilities met the final May 31, 2013, energy and demand reduction targets. As of May 31, 2013, the seven electric distribution companies had collectively saved 5,403,370 MWh per year and 1,540.61 MW. Phase II of the program began June 1, 2013, and will run through May 31, 2016. It requires energy savings that vary by utility from 1.6 to 2.9 percent of June 2009–May 2010 electricity consumption.

To help meet targets, customers are eligible to received Act 129 incentives in addition to PJM program payments for demand response participation. The program works as follows: the local utility will forecast peak demand hours and notify Act 129 CSPs when load reduction is needed. The CSP will estimate projected revenue and will manage and monitor both Act 129 and PJM demand response participation. The CSP then submits settlements, obtains payments, and sends the participant Act 129 earnings.

Pennsylvania conducted a survey of 86 customers in 2013. Of this total, 60 percent first heard about the Act 129 load curtailment program through a CSP, either through an existing relationship or through marketing efforts of another CSP.

Source: PJM. Web link.

evaluate the costs and benefits associated with participation in a demand response program. Inability to predict the timing and frequency of demand response events also makes it difficult for an industrial facility manager to properly assess whether it would be advantageous to participate in a demand response program. The time it takes to evaluate participation in demand response programs and the uncertainty of the results can serve as a barrier to demand response participation.

Lack of Interoperability and Open Standards

Interoperability and open standards refer to the capability of two or more networks, systems, devices, applications, or components to exchange and readily use information—securely, effectively, and with little or no inconvenience to the user.[63] To receive the maximum benefit of demand response and smart grid technology, a standard, interoperable platform should exist to enable communication between demand response devices, customers, utilities, ISOs/RTOs, and wholesale markets (see sidebar on OpenADR). These end-use devices can provide information to a customer on real-time pricing and even automate the demand response of the facility.[64]

OpenADR Alliance
Developing Demand Response

The OpenADR Alliance, a collaborative effort by Demand Response industry stakeholders, was formed in 2010 to "foster the development, adoption, and compliance of the Open Automated Demand Response (OpenADR) standards through collaboration, education, training, testing, and certification." OpenADR represents an open and standardized way for electricity providers and operators to develop technology to communicate across an existing IP-based communications network such as the Internet. Efforts, like OpenADR, to harmonize standards can help lessen demand response communication barriers. OpenADR is a comprehensive standard for automated demand response and as such has achieved significant industry support.

Source: Podorsky, M. Web link.

Another benefit of open standards is that, if they are altered over time, an open development process helps to ensure that solutions are available from different equipment vendors, allowing a low-cost option to provide facilities with the latest software upgrades to participate in automated demand response programs.[65] Without interoperability and open standards, any change in a given standard can be costly and complicated to implement.

Interoperability and open standards are key issues to the continuous growth of demand response.[66] To help counter the lack of technical protocols and standards, the National Institute of Standards and Technology (NIST) enlisted the Electric Power Research Institute to develop a roadmap to serve as a guide to inventory existing standards and to identify gaps in standards; this study was completed in 2009.[67] A 2012 NIST initiative focuses on Smart Grid communication networks. This program seeks to accelerate the development of scalable,

reliable, secure, and interoperable communications and standards for Smart Grid applications by 2016 and to enable informed decision-making by Smart Grid operators by developing measurement science-based guidelines and tools.[68] DOE's Lawrence Berkeley National Laboratory is also working on addressing these issues and is testing and improving strategies and standards for demand side interoperability, wired and wireless communications, communication architectures, devices, and monitoring and controls technologies (in addition, see the SGIP's efforts in the sidebar below).[69,70]

Administrative Burden

There can also be issues with the amount of time and effort required to participate in a demand response program.

Aggregators or CSPs can help reduce the labor burden. CSPs can be incentivized to work with RTOs/ISOs and states to streamline demand response participation requirements, recognizing any resulting changes in demand response participation requirements would need to be filed by the relevant RTO/ISO and acted upon by FERC. For example, EnerNOC, a CSP, offers a demand response program that provides participants with recurring payments in return for agreeing to reduce electricity consumption. There is no cost to participate. EnerNOC manages the customer's participation from start to finish ensuring that the customer receives the highest financial compensation for their participation. As part of participation, the customer receives access to on-demand energy data through DemandSMART, EnerNOC's comprehensive demand response application.[71]

Smart Grid Interoperability Panel (SGIP)

The Smart Grid Interoperability Panel (SGIP) 1.0 was established to help NIST fulfill its responsibilities pursuant to the Energy Independence and Security Act of 2007. The goal of SGIP is to provide a framework for coordinating all Smart Grid stakeholders in an effort to accelerate standards harmonization and advance the interoperability of Smart Grid devices and systems. The public-private partnership, created in November 2009, was initially funded and managed by NIST with the intent to ultimately transition to a nonprofit, public/private funding model. This was successfully accomplished in 2013 and SGIP 2.0 was launched. SGIP now functions as a private entity focused on critical power industry issues for utilities, regulators, equipment vendors, and integrators.

Source: Smart Grid Interoperability Panel. Web link.

Regardless if an aggregator is used, the industrial customer will still need to dedicate time to manage demand response participation. This additional labor burden may exceed the perceived financial value from the demand response program. Some customers have indicated that they do not want to participate in demand response programs due to additional paperwork and other labor involved, along with other burdensome requirements.[72]

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[2] National Action Plan for Energy Efficiency, 2010. "Coordination of Energy Efficiency and Demand Response," prepared by Charles Goldman (Lawrence Berkeley National Laboratory), Michael Reid (E Source), Roger Levy, and Alison Silverstein. Web link, pages 2-7 through 2-9.

[3] Demand Response Resource Center, 2013. Web link.

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[11] Federal Energy Regulatory Commission, 2010. "National Action Plan on Demand Response," Web link, page 3.

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[19] Ibid.

[20] Federal Energy Regulatory Commission, 2008. "Wholesale Competition in Regions with Organized Electric Markets," Order No. 719, 73 Federal Register 61,400, Web link.

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[22] Definition of ancillary services from FERC glossary, Web link.

[23] Cappers, P., et al., 2013. "Market and Policy Barriers for Demand Response Providing Ancillary Services in U.S. Markets," Web link.

[24] Frequency regulations correct for short-term changes in electricity use that might affect the stability of the power system. This service helps match generation and load, and it adjusts generation output to maintain the desired frequency.

[25] Spinning reserves supply electricity if the grid has an unexpected need for more power on short notice. Spinning reserves are online and synchronized to the grid. These reserves can typically meet electric demand within 10 minutes of a dispatch order.

[26] Non-spinning reserve is offline generation capacity that can be ramped to capacity and synchronized to the grid, normally within 10 minutes of a dispatch order.

[27] Moran, D., and Suzuki, J., 2010. "Curtailment Service Providers: They Bring the Horse to Water….Do We Care if It Drinks," prepared for the American Council for an Energy Efficient Economy, Web link.

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[29] EnerNOC, 2014. "Refrigerated Distribution Company Cuts Demand Charges and Reduces Annual Energy Spend by 40 Percent at Ohio Facility; Pennsylvania Site to Follow Suit," Web link.

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[35] Ibid.

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[44] Hurley, D., et al., 2013. "Demand Response as a Power System Resource," prepared for Regulatory Assistance Project.

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[49] Troutman Sanders LLP, 2013. "FERC Adopts NAESB Demand Response and Energy Efficiency Standards," Web link.

[50] Goldberg, M., and G. Agnew, February 2013. "Measurement and Verification for Demand Response," prepared for Lawrence Berkeley National Laboratory, Web link.

[51] North American Energy Standards Board (NAESB), December 2012. "Demand Response and Energy Efficiency Standards," Web link.

[52] Capacity markets or "forward markets" provide payments for capacity, traditionally for power that will be provided at some point in the future. However, there is no functional difference between a megawatt of power generated from a power plant and a megawatt of reduced power from demand response or energy efficiency. Recognizing this fact, some markets allow for demand response or energy efficiency to participate in capacity markets.

[53] Federal Energy Regulatory Commission, 2008. "Assessment of Demand Response & Advanced Metering," Web link.

[54] The Brattle Group, 2014. "Estimating the Economically Optimal Reserve Margin in ERCOT," prepared for the Public Utility Commission of Texas," Web link.

[55] FERC defines ancillary services as "those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system." Ancillary services support daily operation of the grid to maintain reliability.

[56] American Council for an Energy Efficient Economy, April 2014. "State Energy Efficiency Resource Standards (EERS)," Web link.

[57] Peak savings are not the same as energy efficiency. As a result, a separate target/tier should be established for demand response in an EERS, distinct from the target set for energy efficiency.

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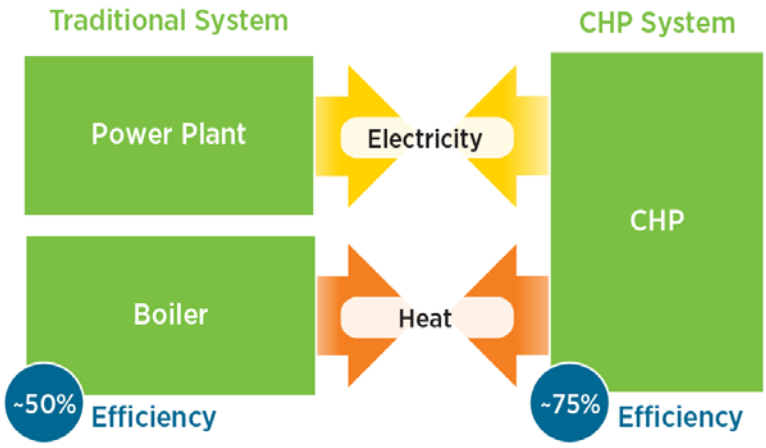
5. Barriers to Industrial Combined Heat and Power

5.1 Background

Combined heat and power, also known as cogeneration, is the simultaneous production of electric and thermal energy from a single fuel source. Instead of purchasing power from the grid and then producing thermal energy on-site in a furnace or boiler, a CHP system produces both forms of energy—useful thermal energy (e.g., hot water or steam) and electricity. Currently, 82.7 gigawatts (GW) of CHP are installed at over 4,300 sites across the United States.[1] These CHP systems, a type of efficient distributed generation, produce 12 percent of the electricity generated in the United States, and account for over 8 percent of total U.S. power-generation capacity.[2]

CHP systems provide significant energy efficiency and environmental benefits. **Figure 23** shows an industrial CHP system that offsets the need for grid electricity and the need for steam or hot water that would otherwise be produced from an on-site boiler. When electricity and thermal energy are provided separately, the overall energy efficiency is in the range of 45–50 percent.[3] While efficiencies vary for CHP installations based on site specific parameters, it is reasonable to expect that a typical topping-cycle CHP system will operate at 65–80 percent efficiency (75 percent shown in figure).[4,5]

Figure 23. Efficiency Comparison between CHP and Conventional Generation[6]



Source: Efficiencies adapted from "Combined Heat and Power: A Clean Energy Solution"[7] and information published by the U.S. Environmental Protection Agency's Combined Heat and Power Partnership[8]

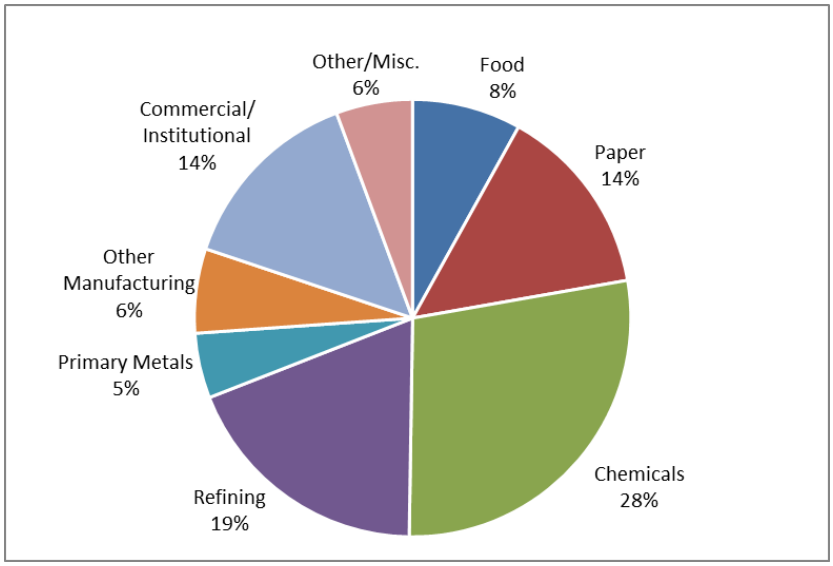
CHP systems are described as either topping or bottoming cycles. In a conventional topping-cycle system, a fuel (e.g., natural gas or biomass) is combusted in a prime mover,[9] such as a gas turbine or reciprocating engine.[10] The prime mover produces mechanical energy in the form of a rotating shaft, and this mechanical energy drives a generator that produces electricity. The thermal energy that is not used to generate electricity (e.g., exhaust heat) is captured from the prime mover and used for an end-use need such as process heating, hot water heating, or space conditioning.[11] In a bottoming cycle, also referred to as waste heat to power (WHP), fuel is combusted to provide thermal input to a furnace or other industrial process and some of the heat rejected from the process is then used for power production.

Within the context of this study, the topic of waste heat recovery is limited to WHP. Most industrial WHP applications are bottoming cycle systems as described in the previous paragraph. Industrial WHP can also include systems in which heat is recovered from the exhaust of an engine or turbine generator and used to generate additional electricity through an organic Rankine cycle or similar technology. This type of system is less common in industrial applications and is not a CHP system, because there is no thermal energy delivered to an end-use. That said, the barriers to implementing non-CHP WHP are similar to those that apply to CHP, such as interconnection and utility rate structures. Therefore, both types of WHP are addressed in conjunction with the discussion of CHP, and both types of WHP are addressed by successful policy examples and opportunities included in this study.

5.1.1 Background on Industrial CHP

CHP is efficient distributed generation that is located at or near the point of energy use or the source of recoverable thermal energy. Most existing CHP capacity (80 percent) is located at industrial manufacturing facilities, with commercial and institutional sites accounting for the balance (see **Figure 24**).[12] In the industrial manufacturing sector, there are an estimated 1,251 CHP installations representing a collective capacity of 66,275 MW.

Figure 24. Existing CHP Capacity in the United States (82.7 GW)



Source: CHP Installation Database, 2014

Note: "Other/Misc." includes agriculture, mining, construction, and sites where the application is unknown.

Industrial CHP installations in the United States have an average system size of 53 MW and a median size of 7 MW. The difference between average size and median size shows that there is a skewed size distribution, with a small number of larger systems accounting for a relatively large fraction of the installed CHP capacity. Data show that 463 industrial CHP systems are greater than 20 MW, which account for 76 percent of the total installed capacity of all CHP systems but only 11 percent of the number of systems of all installed CHP in the U.S.[13]

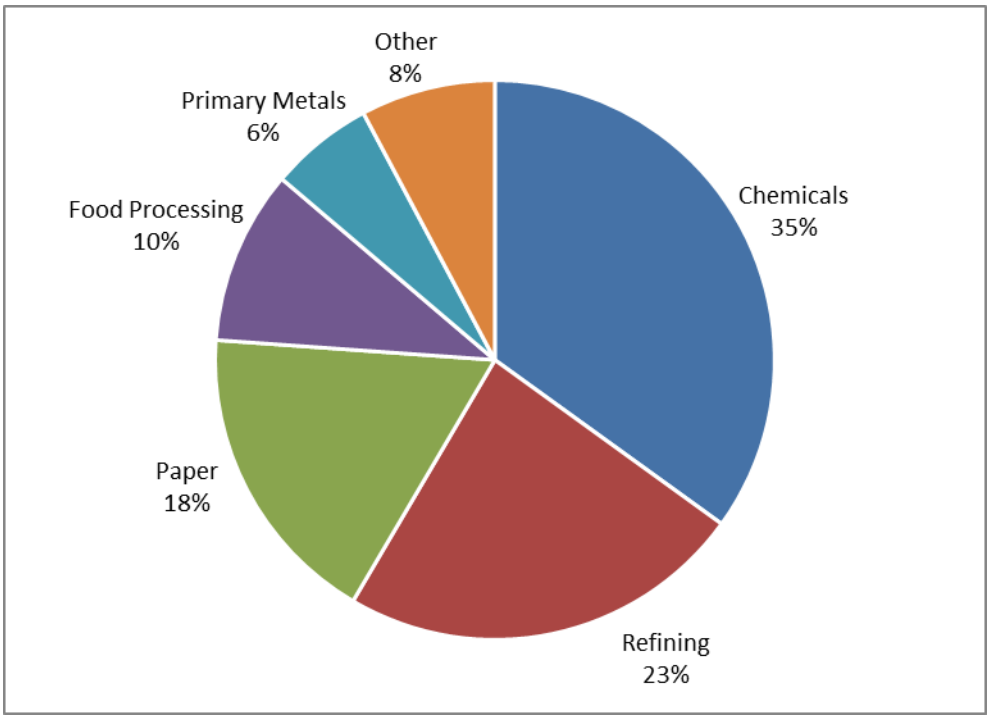
Table 10 shows a breakout of CHP installations for 10 industrial markets that account for the largest share of capacity. The top 10 markets account for 98 percent of total capacity and 87 percent of all sites. The top five markets—chemicals, refining, paper, food processing, and primary metals—account for 92 percent of the industrial CHP capacity (**Figure 25**) and 76 percent of the sites (**Figure 26**).

Table 10. Industrial Sector CHP Market Breakout

Market	NAICS Code	Capacity (MW)	No. of Sites
Chemicals	325	23,171	266
Refining	324	15,577	106
Paper	322	11,711	229
Food Processing	311	6,676	254
Primary Metals	331	3,976	52
Transportation Equipment	336	1,257	22
Wood Products	321	1,013	102
Rubber	326	811	15
Textiles	313, 314, 315	549	27
Non-metallic Minerals (stone, clay, glass)	327	359	20
Other	312, 316, 323, 332, 333, 334, 335, 337, 339	1,175	158
Total	**31-33**	**66,275**	**1,251**

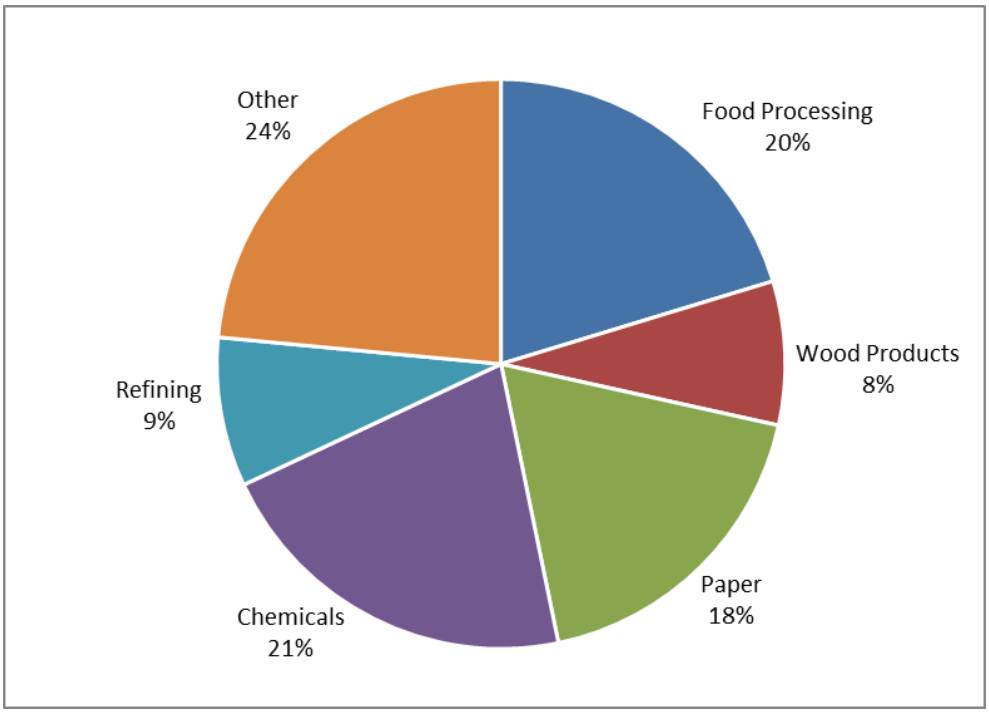
Source: CHP Installation Database, 2014

Figure 25. Industrial CHP Capacity (66,275 MW)



Source: CHP Installation Database, 2014

Figure 26. Industrial CHP Sites (1,251 sites)



Source: CHP Installation Database, 2014

5.1.2 Benefits of CHP

CHP systems are well suited to industrial sector applications that have well-matched large thermal and electric loads and long operating hours. Cost-effective CHP may provide a number of well-established benefits to both the industrial end-user and the nation, including:

Benefits for U.S. businesses:[14,15]

- Reduces energy costs for the user.
- Reduces risk of electric grid disruptions and enhances energy reliability.
- Provides stability in the face of uncertain electricity prices.

Benefits for the nation:[16]

- Improves U.S. industrial competitiveness.
- Offers a low-cost alternative for overall energy needs, including for new electricity generation capacity.
- Provides an immediate path to lower emissions of GHG and air pollutants through increased overall energy efficiency.
- Reduces or defers the need for new T&D infrastructure and enhances power grid security.
- Uses abundant clean domestic energy sources (e.g., natural gas and biomass).
- Uses highly skilled American labor and American technology.
- Supports energy infrastructure reliability and resiliency (see sidebar on Louisiana and Texas).[17]

Louisiana and Texas Legislation—CHP in Critical Government Buildings

Recognizing the ability of CHP to keep critical facilities up and running during emergency events, Louisiana adopted Resolution No. 171 in 2012. This law requires all government entities to identify which government buildings and facilities are considered "critical" in an emergency situation. Prior to constructing or renovating a "critical facility," a study must be completed to determine if CHP is economically feasible for the facility.

Examples of buildings and facilities that may be considered "critical" include hospitals, prisons, police stations, fire stations, and emergency shelters. CHP can be deemed feasible in technical assessments if it can provide a facility with 100 percent of its critical electricity needs, can sustain emergency operations for 14 days, and meets a minimum efficiency of 60 percent. The energy savings must also exceed installation, operating, and maintenance costs over a 20-year period.

Texas has passed similar legislation with House Bill (HB) 1831, HB 4409, and HB 1864. HB 1864 contains guidance on how to conduct a CHP feasibility analysis prior to the construction or renovation of any critical government facility.

Source: ICF. Web link.

5.1.3 U.S. CHP Technical Potential[18]

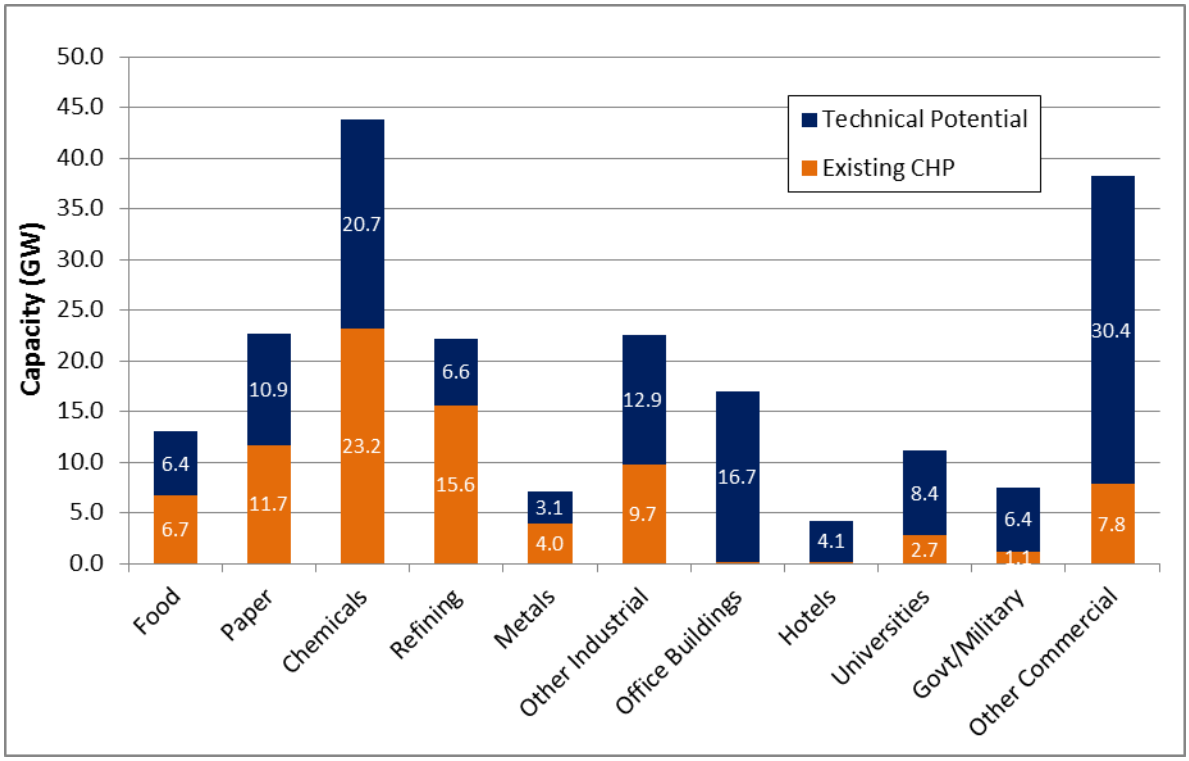
In August 2012, President Obama issued an Executive Order to accelerate the adoption of industrial energy efficiency, with a goal of adding 40 GW of CHP by 2020 (see sidebar).[19] Estimates indicate that approximately 130 GW of additional CHP could be installed at existing industrial, commercial, and institutional sites—slightly less than 65 GW at industrial sites and slightly more than 65 GW at commercial and institutional sites.[20] **Figure 27** shows the existing installed base of CHP along with the estimated technical potential by market sector.

Executive Order 13624 -- Accelerating Investment in Industrial Energy Efficiency

Recognizing the benefits of CHP, the Obama Administration set a goal to achieve 40 GW of new, cost-effective CHP by 2020. The Administration released Executive Order 13624 in August 2012, *Accelerating Investment in Industrial Energy Efficiency*, outlining this goal. Achieving this target would save energy users an estimated $10 billion per year compared to current energy use, and would save 1 quadrillion Btu of energy, which is the equivalent of 1 percent of current energy use. Addressing the key barriers to CHP can help reach this 40 GW goal.

Source: Executive Order 13624. Web link.

Figure 27. Existing CHP (82.7 GW) and Technical Potential (130 GW)



Sources: CHP Installation Database, 2014 (existing capacity); ICF CHP Technical Potential Database, 2014

5.2 Barriers

While the number of CHP installations continues to grow, key barriers to the accelerated adoption of CHP still exist. These barriers are grouped into the following three categories: (1) economic and financial, (2) regulatory, and (3) informational.

5.2.1 Economic and Financial Barriers

Many factors influence the deployment of CHP, and some of these factors can be barriers to widespread adoption. Barriers related to economic and financial constraints include:

- *Internal competition for capital.* Payback expectations and capital budget constraints influence CHP investment decisions.
- *Natural gas outlook.* The availability and long-term price forecast for natural gas impacts investments in CHP.
- *Accounting practices.* Emphasis on minimizing upfront capital costs, and the "split-incentive" between capital improvement and operation and maintenance (O&M) budgets.
- *Financial risk.* Industrial facilities may have difficulty securing low-cost financing due to financial risks.
- *Access to favorable tax structures.* Lack of financing instruments such as Master Limited Partnerships (MLPs) or Real Estate Investment Trusts (REITs).
- *Sales of excess power.* The inability to sell excess power or access to reasonable sales agreements for excess power.

Internal Competition for Capital

Industrial facility capital budgets are limited and there is strong competition for new capital investment. Even a CHP system that has an attractive financial return may not be funded over other alternatives that are closer to a company's core business, such as investments in productivity or product quality or investments to respond to regulatory requirements. A 2012 article estimates that 9 out of every 10 potential CHP projects do not move forward because of capital budget constraints.[21] Another study on financial barriers for energy efficiency projects found that internal capital competition is a major barrier—30 percent of respondents listed this as the top barrier to moving efficiency projects forward, and 28 percent listed insufficient capital as the main constraint.[22]

CHP usually entails a substantial upfront investment, which may overshadow life-cycle returns in a capital-constrained environment, particularly one where other financing is challenging. In addition, companies that are unfamiliar with CHP may seek stronger financial numbers (i.e., a shorter payback period or a higher return on investment) compared to other capital investment alternatives because they may perceive the investment as more risky than another, further disadvantaging CHP as an option (see sidebar on Sikorsky for one example of a company that decided to spend capital on a CHP system).[23]

Sikorsky Aircraft's Decision to Spend Capital on CHP

Sikorsky Aircraft installed a 10.7 MW CHP system in 2011 at their manufacturing facility in Stratford, CT. When their environmental manager initially proposed the project to the corporate board, there was concern due to the estimated $26 million system cost. Sikorsky had competing alternatives for capital expenditures but elected to fund the CHP project, which had an estimated payback of 3.2 years.

The CHP system exceeded expectations. The actual payback is estimated at 2.3 years and CO_2 reductions are approximately 9,000 tons annually.

During Hurricane Sandy, the CHP system continued to operate, providing resiliency benefits. The CHP system remained up and running throughout the storm and its aftermath, allowing production to continue as well as providing employees with access to power for personal purposes (e.g., cell phone charging).

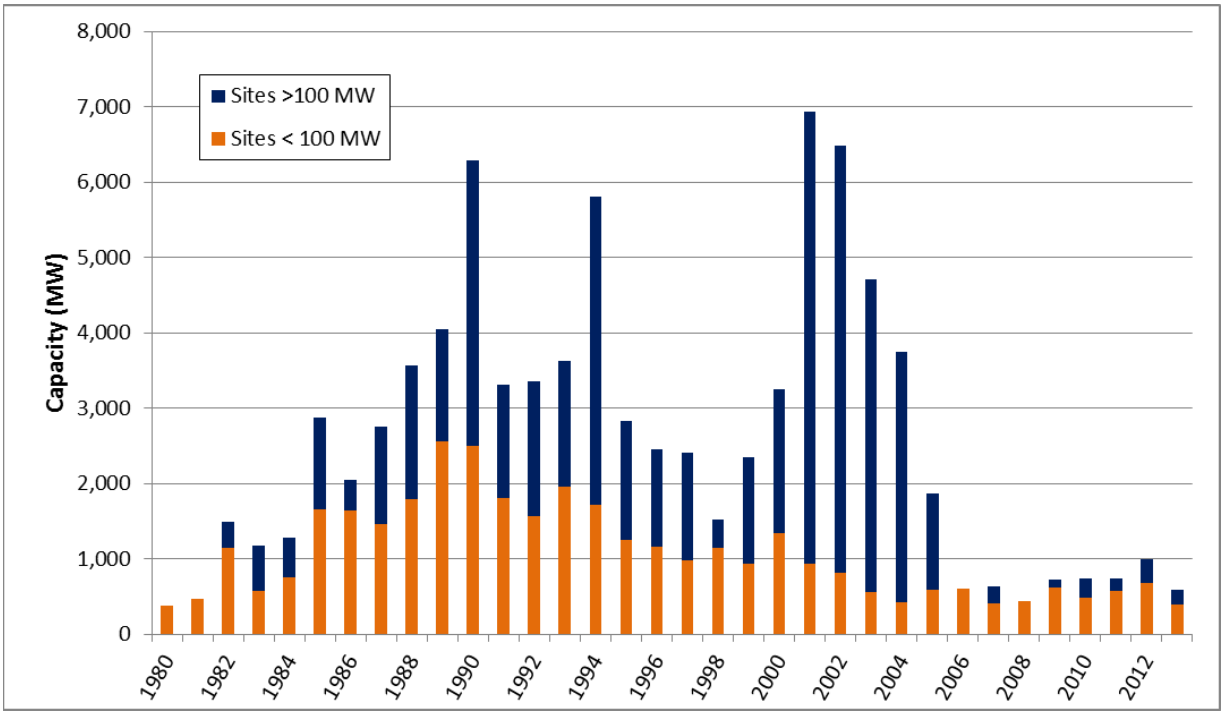
Due to the positive experience at the Stratford plant, Sikorsky is now looking at utilizing CHP at all of its facilities. Sikorsky has manufacturing facilities in 12 states and in 6 countries.

Source: Environmental and Energy Study Institute. Web link.

Natural Gas Outlook

Several economic factors influence CHP investments, and one of these factors is the cost of natural gas, which is a common fuel used for CHP systems. As indicated in **Figure 28**, new CHP installations peaked at over 6,000 MW per year in 2001, coinciding with the end of a period of high overall growth in the electric power sector. The pace of installations declined after 2001, concurrent with increasing volatility in natural gas prices and changes in energy regulations. In recent years, there has been a significant increase in the availability of domestic natural gas, and the long-term price forecast for natural is relatively stable. Since 2010, there has been an upward trend in CHP capacity additions, consistent with long-term stable price forecasts for natural gas.[24]

Figure 28. CHP Capacity Additions



Source: CHP Installation Database, 2014

Accounting Practices

Accounting practices for capital equipment and operating expense budgets can impede investments in CHP. One such practice is the "split ownership" problem. It is common for companies to separate plant operation and maintenance budgets from capital improvement budgets. This practice results in costs and savings accruing to different budgets.[25] This type of accounting can make it difficult to show the benefit of a CHP system or discourage a department from making an investment when the return will accrue elsewhere. It is also common to account for taxes and capital expenses in separate budgets. Therefore, if a CHP installation receives a tax credit, the company may not always accrue those savings to the CHP project. Tax treatment of CHP and availability of tax credits are related topics that are discussed in a following section.

Financial Risk

Industrial facilities interested in installing CHP systems may have a hard time finding low-cost financing due to financial risks.[26,27] Gaining access to capital at affordable rates can be especially difficult for long-term investments in facility upgrades, such as CHP. This difficulty arises from several complicating factors in addition to normal underwriting reviews of loan requirements, including:

- Lender uncertainty about CHP technology and the viability of process-related changes (e.g., how the system works, how it will be incorporated into the process, and whether it will perform as expected).
- Lender uncertainty about fuel and electricity price fluctuations.
- Risk of closure of the industrial plant due to economic recession or bankruptcy of the host company.
- Environmental uncertainties associated with manufacturing projects that may raise lender liability or collateral devaluation concerns.[28]

Access to Favorable Tax Structures

Favorable tax structures have been beneficial in stimulating investments in both conventional energy projects (e.g., coal mining and oil and gas pipelines) and clean energy projects, including solar, wind, and some types of CHP (see sidebar on U.K. tax policy reforms to benefit CHP).[29] In addition to receiving tax credits, conventional energy technologies have access to low-cost capital through two financing mechanisms that are not currently available to CHP and other clean energy projects: Master Limited Partnerships (MLPs) and Real Estate Investment Trusts (REIT).[30] If CHP projects could qualify for MLP and REIT funding, it could improve CHP's attractiveness under current conditions.[31]

United Kingdom's New CHP Energy Tax Exemptions

In 2013, the U.K. changed their energy tax policies, no longer exempting CHP from a climate change levy and leading to a double tax hike for CHP systems. By removing this tax exemption that was supposed to be in effect until 2023, energy tax costs for CHP increased up to three times as high as less-efficient gas power plants.

The U.K.'s Combined Heat and Power Association led a campaign—Less Waste, More Jobs and Growth—calling on government officials to support industrial energy efficiency by exempting CHP systems from the Carbon Price Floor (CPF). The CPF is a tax on fossil fuels used to generate electricity that began in April 2013. In March 2014, the U.K. government exempted CHP from the Carbon Price Floor as part of a £7 billion package to cut energy bills for British manufacturers.

Source: HM Revenue & Customs. Web link.

Master Limited Partnerships

An MLP is a business structure that provides tax advantages to the partners and allows investors to trade shares in the MLP, much like a public stock. As a result, energy projects that qualify as MLPs have access to lower cost of capital, and investors in MLPs generally receive a higher rate of return. MLPs were created in 1981 and are available to projects that involve fossil-fuel extraction (e.g., coal mining) and fossil fuel transportation (e.g., oil and gas pipelines).

Congress has proposed legislation (see sidebar)[32] that would allow clean energy projects to qualify as MLPs.

> ***Proposed Master Limited Partnerships Parity Act***
>
> In April 2013, Senator Chris Coons and Congressman Ted Poe introduced the Master Limited Partnership Parity Act, H.R. 1696. This bill would enable renewable generators and CHP systems to take advantage of MLPs. The bill is intended to give clean energy resources access to low-cost capital, similar to treatment provided for fossil fuel projects. The generation, storage, or distribution of thermal energy from CHP qualifies under H.R. 1696, along with waste heat to power.
>
> *Source: Library of Congress, H.R. 1696. Web link.*

A recent study found that if policies were changed such that CHP projects could qualify for MLP funding, the adoption rate of CHP would likely accelerate.[33] A New York Times article in 2012 by two researchers at Stanford University's Steyer-Taylor Center for Energy Policy and Finance articulated the benefits of applying MLP status to renewables (such benefits also extend to financing energy efficiency projects):"Master limited partnerships carry the fund-raising advantages of a corporation: ownership interests are publicly traded and offer investors the liquidity, limited liability and dividends of classic corporations. Their market capitalization exceeds $350 billion. With average dividends of just 6 percent, these investment vehicles could substantially reduce the cost of financing renewables."[34]

Real Estate Investment Trusts

REITs offer an opportunity to access low-cost capital from the private sector (i.e., investors). Congress created REITs in 1960 to stimulate private sector investment in residential construction, commercial buildings, and industrial factories. A company that qualifies as a REIT can reduce its tax burden by the amount of dividends it pays to shareholders provided the dividends are at least 90 percent of the REIT's taxable income.

CHP installations and other clean energy assets can be considered as eligible real estate investment trust properties. At present, the IRS is determining qualifying status on a case-by-case basis. Rather than a case-by-case IRS ruling, Congress could expand the definition of REITs to clearly include CHP assets, similar to what has been proposed for MLPs. Examples of current or past Federal tax incentives that encourage CHP and can be expanded to further support CHP development or to include waste heat to power projects as eligible include the following:

- The Federal Modified Accelerated Cost Recovery System (MACRS) tax incentive program has helped encourage CHP development. MACRS allowed for a 5-year depreciation schedule for eligible CHP projects.[35] MACRS expired at the end of 2014. Renewably-fueled systems, including CHP projects, were able to receive a 50 percent first year bonus depreciation through the end of 2014.[36] Some have criticized MACRS since it did not allow for traditional CHP systems to qualify for bonus depreciation and did not allow

for most waste heat to power projects to qualify for the bonus depreciation or 5-year depreciation schedule. The MACRS tax incentive can be renewed and eligibility can be extended to include waste heat to power. An analysis by ACEEE discusses the drawbacks of CHP having a different depreciation period, stating that "CHP equipment should have one depreciation period…" and not the five periods as described in their whitepaper.[37]

- The Federal Investment Tax Credit (ITC) has also helped incentivize CHP, although it has been criticized due to its exclusion of waste heat to power projects, and credit limitations for CHP projects. The Emergency Economic Stabilization Act of 2008 added CHP system property to the list of technologies eligible for an investment tax credit under Section 48 of the Internal Revenue Code. Qualifying CHP projects are eligible for a 10 percent ITC through the end of 2016. Waste heat to power projects do not qualify for the ITC. A recent study by the Heat is Power (HiP) Association found that given equal tax treatment, industrial waste heat could provide enough emission-free electricity to power 10 million American homes, provide thousands of new American jobs, and support critical U.S. manufacturing industries.[38] Research sponsored by the World Alliance for Decentralized Energy (WADE) in 2010 looked at the impact on CHP development of expanding the 10 percent ITC to the first 25 MW of capacity for systems of any size as well as expanding the ITC to 30 percent for high efficiency CHP (projects with overall efficiencies of 70 percent lower heating value or greater).[39] The analysis was limited to topping cycle CHP systems using reciprocating engines, gas turbines, or microturbines (waste heat to power wasn't assessed). This analysis found that:
    - The expanded 10 percent ITC increases CHP deployment by about 20 percent over a no ITC baseline (550 additional MW between now and 2017).
    - The expanded 10 percent ITC results in an annual energy savings of 118 trillion Btus and an annual reduction in CO_2 emissions of 14 million metric tons (MMT), equivalent to removing 2.6 million cars from the road. Investment in the projects represented by the expanded 10 percent ITC results in over 17,000 highly skilled, well-paying jobs.
    - The 30 percent ITC for highly efficient CHP increases CHP deployment by more than 60 percent over a no ITC baseline (1,600 additional MW between now and 2017).
    - The 30 percent ITC results in an annual energy savings of 162 trillion Btus and an annual reduction in CO_2 emissions of over 19 million metric tons (MMT), equivalent to removing 3.4 million cars from the road. Investment in the projects represented by the 30 percent ITC results in over 23,000 highly skilled, well-paying jobs.

Sales of Excess Power

Designing a CHP system to meet the thermal needs of a facility often results in the system achieving a high overall efficiency. Industrial facilities that have large thermal needs—such as chemical, paper, refining, food processing, and metals manufacturing plants—often size a CHP system to meet the thermal load, which may result in more electricity generated than required at the site. Excess power sales may provide a revenue stream for a CHP project, possibly enabling the project to go forward.[40] The inability to sell excess power or to sell excess power at a competitive price can serve as a deterrent to CHP projects sized to meet the facility's thermal needs. Options for selling excess power include Power Purchase Agreements (PPAs) with a local electric utility, or retail sales to nearby facilities (see sidebar on FERC ruling related to the use of feed-in-tariffs in California to encourage CHP).[41]

PPAs typically guarantee that a CHP system owner can sell power at a predetermined rate for a fixed number of years. Under the Public Utility Regulatory Policy Act (PURPA), electric utilities are required to purchase electricity and capacity from qualifying CHP facilities at the utility's avoided cost (see avoided cost sidebar).[42,43] However, there has been significant debate over how to calculate a utility's avoided cost, and amendments in 2005 have limited PURPA's applicability in many regions, which may be perceived as a barrier to CHP. The challenge for state utility regulators is to structure an avoided cost for CHP that provides fair treatment of all benefits and costs.

FERC Rules That Multi-tiered Avoided Cost Structures Are Consistent with PURPA

To encourage CHP, California established a feed-in-tariff (FIT) for CHP systems up to 20 MW. The California FIT used a multi-tiered avoided cost calculation, and this avoided cost calculation approach was challenged as not being consistent with PURPA. FERC ruled, however, that a multi-tiered avoided cost rate structure is consistent with PURPA. Specifically, FERC affirmed that state procurement obligations (e.g., capacity additions required by a Renewable Portfolio Standard) can be considered when calculating avoided costs.

In evaluating the avoided costs calculated by the utilities in the state and ensuring alignment with PURPA, state utility regulatory agencies may consider:[1]

- The technical criteria for CHP eligibility (system size and efficiency thresholds) to sell electricity to utilities;
- Use of standard contracts and pricing to simplify the procedures governing CHP electricity sales; and
- Inclusion of locational adders for avoided T&D investments to benefit CHP systems that are in high-value areas that yield significant savings from avoided T&D upgrades.

Source: State and Local Energy Efficiency Action Network. Web link.

In some cases, industrial plants with CHP can also sell excess electricity to neighboring facilities through third-party PPAs. In many states, industrial plants that operate CHP systems do not

have the ability to deliver excess electricity to nearby plants that are under common ownership, or sell excess power to any entity other than the electric utility that serves the CHP site. This may hinder the industrial site from securing financing or moving forward with the project. Texas has recently taken steps to allow electricity sales to neighboring facilities (see sidebar).[44] Some states have adopted provisions that allow electricity sales through non-utility distribution wires to nearby facilities. For example, California and New Jersey (see below for additional information) have statutes that expressly permit CHP owners to serve properties separated by a public right of way, but only if the properties are under common ownership or meet other specific conditions.[45] States can consider similar provisions, as well as allowing CHP users to sell excess electricity to third parties.[46] Successful example policies include the following:

Texas House Bill 2049

HB 2049 was signed into law in June 2013, and clarifies language in the Texas Utility Code to allow CHP facilities to sell electricity and heat to any customer located near the CHP facility. Previously, CHP facilities could only sell electricity to one customer—the electricity service provider. Enactment of HB 2049 opens the market for selling electricity and thereby has the potential to facilitate the adoption of CHP, particularly in industrial facilities with large thermal demands.

Source: Texas Combined Heat & Power Initiative. Web link.

- New Jersey has legislation that defines contiguous property as any site that takes thermal energy from the CHP host, enabling the CHP host to sell electricity to that off-taker as well, potentially improving the economic feasibility of projects by expanding the electric and thermal loads.
- California allows a limited exception to CHP facilities selling power to neighboring loads. A CHP facility selling to contiguous loads is not an electrical corporation under certain conditions. In addition to using power to meet its own load, a CHP facility can sell electrical power to its neighbors over private wires to not more than two other corporations on the same property or to the immediately adjacent properties.[47]

Regulatory Barriers

Regulatory barriers to CHP can be diverse and range from uneven implementation of output-based emissions standards to not including CHP in incentive programs such as Clean Energy Portfolio Standards (CEPS). Regulatory barriers for CHP may include the following:

- *Utility business model.* The structure of utility cost recovery and lost revenue mechanisms can reduce a utility's interest in promoting industrial CHP projects.

- *Environmental permitting and regulatory issues.* Output-based regulations and New Source Review (NSR) permitting requirements.
- *Inconsistent interconnection requirements.* Lack of standardized interconnection requirements can impede CHP.
- *Lack of recognition of environmental benefits.* Lack of financial value for the potential emissions benefits of CHP.
- *Failure to recognize the full value of CHP in regulatory evaluations.* Utility procurement and resource plans may omit some value streams provided by CHP.
- *Standby rates.* Structure of standby rates that are not designed to closely preserve the nexus between charges and cost of service.[48]
- *Exclusion from clean energy standards.* CHP's eligibility under CEPS programs.
- *Capacity and ancillary services markets.* Electricity markets and programs may limit CHP's ability to participate.

Utility Business Model

The traditional business model for regulated utilities can limit investments in CHP. In traditionally regulated electricity markets, utilities recover fixed costs and earn revenue by selling energy, with the cost of building new power plants and transmission and distribution infrastructure recovered through energy sales.[49] The reduction of electricity sales (including energy efficiency and CHP) may reduce utility income and may make it more difficult for the utility to cover fixed costs. This utility model is perceived to create a disincentive for utilities to support efficiency and on-site generation projects like CHP.[50] However, some utilities such as Alabama Power have successfully integrated both the costs associated with purchasing electricity through PPAs and company-owned CHP into its rate base (see sidebar).[51,52]

Alabama Power's "Win-Win" Scenarios for CHP

Alabama Power, owned by Southern Company, has 2,000 MW of CHP in its service territory. Approximately, 1,500 MW is customer-owned CHP and more than 500 MW is company-owned CHP located at large industrial sites. This customer-owned CHP generation was primarily installed in the 1990s and has provided Alabama Power with significant benefits, allowing the company to avoid building an estimated 1,700 MW of central station capacity.

Alabama Power continues to assess customers for CHP potential, seeking "win-win scenarios" that benefit the customer, the utility, and the utility's customers. Alabama Power has been able to incorporate the costs of both new CHP PPAs along with utility-owned CHP into its rate base.

Source: State and Local Energy Efficiency Action Network. Web link.

To address concerns about utility revenue losses due to efficiency, rate designs that remove the link between utility fixed cost recovery and profits from sales volume have progressed in some states.[53] Appropriate rate design is critical for allowing utility cost recovery and to prevent costs from being unfairly shifted between customers. As the grid evolves toward a structure where customer resources are fully compensated for the value of the services they provide to the grid, and utilities are likewise fully compensated for the services they provide to customers, tariffs will need to evolve to fairly reflect the value of these two-way transactions.[54]

State utility regulatory agencies can review, and if necessary, modify regulations to address these utility revenue concerns. Modification of these regulations may encourage utilities to promote CHP projects, while still allowing them to earn a fair rate of return on investments. For example, New York Governor Andrew Cuomo announced a new initiative called Reforming the Energy Vision on April 24, 2014. The proposal calls for redesigning the regulatory framework that applies to the state's electric utilities, and focuses on increasing system reliability and promoting clean energy. The proposed reforms envision that customers will be able to generate their own electricity through CHP and other forms of clean energy. The proposal also envisions that the distribution utility, which will become a Distributed System Platform Provider (DSPP), will function more like a traffic cop instead of a monopoly distributor of power, and will be compensated by the distributed resource providers that deliver electricity. Under Reforming the Energy Vision, the New York Public Service Commission will consider the degree to which DSPPs can own, operate, and/or finance distributed energy resources.[55]

Environmental Permitting and Regulatory Issues

Air quality regulations and permitting requirements can limit CHP development. Many air regulations establish emissions limits on an input basis—pounds of pollutant per unit of fuel input (e.g., lbs/MMBtu of fuel input).[56] Input-based limits do not recognize more-efficient generating technologies, including CHP. When output-based limits are used, they should recognize both the thermal and electrical output of CHP to properly account for its energy efficiency. Output-based emissions regulations relate emissions to the productive output of the process rather than the amount of fuel burned, meaning

Texas Permit-by-Rule

Texas has implemented streamlined permitting for CHP systems using a permit-by-rule (PBR) approach. The Texas PBR was issued in 2012 and applies to CHP powered by "pipeline-quality natural gas-fired engines, including turbines." To qualify, an individual CHP system or any group of units may not exceed 15 MW in capacity. The PBR differs from a standard permit and recognizes the efficiency benefits from CHP by establishing higher output-based NO_X limits for systems from 8 to 15 MW in size. In one case, the Texas PBR allowed a CHP system to obtain an air permit in just 4–6 weeks. Prior to PBR, the average time was typically over a year.

Source: U.S. Environmental Protection Agency. Web link.

limits are based on the amount of pollutant per useful energy output (e.g., lbs/MWh, lbs/MMBtu delivered, or lbs/bhp-hr).[57]

With input-based emissions limits, the reduced emissions from improved energy efficiency are not recognized. Expanded use of output-based limits in state or Federal regulations may encourage energy efficiency improvements such as CHP. A number of states and Federal regulations have begun to include output-based limits (see sidebar on Texas Permit-by-Rule on the previous page for streamlined permitting that considers output-based NO_X emissions).[58]State regulators can also encourage the use of consistently formatted output-based emissions standards that account for both the electric and thermal output of the CHP system. The EPA Combined Heat and Power Partnership provides a variety of resources for states to draw upon when developing output-based regulations.[59]

Ensuring that state permitting processes are straightforward and predictable helps to avoid costly delays and uncertainty in the planning process. For example, Texas and Connecticut have implemented streamlined air permitting for CHP systems and Iowa is considering such an approach. State air agencies can adopt simplified, standardized permitting for CHP systems. The EPA's Combined Heat and Power Partnership works to promote streamlined, priority permitting process for qualifying CHP projects.

Other Federal permitting regulations may also inadvertently deter CHP and efficiency upgrades.[60] Federal regulatory requirements, such as NSR, are perceived by the industry to hinder CHP development. The NSR permitting process applies to any new source whose potential emissions qualify it as a "major source" or a "major" modification that can increase emissions above a certain threshold (typically the threshold is between 10 and 100 tons of emissions per year, depending on the source category and air quality within the area). NSR rules require affected sources to conduct a review of air quality analysis, conduct additional impact analyses, install state-of-the-art pollution control equipment, and undergo a public notice process.[61]

NSR is often perceived to be an uncertain and time-consuming permitting process. CHP systems can commonly increase a facility's on-site emissions, but significantly reduce total emissions across multiple facilities throughout the air shed, as compared to separate heat and power production. The NSR process, however, does not account for these offsite emission reduction benefits when determining permit applicability, but offsite emissions can be considered in assessing the impacts of the control technology options. An industrial site may be reluctant to pursue a CHP project if there is a perceived potential that the CHP project will trigger NSR requirements.

It is important to note that states, not the federal government, issue NSR permits (see the Frito-Lay NSR example in the sidebar[62,63]).

Frito-Lay's CHP NSR Permit

Frito-Lay's manufacturing plant in Killingly, CT, installed a CHP system in 2008. The system is a 4.6 MW, natural gas–fired combustion turbine, which provides 90 percent of the facility's electricity needs and 80 percent of its steam needs.

Frito-Lay received an initial NSR permit in May 2008 for its CHP system, and was issued a modification to its permit in May 2012. Control equipment consists of a selective catalytic reduction system for NO_X control. In addition, Frito-Lay's CHP system has the following benefits:

- Fuel efficiency exceeds 70 percent on average annually.
- Reduces GHG emissions by more than 5 percent.
- Enables continued facility operations during power outages, including during Hurricane Irene in 2011 and Hurricane Sandy in 2012.
- Reduces energy costs, saving the facility over $910,000 annually.

Source: Connecticut Department of Energy & Environmental Protection. Web link.

Inconsistent Interconnection Requirements

Standardized interconnection rules can help establish clear and uniform processes and technical requirements for on-site generation to connect to the electric grid. Most CHP systems rely on the utility grid for supplemental, standby, and backup power services, and in some cases for selling excess power. Being able to safely, reliably, and economically interconnect with the existing utility grid is a key requirement for the success of a CHP project. Technical standards governing how on-site generators connect to the grid serve an important function, ensuring that the safety and reliability of the electric grid is protected. Non-standardized interconnection requirements and uncertainty in the timing and cost of the application process can be a barrier to customer-sited generation.

Forty-three states and the District of Columbia have adopted some form of interconnection standards or guidelines; however requirements and implementation are inconsistent between states and sometimes within states.[64] Effective standards can reduce uncertainty over issues such as technical requirements, costs, dispute resolution, insurance requirements, and timeframes for approval decisions. The lack of uniformity in application processes and fees, as

well as the degree to which these requirements are enforced, makes it more challenging for equipment manufacturers to design and produce modular packages and may reduce economic incentives for on-site generation. Lack of interconnection standards for projects of all sizes can cause confusion and delay in project development (e.g., interconnection standards that apply only to small or mid-size systems, or standards that apply only to certain fuels or net-metered systems). Larger CHP systems (typically greater than 20 MW), such as those found at most industrial sites, typically work through the interconnection process independently with utilities. Having an established dispute resolution process or established timeframes for utility approval may assist in more timely development of CHP projects.

The ability for generators to interconnect to both radial and network grids is important. Some utilities may not allow interconnection of generators on electrical circuits known as network grids. These electrical distribution systems are typically found in urban areas, and the interconnection of CHP systems may be forbidden or may require additional switch gears that could add cost to the interconnection.[65] (see sidebar for an example on interconnection standards for distributed generation systems).[66]

New York's Interconnection Standards

New York first adopted interconnection standards in 1999 that allowed for distributed generation systems up to 300 kW in size to connect to radial distribution systems. In 2005, New York modified its interconnection requirements to allow for distributed generation systems up to 2 MW in size to interconnect to both radial and secondary network systems.

Most buildings with CHP systems in New York City are interconnected, with the CHP providing some portion of their electricity load on-site while receiving the rest of their power from the Con Edison electric grid. This setup occurs due to the density of the city and the high price of local real estate, which often makes it too costly to build a CHP system large enough to meet all of a building's energy needs.

Source: State and Local Energy Efficiency Action Network. Web link.

The lack of uniform standards for interconnection procedures is due in part to the fact that jurisdiction over interconnection can be split between the Federal Energy Regulatory Commission (FERC) and each state's utility regulatory body. FERC has issued model interconnection guidelines, which some states and utilities have adopted, while others have not. FERC issued model interconnection rules for large systems (i.e., greater than 20 MW) in 2003 and issued rules for small systems up to 20 MW in size in 2005.[67] FERC recently improved upon their small generator guidelines by releasing revised standards in November 2013.[68] The FERC model rules seek to promote more consistent and well-structured standards throughout by the country by offering guidance that can be adopted by states and utilities. The FERC model rules establish technical requirements, provide application forms, and define who is responsible for utility system upgrades. For example, FERC's large generator interconnection standards

include a Large Generator Interconnection Procedure (which sets technical requirements) and a Large Generator Interconnection Agreement (which sets contractual provisions and identifies who pays for improvements to the utility's electric system if such modifications are needed).[69] The intent of FERC's small generator standards package of reforms adopted in November 2013 is to reduce the time and cost to process small generator interconnection requests, maintain reliability, increase energy supply, and remove barriers to the development of new energy resources.[42]

Lack of Recognition of Environmental Benefits

Treating environmental benefits as an externality that cannot be monetized reduces the value of CHP projects. For example, in 2008, CHP systems were estimated to have avoided over 1.9 quadrillion Btu of fuel consumption and an estimated 248 million metric tons of CO_2 emissions when compared to the separate production of heat and power.[70,71] This CO_2 reduction is equivalent to the emissions of more than 45 million cars.[72] CHP systems may also lead to significant reductions in NO_X, SO_2, and hazardous air pollutants. These emissions savings typically do not receive economic value from companies because they typically cannot be monetized under existing regulation. However, there may be significant value (monetary and shareholder) from such emissions savings in certain markets, such as CHP systems receiving CO_2 emissions credits under the Regional Greenhouse Gas Initiative (RGGI), as well as in corporate sustainability reporting.

Failure to Recognize the Full Value of CHP in Regulatory Proceedings

Utilities compare the value of resource alternatives in integrated resource plans that are prepared for state utility regulatory commissions; however, these comparisons frequently omit sources of CHP value. For example, the locational benefits of distributed generation can be significant but are often ignored; average line loss benefits are frequently considered even when marginal line loss benefits are relevant; and the benefit of reducing electric sales reduces the cost of complying with clean energy standards. Resource assessments that include a complete set of benefits and a fair value for each provide equitable treatment for all alternatives, including CHP.[73]

Standby Rates

Utility rates and fees can have an impact on CHP economics. Most industrial customers are motivated to install CHP systems to meet electricity and thermal energy needs at a lower cost. Standby rates,[74] or partial requirements tariffs, are a potential impediment to CHP if the rates are not properly designed.[75] Utility rates, including standby charges, should allow a utility to recover costs from customer classes based on energy usage patterns for each class. This

principle of "cost causation" is implemented through rate designs that fairly allocate costs based on measureable customer characteristics.[76]

Utility standby rates cover some or all of the following services:[77]

- *Backup power* during an unplanned generator outage.
- *Maintenance power* during scheduled generator service for routine maintenance and repair.
- *Supplemental power* for customers whose on-site generation under normal operation does not meet all of their energy needs, typically provided under the full requirements tariff for the customer's rate class.
- *Economic replacement power* when it costs less than on-site generation.
- *Delivery* associated with these energy services.

For industrial customers, costs of utility service are typically separated into customer, energy, and demand charges. Customer charges are designed to recover costs incurred to provide metering and billing services and service drop facilities. Energy charges recover the variable costs incurred to generate electricity (i.e., chiefly fuel cost).[78] Demand charges are designed to recover the utility investment cost incurred to provide generating, transmission, and distribution capacity and may vary by season and time of day (see the sidebar on Pacific Power below for an example of a standby rate policy).[79,80]

Standby rates must be balanced to prevent the utility from needing to unfairly shift costs among customers, as well as recognizing the benefits to the utility from distributed generation. The key standby rate implementation approaches that state utility regulators can consider are whether they:[81]

Pacific Power Standby Rates in Oregon

Pacific Power has established standby rates in Oregon that balance the value of on-site power generation and utility cost recovery needs. Several key elements of these standby rates include the following:

- Pacific Power assesses charges for shared distribution facilities, such as substations and transmission lines, based on 15-minute net demand for the month during on-peak hours. There is no annual ratchet.
- Cost recovery for local distribution facilities is based on the average of the two highest monthly peak demands for the past 12 months.
- Scheduled maintenance service must be scheduled 30 days in advance. Pacific Power offers partial requirements customers the option to buy replacement energy at market prices.
- Energy service for unscheduled outages is based on real-time market prices. Demand and transmission charges during scheduled maintenance periods and unscheduled outages are based on daily demands and do not affect charges for T&D services under the base standby tariff.

Source: State and Local Energy Efficiency Action Network. Web link.

- Offer daily or monthly as-used demand charges for backup power and shared transmission and distribution facilities;
- Reflect load diversity of CHP customers in charges for shared delivery facilities;
- Provide an opportunity to purchase economic replacement power;
- Allow customer-generators the option to buy all of their backup power at market prices;
- Allow the customer to provide the utility with a load reduction plan; and
- Offer a self-supply option for reserves.

In addition Pacific Power, another example of successful standby rates is Consolidated Edison's rates. Consolidated Edison offers replacement or supplemental service for approved projects for self-generation customers whose generation capacity is greater than 15 percent of their potential load. Pricing for this service is based on a contract demand representing the highest demand the facility is likely to meet for the customer under any circumstances. The charge for the contract demand reflects both the customer's contribution to local facilities used on a regular basis for baseload demand, as well as customer-specific infrastructure necessary to meet the maximum potential demand with or without the customer's generation in service. The rate for the entire contract demand is generally lower than the otherwise applicable rate. In addition, the company assesses a demand charge based on the actual demand recorded each day. The rate varies by season and time of day—peak versus off-peak. This variable charge recovers shared system (upstream) costs. It is calculated on a daily basis.[82]

Demand charges in standby rates are sometimes "ratcheted," meaning the utility continues to apply some percentage (often as high as 100 percent) of the customer's highest peak demand in a single billing month for up to a year after its occurrence. The use of ratchets can be controversial—some view ratchets as increasing the equity of fixed-cost allocation, while others view ratchets as barriers to CHP. Although demand ratchets may be appropriate for recovering the cost of delivering energy to customers in the vicinity of the generator, some argue that they do not reflect cost causation[83] for shared distribution and transmission facilities. Distribution and transmission facilities are designed to serve a pool of customers with diverse loads. Utility charges based on ratcheted demands may fail to recognize the diversity in load among CHP customers and the cost savings associated with that diversity, particularly regarding shared T&D facilities. Requiring CHP customers to pay ratcheted demands may result in CHP customers overpaying for utility-supplied electricity relative to full requirements customers.[84] Establishing tariffs with fair standby charges can be difficult, but there are best practices from existing tariffs that State utility regulators can draw from (see recent report form Oak Ridge National Lab and the Regulatory Assistance Project on tariff best practices).[85,86]

Exclusion from Clean Energy Standards

State Clean Energy Portfolio Standards (CEPS)[87] commonly require a certain percentage of retail electricity sales in a given state to come from qualifying renewable resources or highly efficient technologies such as CHP, or require that a certain amount of energy savings be achieved from energy efficiency projects. CEPS are an effective tool for encouraging clean or efficient sources of generation.[88] Some CEPS have separate tiers or targets for energy efficient technologies, as compared to those for traditional renewables. Some states, such as Massachusetts and Minnesota (see sidebars [89,90,91]), have established separate energy efficiency resource standards (EERS) that allow energy efficient projects to qualify.[92] Well-designed CEPS programs – those that establish separate targets or tiers for different categories of resources to ensure that a certain class of resource is not encouraged to the detriment of others – have proven effective in encouraging the development of clean energy resources and meeting overall state policy goals (see sidebar on a successful CHP program in Maryland[93]).

Massachusetts's Energy Efficiency First Fuel Requirement

Massachusetts's Green Communities Act of 2008 called for a number of energy reforms in the State, including the establishment of an Energy Efficiency Resource Standard (EERS), termed the Energy Efficient First Fuel Requirement. Under the EERS, electric and gas utilities must prioritize cost-effective energy efficiency and demand reduction resources over supply resources, and they must submit 3-year plans outlining how they plan on meeting the requirement. No defined list of eligible technologies can be used to meet the requirements.

Funding to implement the utility plans comes from a number of sources: a $0.0025/kWh surcharge imposed on customers of all electric IOUs in the State; the Forward Capacity Market administered by ISO-NE; funds from the Regional Greenhouse Gas Initiative funds and the NOx Allowance Trading Program; and other sources approved by state agencies.

Funds then support the Mass SAVE program along with other initiatives. The Mass SAVE programs provides rebates to CHP systems that pass a benefit/cost ratio test. Rebates are $750/kW, and funding is also provided for 50 percent of cost feasibility studies. Program results for 2011 showed that CHP systems represented 30 percent of commercial/industrial energy efficiency target savings, and the $/kWh savings from CHP have been the lowest of all Mass SAVE measures.

The first EERS 3-year plan (2010–2012) delivered 2,390 gigawatt hours and 49 million therms of energy savings, and nearly 1.4 million metric tons of greenhouse gas reductions. These reductions are equivalent to the annual electricity consumption of over 314,000 homes, the natural gas usage of 52,000 homes, and the greenhouse gas emissions from 290,000 cars. Under the EERS plans, Massachusetts is investing more in energy efficiency per capita than any other state.

Source: *Massachusetts Office of Energy and Environmental Affairs. Web link.*

Minnesota Waste Heat Recovery Law (HF 729)

Minnesota's recent Waste Heat Recovery Law signed in May 2013 specifies that "waste heat recovered and used as thermal energy" from existing machinery, buildings, or industrial processes, including combined heat and power, for heating or cooling is eligible for utility conservation programs. HF 729 also specifies, "'energy conservation improvement' means a project that results in energy efficiency or energy conservation. Energy conservation improvement may include waste heat that is recovered and converted into electricity," where waste heat recovery converted to electricity is defined as "an energy recovery process that converts otherwise lost energy from the heat of exhaust stacks or pipes used for engines or manufacturing or industrial processes, or the reduction of high pressure in water or gas pipelines." Resulting energy savings from waste heat recovered and used as thermal energy or recovered and converted into electricity is also now eligible towards a utility's natural gas or electric energy savings goals. The Minnesota Department of Energy Resources is currently working on guidelines for program implementation.

Source: Minnesota Department of Energy Resources. Web link.

Maryland—CHP Incentive Program

Maryland passed the EmPOWER Maryland Energy Efficiency Act of 2008, which sets a goal of reducing overall per capita energy consumption and demand in the State by 15 percent by 2015. The Act requires utilities to develop cost-effective energy efficiency and demand response programs for all customer classes. The State's investor-owned utilities—Baltimore Gas and Electric (BGE), Pepco, and Delmarva Power—implemented similarly structured CHP incentive programs to help meet the objectives of the EmPOWER Act. All applications under these CHP incentive programs must be submitted by the end of 2014. Reciprocating engine or gas turbine CHP systems that meet a minimum efficiency of 65 percent or higher typically qualify for incentives, including:

- Design incentive ($75/kW)
- Installation incentive ($175/kW)
- Production incentive ($0.07/kWh for 18 months)
- The preproduction incentives and the production incentive (both capped at $1,000,000 each such that the total incentive for any one project does not exceed $2,000,000)

This CHP incentive program is expected to help significantly increase the use of CHP in Maryland. For example, the 2012 EmPOWER compliance report states that, based on proposals received, BGE will likely approve 16 CHP system applications with potential annual energy savings of 102,000 MWh. Pepco is expected to approve 11 applications with potential annual savings of 219,000 MWh, and Delmarva is expected to approve 6 applications with potential annual savings of 33,000 MWh.

Source: State and Local Energy Efficiency Action Network. Web link.

Performance-based incentives have been shown to be an effective tool in encouraging efficient, new CHP installations, and can help meet state CEPS goals. For example, to help meet EmPOWER Act of 2008 energy savings targets, Maryland's three IOUs all have similar performance-based incentive programs for certain CHP system types that meet a minimum efficiency of 65 percent. The programs provide eligible CHP systems with a production incentive of $0.07/kWh (see details in the sidebar below). States can consider allowing for performance-based incentive programs for CHP systems where it aligns with state policy goals.

Many states differentiate between topping cycle CHP projects and bottoming cycle, or WHP projects. Twenty-five states explicitly include CHP and/or waste heat recovery as an eligible resource; however, from state-to-state the specifics of how CHP or WHP qualifies vary.[94] Fifteen of these states explicitly include WHP in their renewable portfolio standards. In some states, CHP is treated as an efficiency resource and WHP is treated as a renewable resource. Elsewhere, both are treated as efficiency resources. This inconsistent treatment creates confusion among end-users and project developers.

Capacity and Ancillary Services Markets

The electric grid is dynamic and grid operators continuously monitor the system to ensure that proper voltages, frequencies, and reserve margins[95] are maintained. In regions with organized markets, much of this support is coordinated through market programs. Providing these services to the grid is one form of additional revenue that may be earned by a CHP project. Short-term adjustments to the grid (measured in minutes or hours) are referred to as ancillary services. Longer-term support for the grid (measured in years) is covered by capacity markets. Specifically:

- *Ancillary Services Markets* include (see sidebar comments from former FERC Chairman Wellinghoff on value of ancillary services):[96]
- *Capacity or Forward Capacity Markets* are markets where new and existing resources bid into grid operator auctions to acquire capacity

Remarks from Former FERC Chairman Jon Wellinghoff at CAISO Stakeholder Symposium (October 7, 2009)

"Ancillary services are essential to keep the system balanced and prevent it from cascading into a blackout. And it turns out that demand response, local storage, and distributed generation are among the best 'dance partners' to ensure we can reliably integrate renewable energy resources into the grid. Indeed, it has been demonstrated that these distributed resources are more efficient than central station fast response natural gas–fired generators at matching load variations and providing ancillary services needed to ensure reliability. They are even faster, generally cheaper, and have a lower carbon footprint than the traditional power plant provided ancillary service."

Source: Wellinghoff, J. Web link.

for future years.

- *Operating & Spinning Reserves* supply electricity if the grid has an unexpected need for more power on short notice.
- *Regulation and Frequency Response* service corrects for short-term changes in electricity use that might affect the stability of the power system. This service helps match generation and load, and it adjusts generation output to maintain the desired frequency.
- *Reactive Power and Voltage Control* service corrects for reactive power and voltage fluctuations caused by customer operations.

Regional transmission organizations (RTOs) and independent system operators (ISOs) administer and manage capacity and ancillary services markets. As more CHP and distributed generation resources are added as electric supply resources, ISOs and RTOs are allowing or evaluating participation by these resources in capacity and ancillary services markets. As an example, in ISO-NE,[97] CHP systems with a capacity of 1 MW or larger can participate in capacity and ancillary service markets.[98]

Current CHP participation in capacity and ancillary services markets is low.[99] One reason for the low participation is that each of the markets for these services is highly specialized with detailed rules to ensure that the electric system remains safe and reliable, which places time demands on the CHP owner or operator. In capacity markets, compensation is established through a competitive auction and paid to resources that commit several years in advance to being available to meet peak demand. A penalty may be invoked if the supplier fails to meet its contractual obligation. The ancillary services market is also governed by detailed rules, and in many cases a system aggregator or the load-serving entity will arrange participation on behalf of the CHP owner. Participation requirements include metering that allows for financial settlement, active market engagement, and periodic ISO training courses to maintain certification—all of which place time demands on the CHP owner.

Another reason for low participation is that CHP operating characteristics may not align with participation requirements. CHP systems are usually sized to meet site thermal loads and are normally operated in a baseload manner or follow the operating schedule of the facility to maximize savings.[100] Because electricity production is typically driven by thermal needs, in most cases, electricity produced by these systems is typically less than customer demand and no excess electricity is generated. It may be possible for CHP to participate in ancillary services markets if operational flexibility is designed into the system (e.g., the CHP system is sized with single or multiple prime movers that provide excess capacity when needed or the system can operate during times when the thermal load is lower).

5.2.2 Informational Barriers

Industrial facilities typically view CHP as one option—often among several competing options—for reducing energy costs. To make an informed decision, industrial customers need accurate and complete information to reach valid conclusions on whether and how CHP may benefit their operation. The core business for industrial customers is not producing electricity or recovering thermal energy, and they generally have very limited time to evaluate non-core topics such as CHP. CHP implementation will lag if relevant information is not readily available, is difficult to comprehend, is subject to change, or if resources are not available to hire outside expertise. Informational barriers include:

- *Awareness of available incentives.* Insufficient knowledge of federal, state and utility incentives and eligibility requirements for CHP projects.
- *Technical knowledge and resource availability.* Lack of in-house technical expertise or the resources to hire outside staff for the design, development, and operation of a CHP system.

Awareness of Available Incentives

A variety of incentive programs can support CHP, through capital cost buy-downs, tax credits, regulatory incentives, utility rates, and other measures. The diversity of such state programs makes it difficult for CHP project developers to be aware of the available incentives. Insufficient awareness of CHP incentives can result in missed opportunities. The New York State Energy Research and Development Authority's (NYSERDA's) FlexTech program (see sidebar)[101] is an example of successful coordination of information on the availability of incentives and technical assistance resources. Many incentive programs are periodically redesigned or funding may be available for only a limited period. To help raise awareness of available incentives and policies that support CHP development, the North Carolina Solar Center and EPA's Combined Heat and Power Partnership have developed databases (see sidebar).[102,103]

NYSERDA FlexTech Program

NYSERDA's FlexTech program provides New York State industrial, commercial, institutional, government, and nonprofits with technical assistance to help them make informed energy decisions. The goal of the FlexTech program is to increase the productivity and economic competitiveness of facilities by identifying and helping assist with the development of certain energy efficiency projects, including CHP. Cost-sharing incentives are available for a range of studies, including CHP project classification studies and industrial process efficiency analysis. For CHP project classification studies, site-specific technical requirements and economic feasibility of installing natural gas–fired CHP are assessed. For energy efficiency and CHP studies, NYSERDA will cost share up to $1 million.

Source: New York State Research and Development Authority. Web

Technical Knowledge and Resource Availability

A 2013 survey found that lack of technical expertise is one of the top barriers to energy efficiency in the United States and Canada.[104] Lack of in-house technical expertise, especially in small- to medium-size companies without sophisticated energy management systems, can limit the ability to evaluate opportunities for CHP and the economic benefits thereof. The complex nature of most industrial facilities means that incorporating a CHP system often requires extensive engineering to integrate them into the facility's energy infrastructure. Specialized experience is needed to conduct the technical assessments to determine the appropriate CHP system size, technology type, and other characteristics required to meet a facility's energy needs.

This design and sizing of CHP installations typically requires an engineer with site design and operational experience. Many industrial companies do not have on-site staff that can devote their full-time attention to assessment and design tasks, and may have to seek outside support, which can add cost and delay to project development. To overcome this, many

CHP Incentive Resources—DSIRE and dCHPP

The Database of State Incentives for Renewables & Efficiency (DSIRE) is operated and funded by the NC Solar Center at NC State University. DSIRE contains information on federal, state, city, utility and other incentive programs and policies to encourage clean energy projects, including CHP. DSIRE contains a program overview and summary information for each incentive program. DSIRE serves as an important resource for project developers, policymakers, and state regulators.

EPA's Combined Heat and Power Partnership developed the CHP Policies and Incentives Database (dCHPP), and contains information on incentives and beneficial policies for CHP. The database allows users to search for policies and incentives at the state or federal level. It contains information on items such as state energy plans that include CHP, utility rate structures favorable to CHP, and grant/loan programs.

Source: North Carolina Solar Center. Web link, and EPA dCHPP. Web link.

Department of Energy CHP Technical Assistance Partnerships (TAPs)

DOE's CHP Deployment Program provides stakeholders with resources necessary to identify CHP market opportunities and supports implementation of CHP systems in industrial, commercial, institutional, and other applications. Site-specific technical assistance is provided by regional CHP Technical Assistance Partnerships (CHP TAPs). The CHP TAPs promote cost-effective CHP, waste heat to power, and district energy with CHP. Services include: market assessments for CHP; education and outreach to provide information on the benefits and applications of CHP to state and local policy makers, regulators, energy end-users, trade associations, and others; and technical assistance, including project screenings and feasibility analyses, for energy end-users and others to help them consider CHP

Source: U.S. Department of Energy. Web link.

industrial companies work with firms that offer a full suite of CHP project services, including design, build, ownership, and operation of a CHP system.

A variety of resources are available through state, federal, and utility programs, which provide information on CHP and guidelines on how to develop a project.[105] However, industrial companies may not be aware of these programs and resources (see DOE CHP Technical Assistance Partnerships [TAPs] sidebar above for an example program that provides CHP support).[106] Several examples of other successful CHP efforts include:

- Executive Order 13624—Accelerating Investment in Industrial Energy Efficiency. This Executive Order, issued in August 2012, sets a national goal of 40 GW of new, cost-effective CHP in the United States by the end of 2020. If the target is met, it will save 1 quad of energy (~1 percent of annual energy consumption in the United States).
- EPA Combined Heat and Power Partnership—The CHP Partnership is a voluntary program that promotes high-efficiency CHP technology to reduce the environmental impact of power generation. The CHP Partnership promotes CHP by fostering cooperative relationships with the CHP industry, state and local governments, and other relevant stakeholders. Accomplishments from 2001 through 2011 include: Assisting more than 640 CHP projects, representing 5,490 MW of new CHP capacity. On an annual basis, these projects will prevent the emission of 14.5 million metric tons of carbon dioxide equivalent.
- Southwest Gas, Inc., provides incentives for CHP projects in Arizona, California, and Nevada. Southwest Gas Key Account Management group has Industrial Gas Engineers who will work with customers or customer consultants to determine the feasibility of a CHP project and prepare economic studies. Southwest Gas also partners with the Southwest CHP Technical Assistance Partnership to promote CHP regionally through outreach efforts.

EU Energy Efficiency Directive—The EU's 2004 CHP Directive has played an important part in the encouragement and recent introduction of CHP incentives across several member states, according to an International Energy Agency report on Cogeneration and District Energy. The Directive establishes general principles for CHP policy but leaves detailed implementation to member states. The purpose of the CHP Directive is to “increase energy efficiency and improve security of supply by creating a framework for promotion and development of high efficiency cogeneration of heat and power based on useful heat demand and primary energy savings” in the internal energy market. As such it covers a number of definitional issues, as well as calculation methodologies and several key areas.[107]

Endnotes

[1] CHP Installation Database, 2014. Database developed by ICF International for Oak Ridge National Laboratory and DOE, Web link.

[2] U.S. Department of Energy and U.S. Environmental Protection Agency, 2012. "Combined Heat and Power: A Clean Energy Solution," Web link.

[3] Ibid.

[4] Bottoming cycle CHP systems can have, in some cases, lower efficiencies than the CHP system efficiency noted of 65 to 80 percent.

[5] Environmental Protection Agency, 2008. "Catalog of CHP Technologies," Web link. The efficiency of a CHP system varies based several factors, including the type of prime mover used. This reference provides efficiencies for several types of CHP systems.

[6] American Gas Association, 2013. "The Opportunity for CHP in the United States," prepared by ICF International. This report shows an efficiency of 49 percent for conventional generation (power plant and on-site boiler) due to recent increases in power plant efficiency and decreases in T&D losses.

[7] U.S. Department of Energy and U.S. Environmental Protection Agency, 2012. "Combined Heat and Power: A Clean Energy Solution," Figure 1, page 7, Web link.

[8] U.S. Environmental Protection Agency, Combined Heat and Power Partnership, Efficiency Benefits, online data, Web link.

[9] A "prime mover" means a type of generating technology.

[10] In the case of fuel cells, the fuel is use to create heat and electricity through a chemical reaction rather than through combustion.

[11] In another version of a topping cycle, fuel is burned in a boiler to produce high-pressure steam. That steam is fed to a steam turbine, generating mechanical power or electricity, before exiting the turbine at lower pressure and temperature and used for process or heating applications at the site.

[12] CHP Installation Database, 2014. Database developed by ICF International for Oak Ridge National Laboratory and DOE, Web link.

[13] Ibid.

[14] U.S. Department of Energy and U.S. Environmental Protection Agency, 2012. "Combined Heat and Power: A Clean Energy Solution," Web link.

[15] Industrial CHP also has specific product benefits. Examples include producing higher-quality metallurgical coke, utilizing CO_2 emissions as fertilizer, and utilizing landfill waste as fuel. See the following report for more information: Vignesh Gowrishankar, Christina Angelides, and Hannah Druckenmiller, April 2013. "Combined Heat and Power Systems: Improving the Energy Efficiency of Our Manufacturing Plants, Buildings, and Other Facilities," Natural Resources Defense Council, Web link.

[16] U.S. Department of Energy and U.S. Environmental Protection Agency, 2012. "Combined Heat and Power: A Clean Energy Solution," Web link.

[17] ICF, 2013. "Combined Heat and Power: Enabling Resilient Energy Infrastructure for Critical Facilities," prepared for Oak Ridge National Laboratory, Web link.

[18] The technical market potential is an estimation of market size constrained only by technological limits—the ability of CHP technologies to fit existing customer energy needs. The technical potential includes sites that have

the energy consumption characteristics that could apply CHP. The technical market potential does not consider screening for other factors such as ability to retrofit, owner interest in applying CHP, capital availability, fuel availability, and variation of energy consumption within customer application/size classes. All of these factors affect the feasibility, cost, and ultimate acceptance of CHP at a site and are critical in the actual economic implementation of CHP.

[19] Executive Order 13624, 2012. "Accelerating Investment in Industrial Energy Efficiency," Web link.

[20] U.S. Department of Energy and U.S. Environmental Protection Agency, 2012. "Combined Heat and Power: A Clean Energy Solution," Web link.

[21] Cogeneration & On-Site Power Production, 2012. "CHP Project Finance More than Just Money," Web link.

[22] Institute for Building Efficiency, 2013. "2013 Energy Efficiency Indicator Survey," Web link.

[23] Environmental and Energy Study Institute, May 2013. "How Combined Heat and Power Saves Money, Reduces Emissions and Improves Energy Security," Robert Araujo, Manager for Sustainable Development and Environment Health & Safety, Sikorsky Helicopter, Web link.

[24] The Economist, 2013. "Coming Home—a growing number of American companies are moving their manufacturing back to the United States," Web link. This article discusses several factors that are driving re-shoring. These factors include: (1) wages in some countries other than the United States have increased significantly, decreasing or eliminating the labor cost differential between the United States and other countries; (2) natural gas prices are relatively low in the United States and are expected to remain stable for several years; and (3) manufacturing in the United States can avoid transportation costs associated with shipping raw materials or subcomponents overseas for integration into finished products.

[25] McKinsey & Company, 2009. "Unlocking Energy Efficiency in the U.S. Economy," Web link.

[26] Northeast-Midwest Institute. "Financing Combined Heat and Power: Techniques for Addressing Barriers and Opportunities." Web link.

[27] James, A., April 2013. "How Do We Reverse the Drop in Combined Heat and Power Use?" Web link.

[28] Ibid.

[29] HM Revenue & Customs, 2014. Carbon Price Floor, Web link.

[30] The Pew Charitable Trusts, 2013. "Expanding Investment Opportunities for Clean Energy: Master Limited Partnerships and Real Estate Investment Trusts," Web link.

[31] American Council for an Energy-Efficient Economy, 2013. "Financing Industrial Energy Efficiency & CHP," prepared for the National Governors Association Policy Academy, Web link

[32] Library of Congress, 2014. Bill Summary & Status, 113th Congress (2013–2014), H.R. 1696, Web link.

[33] American Council for an Energy-Efficient Economy (ACEEE), 2013. "Financing Industrial Energy Efficiency & CHP," prepared for the National Governors Association (NGA) Policy Academy," Web link.

[34] F. Mormann and D. Reicher, June 2012. "How to Make Renewable Energy Competitive," The New York Times, Web link.

[35] The IRS defines CHP as follows - Combined heat and power system property is property that uses the same energy source for the simultaneous or sequential generation of electrical power, mechanical shaft power, or both; in combination with the generation of steam or other forms of useful thermal energy (including heating and cooling applications); the energy efficiency percentage of which exceeds 60 percent; and it produces: 1) At least 20 percent of its total useful energy in the form of thermal energy that is not used to produce electrical or mechanical

power (or a combination thereof), and 2) At least 20 percent of its total useful energy in the form of electrical or mechanical power (or a combination thereof).

[36] Bonus depreciation is a method of accelerated depreciation, which allows a business to make an additional deduction of 50% of the cost of qualifying property in the year in which it is put into service. Depreciation is a reduction in the value of an asset with the passage of time.

[37] S. Nadel, and K. Farley, February 2013. "Tax Reforms to Advance Energy Efficiency," American Council for an Energy Efficient Economy (ACEEE), Web link.

[38] Heat is Power (HIP), April 2013. "Comments: Energy Tax Reform" Submitted to the House Ways and Means Tax Reform Working Group on Energy. Web link.

[39] ICF International, October 2010. "Effect of a 30 Percent Investment Tax Credit on the Economic Market Potential for Combined Heat and Power," prepared for the World Alliance for Decentralized Energy (WADE), Web link.

[40] State and Local Energy Efficiency Action Network, March 2013. "Guide to the Successful Implementation of State Combined Heat and Power Policies, Appendix D: Capacity and Ancillary Service Markets: How CHP can Participate," Web link.

[41] State and Local Energy Efficiency Action Network, March 2013. "Guide to the Successful Implementation of Combined Heat and Power Policies," Web link.

[42] Congress passed PURPA in 1978, codified at 16 U.S.C. § 824a-3.

[43] State and Local Energy Efficiency Action Network, March 2013. "Guide to the Successful Implementation of Combined Heat and Power Policies," Web link, page xi.

[44] Texas Combined Heat & Power Initiative, May 2013. "Texas Legislature Passes New Energy Policy to Support Cogeneration," Web link.

[45] U.S. DOE, January 2009. "The Effect of Private Wire Laws on Development of Combined Heat and Power Facilities," Web link.

[46] Some industry stakeholders note that the sale of excess power to third parties may incentivize industrial customers or third party developers to oversize the CHP electric capacity, which can reduce overall CHP system efficiency. Overall project economics drive the project size, including efficiency, emissions requirements and payback.

[47] State and Local Energy Efficiency Action Network, March 2013. "Guide to the Successful Implementation of State Combined Heat and Power Policies," Appendix E: Revision of Utility Franchise Regulations to Allow Non-Utility CHP to Serve Neighboring Loads, Web link.

[48] California has departing load charges applicable to CHP. See ICF International, May 2013, "The Effects of Departing Load Charges on the Costs and Benefits of Combined Heat and Power," prepared for California Clean DG Coalition, Web link.

[49] Regulatory Assistance Project, 2011. "Electricity Regulation in the U.S.: A Guide," Web link.

[50] U.S. Environmental Protection Agency, 2006. "Clean Energy-Environment Guide to Action". Web link, Chapter 6.

[51] American Council for an Energy-Efficient Economy, July 2013. "How Electric Utilities Can Find Value in CHP," Web link.

[52] State and Local Energy Efficiency Action Network, March 2013. "Guide to the Successful Implementation of Combined Heat and Power Policies," Web link, pages 46–47.

[53] Regulatory Assistance Project, 2011. "Electricity Regulation in the U.S.: A Guide," Web link.

Industrial Energy Efficiency, July 2013. "State Electric Efficiency Regulatory Frameworks," Web link.

[54] Linvill, C., Lazar, J., and Shenot, J., November 2013. "Designing Distributed Generation Tariffs Well: Fair Compensation in a Time of Transition," Regulatory Assistance Project, Web link.

[55] National Action Plan for Energy Efficiency, "Aligning Utility Incentives with Investment in Energy Efficiency," 2007, Web link.

[56] American Council for an Energy-Efficient Economy, 2013. "Overcoming Market Barriers and Using Market Forces to Advance Energy Efficiency," Report No. E136, Web link.

[57] U.S. Environmental Protection Agency, 2011. "Output-Based Environmental Regulations: An Effective Policy to Support Clean Energy Supply," Web link.

[58] Ibid.

[59] National Action Plan for Energy Efficiency, "Aligning Utility Incentives with Investment in Energy Efficiency," 2007, Web link.

[59] EPA Combined Heat and Power Partnership, February 2013. "Accounting for CHP in Output-Based Regulations," Web link.

[60] Executive Order 13624, 2012. "Accelerating Investment in Industrial Energy Efficiency," Web link.

[61] Oak Ridge National Laboratory, 2008. "Combined Heat and Power: Effective Energy Solutions for a Sustainable Future," Web link.

[62] Connecticut Department of Energy & Environmental Protection, 2012. "New Source Review Permit, Frito-Lay, Inc., Dayville Facility," Web link.

[63] U.S. Department of Energy, 2011. Combustion Turbine CHP System for Food Processing Industry, Web link.

[64] Database of State Incentives for Renewables & Efficiency, 2013. Interconnection Standards, Web link.

[65] State and Local Energy Efficiency Action Network, March 2013. "Guide to the Successful Implementation of Combined Heat and Power Policies," Web link, page 16.

[66] Ibid.

[67] Database of State Incentives for Renewables & Efficiency, 2012. "Interconnection Standards for Small Generators," Web link.

[68] Federal Energy Regulatory Commission, 2013. "Standard Interconnection Agreements & Procedures for Small Generators," Web link.

[69] Ibid.

[70] Oak Ridge National Laboratory, 2008. "Combined Heat and Power Effective Energy Solutions for a Sustainable Future," Web link.

[71] These values correspond to national averages. There are regional differences in grid emissions, and these regional differences will influence CHP results in specific regions.

[72] Ibid.

[73] The full value of CHP includes many of the benefits identified in Lazar, J., and Colburn, K., September 2013. "The Full Value of Energy Efficiency," Regulatory Assistance Project, Web link; and Linvill, C., Lazar, J., and Shenot, J., November 2013. "Designing Distributed Generation Tariffs Well," Regulatory Assistance Project, Web link.

[74] U.S. Environmental Protection Agency, December 2009. "Standby Rates for Customer-Sited Resources—Issues, Considerations, and the Elements of Model Tariffs," Web link.

[75] In restructured States, the utility may provide only delivery services and provider-of-last-resort energy service.

[76] State and Local Energy Efficiency Action Network, March 2013. "Guide to the Successful Implementation of Combined Heat and Power Policies," Web link, pages 7–8.

[77] Ibid, pages 7–8.

[78] Some fixed costs may be recovered through variable energy charges.

[79] In restructured markets, generation-related costs are not recovered in regulated revenue requirements, but in market-based supply prices.

[80] State and Local Energy Efficiency Action Network, March 2013. "Guide to the Successful Implementation of Combined Heat and Power Policies," Web link, pages 9–10.

[81] State and Local Energy Efficiency Action Network, March 2013. "Guide to the Successful Implementation of State Combined Heat and Power Policies," Web link.

[82] State and Local Energy Efficiency Action Network, March 2013. "Guide to the Successful Implementation of State Combined Heat and Power Policies," Web link.

[83] Cost causation is the principle that cost should be borne by those who cause them to be incurred. Alt, L.E., 2006. "Energy Utility Rate Setting," Web link.

[84] A "full requirements customer" typically means a customer that relies on the utility for all power needed to supply its total load requirement. A "partial requirements customer" often means a customer who normally self-generators all, or a portion of, its electrical and energy needs. Partial requirements customers usually need backup and optional electric service.

[85] Selecky, J., Iverson, K., and Al-Jabar, A., February 2014. "Standby Rates for Combined Heat and Power Systems: Economic Analysis and Recommendations for Five States," Oak Ridge National Laboratory and the Regulatory Assistance Project, Web link.

[86] Some organizations note that limiting standby charges to only an "as-used" basis can lead to an imbalance, shifting fixed costs to non-CHP customers. Utilities need to be able to recover costs associated with a number of items such as reductions in the consumer base over which distribution capital investments and regional transmission charges can be spread; changes in planning for transmission and distribution capacity expansion resulting from CHP; required system upgrades due to CHP; impacts of CHP on utility's load profile; and additional distribution system fault protection and emergency repairs due to CHP. Utilities may have stranded costs if they cannot collect for investments made to meet the capacity needs of the customer regardless of how often the need arises.

[87] Clean energy portfolio standards can have a variety of names, such as renewable portfolio standards, alternative energy portfolio standards, energy efficiency resource standards, advanced energy portfolio standards, energy efficiency performance standards, and renewable energy standards. This study uses the umbrella term "clean energy portfolio standards" to capture this suite of policies.

[88] U.S. Environmental Protection Agency, 2006. "Clean Energy-Environment Guide to Action," Chapter 5, Energy Supply Actions, Web link.

[89] Berger, D., November 2013. "Massachusetts Incentives for Combined Heat and Power, Mass Save Energy Efficiency Incentives and the Alternative Portfolio Standard," Web link.

[90] Massachusetts Office of Energy and Environmental Affairs, December 2013. "Patrick Administration Announces Results of Three-Year Statewide Energy Efficiency Plans," Web link.

[91] Ibid.

Database of State Incentives for Renewables and Efficiency, November 2012. "Massachusetts, Energy Efficiency Fund," Web link.

Massachusetts Office of Energy and Environmental Affairs, December 2013. "Patrick Administration Announces Results of Three-Year Statewide Energy Efficiency Plans," Web link.

[92] International District Energy Association.

[93] State and Local Energy Efficiency Action Network, March 2013. "Guide to the Successful Implementation of Combined Heat and Power Policies," Web link, page 35.

[94] U.S. Department of Energy and North Carolina Solar Center, 2014. "Database of State Incentives for Renewables and Efficiency," Web link.

U.S. Environmental Protection Agency, Combined Heat and Power Partnership, March 2013. "Portfolio Standards and the Promotion of Combined Heat and Power," Web link.

[95] A "reserve margin" is a measure of extra generating power during peak loads (e.g., hot summer days) and incidents when power plants are forced to shut down. A reserve margin provides protection against brownouts and blackouts. A typical desired reserve margin is 15 percent.

[96] Wellinghoff, J., October 2009. "Remarks of FERC Chairman Jon Wellinghoff CAISO Stakeholder Symposium," Web link.

[97] ISO New England, Web link.

[98] Pentland, W., May 2012, Forbes Magazine. "Dirty Bums, Clean Energy and the Battle over Demand Response," Web link.

[99] State and Local Energy Efficiency Action Network, March 2013. "Guide to the Successful Implementation of State Combined Heat and Power Policies, Appendix D: Capacity and Ancillary Service Markets: How CHP can Participate," Web link.

[100] Bottoming cycle, meaning WHP projects are based on available waste heat and not the thermal demands of the site. This explanation, and others in the document apply exclusively to topping-cycle CHP systems and not WHP.

[101] New York State Research and Development Authority, 2014. "FlexTech Program," Web link.

[102] North Carolina Solar Center, 2014. "Database of State Incentives for Renewables and Efficiency (DSIRE)," Web link.

[103] U.S. Environmental Protection Agency, Combined Heat and Power Partnership, 2014. "dCHPP (CHP Policies and Incentives Database)," Web link.

[104] Institute for Building Efficiency, 2013. "2013 Energy Efficiency Indicator Survey," Web link.

[105] CHP programs include DOE's Technical Assistance Partnerships, Web link; EPA's CHP Partnership, Web link; and NYSERDA's CHP Performance Program, Web link.

[106] U.S. Department of Energy, 2014. "CHP Technical Assistance Partnerships," Web link.

[107] Gas to Power Journal, April 2013. "EU CHP Directive and National Policies Encourage Cogeneration in Europe," Web link.

6. Economic Benefits of Energy Efficiency Grants

The Act requests the development of estimated economic benefits from Federal energy efficiency matching grants. The specific language is:[1]

> *[… shall conduct a study of …the] estimated economic benefits to the national economy of providing the industrial sector with Federal energy efficiency matching grants of $5,000,000,000 for 5- and 10-year periods, including benefits relating to—*
>
> *i. Estimated energy and emission reductions;*
> *ii. Direct and indirect jobs saved or created;*
> *iii. Direct and indirect capital investment;*
> *iv. The gross domestic product; and*
> *v. Trade balance impacts.*

This chapter discusses estimated economic benefits, including the assumptions and approach used to derive these estimates. This chapter is organized as follows:

- Section 6.1—Assumptions
- Section 6.2—Approach
- Section 6.3—End-Use Energy Efficiency and Demand Response
- Section 6.4—CHP
- Section 6.5—Summary

6.1 Assumptions

To develop estimates of economic benefits, assumptions are required to establish a framework for the analysis. These framework assumptions are shown in **Table 11** along with a brief discussion of the rationale for each assumption. These framework assumptions describe the foundation for the economic analysis that estimates benefits to the national economy from a $5 billion dollar Federal matching grant program. As described in the assumptions, the Federal grant funds will be leveraged with 80 percent cost sharing from participants, resulting in a total funding pool of $25 billion ($5 billion Federal, $20 billion participant). The $25 billion dollar funding pool will be used to deploy end-use energy efficiency, demand response, and CHP technologies in the manufacturing sector.

As noted, 100 percent of the funds for this hypothetical grant program are used for deployment of commercially available technologies. In practice, an actual grant program could also allocate funds for related activities that stimulate industrial energy efficiency. For example, a modest

percentage of funding could be allocated for marketing and outreach, and also for research and development, while preserving the majority of grant funds for deployment.

Table 11. Economic Analysis Framework Assumptions

Assumption	Rationale
1. $5 billion of Federal funds are spread equally over 10 years (i.e., $500 million per year for 10 years).	Subpart 7(b)(2)(C) of the Act specifies $5 billion of Federal matching grants, with an implied time frame of 10 years. A prescribed allocation of funding between years is not provided. For the economic analysis, it is assumed that the funding is allocated equally across a 10-year period.
2. Estimates are developed for the national economy.	The national economy is specified in Subpart 7(b)(2)(C) of the Act. For the economic analysis, the entire United States is treated as one region. Estimates are not developed at a more granular level (e.g., state by state).
3. Grant funds are used to support end-use energy efficiency, demand response, and CHP.	Energy efficiency, demand response, and CHP are all identified in Subpart 7(a)(1) of the Act. Subpart 7(b)(2)(A) provides additional guidance, which suggests that on-site power generation (e.g., CHP) is of particular interest for this study. Subpart 7(a)(1) calls out waste heat recovery. In the context of this study, waste heat recovery is limited to waste heat to power (WHP), and included with CHP (CHP bottoming cycles are a form of (WHP).
4. Funds are used for deployment projects. Funds are not used for research and development or demonstration projects.	Subpart 7(b) of the Act specifies that the focus is deployment of industrial energy efficiency. For the economic analysis, deployment projects are interpreted to use commercially available, or near commercial, technologies.
5. Funds support projects in the manufacturing sector (NAICS codes 31–33).	This assumption is consistent with Subpart 7(a)(2) of the Act.
6. Participant cost share is 80 percent	Subpart 7(b)(2)(C) states that the Federal funds will be provided as matching grants, but no matching ratio is provided for expected participant cost sharing. For the economic analysis, the participant cost sharing is assumed to be 80 percent (rationale for cost sharing is discussed below).
7. Funds are split 50 percent for CHP and 50 percent for End-Use Energy Efficiency/Demand Response	The Act does not specify how the funds should be allocated between technologies. The language in Subpart 7(b)(2)(A) suggest that that there is a focus on power generation and based on this language 50 percent of the funds are assumed to support CHP deployment. The remaining 50 percent is allocated to deployment of end-use energy efficiency and demand response. For the economic analysis, energy efficiency and demand response are combined into a single group (rationale for combining end-use energy efficiency and demand response is discussed below).

6.1.1 80 percent Cost Sharing from Participants (Assumption 6 in **Table 11**)

The required participant cost share is typically proportional to the maturity level of the technology. A simplified maturity path for a product may start with fundamental research and development, followed by laboratory testing, prototype development, field testing and demonstration, and finally commercial deployment. For early stage research and development, little or no participant cost share may be required. As technologies mature and approach commercialization, cost sharing requirements generally increase. Guidelines from the U.S. DOE state that the minimum cost share for demonstration and commercial projects is 50 percent.[2] The economic analysis in this study is focused on deployment projects, which are viewed as established commercially available products. Deployment projects are beyond the demonstration phase and it would be reasonable to set the required participant cost share above the minimum DOE guideline of 50 percent for these commercially available technologies. For the economic analysis described in this chapter, the participant cost share is assumed to be 80 percent of the total project cost.

For comparison, an analysis based on 50 percent participant cost share is described in **Appendix B**. As the participant cost share declines the overall beneficial impacts to the U.S. economy decrease. These results indicate that to maximize the benefits of a Federal grant program, it is advantageous to leverage Federal funds to the maximum extent possible. The 80 percent participant cost share scenario is viewed as a reasonable leveraging level that will stimulate the deployment of commercially available industrial energy efficiency technologies along the technology development curve.

6.1.2 Combined End-Use Energy Efficiency and Demand Response (Assumption 7 in **Table 11**)

For the purposes of this study, end-use energy efficiency technologies and demand response technologies are grouped into a single category. As stated in Chapter 4, the distinction between energy efficiency and demand response can be blurry, and the two combined could be considered a continuum in terms of customer impacts and energy grid benefits. Innovations in energy efficiency technologies are moving towards devices or systems that are demand response enabled. A demand response-enabled technology includes integration of features and software that allow the device to be more easily operated as a demand response resource. For example, a manufacturing plant may be interested in utilizing electric chiller cycling to participate in a utility demand response program. If the manufacturing plant replaces an old inefficient chiller with a modern energy efficient chiller that is demand response-enabled, this new chiller can be relatively easily configured as a demand response resource. The manufacturing plant can determine whether to retain internal control of the chiller in response to demand response events, or allow utility control (auto-demand response) in response to

events. In either case, a demand response-enabled technology provides flexibility and ease-of-use advantages to the manufacturing plant.

6.2 Approach

Based on the assumptions shown in **Table 11**, the total funding pool amounts to $25 billion over a 10-year period. These funds are divided equally among the years and equally between the end-use energy efficiency/demand response technologies and the CHP technologies, which results in an annual funding amount of $1.25 billion for each technology category.

An Excel model was created to estimate energy and emission impacts derived from deploying technologies consistent with the funding pool described in **Table 12**. IMPLAN, which is a commercially available regional economic impact model, was used to estimate economic impacts such as on jobs and gross domestic product.

Table 12. Total Funding for Energy Efficiency/Demand Response and CHP

Description		Technology		Total
		Energy Efficiency/Demand Response	CHP	
Federal Funds	($ billion)	$2.5	$2.5	**$5.0**
	(percent of total project cost)	20%	20%	**20%**
Participant Cost Share	($ billion)	$10.0	$10.0	**$20.0**
	(percent of total project cost)	80%	80%	**80%**
TOTAL	($ billion)	$12.5	$12.5	**$25.0**
	($ billion/year)	$1.25	$1.25	**$2.5**

Note: Unless indicated otherwise, all monetary values are expressed in 2012 dollars.

6.2.1. Approach for Estimating Energy and CO_2 Impacts

Using an Excel model, estimates were developed for energy and CO_2 emissions impacts from end-use energy efficiency/demand response and CHP technologies deployed in all manufacturing subsectors (as defined by 3-digit NAICS codes). The energy consumption patterns (e.g., levels of energy, electricity, and fuel consumption) and energy prices for each group differ, and estimating the impacts at the subsector level provides a clearer understanding of the results. Thus, the Federal grant funds were distributed by industry group based on factors such as number of establishments, electricity use, and fuel loads.

Although the approach used to estimate energy and CO_2 impacts of the end-use energy efficiency/ demand response and CHP technologies is generally similar, there are differences in the methodology. The CHP technology characteristics are relatively well defined, and it was therefore possible to evaluate CHP impacts at the technology level. The end-use energy

efficiency/demand response measures are less defined for the purposes of this study, and calculations were completed with higher level assumptions compared to the CHP analysis. Further information on how the calculations were completed is discussed in the sections that follow with supporting material in **Appendix C** (end-use energy efficiency and demand response) and **Appendix D** (CHP).

6.2.2 Approach for Estimating Jobs and GDP Impacts

The IMPLAN model was used to estimate employment and gross domestic product (GDP) impacts. The IMPLAN model, developed and maintained by the Minnesota IMPLAN Group (MIG), is an economic model for the U.S. economy based on input-output relationships of various sectors. The model divides the economy into 440 NAICS-based sectors, including 278 manufacturing sectors (NAICS codes 31–33). In this study, costs of CHP and end-use energy efficiency/demand response scenarios were calculated exogenously and used as inputs to IMPLAN. Using these inputs, IMPLAN generates impacts on GDP, jobs, household incomes, and tax impacts across the 440 economic sectors. Additional details are included in **Appendix E**.

6.3 End-Use Energy Efficiency and Demand Response

The economic benefits of investing $12.5 billion over a 10-year period to deploy end-use energy efficiency and demand response technologies was completed using the following steps:

1) The portfolio of end-use energy efficiency/demand response technologies was assumed to have an average payback of 2½ years. With 20 percent of the installed capital cost covered by Federal matching grants, the payback is reduced to 2 years for manufacturing sites that implement these technologies.
2) Three end-use energy efficiency/demand response scenarios were evaluated (see
3) **Table** 13):
    - **Scenario 1**: 80 percent of available funds used to deploy natural gas end-use technologies, and 20 percent used to deploy electric end-use technologies.
    - **Scenario 2**: 50 percent of available funds used to deploy natural gas end-use technologies, and 50 percent used to deploy electric end-use technologies.
    - **Scenario 3**: 20 percent of available funds used to deploy natural gas end-use technologies, and 80 percent used to deploy electric end-use technologies.
4) Energy and emission impacts were estimated with an Excel model. Estimates of jobs, gross domestic product, and trade impacts were completed with IMPLAN.

Table 13. Funding for Energy Efficiency/Demand Response Scenarios

Description		Scenario		
		1	2	3
Total Funding for End-Use Energy Efficiency/Demand Response Measures	($ billion)	$12.5	$12.5	$12.5
Share for Electric Measures	(percent)	20%	50%	80%
	($ billion)	$2.5	$6.25	$10.0
Share for Fuel Measures (natural gas)	(percent)	80%	50%	20%
	($ billion)	$10.0	$6.25	$2.5

6.3.1 Energy and Emission Impacts

The Excel model used for energy and emission impacts was constructed as follows:

1) The total electricity and fossil fuel (natural gas, petroleum, coal) expenditures were developed for each industry (following 3-digit NAICS code aggregation). Cost estimates include heat and power and non-fuel (feedstocks) uses (see **Table 43** in **Appendix C**).

2) The fuel and electricity funds were further allocated by industry group (3-digit NAICS aggregation) according to total fuel and electricity consumption, respectively. **Table 44** and **Table 45** in **Appendix C** show the allocation of the funds by industry group, for electricity and fuel end-use energy efficiency/demand response measures, respectively.

3) Given the assumed 2½-year simple payback, energy savings are calculated. To estimate the impacts on energy savings, energy prices were differentiated by industry group. Manufacturing facilities and companies incur different energy prices driven by location (areas with abundant energy supply tend to have lower prices) and energy demand loads (larger users tend to enjoy lower prices). **Table 46** in **Appendix C** shows the energy price assumptions. Energy savings are presented as delivered energy savings and end-use energy savings (see definitions below). To estimate the end-use energy savings, fuel inputs for electricity generation (at central stations) are incorporated. **Appendix F** shows how the end-use energy factors, which are used to estimate end-use energy savings, were calculated. This appendix also contains information on calculation CO_2 emissions associated with the electric grid.

4) To calculate CO_2 emissions saved, a fuel combustion CO_2 emissions factor was estimated for each industry group, based on its fuel mix and use of feedstocks (which is assumed to have zero CO_2 emissions). **Table 47** in **Appendix C** shows the CO_2 emissions factors used by industry group.

In this chapter, energy results are expressed in terms of delivered energy and end-use energy. These terms are consistent with the EIA definitions discussed in Chapter 2, and summarized below:

- *Delivered energy (also referred to as site energy).* Delivered energy is the amount of energy consumed at the point of use. In practical terms, delivered energy is the amount of energy purchased by an industrial site.
- *End-use energy (also referred to as source energy).* End-use energy is delivered energy plus electricity system losses that occur during generation, transmission and distribution. Electricity losses are allocated to each end-use sector in proportion to the amount of electricity consumed by each sector

Results for All Three Scenarios

This section presents the results for energy use, energy cost savings, and CO_2 emissions reductions from investments in end-use energy efficiency/demand response technologies. Note that energy use in this section refers to delivered energy use (refer to Section 2.1.1 for definition).

Table 14 summarizes the results of the energy efficiency/demand response measures. These results are discussed in the sections that follow.

Table 14. Summary Results for End-Use Energy Efficiency/Demand Response Measures

Description	Scenario		
	1	2	3
Funding ($ billion)			
Electricity Measures	$2.5	$6.25	$10.0
Fuel Measures	$10.0	$6.25	$2.5
TOTAL	$12.5	$12.5	$12.5
Delivered Energy Savings (TBtu/yr)			
Electricity	52	129	207
Fuel	591	369	148
TOTAL [(a)]	642	499	355
End-Use Energy Savings (TBtu/yr)			
Electricity [(b)]	150	375	601
Fuel	591	369	148
TOTAL [(a)]	741	744	748
Energy Cost Savings ($ billion/yr)			
Electricity	$1.0	$2.5	$4.0
Fuel	$4.0	$2.5	$1.0
TOTAL	$5.0	$5.0	$5.0
CO_2 Emissions Reduction (million metric tons/yr)			
TOTAL	36.9	47.3	57.6

Notes: a) Sums may differ due to rounding.

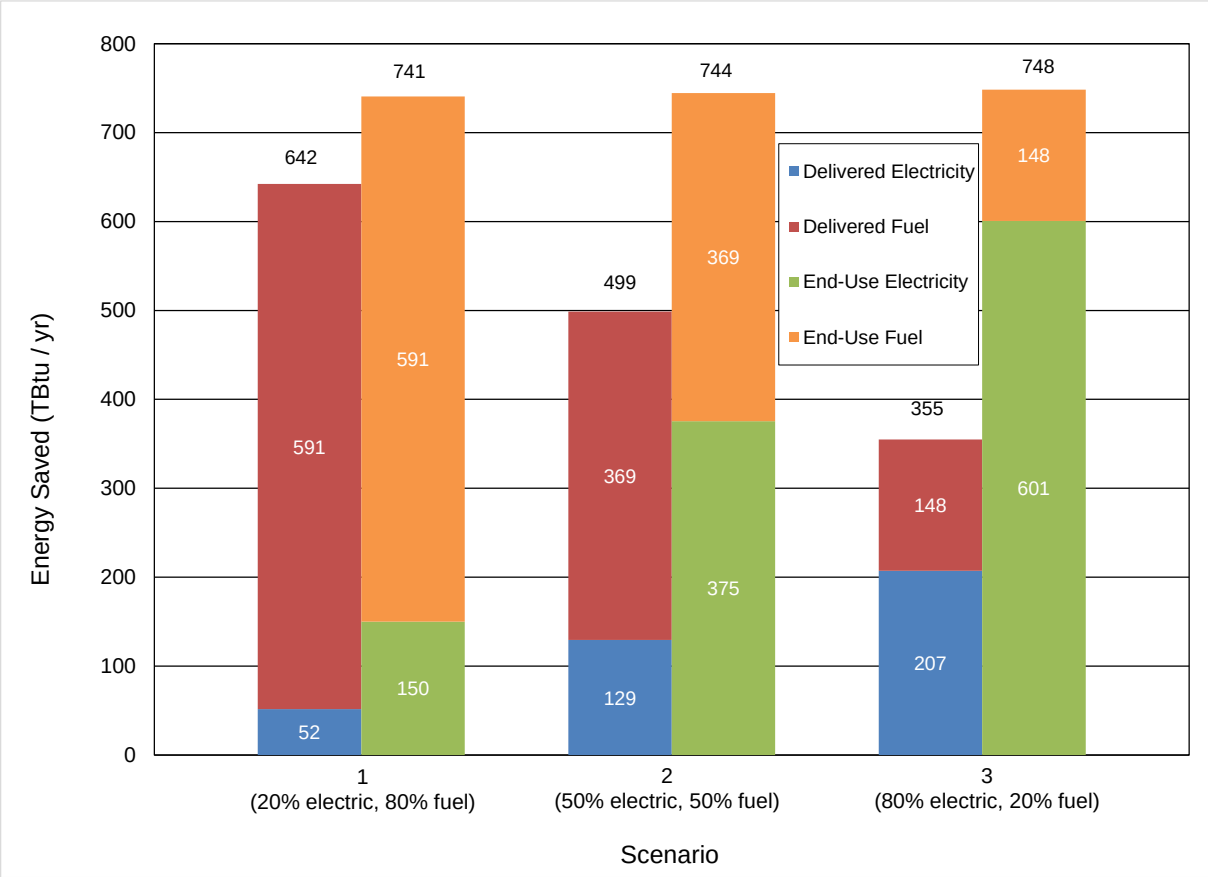
b) See Appendix F for conversion between delivered electricity and end-use electricity.

Energy Savings

As indicated previously, end-use (or source) energy accounts for energy losses that occur during the generation of electricity at central power plants, and transmission and distribution losses that occur during electricity delivery. Delivered (or site) energy only accounts for the energy consumed on-site at industrial plants.

Figure 29 shows annual delivered and end-use energy savings for each of the three scenarios. As indicated, Scenario 1 results in the largest delivered energy savings. The delivered energy savings for Scenario 1 are 642 TBtu, followed by Scenario 2 (499 TBtu) and Scenario 3 (355 TBtu). Total end-use energy savings are relatively constant across all three scenarios, ranging from 741 TBtu in Scenario 1 to 748 TBtu in Scenario 3.

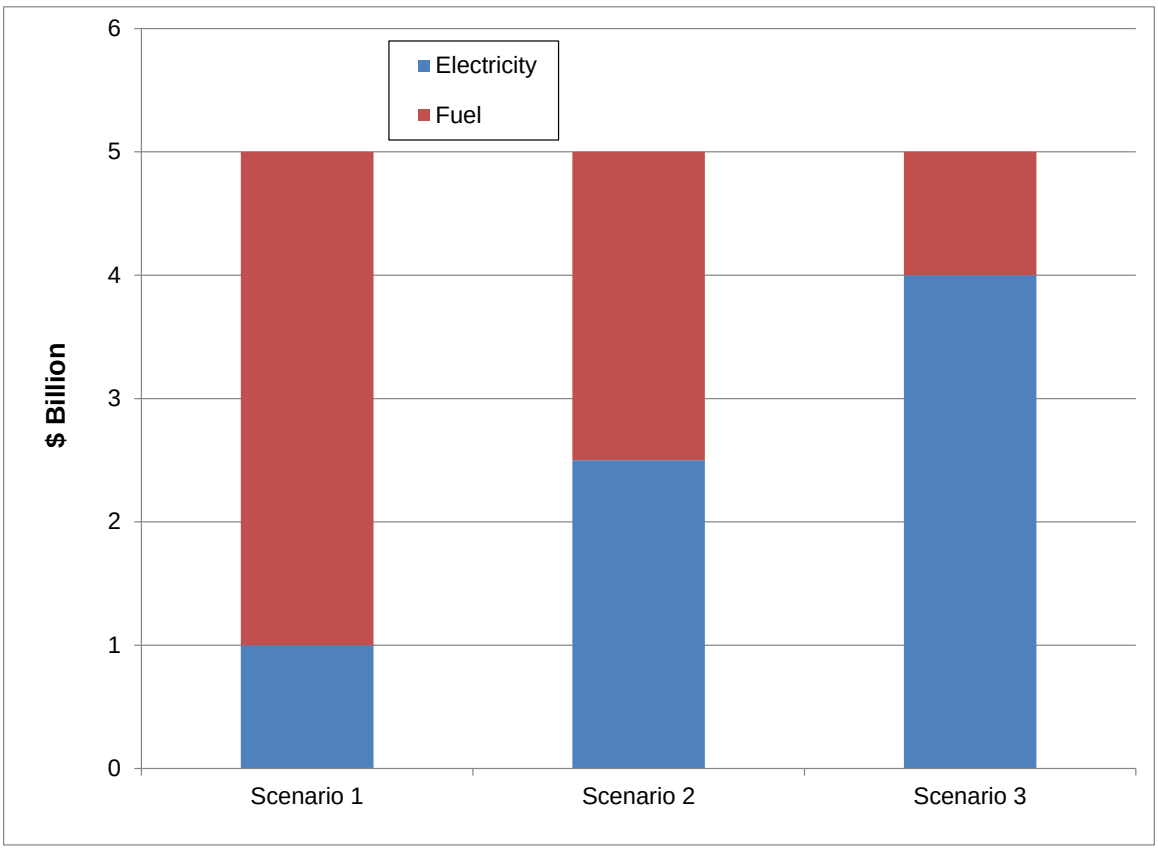
Figure 29. Total Annual Energy Savings (end-use energy efficiency/demand response measures)



Energy Cost Savings

Figure 30 shows energy costs savings for each of the three scenarios. As indicated, the total savings are equivalent for all scenarios. This outcome is a direct result of setting the average payback at 2½ years for the entire portfolio of measures. The savings split between fuel and electricity follows the assumptions used for each scenario. Scenario 1 saves 80 percent in fuel costs ($4 billion) and 20 percent in electricity costs ($1 billion). Scenario 2 saves 50 percent in fuel and 50 percent in electricity ($2.5 billion each). Scenario 3 saves 20 percent in fuel costs ($1 billion) and 80 percent in electricity costs ($4 billion).

Figure 30. Total Energy Cost Savings (end-use energy efficiency/demand response measures)

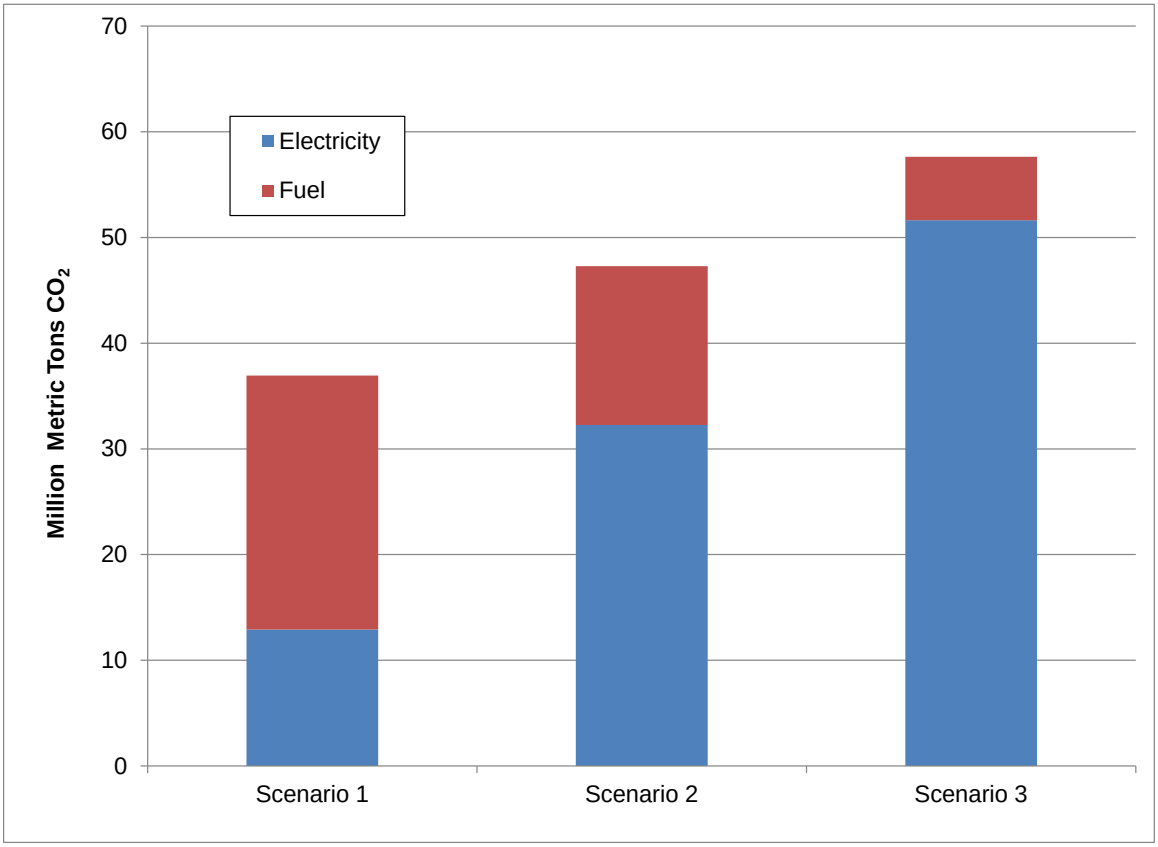


CO_2 Reductions

Figure 31 presents a summary of the CO_2 emissions reduction results for each of the three scenarios. The figure shows that total CO_2 emissions reductions are largest in Scenario 3 (59 million metric tons of CO_2), followed by Scenario 2 (48 million metric tons of CO_2), and Scenario 1 (38 million metric tons of CO_2). For Scenario 2 and Scenario 3, electricity CO_2 emissions

reductions account for the largest reduction. Scenario 1 shows fossil fuel emissions accounting for the largest reduction.

Figure 31. Total CO_2 Emissions Reduction (end-use energy efficiency/demand response measures)

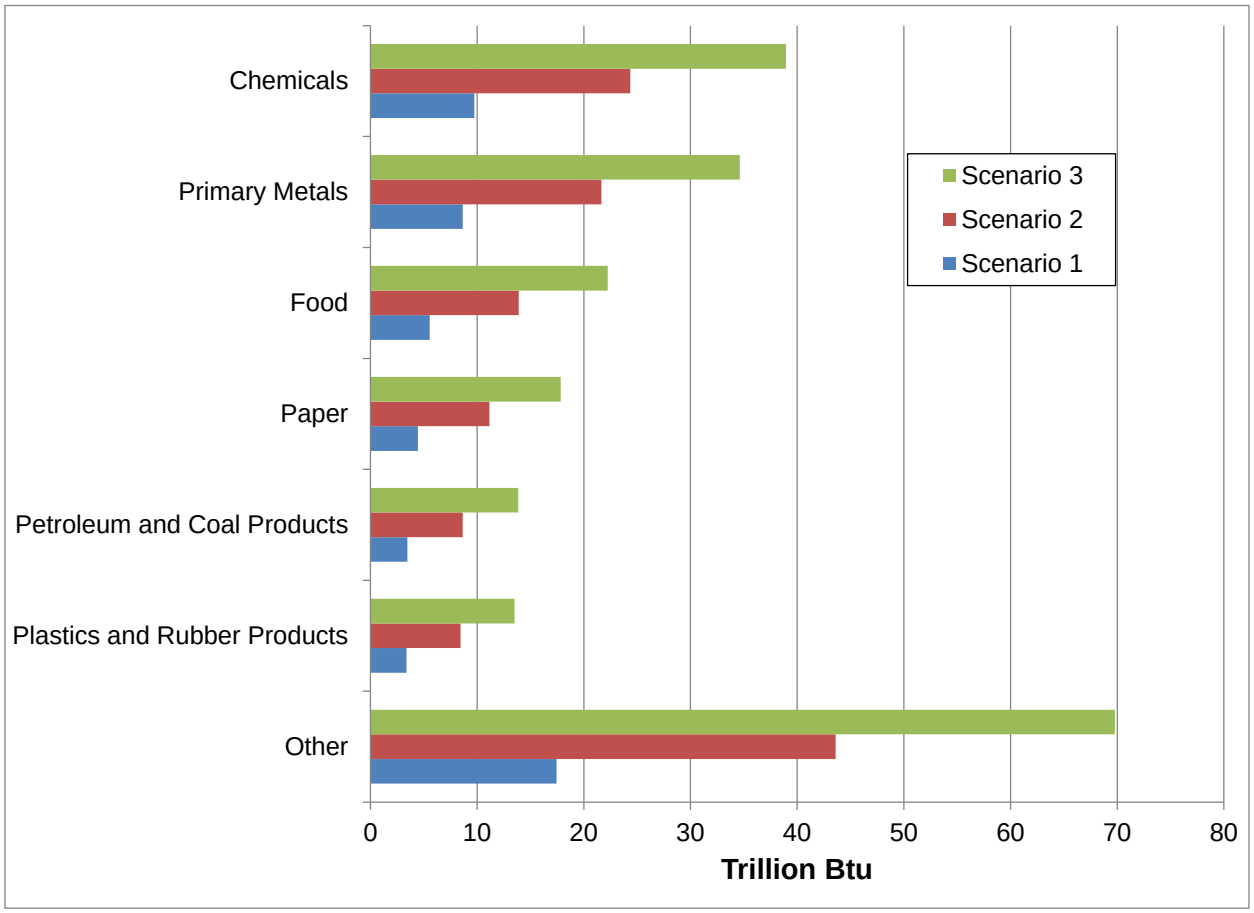


<u>Comparison of Results between Manufacturing Subsectors</u>

<u>Delivered Electric Energy Savings</u>

The results by industry subsector are presented in the figures that follow. **Figure 32** shows that the chemical industry has the largest delivered electricity savings across all three scenarios, followed by primary metals, food, paper, petroleum refining, and plastic and rubber, respectively.

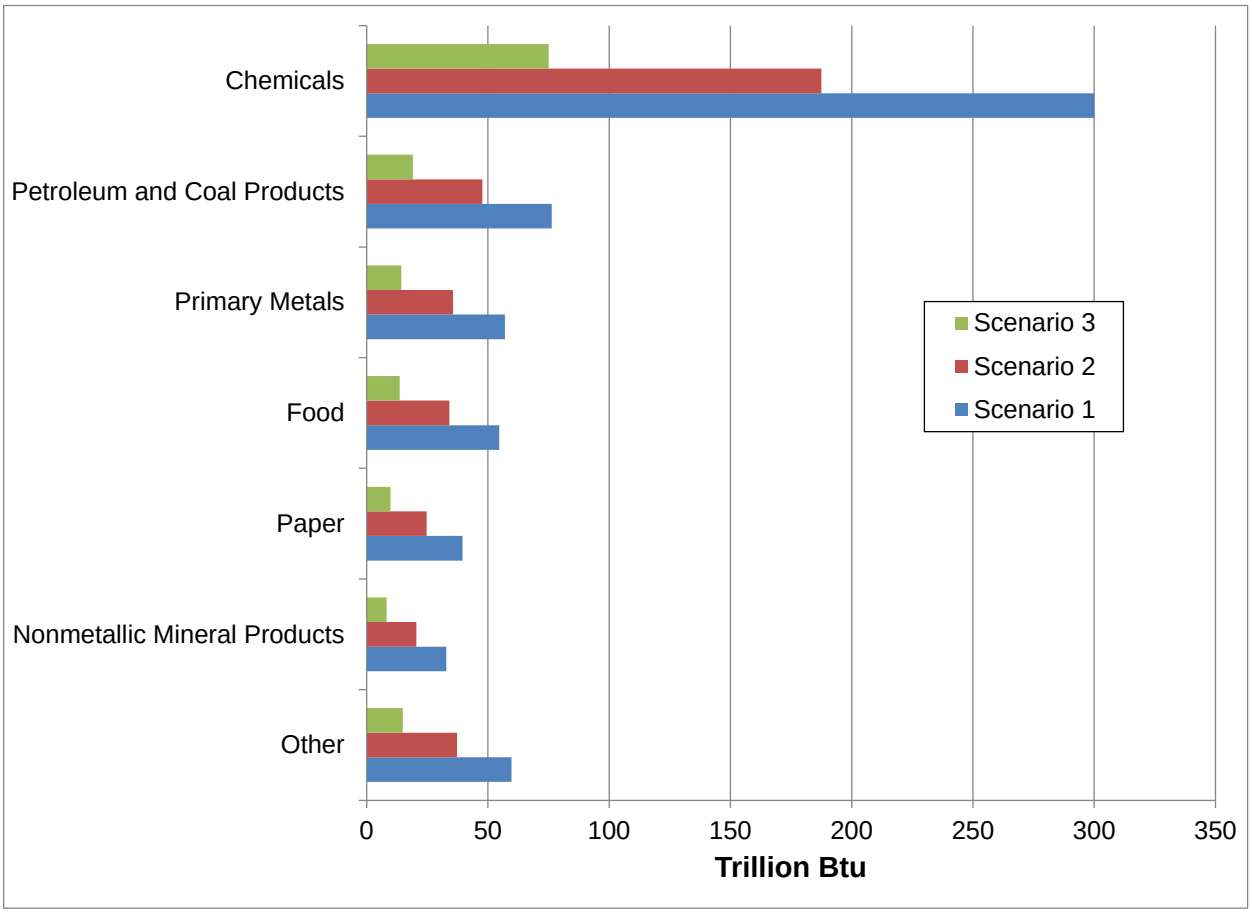
Figure 32. Total Delivered Electricity Savings (end-use energy efficiency/demand response measures)



Fuel Savings

Figure 33 shows delivered fuel savings by major industry subsector. Similar to electricity, the chemical industry has the largest fuel savings, in all three scenarios. This industry consumes the largest amount of fuels and electricity in the manufacturing sector. As such, given the assumption that funds are allocated based on the energy consumption levels of an industry group, this results with the chemical industry accounting for the largest funds. Also, the chemical industry consumes much more fuel than electricity, so with Scenario 1 investing more on fuel energy efficiency measures, and with electricity prices higher than fuel prices, fuel savings would be significant. Petroleum refining, primary metals, food, paper, and non-metallic mineral industries follow, but with substantially less savings than the chemical industry.

Figure 33. Total Delivered Fuel Savings (end-use energy efficiency/demand response measures)



Total Energy Savings

Figure 34 shows total delivered energy savings by major industry group. The chemical industry has the largest total energy savings, across all three scenarios. The primary metals industry has the second largest total savings, followed by food, petroleum refining, paper, and non-metallic industries, respectively. **Figure 35** shows total end-use energy savings by major industry group. The results are similar to the delivered energy savings in which chemical, primary metals, food, petroleum refining, paper and non-metallic industries show the largest savings.

Figure 34. Delivered Energy Savings, End-Use Energy Efficiency/Demand Response

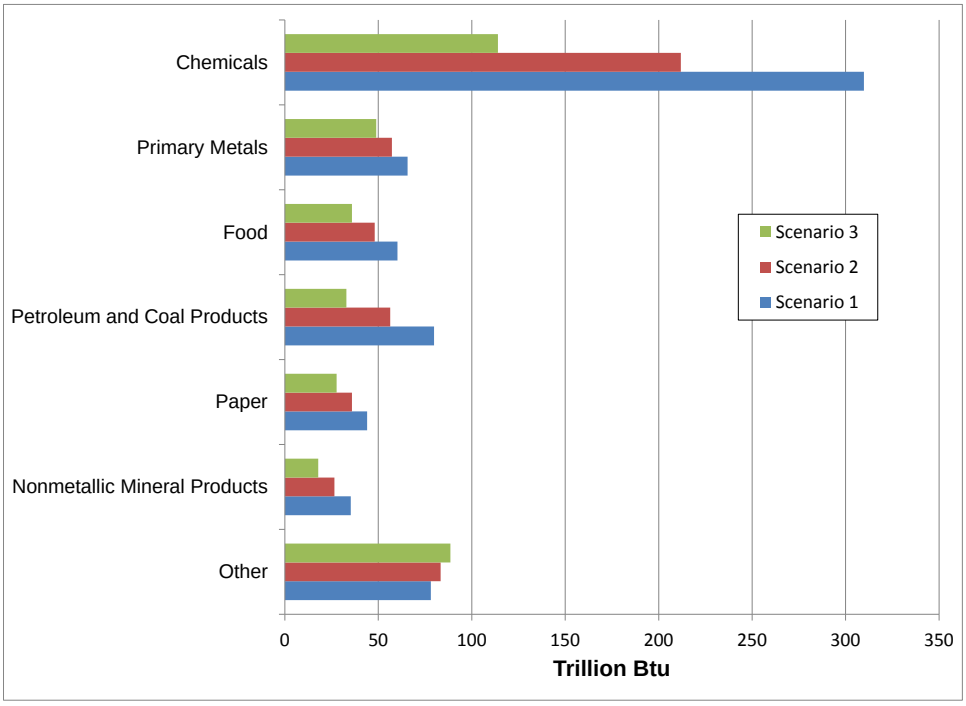
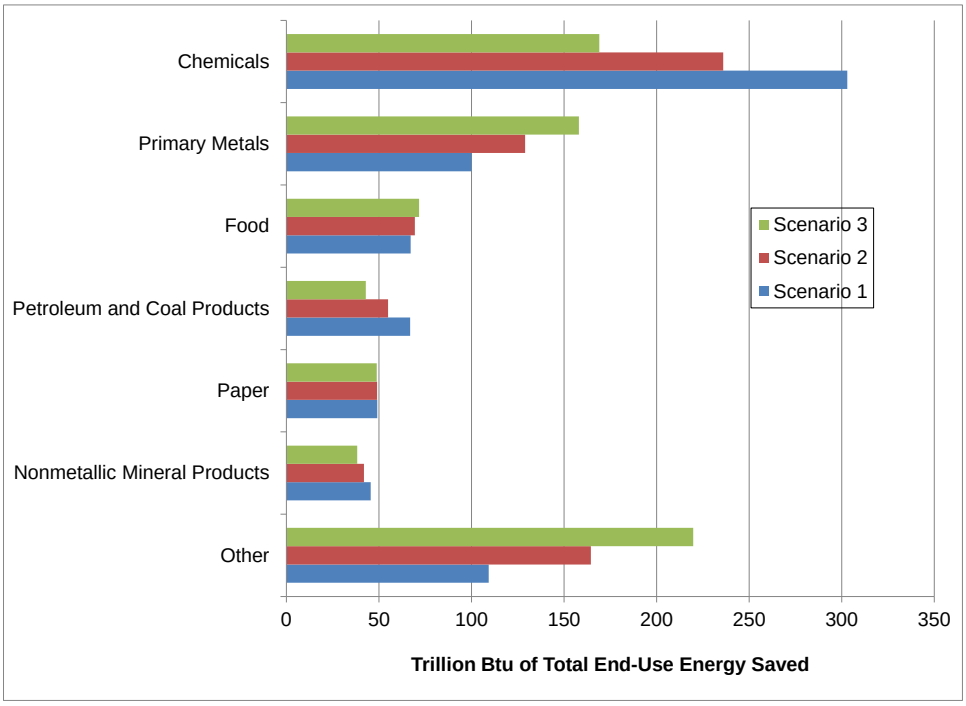


Figure 35. End-Use Energy Savings, End-Use Energy Efficiency/Demand Response



Energy Cost Savings

The results of energy cost savings by major industry group are presented in the next three figures. **Figure 36** illustrates electricity cost savings and shows that the primary metals industry has the largest electricity cost savings, followed by chemicals, food, transportation equipment, plastics, and fabricated metal industries, respectively. **Figure 37** shows that the chemical industry has the largest fuel cost savings, followed by primary metals, petroleum refining, food, paper, and non-metallic industries, respectively. **Figure 38** shows the results of total energy savings by industry. The chemical industry shows the largest energy savings, followed by primary metals, food, petroleum refining, paper and non-metallic minerals industries, respectively.

Figure 36. Electricity Cost Savings, End-Use Energy Efficiency/Demand Response

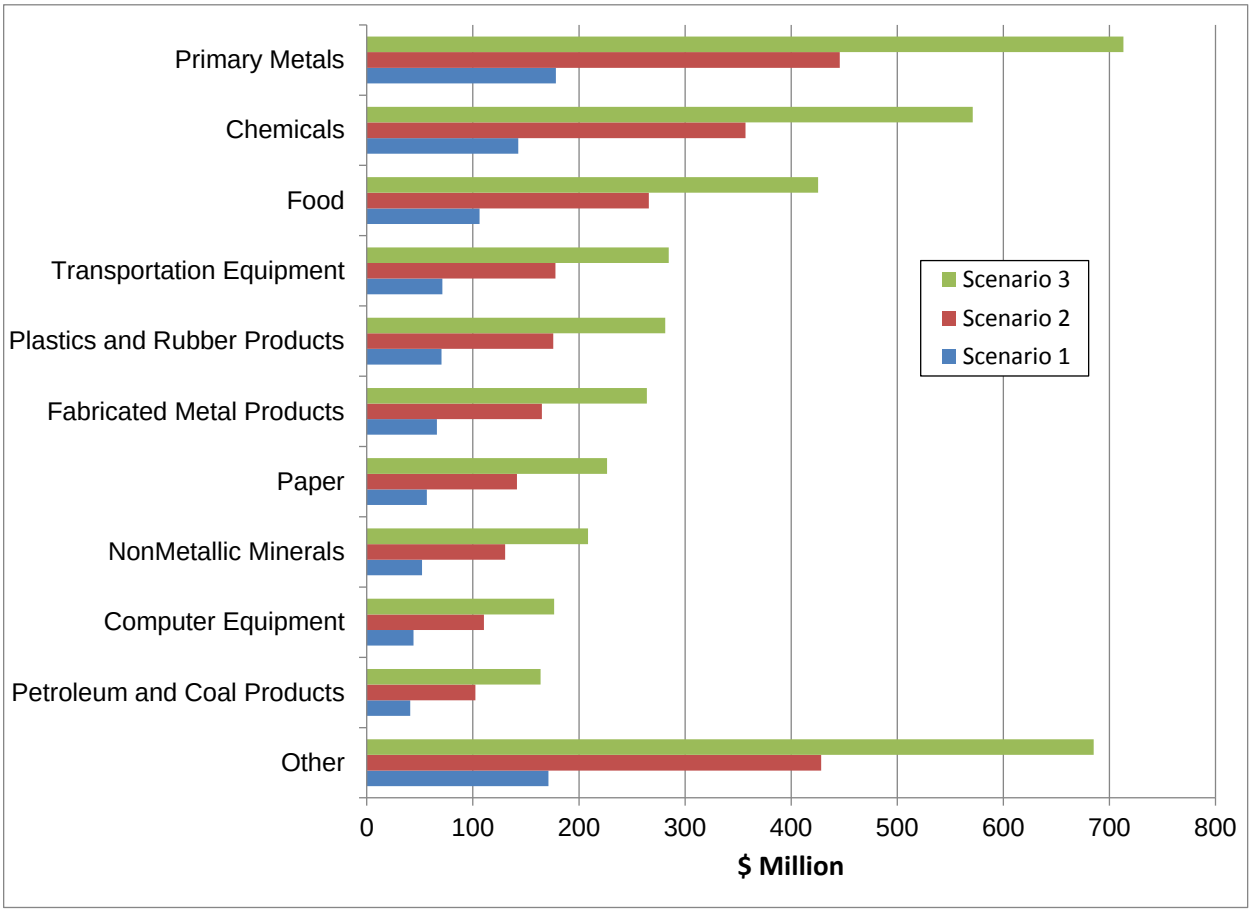


Figure 37. Delivered Fuel Cost Savings, End-Use Energy Efficiency/Demand Response

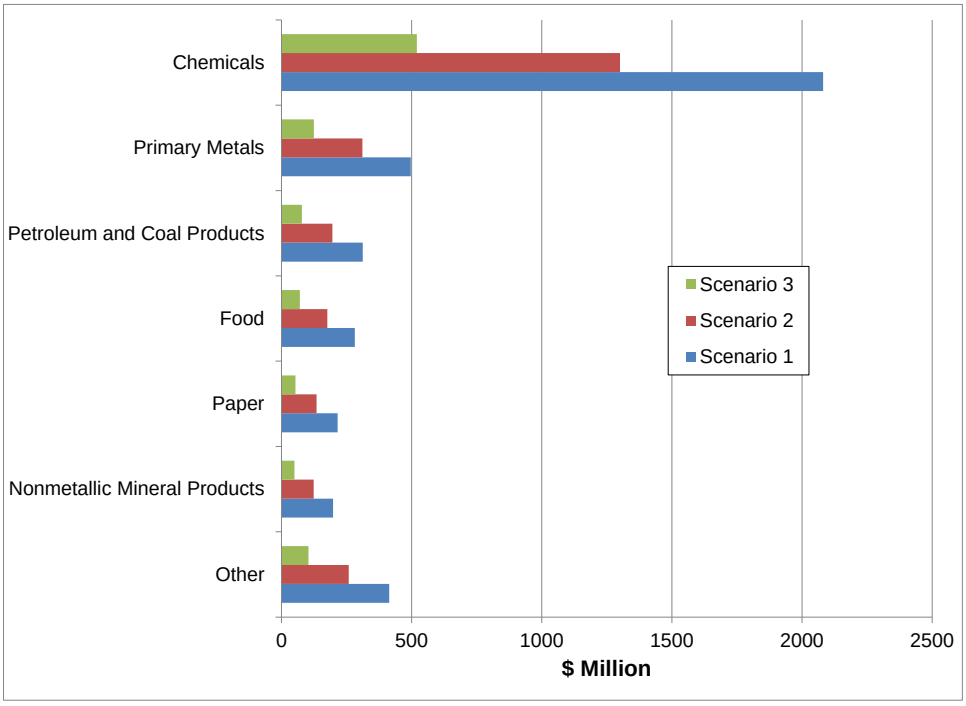
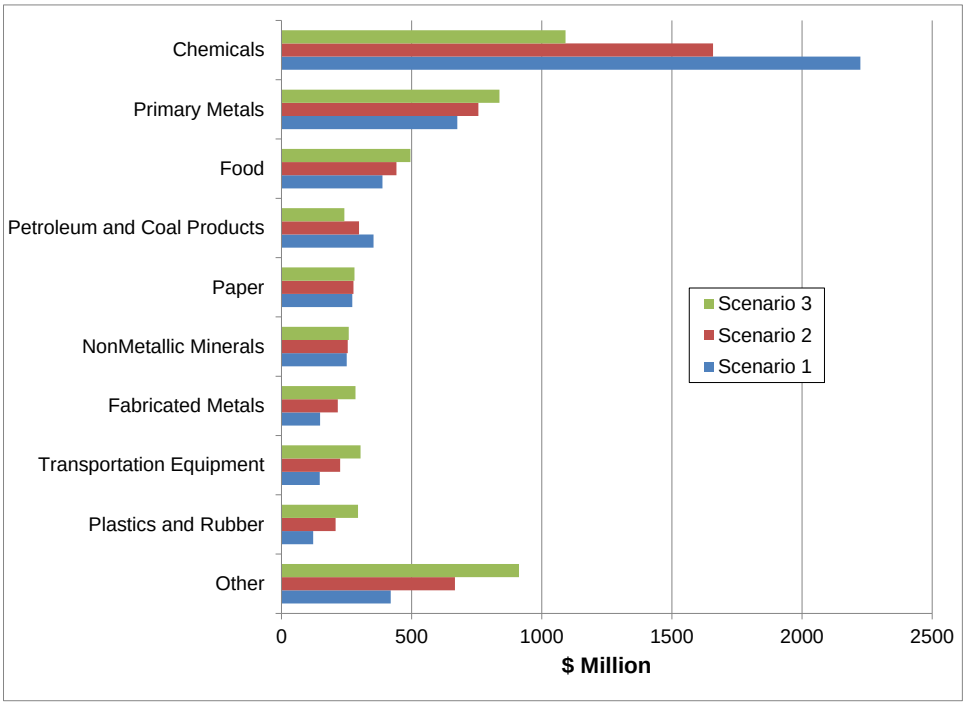


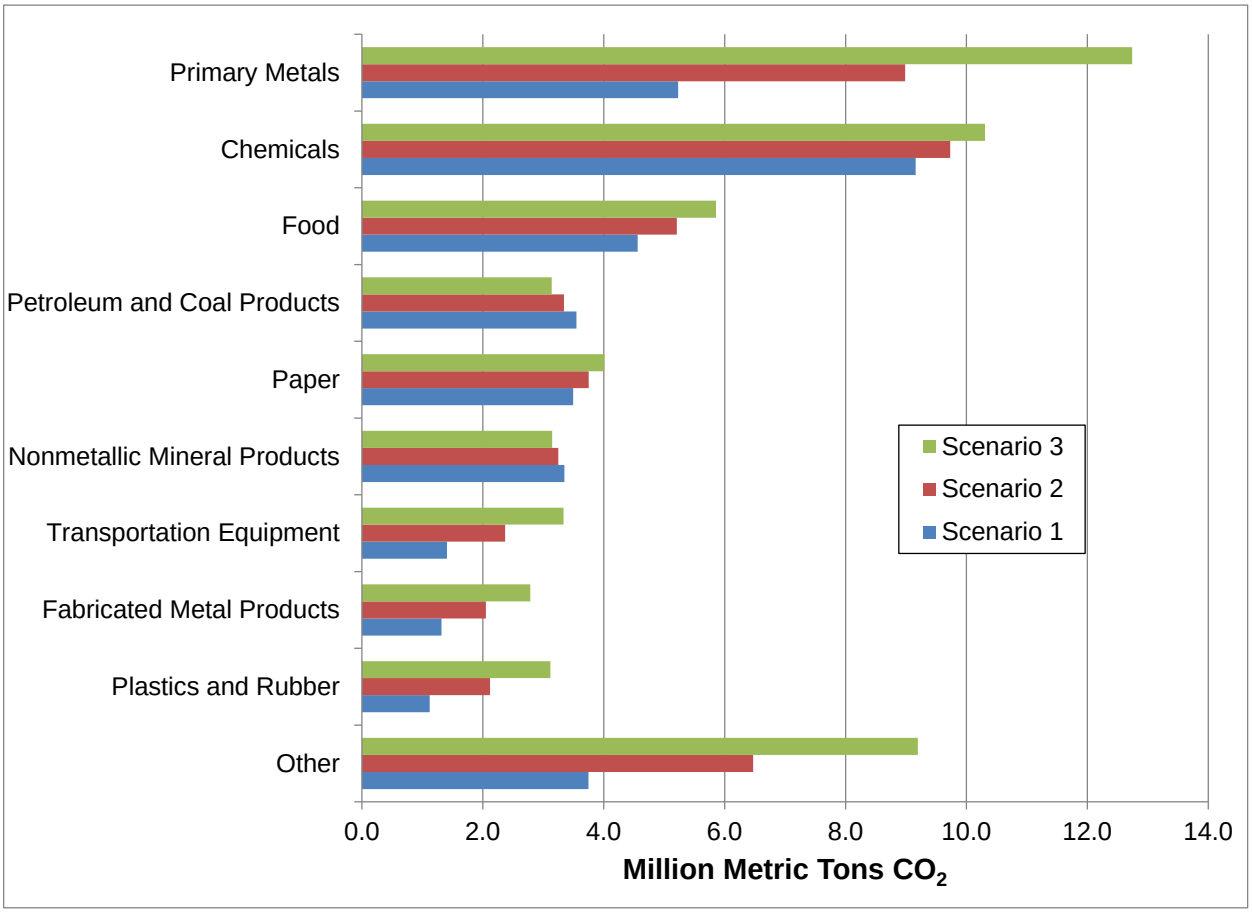
Figure 38. Delivered Energy Cost Savings, End-Use Energy Efficiency/Demand Response



CO_2 Reductions

Figure 39 shows CO_2 emissions reduction by major industry group. The figure shows that the largest reductions in CO_2 emissions occur in the primary metals and chemical industries, with the primary metals having the largest reduction under Scenario 3 and the chemical industry having the largest reductions under Scenarios 1 and 2. These two industries are followed by food, paper, petroleum refining, paper, and non-metallic mineral industries, respectively.

Figure 39. CO_2 Emissions Reduction, End-Use Energy Efficiency/Demand Response



6.3.2 Job, Gross Domestic Product, and Trade Impacts

This section describes national level impacts on jobs, gross domestic product (GDP), and trade as a result of deploying end-use energy efficiency and demand response technologies in the industrial sector. These impacts were evaluated using the IMPLAN model with inputs based on the three scenarios described at the beginning of this section. For reference, these scenarios are:

- **Scenario 1**: 80 percent of available funds used to deploy natural gas end-use technologies, and 20 percent used to deploy electric end-use technologies.
- **Scenario 2**: 50 percent of available funds used to deploy natural gas end-use technologies, and 50 percent used to deploy electric end-use technologies.
- **Scenario 3**: 20 percent of available funds used to deploy natural gas end-use technologies, and 80 percent used to deploy electric end-use technologies.

The IMPLAN evaluation is based on equal investments each year over a 10-year period (2015–2024). The total funding amount over 10 years is $12.5 billion, with $1.25 billion invested each year.

IMPLAN was used to estimate benefits to the U.S. economy measured by jobs and economic output (GDP). Future projections of job impacts and GDP estimates in years 2020 and 2024 were based on the year 2015 results, under the assumptions that there is no change in labor productivity, the dollar value stays constant during this time frame, and funds realized through avoided energy expenditures are utilized starting from the first year of investment.

The $1.25 billion was assumed to be invested annually towards the construction and installation of end-use energy efficiency systems and demand response systems, leading to direct economic benefits for selected economic sectors that manufacture end-use energy efficiency and demand response products such as lighting fixtures and electrical appliances (and secondary impacts arising from those direct impacts).

Additionally, when manufacturing sectors install end-use energy efficiency and demand response systems, there are associated energy savings. Based on the 2½-year payback assumption (2-year payback from participant perspective after Federal grant funds are considered), the $1.25 billion annual investment produces savings of $500 million per year in energy costs. For modeling purposes, it is assumed that the $500 million per year in avoided energy expenditures is reinvested by the manufacturing sectors in NAICS codes 31–33 according to their energy expenditures data from the 2010 MECS survey. Additionally, because resources are scarce, we assumed that investing in energy efficiency and demand response has an opportunity cost for the economy, in that these vital resources could have otherwise been invested by the manufacturing sectors (and the Federal grant portion by the Federal Government). Thus, the modeling implicitly assumed that under a status quo business-as-usual (counterfactual) scenario, these resources would have generated economic output and jobs in the national economy, but not through the same channels as investing in end-use energy efficiency and demand response technologies. Hence, the job impacts due to energy efficiency and demand response investments are considered to be net impacts that account for the

impacts that would otherwise occur without the end-use energy efficiency/demand response investment.

Job Impacts

Job results are described in terms of direct, indirect, and induced jobs, which are defined as follows (see **Appendix E** for more information on IMPLAN, and how jobs are defined):

- **Direct Jobs** – Employment changes due to investments that result in final demand changes. For example, financial expenditures for installation of energy efficiency projects generate direct jobs in the construction sector.
- **Indirect Jobs** – Employment changes due to industry inter-linkages. For example, construction companies purchase materials and supplies from other sectors of the economy in the course of completing energy efficiency projects. Jobs created in the supply chain are called indirect jobs.
- **Induced Jobs** – Employment changes due to local expenditures. For example, increased household expenditures in the local economy support additional jobs. These local economy jobs are called induced jobs.

The IMPLAN model was used to determine job impacts for Scenarios 1, 2, and 3. There are similarities in the modeling approach for all three scenarios; the discussion in this section uses Scenario 2 as a representative scenario for highlighting the inputs and results, followed by a summary discussion of the main findings for the remaining scenarios.

Table 15 shows the net job impacts from Scenario 2. A direct investment of $1.25 billion per year in end-use energy efficiency and demand response results in an annual net gain of about 6,000 jobs. Of these, about 4,000 jobs come from the investment in the construction sectors (first row in **Table 15**). The remaining 2,000 jobs are driven by the changes in energy consumption as a benefit of the end-use energy efficiency/demand response investment.

Table 15. Net Job Impacts, End-Use Energy Efficiency/Demand Response, Scenario 2[3]

Description	Annual Net Job Impacts			
	Direct	Indirect	Induced	**Total**
Jobs due to Construction/Installation of Energy Efficiency/Demand Response	3,155	-700	1,551	4,007
Job Losses Due to Reduced Energy Demand	-593	-1,165	-1,363	-3,120
Jobs Due to Reinvesting Energy Savings	1,058	2,070	1,941	5,069
Annual Net Job Impacts	**3,620**	**205**	**2,129**	**5,956**

Notes: 1) Job impacts shown are net jobs, and take into account jobs that would have occurred absent the grant program.
2) Sums may differ due to rounding.

Investing in end-use energy efficiency/demand response leads to two competing effects for the national economy. On the one hand, it leads to job losses (negative numbers in **Table 15**) in the utility sector as businesses reduce their demand for energy. On the other hand, reduced energy consumption allows businesses to reinvest utility bill savings in other opportunities, which leads to business growth and increased hiring. The net effect of these two competing factors results in a net gain of about 2,000 jobs (sum of second and third rows in **Table 15**).

The IMPLAN modeling results show that construction and installation of the end-use energy efficiency and demand response systems creates 3,155 direct jobs for Scenario 2 (see **Table 15**). Seven hundred indirect construction/installation jobs are lost because end-use energy efficiency/demand response technologies create fewer jobs compared to business as usual. There are 1,551 induced construction/installation jobs created, resulting in a total of 4,007 construction/installation jobs. As indicated in **Table 15**, there are 3,120 total jobs lost due reduced energy demand, and 5,069 jobs created due to reinvestment by manufacturing plants that save energy. The total annual impact is 5,956 jobs.

The energy savings generated by investments in end-use energy efficiency/demand response have a negative impact on the utility sectors. Reduced energy demand creates direct job losses for utility sectors (both electric and natural gas utilities), and corresponding indirect and induced job losses in other sectors that depend on these utility sectors. The economic modeling assumed that investments in end-use energy efficiency/demand response led to $500 million in annual energy savings, and corresponding reductions in expenditures in the utility sectors. The IMPLAN results showed direct job losses of 593 in utility sectors, along with indirect job losses of 1,165 and induced job losses of 1,363. The total jobs lost annually due to reduced energy demand is around 3,100 with the bulk of these losses in upstream supporting industries as well downstream industries that depend on consumption expenditures from utility sector workers (i.e., induced job losses).

For the IMPLAN modeling, it is assumed that the manufacturing sectors will immediately reinvest energy savings into additional production. This reinvestment produces a direct gain of 1,058 jobs in the manufacturing sectors along with indirect and induced job gains of 2,070 and 1,941, respectively, in supporting industries.

Taking all these factors into consideration, a $1.25 billion investment is estimated to create about 6,000 net jobs in the economy.[4] Of these, the total direct job gain is approximately 3,600 jobs, with the highest gain in the construction sectors. Of the total secondary impacts due to these investments, the majority of those job gains are likely to come from induced job impacts of about 2,100, with the remaining 200 jobs coming from indirect impacts in upstream sectors.

The top ten sectors in terms of net jobs gained annually as a result of the investment in end-use energy efficiency and demand response are listed in **Table 16**. As indicated, most jobs are created directly in the construction sectors. The electrical equipment and appliance manufacturing sector also experiences significant direct job gains.

Table 16. Top Ten Net Job Impacts by Economic Sector (Scenario 2)

NAICS Code		Annual Net Job Impacts			
No.	Description	Direct	Indirect	Induced	**Total**
23*	Construction	4,877	-255	27	**4,648**
335	Electrical Equipment & Appliance Manufacturing	1,447	131	2	**1,580**
42*	Wholesale Trade	-3	134	68	**199**
541	Professional, Scientific, & Technical Services	-60	140	107	**187**
722	Food Services & Drinking Places	-9	-50	196	**137**
333	Machinery Manufacturing	93	31	2	**127**
621	Ambulatory Health Care Services	-18	0	143	**125**
531	Real Estate	-3	-16	104	**84**
622	Hospitals	-4	0	88	**84**
452	General Merchandise Stores	-9	31	62	**84**

Note: "" designates sectors that have been mapped to 2-digit, rather than 3-digit, NAICS codes by IMPLAN*

The methodology used to determine the net job impacts for Scenarios 1 and 3 were largely the same as described for Scenario 2. The only difference was the percentage of energy savings attributed to electricity and fuel.

- In Scenario 1, fuels were the source of 80 percent of the energy cost savings with the remaining 20 percent coming from electricity energy cost savings.
- In Scenario 3, electricity was the source for 80 percent of the energy cost savings (20 percent from fuels).

As discussed previously for Scenario 2, while energy savings were overall beneficial for the economy, it does reduce the demand for the utility energy and thereby lead to corresponding job losses. Thus, in Scenario 1 more jobs were lost in the sectors that consumed more fuels, while more jobs were lost in the electricity sector in Scenario 3. In Scenario 2, which has an even split between electricity and natural gas, the electricity sector lost about 1,500 jobs, while the natural gas sector lost about 1,600 jobs. In Scenario 1, job losses in the natural gas sector are more than four times the job losses in the electricity sector. The opposite trend holds for Scenario 3, where electricity sector job losses are close to four times the job losses in the natural gas sector. Despite these variations, the overall job impacts on the national economy are relatively consistent across all three scenarios, with an average annual net gain of about 6,000 jobs. Among the three scenarios, the direct job impacts varied between approximately 3,575 and 3,650 jobs. The indirect jobs varied between approximately 175 jobs and 225 jobs while the induced jobs varied by fewer than 30 jobs among the scenarios. **Table 17** summarizes the results for each scenario.

Table 17. Net Jobs for End-Use Energy Efficiency/Demand Response Scenarios

Scenario	Annual Net Job Impacts			
	Direct	Indirect	Induced	**Total**
1	3,578	176	2,116	**5,871**
2	3,620	205	2,129	**5,956**
3	3,664	234	2,142	**6,041**

Note: Sums may differ due to rounding.

Gross Domestic Product (GDP)

In IMPLAN, the GDP, represented as the total value added, is the sum of employee compensation, proprietor income, and other property income and indirect business taxes. Based on the results from 2015, an investment of $1.25 billion in end-use energy efficiency and demand response adds approximately $223 million per year to the economy in value added GDP.

The top ten sectors in terms of annual net GDP impacts as a result of the investment in end-use energy efficiency and demand response programs are listed in **Table 18**. As shown, the construction sectors add the most value to the economy.

Table 18. Top Ten Net GDP Impacts by Economic Sector (Scenario 2)

NAICS Code		Annual Net GDP Impacts ($ millions)			
No.	Description	Direct	Indirect	Induced	**Total**
23 *	Construction	$291.22	-$15.28	$1.90	**$277.85**
335	Electrical Equipment & Appliance	$174.98	$15.03	$0.29	**$190.29**

NAICS Code		Annual Net GDP Impacts ($ millions)			
No.	Description	Direct	Indirect	Induced	**Total**
	Manufacturing				
333	Machinery Manufacturing	$34.54	$4.25	$0.25	**$39.03**
42 *	Wholesale Trade Business	-$0.42	$18.30	$9.33	**$27.21**
N.A.	---	-$1.70	-$0.55	$17.92	**$15.67**
541	Professional, Scientific, & Technical Services	-$5.28	$8.43	$11.19	**$14.35**
621	Ambulatory Health Care Services	-$1.10	-$0.03	$10.94	**$9.80**
531	Real Estate	-$0.39	-$1.88	$12.07	**$9.80**
524	Insurance Carriers & Related Activities	-$0.68	-$0.31	$7.75	**$6.75**
622	Hospitals	-$0.29	$0.00	$6.67	**$6.39**

Notes 1) "" designates sectors which have only been mapped to the 2 digit NAICS code by IMPLAN.*
2) "N.A." represents IMPLAN sectors 428–440, which includes government enterprises and government payroll. These sectors do not have corresponding NAICS codes.

As shown in **Table 19**, the annual net GDP impact ranged from $206 million to $240 million for the three scenarios. Scenario 3 is estimated to have the lowest GDP impact for the national economy at slightly above $200 million. Scenario 1 is expected to have the largest impact, estimated at about $240 million in positive GDP impact. Scenario 3 has the smallest GDP impact, but has the largest jobs impact. This outcome occurs because the majority of the energy savings in Scenario 3 come from the electric power sector. In this scenario, the demand for electricity is significantly lower than the demand for natural gas. Because electricity costs are relatively high compared to natural gas costs, the decrease in demand results in a higher loss in GDP. However, the electricity sector has a lower impact on jobs compared to the natural gas sector, resulting in a higher net job impact for Scenario 3.

Table 19. Net GDP Impacts for Energy Efficiency/Demand Response Scenarios

Scenario	Annual Net GDP Impact ($ Millions)			
	Direct	Indirect	Induced	**Total**
1	$79	-$16	$177	**$240**
2	$49	-$5	$178	**$223**
3	$20	$8	$179	**$206**

Note: Sums may differ due to rounding.

Trade Impacts

The economic modeling conducted with IMPLAN focused on the impacts on the national economy and quantifying the trade balance impacts from this type of modeling is not possible. While it is likely that there could be some changes in trade from these investments, the IMPLAN model does not have the capability to model these effects. The benefits of investing in end-use energy efficiency and demand response, however, are expected to primarily benefit the U.S.

economy, with only minor impacts on trade. The application of end-use energy efficiency measures and demand response measures is likely to be implemented using American labor and products manufactured in the United States.

6.4 CHP

This section discusses the economic benefits of investing $12.5 billion over a 10-year period to deploy CHP technologies in the industrial sector. The analysis was completed through the following steps:

1) Characteristics were developed for three representative CHP systems that would likely be installed in the manufacturing sector. The systems are a 3 MW reciprocating engine, a 12.5 MW combustion turbine, and a 40 MW combustion turbine. Key characteristics are shown in **Table 20**, with additional details included in **Appendix D**, **Table 48**.

2) Three CHP scenarios were evaluated:
   - **Scenario 1**: All funds ($12.5 billion) invested to deploy 3 MW systems
   - **Scenario 2**: All funds invested to deploy 12.5 MW systems
   - **Scenario 3**: All funds invested to deploy 40 MW systems

3) An Excel model was created to estimate energy and emission impacts. IMPLAN was used to estimate the jobs and gross domestic product impacts.

Table 20. CHP Systems Assumptions

Characteristic	Technology		
	Reciprocating Engine	Combustion Turbine	Combustion Turbine
Size (MW)	3.0	12.5	40.0
Operating Time (percent)	80	85	92
Electric Efficiency (percent)	35	29	37
Thermal Efficiency (percent)	43	40	35
Total Efficiency (percent)	78	69	72
O&M Costs (¢/kWh)	1.6	0.9	0.5
Installed Cost ($/kW)	$2,400	$1,980	$1,580
Installed Cost ($ million)	$7.2	$24.8	$63.2

Note: Operating time is percentage of total time. For example, 80 percent corresponds to approximately 7,000 hours per year.

6.4.1 Energy and Emission Impacts

The Excel model used for energy and emission impacts was constructed as follows:

1) Deployment funds ($12.5 billion) were allocated by the number of potential sites by industry group (aggregated by 3-digit NAICS) and by CHP system using the following steps (summary table shown in **Appendix D**, **Table 49**):

    a) Census of Manufacturers 2010 data was used to determine the number of manufacturing establishments that have load capacities that match each type of CHP system.[5]

    b) The number of facilities with existing CHP systems was subtracted from the result from step (a) to arrive at a remaining potential.[6]

2) To estimate the impacts on energy savings, electricity and natural gas prices were differentiated by industry group. **Table 50** in **Appendix D** shows the energy price assumptions. Also, energy savings are presented as delivered energy savings and end-use energy savings (see definitions below). To estimate the end-use energy savings, fuel inputs for electricity generation (at central stations) are incorporated. **Appendix F** shows how the end-use energy factors, which are used to estimate end-use energy savings, were calculated.

3) To calculate reduced CO_2 emissions, CO_2 emissions factor were used for grid electricity and on-site natural gas use (factors shown in **Appendix F**).

<u>Results for All Three Scenarios</u>

This section presents the results for energy use, energy cost savings, and CO_2 emissions reductions from CHP investments. Note that energy use in this section refers to delivered energy use (refer to **Chapter 3** for definition). The CO_2 emissions reduction includes CO_2 emissions reduction from reduced fuel use in the manufacturing plant and the reduced emissions from displaced grid electricity. Also, these impacts are the yearly benefits after all CHP systems have been installed as a result of the 10-year grant program.

Table 21 summarizes the results for each scenario. The results show that Scenario 1 (3 MW) has the largest number of CHP systems installed, but the lowest total installed capacity compared to Scenarios 2 and 3. This result is consistent with the installed cost trend, which shows that the installed cost on a $/kW basis declines with size. As installed cost declines, the total installed capacity increases for a fixed investment level. Consistent with the installed capacity trends,

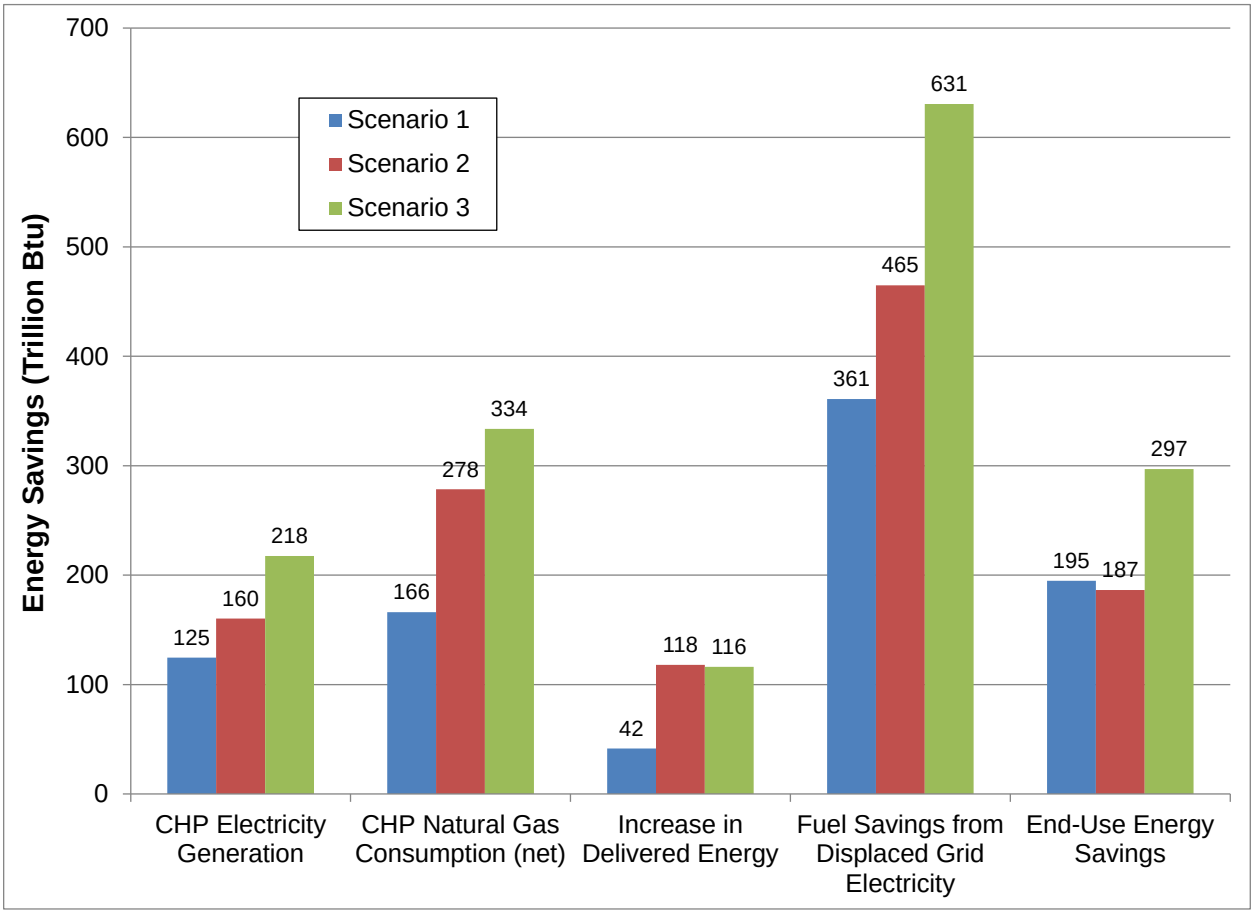
Scenario 3 (40 MW) shows the largest reduction in grid electricity consumption and the largest reduction in CO_2 emissions compared to the other two scenarios.

Table 21. Summary of CHP Results

Description	CHP Scenario		
	1	2	3
Deployment Funds (Federal plus participant cost share, $ billion)	$12.5	$12.5	$12.5
Unit Size (MW)	3.0	12.5	40.0
Installed Cost ($/kW)	$2,400	$1,980	$1,580
Number of CHP Systems Installed	1,736	505	198
Total Installed Capacity (MW)	5,208	6,313	7,911
Increased Gas Consumption (billion cubic feet [bcf]/yr)	163	273	327
Decreased Electricity Use (million MWh/yr)	37	47	64
Total End-Use Energy Savings (TBtu)	195	187	297
Net CO_2 Reduction (million metric tons [MMT]/yr)	11	11	17

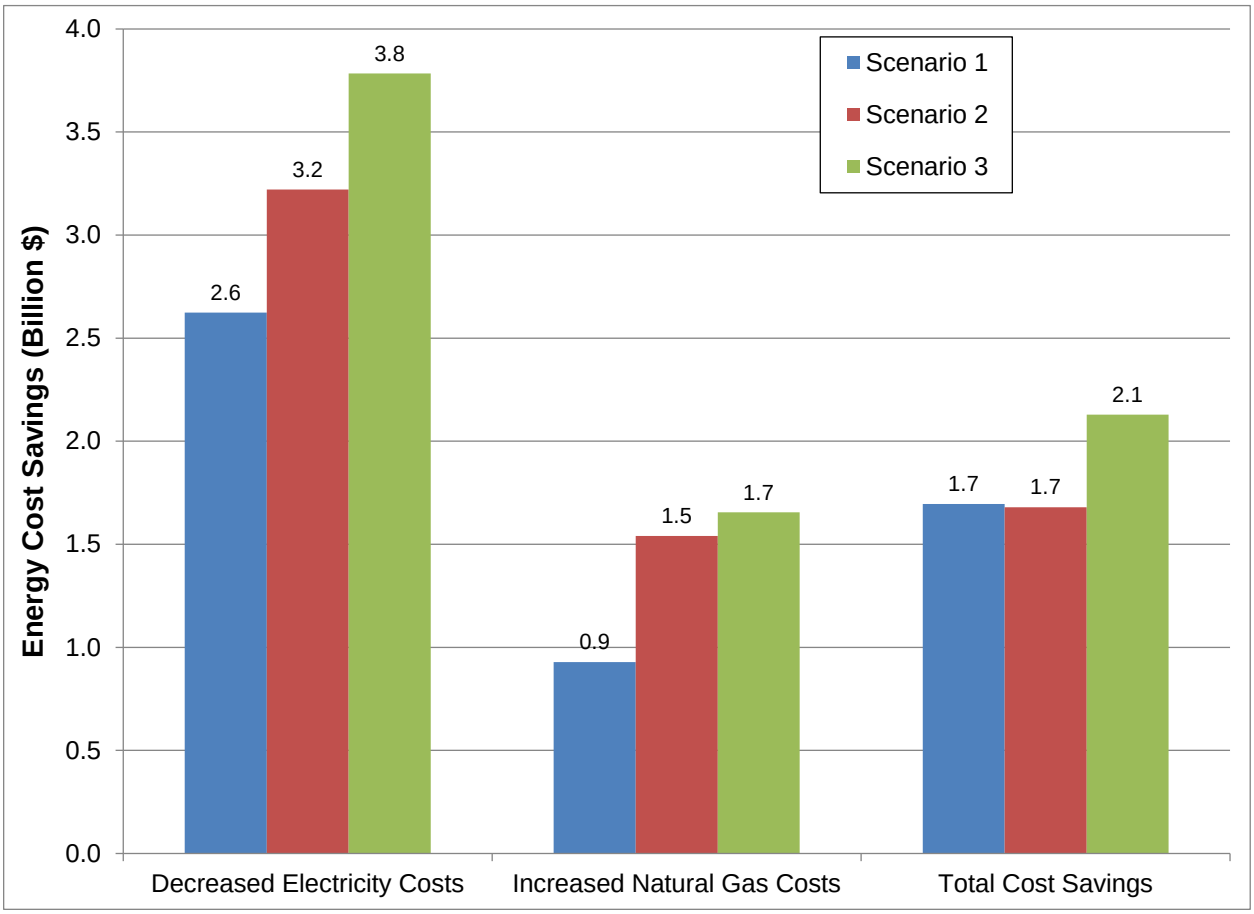
Figure 40 shows the energy savings from the CHP investments for the 3 scenarios. Electricity generated from CHP that could result in an equal amount of grid electricity savings reaching 218 TBtu under Scenario 3, with Scenarios 1 and 2 generating lower electricity savings. The net increase in natural gas use is the consumption of the CHP system minus avoided natural gas that would have otherwise been required for boiler fuel to produce the same useful thermal output as the CHP system. The net increase for natural gas reaches 334 TBtu for Scenario 3. The delivered energy savings (increased gas use minus decreased electricity use at the site) is negative for all three scenarios. If the fuel to generate grid electricity is considered, the fuel savings increase significantly, reaching 361 TBtu for Scenario 1 and 631 TBtu for Scenario 3. This is because the real positive impact of CHP is the savings from the fuel input to generate electricity at the central generating station. The end-use (i.e., source basis) energy savings are positive in all cases, ranging from 187 TBtu for Scenario 2 to 297 TBtu for Scenario 3.

Figure 40. Energy Impacts from CHP



While there is no reduction in delivered energy consumption between the three scenarios, there is a reduction in energy costs based on the assumptions used. **Figure 41** shows that total energy cost savings exceed $2 billion under Scenario 3, with electricity cost savings at almost $4 billion and gas expenditures at $1.7 billion. Scenarios 1 and 2 have lower energy cost savings. With electricity prices over four times gas prices, CHP investments result in energy cost savings, despite an increase in gas use at the site. It should be noted that total energy savings will vary depending on price assumptions for both electricity and natural gas and as relative efficiencies between state-of-the-art central station electric generation and CHP narrow.

Figure 41. Energy Cost Savings from CHP



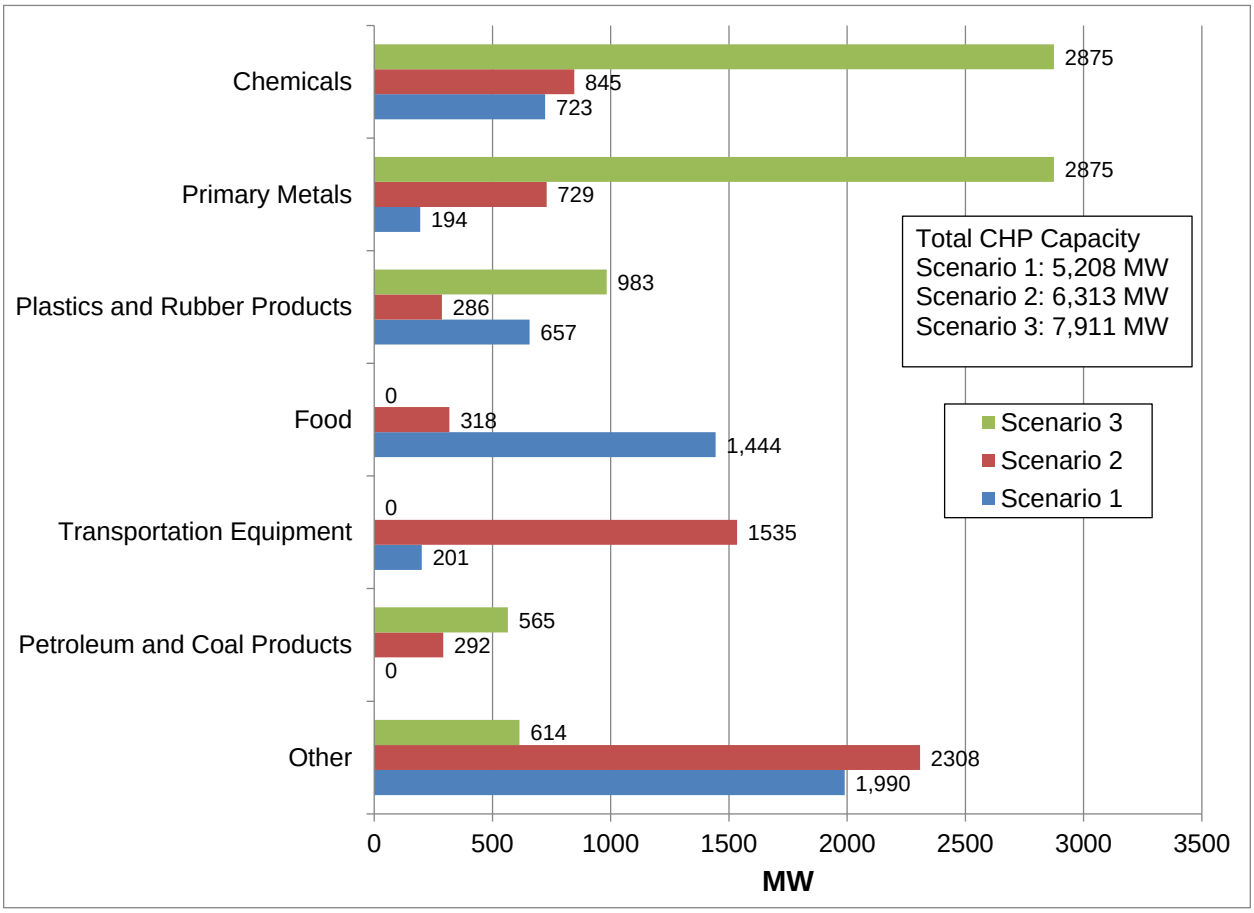
<u>Comparison of Results between Manufacturing Subsectors</u>

<u>CHP Capacity</u>

Figure 42 shows new CHP capacity added by manufacturing subsector. The amount of CHP capacity is the amount of electricity generating capacity installed by the industry. It is noted that the results by industry are based on the potential number of sites for each industry. It is difficult to predict how the market might truly develop in the future. Nevertheless, this analysis is a good initial assessment of which industries might install CHP. The figure shows that the largest installed capacity occurs in the chemical and primary metals industries in Scenario 3. Most chemical and primary metals plants are relatively large energy consumers compared to plants in other manufacturing subsectors, and these plants are a good match for the CHP system capacity used in this scenario (40 MW). In Scenario 3, the rubber and plastics, food, transportation equipment, and petroleum refining follow the chemicals and primary metals subsectors in terms of added capacity. In Scenario 1, the food industry has the largest capacity

because it has a relatively large number of facilities that are well matched to the CHP system used in this scenario (3 MW).

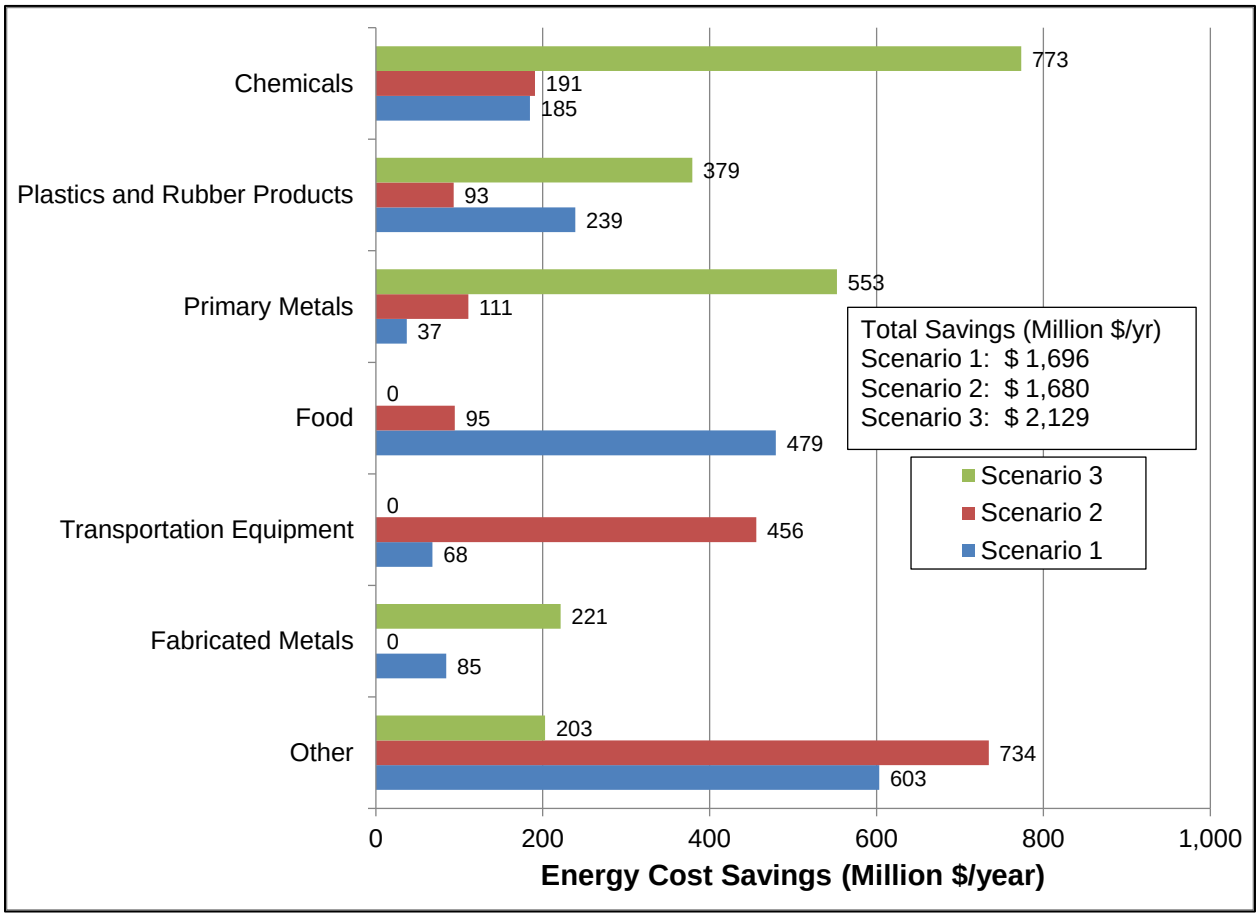
Figure 42. Total CHP Capacity Added by Industry Group



Energy Cost Savings

Figure 43 shows energy cost savings by manufacturing subsector for each scenario. The figure shows that the chemical industry will save the most under Scenario 3 at $773 million per year. The primary metals industry also has substantial savings under Scenario 3 but like the chemical industry, the savings are lower compared to Scenarios 1 and 2. The food industry has the highest savings under Scenario 1, which is consistent with the largest capacity addition previously discussed.

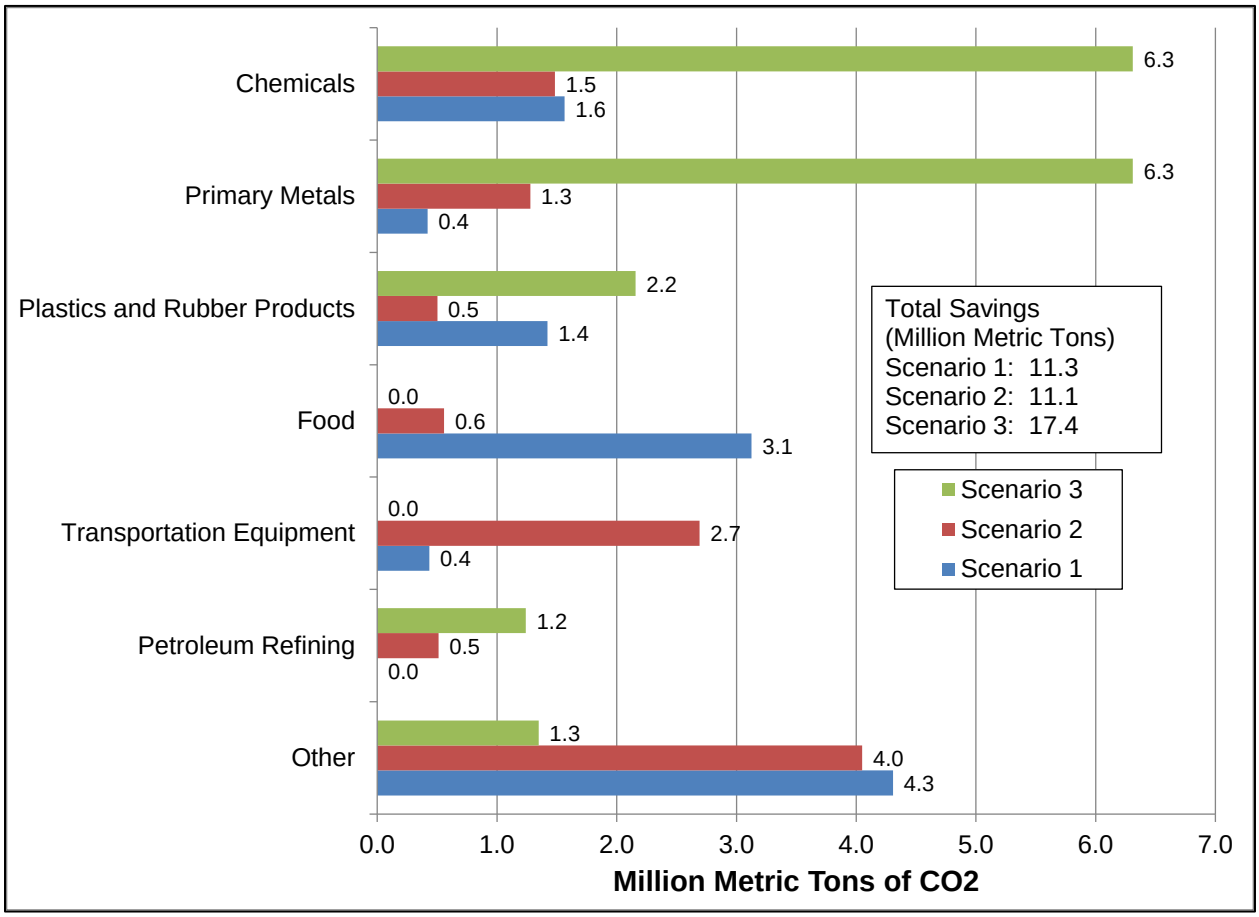
Figure 43. Total Energy Costs Savings from CHP Scenarios by Industry Group



CO_2 Reductions

Figure 44 shows CO_2 emissions reduction by industry group for each scenario. The figure shows that the chemical and primary metals industries have the largest emissions reduction at 6.3 million metric tons of CO_2 under Scenario 3. The CO_2 emissions reductions for these two industries are lower for Scenarios 1 and 2. The food industry shows the largest CO_2 emissions reduction under Scenario 1, and the transportation industry shows the largest reduction under Scenario 2.

Figure 44. CO_2 Emissions Reduction from CHP Scenarios by Industry Group



6.4.2 Job, GDP, and Trade Impacts

This section describes national level impacts on jobs, GDP, and trade. Similar to the end-use energy efficiency/demand response analysis, these impacts were evaluated using the IMPLAN model. IMPLAN was used to evaluate the three scenarios described at the beginning of this section. For reference, these scenarios are:

- **Scenario 1**: All funds ($12.5 billion total, $1.25 billion per year) invested to deploy 3 MW CHP systems
- **Scenario 2**: All funds invested to deploy 12.5 MW CHP systems
- **Scenario 3**: All funds invested to deploy 40 MW CHP systems

The IMPLAN evaluation is based on equal investments each year over a 10-year period (2015–2024). Therefore, $1.25 billion is invested each year in the deployment of CHP systems. As indicated in **Table 21**, Scenario 1 results in a total installed population of 1,736 CHP units,

Scenario 2 supports the deployment of 505 total units, and Scenario 3 corresponds to the installation of 198 total CHP systems.

Future projections of job impacts and GDP estimates in years 2020 and 2024 were based on the year 2015 results, under the assumption that there is no change in labor productivity, the dollar value stays constant during this time frame, and funds realized through avoided energy expenditures are utilized starting from the first year of investment.

The $1.25 billion was assumed to be invested toward capital and labor involved in CHP system installation. For Scenario 2—used as an example scenario for discussing the methodology and results—15 percent of total annual funding ($187.5 million) was allocated toward labor costs, which directly impacts the construction sector, while 85 percent ($1.06 billion) was allocated toward capital costs, which directly impacts the manufacturing sector.

It was determined that with a $1.25 billion investment, the manufacturing plants that implement CHP could save up to $223 million in associated energy savings. For IMPLAN modeling, it was assumed that these plants immediately reinvest all savings to increase production.[7]

Because resources are scarce, the IMPLAN model was set-up with the assumption that investing in CHP has an opportunity cost for the economy, in that these vital resources could have otherwise been invested by the manufacturing sector (and the Federal grant portion by the Federal Government). The IMPLAN modeling implicitly assumed that under a status quo business-as-usual case these resources would have generated economic output and jobs in the national economy. Therefore, the job impacts due to investments in CHP are considered to be net impacts taking into account impacts that would have occurred absent investment in CHP.

Job Impacts

This section discusses the job impacts of the three CHP scenarios as modeled in IMPLAN. The discussion focuses on the model for Scenario 2 to illustrate the inputs used in IMPLAN. While the same type of input variables were used in all three scenarios, the numerical values varied because of different characteristics for the three CHP systems.

Table 22 shows the net job impacts from CHP Scenario 2. The direct investment of $1.25 billion per year resulted in an annual net gain of about 4,500 jobs. Of these, about 4,000 total jobs came from the construction and installation of CHP systems. Similar to the energy efficiency/demand response analysis, installation of new CHP systems is likely to lead to two additional competing types of employment impacts. On the one hand, it is likely to lead to some job losses due to reduced energy demand. On the other, reduced energy consumption is

also likely to improve businesses ability to reinvest "bill savings" back into other productive avenues, creating or supporting additional jobs for the national economy. Unlike the energy efficiency/demand response analysis, these two competing effects for CHP appear to be similar in scale, resulting in a net gain of about 500 additional jobs per year.

Table 22. Annual Net Job Impacts (CHP Scenario 2)

Description	Annual Net Job Impacts			
	Direct	Indirect	Induced	**Total**
Jobs due to Construction/Manufacturing of CHP	961	1,278	1,713	**3,954**
Job Losses Due to Reduced Energy Demand	-233	-499	-599	**-1,331**
Jobs Due to Reinvesting Energy Savings	582	516	762	**1,861**
Total Annual Net Job Impacts	**1,310**	**1,296**	**1,876**	**4,483**

Notes: 1) Job impacts shown are net jobs, and take into account jobs that would have occurred absent the grant program.
2) Sums may differ due to rounding.

Of the roughly 4,000 total jobs created during the construction/installation phase for CHP, less than one thousand jobs are likely to come from the direct installation of these CHP systems. Roughly 52 percent of the jobs come from the construction sector, while 48 percent come from the manufacturing sector. Moreover, these direct jobs could create an additional 3,000 jobs in support industries due to indirect and induced expenditures.

The energy savings generated by investments in CHP have a negative impact on certain sectors. Reduced energy demand creates direct job losses in the utility sector, and corresponding indirect and induced job losses in other sectors that depend on this sector. For IMPLAN modeling, it was assumed that investments in CHP for Scenario 2 yield $223 million in energy savings, and an equivalent reduction in revenue for the electric utility sector. IMPLAN modeling estimated the direct losses in the electric sector to be about 200 jobs, along with additional indirect job losses of about 500, and induced job losses of about 600, for a total of slightly above 1,300 job losses. For the manufacturing sector, it was assumed that all energy savings would be reinvested to buy fuel for the CHP technologies, and to maintain the CHP technologies. IMPLAN results showed an estimated direct gain of about 600 jobs, of which roughly 42 percent were in the oil and gas extraction and utilities sector, and the remaining 58 percent were in repair and maintenance sectors. Additionally another 500 indirect and about 750 induced jobs are created in supporting industries due to these reinvestments.

Taking all of these factors into consideration, a $1.25 billion annual investment in 12.5 MW CHP systems is estimated to create a net total of about 4,500 jobs in the economy. The IMPLAN analysis showed the direct gain to be 1,300 jobs, with the highest gain in the construction

sector. Additionally, another 1,300 jobs could be created through indirect impacts, with the remaining 1,900 jobs coming from induced impacts in supporting industries.

The top ten sectors in terms of total net jobs gained annually as a result of the investment in CHP for Scenario 2 are listed in **Table 23**. As shown, most jobs are created in the machinery manufacturing and construction sectors.

Table 23. Top Ten Net Job Impacts by Economic Sector (CHP Scenario 2)

Sector	Description	Annual Net Job Impact			
		Direct	Indirect	Induced	**Total**
333	Machinery Manufacturing	1,625	57	2	**1,684**
23	Construction	1,750	-434	23	**1,339**
561	Administrative & Support Services	-59	1,106	106	**1,153**
332	Fabricated Metal Product Manufacturing	-43	412	7	**376**
811	Repair & Maintenance	307	39	29	**375**
541	Professional, Scientific, & Technical Services	-60	269	95	**304**
331	Primary Metal Manufacturing	-10	235	2	**227**
42	Wholesale Trade	-3	111	60	**168**
621	Ambulatory Health Care Services	-18	0	127	**108**
531	Real Estate	-3	-7	91	**80**

The methodology used to determine the net job impacts for Scenarios 1 and 3 was essentially the same as described above for Scenario 2. The two main components in the model that created variations in the job impact estimates between the three scenarios were the installation and labor costs for each system type. The installation and labor costs for Scenario 3 are approximately nine times higher than the comparable costs for Scenario 1. Because of the higher per unit cost for Scenario 3, the number of systems installed with a fixed amount of funding is lower compared to the other scenarios. Hence, a $1.25 billion annual investment translates to 174 CHP units in Scenario 1, 50 units in Scenario 2, and 20 under Scenario 3. This variation tracks the job impacts, where Scenario 1 creates the largest number of net jobs and Scenario 3 creates the fewest.

Table 24 shows a summary of the net job impacts for all three scenarios. The net job totals take into account job losses that occur in the electric utility sector. Scenario 1 had the lowest number of job losses in the electricity sector (1,015 jobs), followed by Scenario 2 (1,331 jobs) and Scenario 3 (1,490 jobs). Despite job losses in the electricity sector, net job impacts are positive for all three scenarios. The total jobs supported are proportional to the number of CHP systems being installed in the economy. As discussed above, all money in Scenario 1 is invested to install the smallest CHP system (3 MW), resulting in over 174 installations annually. Under Scenario 3, however, all funds are invested to install the largest CHP system (40 MW), resulting in approximately 20 installations annually. The economic analysis in this study suggests that

manufacturing and installing relatively small capacity CHP systems leads to greater job creation compared to an equal investment in relatively large capacity CHP units, likely due to economies of scale.

Table 24. Comparison of Net Job Impacts for Three CHP Systems

Scenario	Annual Net Job Impacts			
	Direct	Indirect	Induced	**Total**
1	1,904	1,189	2,070	**5,163**
2	1,311	1,296	1,877	**4,483**
3	758	1,385	1,698	**3,840**

Note: Sums may differ due to rounding.

Gross Domestic Product

Based on the results from the year 2015, an investment of $1.25 billion in Scenario 2 added approximately $200 million per year to the economy. The top ten sectors in terms of annual net GDP impacts because of the investment in CHP in Scenario 2 are listed in **Table 25**. As shown, the construction sectors add the most value to the economy.

Table 25. Top Ten Annual Net GDP Impacts by Economic Sector (CHP Scenario 2)

Sector	Description	Annual Net GDP Impacts ($ millions)			
		Direct	Indirect	Induced	**Total**
333	Machinery Manufacturing	$504.41	$6.60	$0.22	**$511.23**
23	Construction	$103.93	-$25.97	$1.67	**$79.63**
561	Administrative & Support Services	-$2.80	$48.32	$4.16	**$49.69**
332	Fabricated Metal Product Manufacturing	-$4.38	$39.61	$0.64	**$35.86**
811	Repair & Maintenance	$26.96	$2.54	$1.58	**$31.08**
541	Professional, Scientific, & Technical Services	-$5.28	$20.60	$9.87	**$25.19**
42	Wholesale Trade Business	-$0.42	$15.19	$8.20	**$22.98**
331	Primary Metal Manufacturing	-$0.92	$20.73	$0.16	**$19.97**
531	Real Estate	-$0.39	-$0.87	$10.61	**$9.35**
621	Ambulatory Health Care Services	-$1.10	-$0.02	$9.65	**$8.53**

Similar to the job impacts, there is a variation in the net GDP impact for the three CHP scenarios. Scenario 1 results in a $212 million GDP gain to the economy, followed by Scenario 2 ($189 million) and Scenario 3 ($168 million). The smaller GDP impact from Scenario 3 results in part from a slight loss of GDP through direct impacts. Scenario 3 produces the largest reduction in the demand for grid electricity, and this reduced demand results in a loss of direct GDP in the economy. **Table 26** summarizes the GDP results.

Table 26. Comparison of Net GDP Impacts for Three CHP Systems

Scenario	Annual Net GDP Impacts ($ millions)			
	Direct	Indirect	Induced	**Total**
1	$23	$16	$173	**$212**
2	$4	$28	$157	**$189**
3	-$10	$36	$142	**$168**

Note: Sums may differ due to rounding.

Trade Impacts

The IMPLAN economic modeling focused on the impacts on the national economy. International trade balance impacts were not included in this evaluation. While it is likely that there would be some changes in international trade from these investments, the IMPLAN model does not have the capability to model these effects. The majority of the impacts of CHP investments are expected to occur within the U.S. economy. While some components of the CHP technologies may be produced outside of the United States, this model was structured with the assumption that all CHP technologies will be acquired from manufacturing plants and suppliers within the United States, though some of the secondary benefits might accrue to firms outside the U.S.

6.5 Summary

Table 27 shows a summary of the end-use energy efficiency, demand response, and CHP results for Year 10 (final year of Federal matching grants). In Year 10, all technologies that were acquired over the 10-year program are assumed to remain in place, and all technologies are assumed to operate in the same manner as originally installed (e.g., no degradation in efficiency and other performance characteristics over time). Year 10 therefore represents the energy and CO_2 savings that are derived in Year 10 from all technologies acquired with $25 billion of investment. For job and GDP impacts, an underlying assumption is that these results are sustained within a single year because of the investment that occurs in that year. For jobs and GDP, there is no carry over from one year to the next.

Table 27. Summary of Results for Year 10

Description	End-Use Energy Efficiency/Demand Response Scenarios			CHP Scenarios		
	1	2	3	1	2	3
Capacity (MW)	N/A	N/A	N/A	3.0	12.5	40.0
Funding for Electric Technologies (percent)	20%	50%	80%	N/A	N/A	N/A
Funding for Natural Gas Technologies (percent)	80%	50%	20%	N/A	N/A	N/A
Total Investment Over 10 Years ($ billion)	$12.5	$12.5	$12.5	$12.5	$12.5	$12.5
Investment Rate ($ billion / yr)	$1.25	$1.25	$1.25	$1.25	$1.25	$1.25
Delivered Energy Saved (TBtu/yr)	642	499	355	-42	-118	-116
Total End-Use Energy Saved (TBtu/yr)	741	744	748	195	187	297
Value of Saved Energy to Industrial Customers ($ billion)	$5.00	$5.00	$5.00	$1.70	$1.68	$2.13
Reduced CO_2 Emissions (million MT/yr)	37	47	58	11	11	17
Job-Years	5,871	5,956	6,041	5,163	4,483	3,840
Net Jobs (per $ million invested)	4.7	4.8	4.8	4.1	3.6	3.1
Net GDP ($ million/yr)	$240	$223	$206	$212	$189	$168

As indicated in **Table 27**, the end-use energy efficiency/demand response scenarios generally provide larger benefits compared to the CHP scenarios. This outcome is driven, in part, from the relatively high performance expectation established for the portfolio of end-use energy efficiency and demand response measures. One of the underlying assumptions for the end-use energy efficiency/demand response portfolio is that these technologies have a 2½-year payback (2-year payback based on cost share provided by industrial participant). In contrast, the CHP scenarios are created using cost and performance specifications for commercially available equipment. These commercially available CHP systems have paybacks in the range of 4 to over 10 years depending on the technology and site specific operating parameters.

The scenario trends within a technology category show interesting results. For example, within CHP, Scenario 3 shows the largest value of saved energy (i.e., reduced energy bills for manufacturers that adopt technology), but shows the smallest level of jobs created in the national economy. Within end-use energy efficiency/demand response, the value of saved energy remains constant due to the assumption that the technologies have a 2½-year payback. Scenario 3 (80 percent electric) shows the lowest level of saved energy, but shows the highest level of job creation.

The Act requires that estimated economic benefits be provided at 5- and 10-year intervals for the following five metrics:

- Direct and indirect capital investment.
- Energy and emission reductions.
- Direct and indirect jobs saved or created.
- Gross domestic product.
- Trade balance impacts.

Quantitative estimates were developed for the first four bullets. The economic impact modeling conducted for this study was completed with the IMPLAN model, which does not have the capability to rigorously account for trade balance effects (last bullet in preceding list).

Table 28 shows quantitative metrics that were calculated for Year 5 and Year 10 of a hypothetical Federal industrial energy efficiency grant program. The direct capital investment is $2.5 billion in Year 5 and $5.0 billion in Year 10 (annual Federal investment rate of $500 million per year). The Federal grant funds are matched with 80 percent participant cost share (indirect investment), resulting in a total funding pool of $12.5 billion in Year 5, and $25 billion in Year 10. These funds are allocated equally across all 10 years of the hypothetical program, yielding an annual investment rate of $2.5 billion per year.

As indicated in **Table 28**, the $5 billion Federal grant program is expected to reduce annual energy consumption by 119 to 300 TBtu in Year 5, and 237 to 600 TBtu in Year 10. The value of this reduced energy consumption is expected to save participating manufacturers $3.3 to $3.6 billion per year in Year 5, and $6.7 to $7.1 billion per year in Year 10. Annual CO_2 emissions are expected to be reduced by 24 to 38 million metric tons in Year 5, and 48 to 75 million metric tons in Year 10. The grant program is expected to support approximately 9,700 to 11,200 jobs per year, which equates to 3.9 to 4.5 jobs per million dollars of investment. The GDP impact is expected to be in the range of $374 to $452 million per year.

The economic analysis did not consider impacts that might be derived from increased awareness that would be generated as a result of a $5 billion Federal grant program. Based on observations from the American Recovery and Reinvestment Act (ARRA) and other energy efficiency incentive programs, there is frequently a “spillover” effect that creates activity by market participants that do not receive incentive payments. In the case of the hypothetical $5 billion grant program, some manufacturing plants would likely move ahead with industrial energy efficiency projects even though they do not receive grant funds. These plants could decide to move ahead with an energy efficiency project that they would not otherwise consider

because of increased awareness and education resulting from the grant program. Due to modeling limitations, this spillover effect was not captured in the analysis completed for this study.

Table 28. Summary of Benefits from Grant Program
(80 percent cost share case; end-use energy efficiency/demand response plus CHP)

Benefit	Description	Year Following Start of Grant Program	
		5	10
Capital Investment	Direct Capital Investment (Federal matching grant, $ billion)	$2.5	$5.0
	Indirect Capital Investment (participant cost share, $ billion)	$10.0	$20.0
	Total Investment ($ billion)	$12.5	$25.0
	Investment Rate ($ billion/yr)	$2.5	$2.5
Energy and Emission Reductions [1]	Net Energy Impact (TBtu/yr)	119 to 300	237 to 600
	Reduced Energy Costs ($ billion/yr) [2]	$3.3 to $3.6	$6.7 to $7.1
	Reduced CO_2 (million MT/yr)	24 to 38	48 to 75
Jobs Saved or Created [3]	Average Annual Jobs Supported	9,711 to 11,204	9,711 to 11,204
	Net Jobs (per $ million invested)	3.9 to 4.5	3.9 to 4.5
Net Gross Domestic Product ($ million/yr) [3]		$374 to $452	$374 to $452

Notes: 1) Energy and emission reductions were estimated with an Excel model, and the results shown in the table are cumulative for the year shown in the table heading (grant program Year 5 or Year 10).
2) Reduced energy costs are cumulative. The single year value for reduced energy costs in Year 5 of the grant program is $670 million to $710 million. The single year value for reduced energy costs in Year 10 is identical to Year 5, which is consistent with a constant annual investment rate.
3). Jobs saved or created and gross domestic product were evaluated with IMPLAN. IMPLAN is a static model that does not account for cumulative effects. The values shown are the impacts in a single year. The results are identical for Year 5 and Year 10 of the grant program, which is consistent with a constant annual investment rate.

Endnotes

[1] Section 7 of the Act is contained in the front matter of this study. Economic benefits are discussed in Section 7(b)(2)(C). The complete Act can be accessed at Web link.

[2] "Cost Sharing and DOE Financial Assistance Awards," Web link.

[3] These job impacts could be interpreted as job-year or full time equivalent (FTE) jobs.

[4] This translates into 4.8 jobs per $1.0 million invested.

[5] U.S. Census Bureau, Census of Manufactures 2010.

[6] CHP Installation Database, Web link.

[7] Energy Information Administration (EIA), AEO 2013. Energy savings estimates are based on electricity cost of $17.88 per MMBtu and natural gas cost of $4.42 per MMBtu (2011 dollars).

7. Energy Savings from Increased Recycling

The Act requests to estimate energy savings from increased use of recycled material in energy-intensive manufacturing processes. The specific language is:[1]

> *[… shall conduct a study of …the] estimated energy savings available from increased use of recycled material in energy-intensive manufacturing processes.*

Estimating the benefits and impacts of recycling can be a complex undertaking. For estimating specifically the energy impacts of increased recycling, there are several analysis concepts that can be considered. The most comprehensive analysis concepts include life cycle analysis (also called cradle-to-grave analysis), environmental impact assessment, cost-benefit analysis, and regulatory impact analysis (if increased recycling is introduced as a regulation). For these concepts, the usual goal is to provide an overarching assessment (with energy as only one of several factors being analyzed) of the impacts of recycling.

However, the Act asks for the estimated energy savings only, so a simpler assessment methodology focusing only on energy savings was a major consideration. Nevertheless, there are complexities as well when focusing only on energy impacts of recycling. Each product that is manufactured and ultimately enters the waste stream has energy impacts at each stage of its life cycle – raw material acquisition, manufacture of the products, use of the products and disposal. Section 7 (Reducing Barriers to the Deployment of Industrial Energy Efficiency) of the Act, under which this analysis is requested, focuses on barriers to deployment of industrial energy efficiency. As such, it was assumed that the analysis would focus on how recycling can support the increase in industrial energy efficiency. It was assumed that this meant energy savings in the industrial plant or within the realm of the industrial sector only. Further, as the specific statement from the act states to estimate "…energy savings available increased use of recycled material in energy-intensive manufacturing processes", which is interpreted to focus on energy savings on energy intensive manufacturing processes.

A further complication of the analysis is data availability. As is typical in any industrial sector analysis, data can be sparse. For this study, most the data used were from the U.S. EPA, industry and trade associations, and recent studies. In cases where data were grossly unavailable or severely weak, it was decided to exclude those cases from the study. An example of this situation is the data source for supply of waste materials and recovery rates. This study was limited to focus only on MSW sources of waste materials since data are abundant. Useful data on recycling and recovery from other sources of waste materials (e.g., construction and debris) are not available and so were excluded from the study.

Thus, as will be presented in this section, the analysis approach used for this study may be seen as limited to experts in the recycling field. However, the limits were intentional (so that the analysis will be more focused on the objectives of the Act) and were also due to inherent data issues. This chapter discusses estimated energy savings from increased recycling possible with currently deployed technologies, including the assumptions and approach used to derive these estimates. This chapter is organized as follows:

- Section 7.1—Introduction
- Section 7.2—Current Use of Recycled Materials and Opportunities for Increased Use
- Section 7.3—Framework for Analyzing Possible Energy Savings from Increased Recycling
- Section 7.4—Estimated Energy Savings from Increased Recycling
- Section 7.5—Summary

7.1 Introduction

EPA defines recycling as collecting and processing materials that would otherwise be thrown away and turning these materials into new products.[2] It excludes the reuse of products (e.g., clothes and furniture donated to charitable organizations for use by others), as well as the use of the waste product as a fuel source. Recycling provides opportunities to reduce energy use, decrease carbon dioxide emissions, and minimize the quantity of waste requiring disposal. This chapter provides an estimated range of energy savings that might be expected in the manufacturing sector from increased recycling.

Based on information from EPA, **Table 29** shows non-hazardous materials that are recovered for recycling in the United States:[3]

Table 29. Non-hazardous Materials Recovered for Recycling

Aluminum	Disaster Debris	Scrap Tires
Antifreeze	Food Waste	Steel
Automotive Parts	Glass	Textiles
Batteries	Household Hazardous Waste	Used Oil
Composting	Paper	Yard and Wood Waste
Consumer Electronics	Plastics	

While many products are recycled, this study focuses on how energy can be saved by recycling in the following energy-intensive industries:

- Paper
- Aluminum

- Glass
- Steel
- Plastics

Table 30 shows the energy intensities of the paper, aluminum, glass, steel, and plastics industries and compares them to the energy intensities of the total manufacturing group. Three energy intensity metrics are shown: energy consumption per employee, energy consumption per dollar of value added, and energy consumption per dollar of value of shipments. The table shows that for each metric, the energy intensities of the above industries are much higher than the intensities for total manufacturing. The previous chapters discussed how these industries could be more energy efficient through end-use energy efficiency, demand response, and CHP investments. This chapter discusses how the recovery and use of recycled products can save energy in energy-intensive industries.

Table 30. Energy Intensities of Industries, 2010

Industry	Energy Consumption Metric		
	Million Btu per Employee	**Thousand Btu per Dollar of Value Added**	**Thousand Btu per Dollar of Shipments**
Paper (NAICS 322)	6,022	26.4	12.1
Alumina and Aluminum (NAICS 3313)	4,517	25.7	6.8
Glass Containers (NAICS 327213)	4,380	20.2	12.2
Steel (NAICS 331111)	12,697	29.8	9.3
Plastics (NAICS 325211)	8,583	17.3	6.2
All Manufacturing (NAICS 31-33)	**861**	**4.8**	**2.2**

Source: EIA Manufacturing Energy Consumption Survey, 2010

The analysis in this chapter does not include the cement industry. The chemical process used to create cement is irreversible and cement cannot be recycled.[4] It is important to recognize, however, that concrete—a mixture of cement, sand, gravel, and water—can be recovered and reused. Also, cement manufacturers consume alternative fuels such as recycled tires and plastics.[5,6,7] While these benefits are significant, they do not have a direct impact on the energy-intensive cement production process. Because cement cannot be recycled and concrete recycling does not have a direct impact on the cement production process, the cement industry was not included in the recycling analysis prepared for this study.

Conceptual frameworks used to describe recycling include:[8]

- *Primary* or closed-loop recycling, in which the recycled product is mechanically reprocessed into a product with equivalent properties. This category also includes

recycling of products to replace all or some of the virgin materials. The five products listed in **Table 30** have been successfully recycled under this category.

- *Secondary* or downgrading, in which the recycled material is mechanically reprocessed to produce another product generally viewed to have lower quality or value. Examples include recycling plastic bottles and milk jugs to form plastic lumber or the use of recycled glass as road-bed aggregate or cover at landfill operations.
- *Tertiary* recycling, where chemical constituents from the waste material are recovered. Despite being technically feasible, this type of recycling is generally not cost-effective.[9]

The intent of the analysis in this chapter is to determine energy savings that could be derived from increasing the amount of recycled material used as a manufacturing feedstock. To focus the evaluation, only primary recycling is considered where the recycled material is used to produce a product similar to the original. Downgrading (secondary recycling) and chemical recovery (tertiary recycling) are not included in the evaluation.

Within the industry, the term "secondary process" is often used to describe a process that uses recycled material in either a primary or secondary recycling framework (see preceding bullets). In the remainder of this chapter, the term "secondary process" is used exclusively to mean the use of recycled material in a primary recycling framework.

The remainder of this introduction provides background on the five energy-intensive industries previously mentioned—paper, aluminum, glass, steel, and plastics (Sections 7.1.1–7.1.5). These industries were selected based on statutory guidance that directs the recycling analysis to focus on energy intensive manufacturing processes (see Statutory Requirement on page iii, (b) (2) (D). Section 7.2 discusses the current level of recycling in these industries, Section 7.3 describes two possible scenarios (modest and aggressive) with currently deployed technologies for increased recycling, Section 7.4 provides the energy savings results from these scenarios, and Section 7.5 provides a brief summary of key findings.

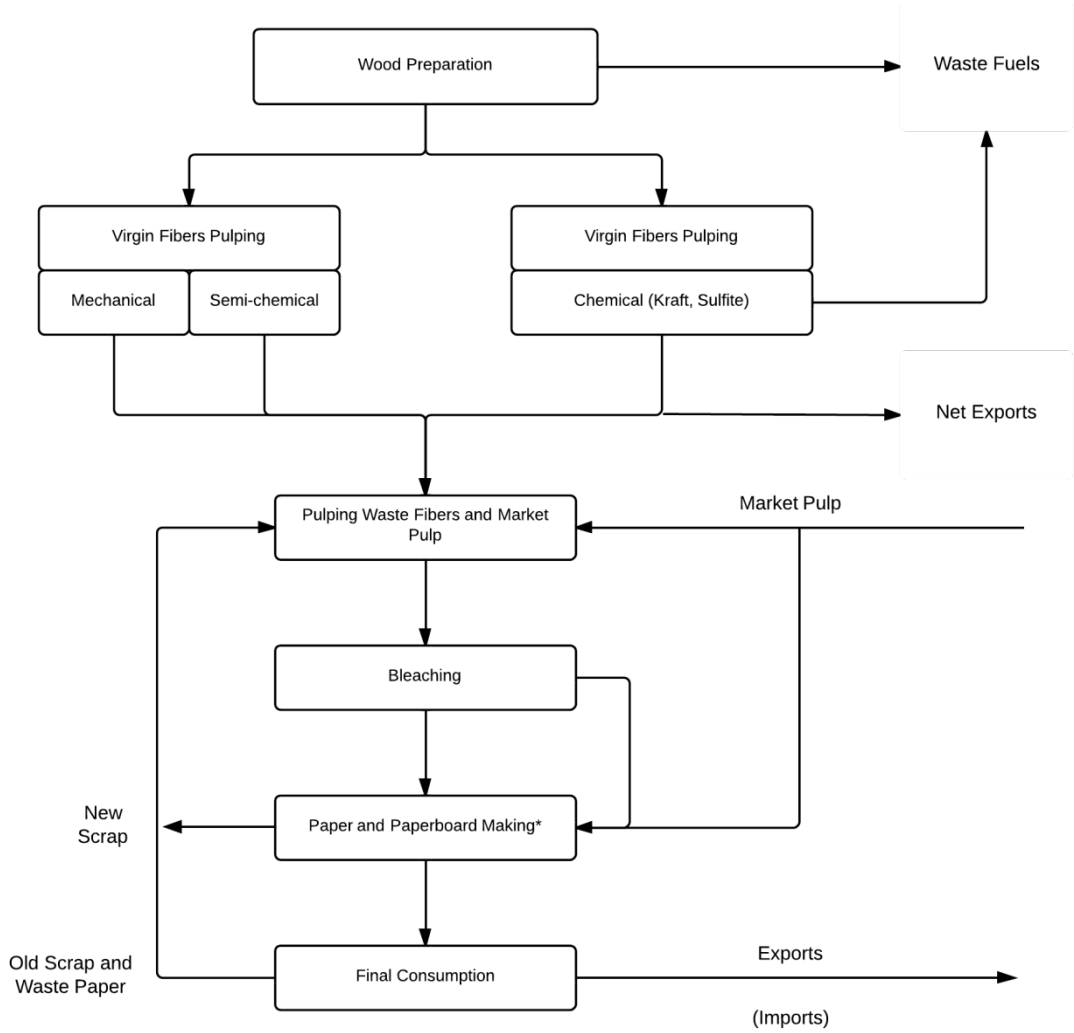
7.1.1 Paper

Figure 45 shows a simple flow model of paper production, illustrating the various processes, including the incorporation of recycled (scrap) paper in paper production. Paper is made from pulp, which in turn is created from a variety of sources including wood products and recycled paper products. The two main methods for deriving pulp from wood are through a chemical process or a mechanical process, both of which are energy-intensive.

The dominant method for producing pulp in the United States is through the chemical process (Kraft, sulfite). The chemical process uses "white liquor"—a mixture of sodium hydroxide

(NaOH), sodium sulfide (Na_2S), and other chemicals—to break down lignin bonds holding the cellulosic fibers together in a process known as "cooking." After being cooked, the pulp is separated from the liquor, washed, and dried. The chemical process creates strong paper, which is used to make products like boxes, paper bags, wrapping paper, writing paper, paperboard, and diapers. Yields from chemical pulps average about 45 percent of the original virgin feedstock.[10]

Figure 45. Paper Production Process Flow



Source: EIA NEMS Industrial Model Documentation, 2013

The mechanical process—which includes the groundwood and thermomechanical processes—loosens the lignin bonds by pressing the wood chips against a grinder, or refiner plate. In the thermomechanical process, the wood chips are heated before they are ground. The mechanical process creates weaker paper but yields 95 percent of the original virgin feedstock.[11] Mechanical pulps can be used to make products such as newsprint, printing papers, specialty

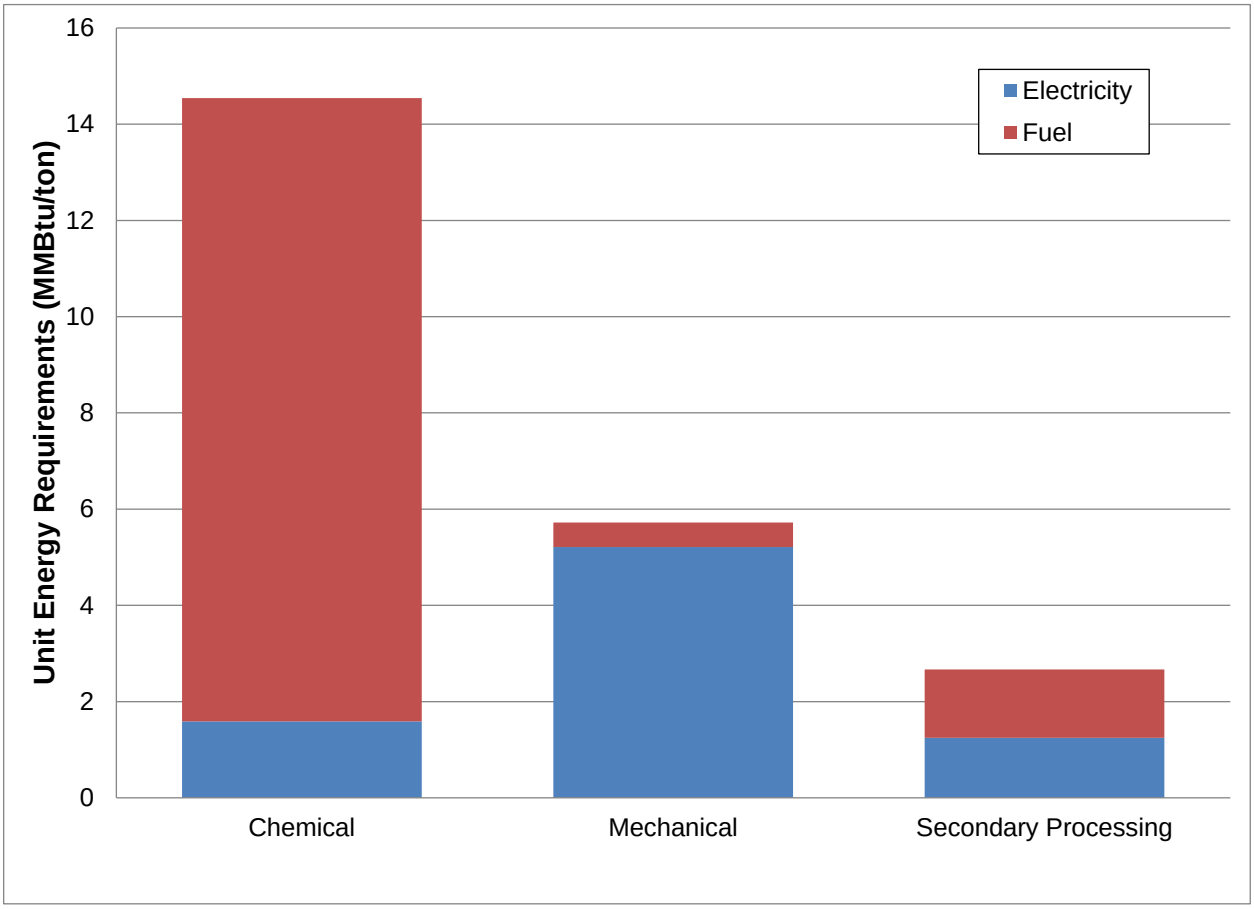
papers, tissue, toweling, paperboard, and wallboard. After pulping, the pulp mixture is converted into paper and paperboard products by performing several more steps such as washing, bleaching (if needed), forming, pressing, and drying. In addition, other energy-intensive auxiliary processes are performed, particularly for chemical pulping. These processes include lime calcining, pulp drying (for market), and recovery of chemicals and using them as fuel in recovery boilers.

Producing paper products from recycled material is a much less resource-intensive process compared to producing paper from virgin material. Production with recycled materials begins with several preprocessing steps: sorting, collection, transportation, and storage. When recycled paper is processed for use, it is moved to a big vat (pulper) of water and chemicals. In the pulper, the recovered paper is chopped into smaller pieces. The pieces are further broken down to fibers by heating, which eventually turns them into recycled pulp. The pulp is further processed by screening to remove small contaminants and further cleaned by spinning and deinking. Deinking is the process of removing printing ink and glue residue and adhesives. After deinking, the pulp is refined to remove any large bundles of fibers and remove dyes from the paper. If white paper is being made, the pulp is bleached.

The resulting recycled fiber can be used alone, or blended with virgin fiber to make it stronger or smoother. The pulp is further processed with water and chemicals, then drained and rolled. The resulting sheet is then dried through heated metal rollers. Final processing and coating, if needed, is then performed. In general, recovered paper is recycled back to a similar or lower grade than the original product.

Figure 46 compares the unit energy requirements of paper production using chemical pulping of virgin fibers, mechanical pulping of virgin fibers, and using recycled paper in a secondary process. In the figure, fuel includes all non-electricity energy sources. The figure shows large differences in energy requirements between the virgin chemical, virgin mechanical, and recycled paper processes. Making pulp from recycled paper saves over 80 percent of energy compared to the virgin fiber chemical process and saves over 50 percent compared with the virgin fiber mechanical process.

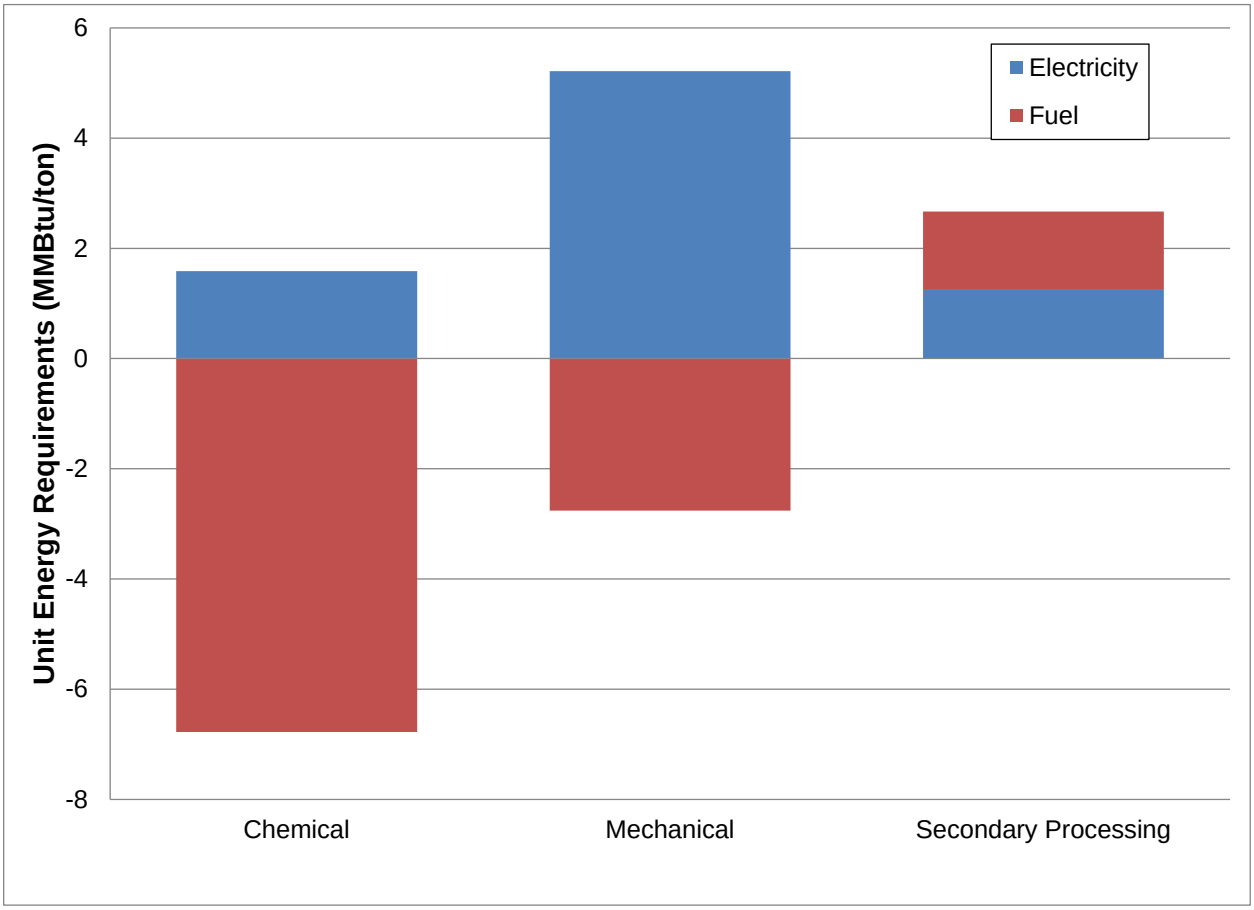
Figure 46. Paper Unit Energy Requirements, Excluding Use of Byproduct Fuels



Source: U.S. EIA, September 2013

One important factor that **Figure 46** does not take into account is the generation and on-site use of paper manufacturing byproduct fuels in the chemical and mechanical pulping methods.[12] When these are taken into account, the picture is significantly different (**Figure 47)**. When byproduct fuels are included in energy use accounting, chemical pulping shows negative energy use (i.e., net energy producer), mechanical pulping energy is reduced substantially, and recycled paper use becomes the process with the highest unit energy requirement. Chemical and mechanical pulping processes are net energy producers because they generate more byproduct fuels than they use during the manufacturing process. The excess fuels are frequently used to generate steam, which is then used for downstream processes such as bleaching and paper drying. The production of byproduct fuels makes the energy analysis more complex, as discussed later in this chapter.

Figure 47. Paper Unit Energy Requirements, Including Use of Byproduct Fuels



Source: U.S. EIA, September 2013

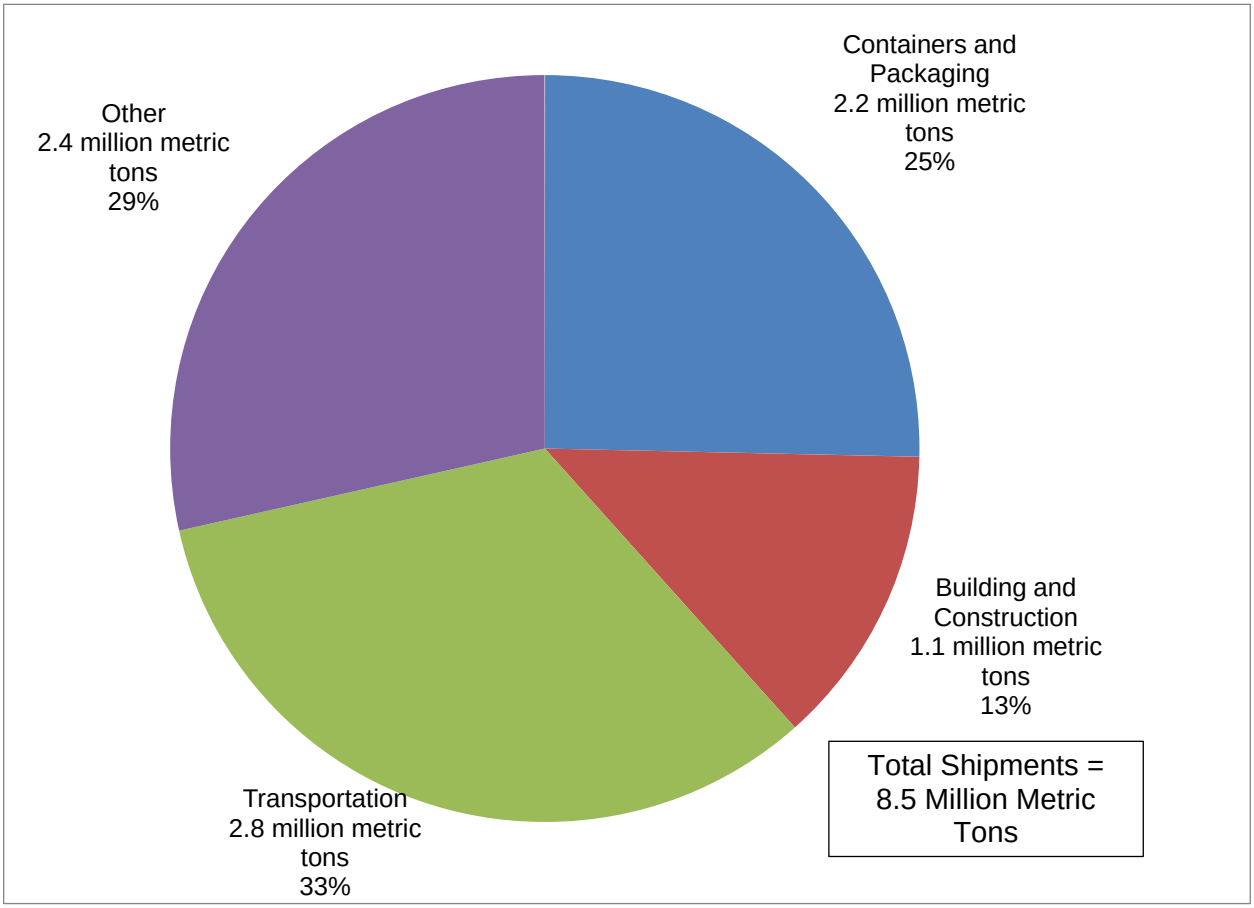
7.1.2 Aluminum

Aluminum is the most abundant metallic element and the third most abundant of all elements in the earth's crust. It is used in many applications because of its strength and its lightweight characteristics. It is corrosion-resistant and is an excellent conductor of electricity and heat. As indicated in **Figure 48**, the three largest applications of aluminum in the United States are transportation (33 percent), containers and packaging (25 percent), and building and construction (13 percent).[13]

Significant growth in the use of aluminum in the automobile industry has occurred in the past 15 years, specifically in transmissions and wheels. Container and packaging applications include aluminum beverage cans, food containers, and household and industrial aluminum foils. Aluminum beverage cans are the single largest use of aluminum in the container and packaging sector. In 2011, 93.6 billion aluminum cans were sold.[14] Aluminum beverage cans are also one

of the largest sources of recycled aluminum. The principal uses of aluminum in the construction industry are interior and exterior building applications, including window frames, roofing, siding, and air ducts for heating, ventilating, and conditioning (HVAC).

Figure 48. U.S. Aluminum Shipments, 2011



Note: Transportation applications for aluminum include airplanes, trucks, buses, railroad cars, and tractor trailers.

Source: U.S Geological Survey—Aluminum, 2013

Because of its innate ability to bond, aluminum is not found in its pure form in nature. The production of primary aluminum (produced from virgin ore) consists of five stages: mining of bauxite (the primary raw material), production of alumina, primary aluminum production, aluminum fabrication, and production of finished products.

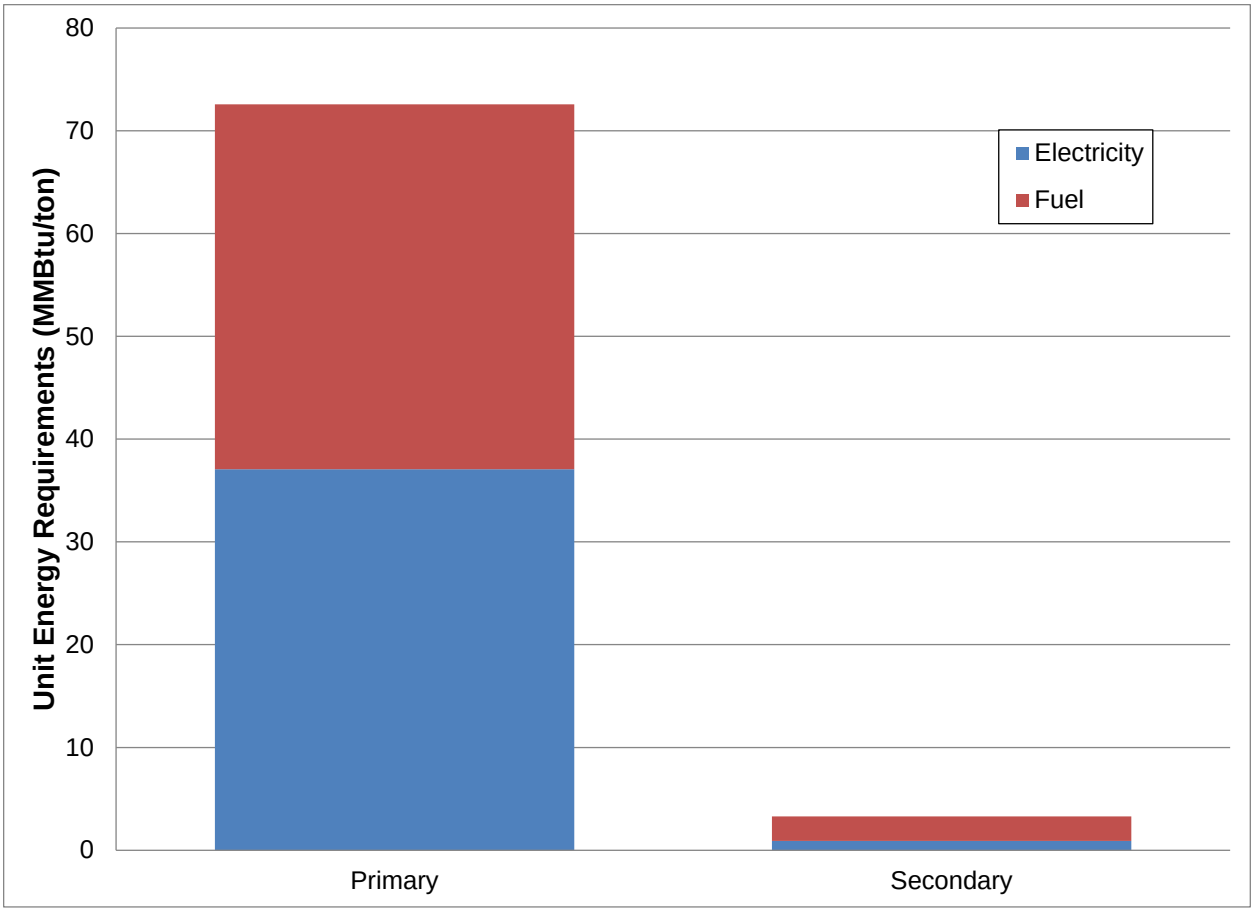
Primary aluminum production begins with the mining of bauxite in open pits. After the bauxite is crushed, it is processed using the Bayer process, which converts the aluminum in the bauxite to alumina. The alumina is then transported to a smelting plant, where primary smelting occurs using the electrolytic Hall-Heroult process. The Hall-Heroult process is one of the most electric-intensive manufacturing processes in the industrial sector. After the aluminum alloy is made, it

is transported to semi-fabrication plants that produce aluminum products such as metal sheets, plates, and forged parts. The semi-fabricated products are then shipped to fabrication plants, where finished products are made for consumers.

Unlike primary aluminum production, secondary aluminum production (using recycled aluminum scrap) is relatively simple. The first step is preprocessing, which involves the crushing, shredding, and drying of the scrap. This step also removes contaminants to minimize air pollution from the melting furnace and to lower the amount of oxidation during the melt process. The process of melting aluminum scrap uses reverberatory furnaces. These are fossil-fired, usually with natural gas.

Figure 49 compares the unit energy requirements between primary and secondary aluminum production. The unit energy requirements for secondary aluminum are less than 5 percent of the unit energy requirements for primary aluminum.

Figure 49. Aluminum Unit Energy Requirements



Source: PE Americas, 2010

7.1.3 Glass

The U.S. glass industry consists of flat glass, container glass, and pressed/blown glass. Each of these product types has a different set of consumers and markets. Container glass, which has the highest production level among the three, is used primarily in the food and beverage industries. Flat glass is used primarily in the construction and automotive industries, while pressed/blown glass, which is the smallest among the three, is used for tableware, kitchenware, and electronic products.

Glass production is an energy-intensive process. The major processes involved in the production of glass are similar across the major products. There are four major process steps in glass production: (1) batch preparation, (2) melting and refining, (3) forming, and (4) post-forming. Batch preparation involves mixing the raw materials, including silica, limestone, and soda ash. Other ingredients are added depending on the type of glass being produced. Cullet, which is recycled glass, is also added into the batch.

The melting and refining of the batch is the most energy-intensive step. Depending on the type of glass being produced, the batch is processed in different types of furnaces and at different temperatures. Glass-melting furnaces, which are mostly fueled with natural gas, are capital-intensive to build. To avoid thermal cycling damage, these furnaces are designed for continuous operation. It is not uncommon for glass melters to operate continuously for many years, 365 days, 24 hours per day.

The forming step is highly dependent on the final product. The forming step for flat glass includes either the float process or the rolling process. For container glass, the forming stage includes blowing and pressing processes. The post-forming step includes a variety of processes that finalize the glass product requirements. This step might involve annealing, tempering, coating, and other finishing processes.

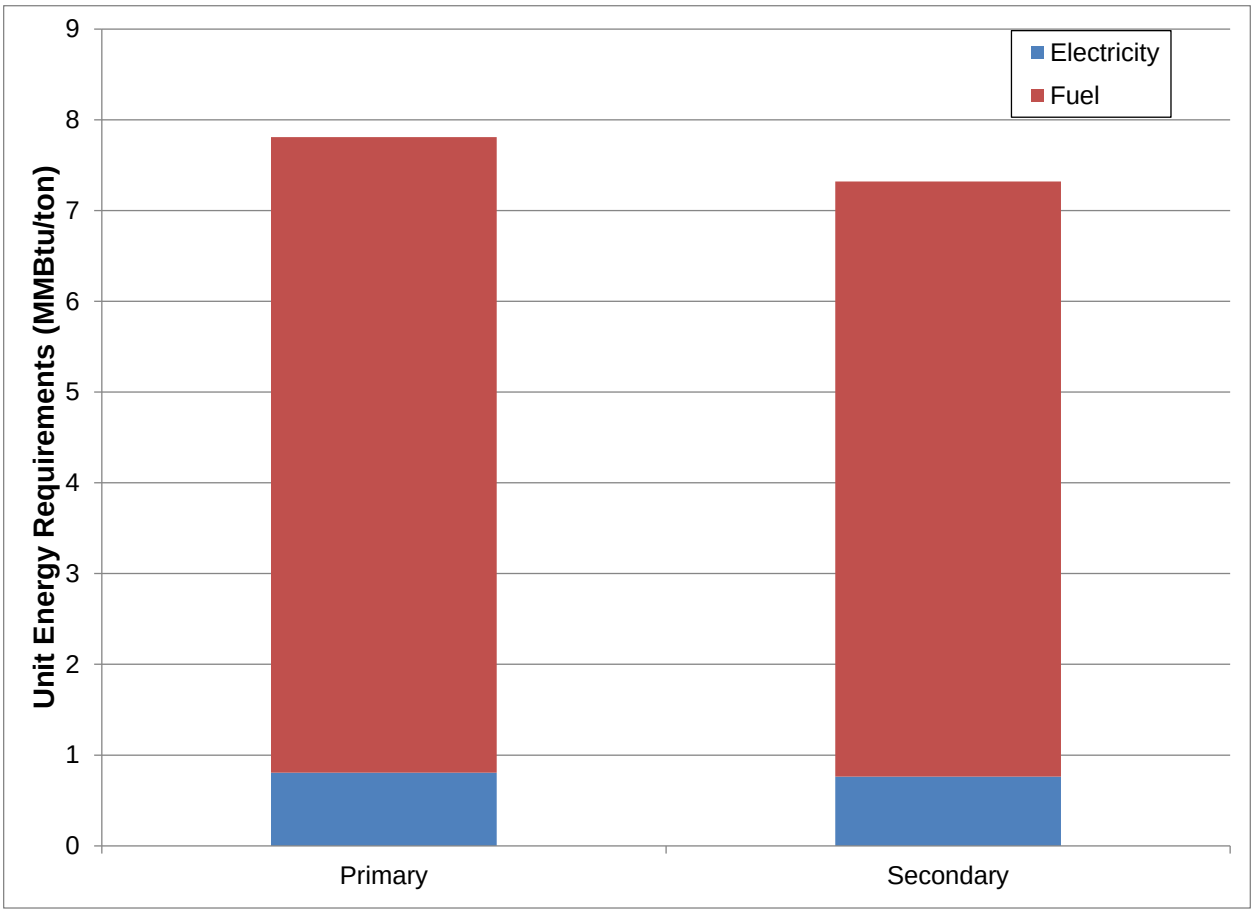
Glass can be recycled an indefinite amount of times without loss of quality. As mentioned above, cullet (recycled glass) is usually mixed with the glass batch. This mixing has important benefits, including lower raw material and processing costs, reduced landfill wastes, and lower energy costs. However, to use recycled glass effectively, the recycled material must be free from contaminants such as ceramics and metals. In addition, most glass needs to be separated by color. As such, the collection, separation, and processing of recycled glass is critical.

The collection of recycled glass includes several methods. The most prevalent are curbside collection, bottle deposits, and post-consumer collection (e.g., at public venues). When recycled glass is mixed with other recyclables during collection, contaminants present a significant problem for manufacturers. Therefore, separating the glass from other materials is a critical

step. Currently, most sorting is done mechanically and is labor-intensive.[15] If problems in acquiring quality cullet are overcome, energy savings are significant. Glass recycling has been shown to save 2 to 3.5 percent of energy for every 10 percent of recycled glass used in the manufacturing process.[16] Recycled glass could come from glass waste in the glass plant itself, or from post-consumer recycling. Glass manufacturers already capture glass waste from the plant; thus, the opportunity for increased glass recycling is based on increased supply of uncontaminated post-consumer glass.

Figure 50 shows the unit energy requirements of glassmaking using 100 percent virgin raw materials, and glassmaking using 75 percent virgin raw materials and 25 percent recycled glass. With the use of 25 percent recycled glass, and assuming a 2.5 percent energy savings for every 10 percent use of recycled glass, energy savings is around 6 percent.

Figure 50. Glass Unit Energy Requirements



Source: Worrell, Ernst, et al., March 2008

7.1.4 Steel

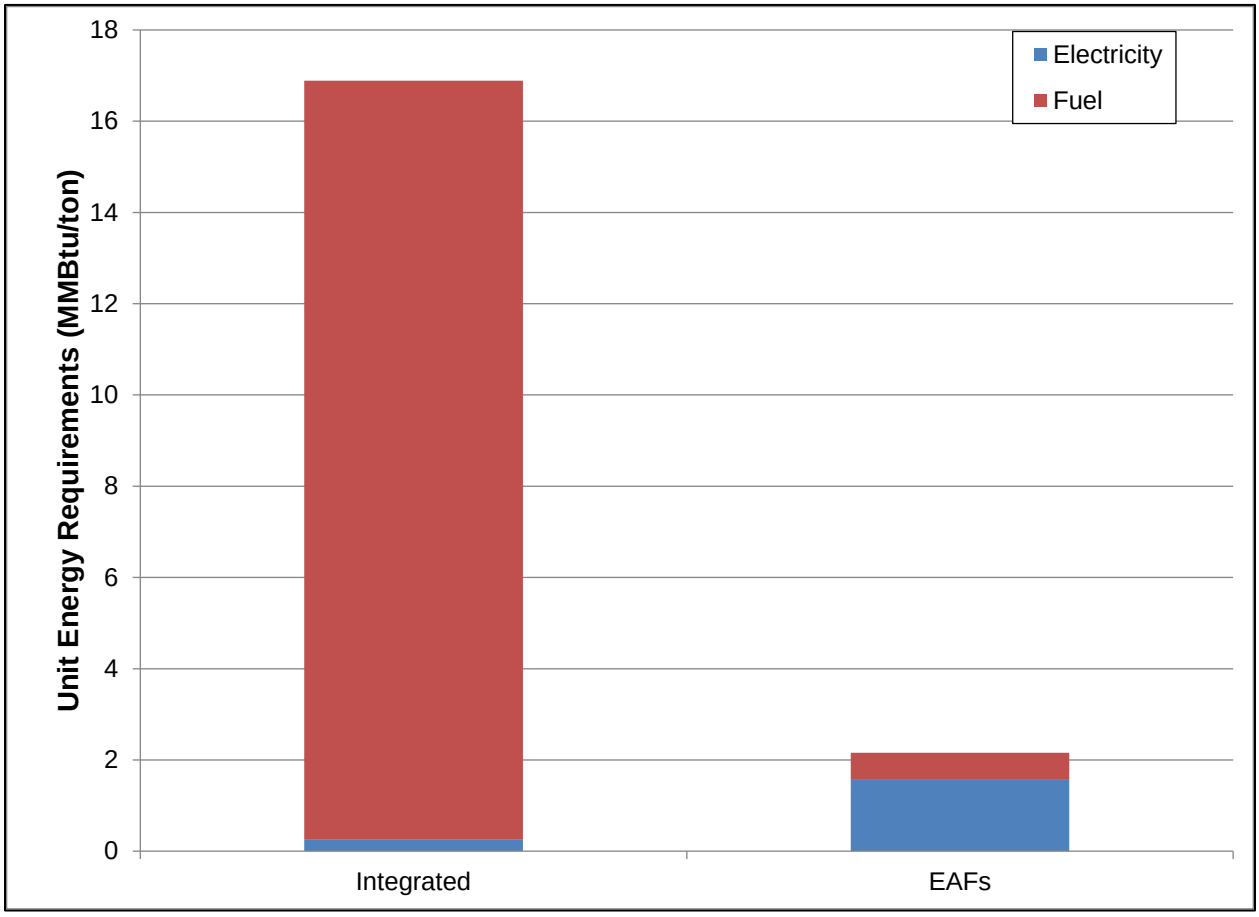
Steel is a widely used commodity. It is one of the largest bulk commodities in commercial use, having many structural applications, and it competes for applications with other structural materials such as aluminum, plastics, and wood. Steel is produced in many forms, including sheet and strip, structural beams and plates, bars, pipes and tubes, wire and wire products, and tin mill products. The markets for steel are many and diverse, with the major markets being automotive, steel service centers, construction, machinery and equipment, containers and packaging, and the oil and gas industry.

Steel producers can be classified as either integrated plants or mini-mills. An important feature of energy use in the steel industry is the marked difference between integrated mills and mini-mills in the types of fuels used and the level of energy use. In integrated plants, where the major iron-bearing raw material is iron ore, reducing the ore to molten pig iron in a blast furnace is the most energy-intensive step. The coke that is used as the reducing agent is produced by carbonizing coal in coke ovens. Both coke ovens and blast furnaces produce byproduct fuels. Use of these byproduct fuels is a characteristic feature of energy consumption in integrated mills. The major byproduct formed in coke ovens is coke oven gas, a mixture consisting primarily of hydrogen and methane. Other byproducts are tar and pitch (similar to heavy oil) and breeze, a finely powdered coke. The off-gas produced in the blast furnace, called blast furnace gas, consists mainly of nitrogen, carbon dioxide, and carbon monoxide. In an integrated steel plant, these internally generated fuels are used in various on-site processes and supplemented by purchased fuels. After the pig iron is produced in the blast furnace, it is converted to steel in a basic oxygen furnace (BOF).

Mini-mills produce raw steel by melting recycled steel scrap in electric arc furnaces, thereby, eliminating the coking and iron-making steps. Hence, mini-mills do not consume metallurgical coal. Also, they rely heavily on purchased fuels, since byproduct fuels are not available. The consumption of electricity is proportionally higher in a mini-mill compared to an integrated plant because the sole steelmaking technology in a mini-mill is the electric arc furnace (EAF).

Figure 51 compares the unit energy requirements between iron and steelmaking using the integrated process (metallurgical coal, blast furnace, and BOF) and the use of EAFs, which use steel scrap. The figure shows that the electricity requirement for the EAF is higher (six times) than for the primary process. However, for fuel, the EAF unit energy requirement is less than 4 percent of the primary process. Overall, EAF saves 87 percent of energy used in the primary process.

Figure 51. Iron and Steel Unit Energy Requirements



Source: U.S. EIA, 2013

7.1.5 Plastics

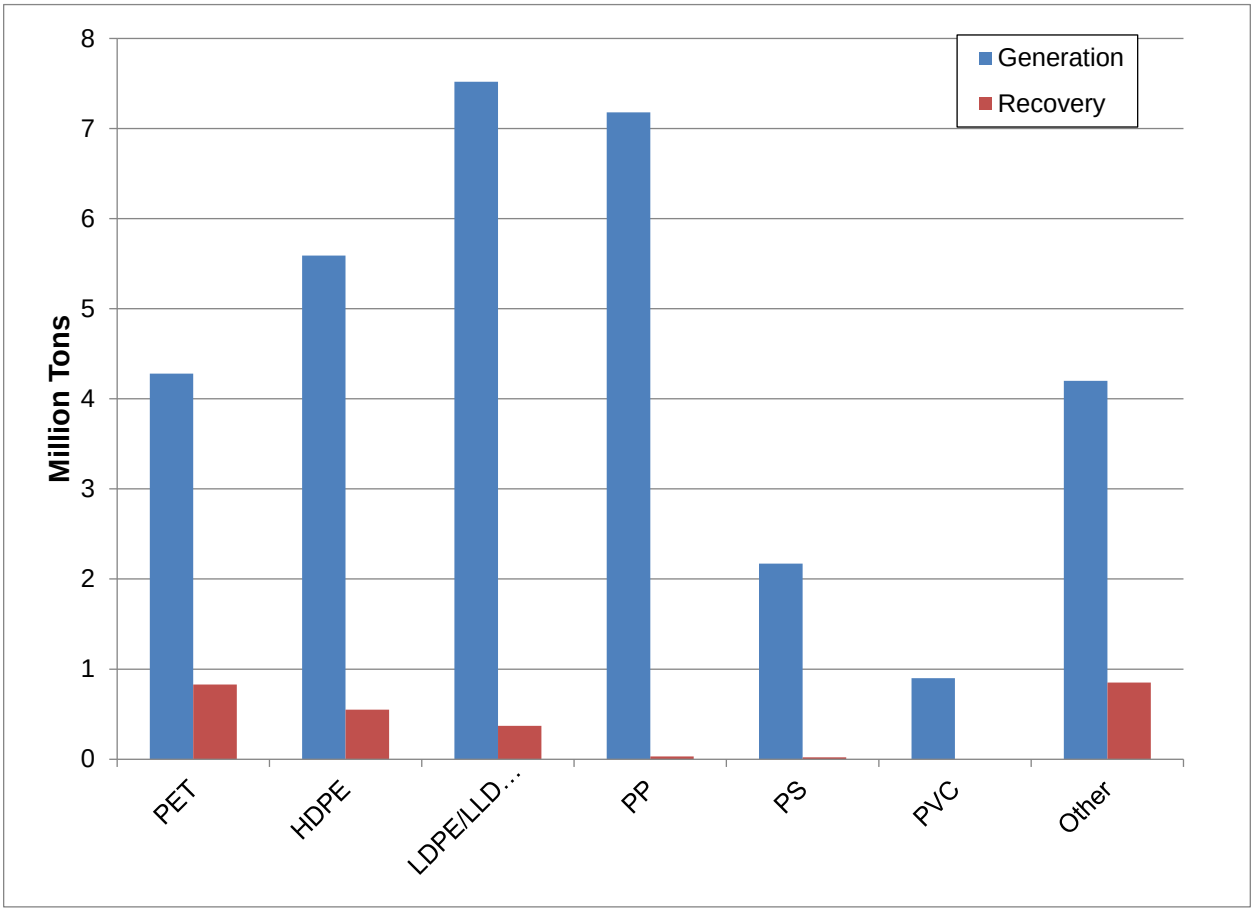
Plastics are synthetic materials that are molded into a variety of shapes by applying heat and pressure. There are two groups of plastics: thermoplastics and thermosets. Thermoplastics can be repeatedly melted and re-formed without any major property changes. Thermosets, in contrast, are cross-linked plastics that cannot be re-melted or reprocessed without major property changes. Thus, thermoplastics (e.g., polyethylene) can be recycled, but thermosets (e.g., polyester) cannot.

The major thermoplastics in the U.S. waste stream are polyethylene terephthalate (PET), high density polyethylene (HDPE), low density polyethylene (LDPE), linear low density polyethylene (LLDPE), polyvinyl chloride (PVC), polypropylene (PP), and polystyrene (PS). These thermoplastic materials comprise the vast majority (87 percent) of plastics in the waste stream. Common uses for these plastics include the following:

- PET is used in soft drinks packaging (PET bottles) and some synthetic fibers. It has a high recovery rate among plastics.
- Polyethylene (PE), because of its versatility, is used for various packaging materials. PE is used to make LLDPE (used to make stretch wrap), LDPE (used to make plastic bags), and HDPE (used to make jugs).
- PVC is used primarily in plumbing and other construction applications, although it is sometimes used for synthetic leathers.
- PP has many varied applications such as film and automotive interiors.
- PS is used to make Styrofoam and rigid products such as drinking straws and coffee cups and lids, and takeout containers.

Figure 52 shows the breakdown of plastics in municipal solid waste (MSW), showing generation and recovery by resin type.[17] The figure shows that the main recycled plastic resins are PET, HDPE, and LDPE/LLDPE. These resins account for 55 percent of total plastics generated in MSW and 66 percent of recovered plastic products. Thus, these resins are the focus of this analysis.

Figure 52. Generation and Recovery of Plastic Wastes, 2011



Source: U.S. EPA, May 2013

The post-consumer recycling of plastic bottles and milk jugs consists of several stages: collection, sorting, cleaning, size reduction, and separation of different polymer types. The collection of recycled plastics includes several methods. The most prevalent are curbside collection, plastic bottle deposits, and post-consumer collection (e.g., at public venues). The sorting process, which separates the plastic from the non-plastic material and which separates different polymers from one another, is a critical step. Currently, sorting is done mechanically and is labor-intensive. New technologies are being developed to streamline sorting, including froth flotation, density separation, and others.

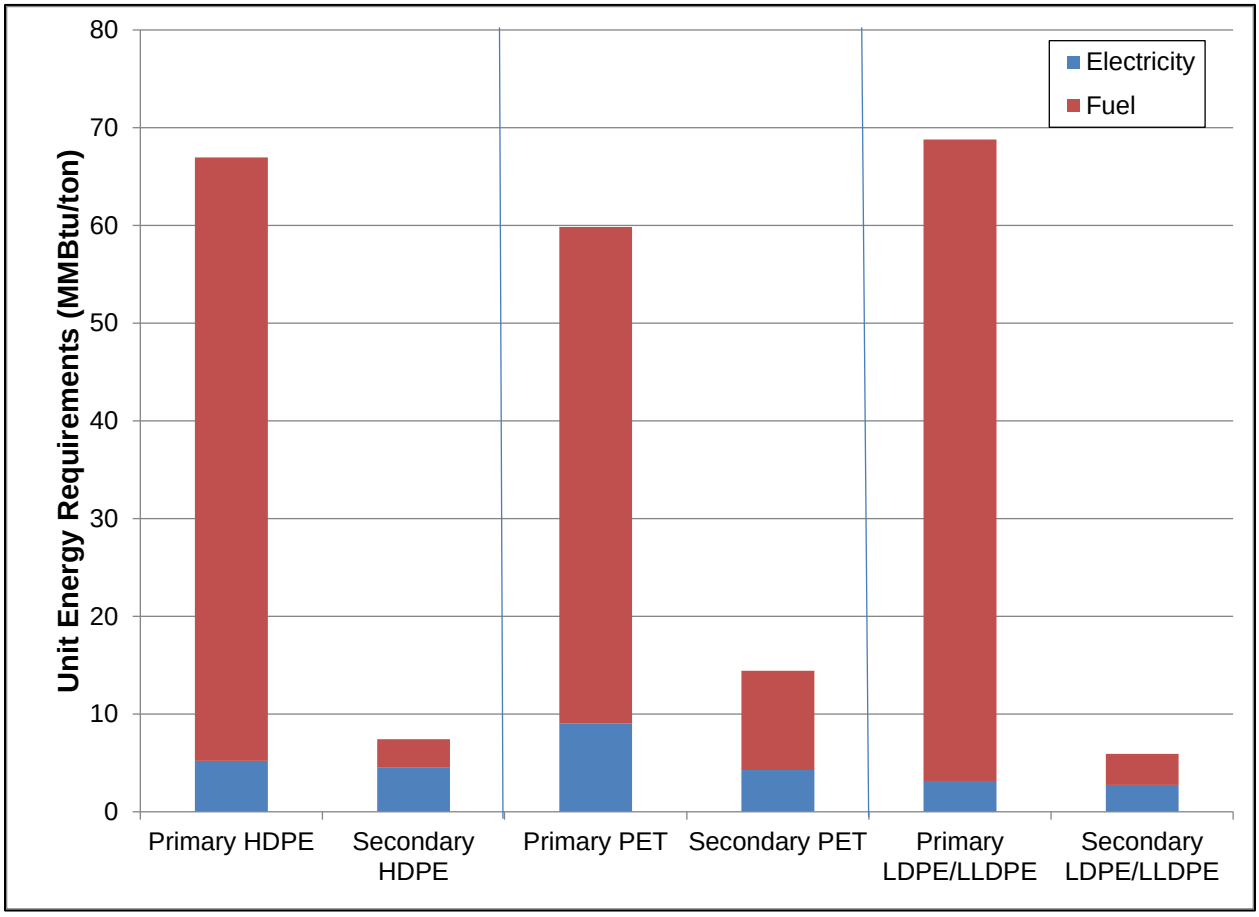
A critical challenge in the production of resins from plastic wastes is that different plastic types are not compatible with one another because they are not molecularly immiscible. Further, there are major differences in processing requirements. Usually, it is not technically feasible to add recovered plastic to virgin polymer without compromising some quality properties (e.g., color or clarity) or mechanical properties. The blending of recycled resin with virgin resin is usually performed with polyolefin films for applications such as refuse bags, and certain types

of irrigation or drainage pipes. The substitutability of virgin polymer with recycled plastic depends on the purity of the recovered plastic feed and the property requirements of the plastic product to be manufactured. Because recovered plastics need to be properly identified for recycling purposes, post-consumer waste collection systems typically concentrate on the most easily separated packages, such as PET soft-drink and water bottles and HDPE milk bottles, which can be positively identified and sorted out of a commingled waste stream.[18]

The manufacture of plastic resins requires substantial amounts of fuel, particularly oil and natural gas liquids, as these are typically the main raw materials in making plastics. PET, HDPE, and LDPE/LLDPE are all resins made from ethylene (an olefin). Ethylene is an energy-intensive chemical product that requires substantial amounts of oil or natural gas liquids as feedstock. The feedstocks are broken down to ethylene, propylene, and butadiene at relatively high temperatures. These molecules are processed to create polymers, which are then used to make resins such as PET, HDPE, and LDPE/LLDPE. In the secondary process, after the recycled plastic materials are sorted, they are cleaned, washed, and shredded. Next, the materials are tested, identified, classified, and mixed with virgin polymer resins. These resins, which are a mixture of virgin and recycled polymer, are then used to manufacture plastic products.

Figure 53 compares the unit energy requirements between (1) virgin PET and recycled PET manufacturing; (2) virgin HDPE and recycled HDPE manufacturing; and (3) virgin LDPE/LLDPE and recycled LDPE/LLDPE.[19] The figure shows that there are significant differences in the unit energy requirements between the primary process and secondary process for each of the resins, and that substantial energy savings are incurred when recycled materials are used instead of producing virgin polymers.

Figure 53. Plastics Unit Energy Requirements

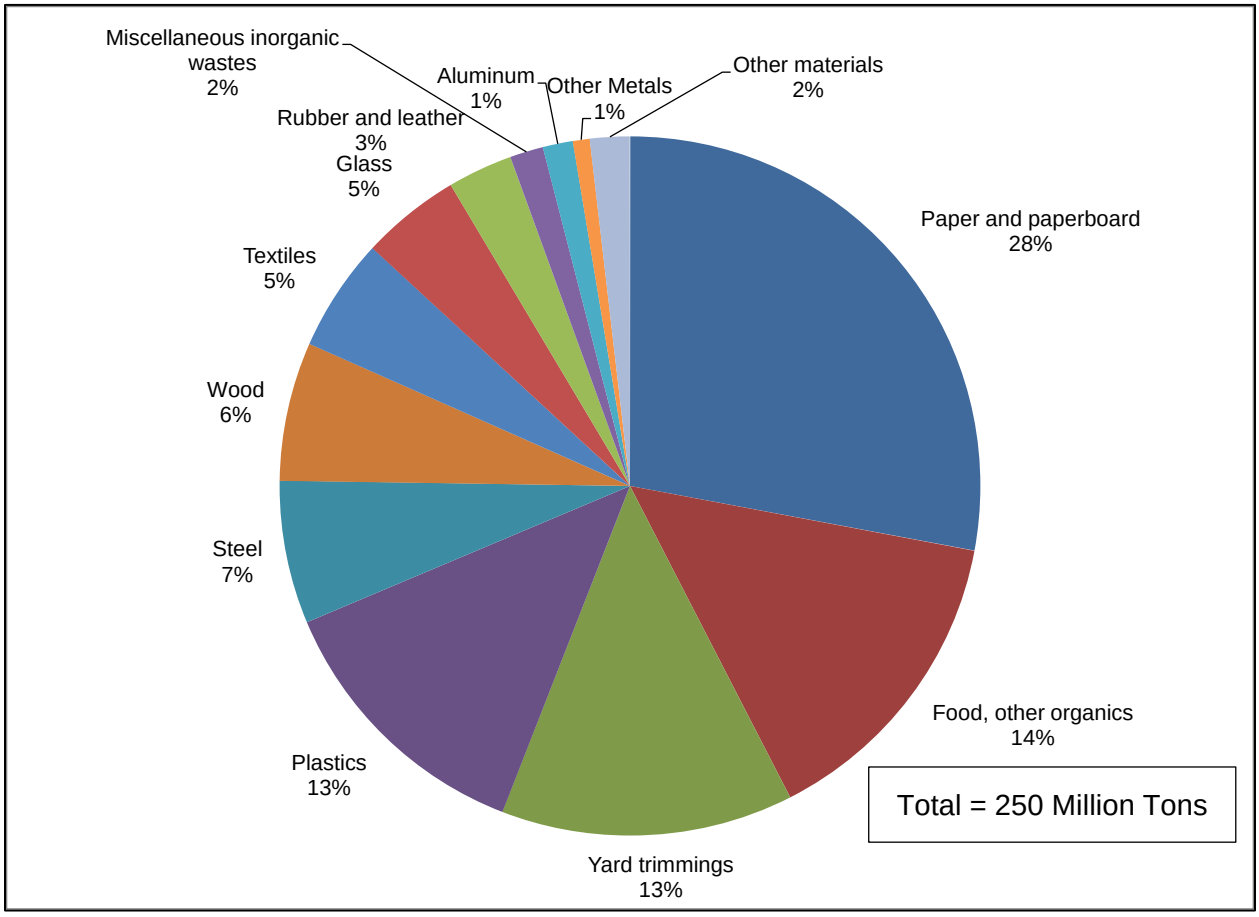


Source: Franklin Associates, 2011

7.2 Current Use of Recycled Materials and Opportunities for Increased Use

According to EPA, the United States generated 250 million tons of municipal solid waste in 2011.[20] Of the total MSW, waste from the five energy-intensive industries accounted for 53 percent, or 133 million tons. **Figure 54** breaks down the MSW by type of waste material. Paper is the most abundant MSW material, accounting for 28 percent of MSW. Food and other organic wastes represent the second largest share at 14 percent, followed by yard trimmings (13 percent) and plastics (13 percent). Steel, glass, and aluminum represent much smaller shares at 7, 5, and 1 percent, respectively. It is important to note that the EPA MSW report does not include automobile and engine scrap in the steel estimate, which is the largest supply of scrap steel.[21]

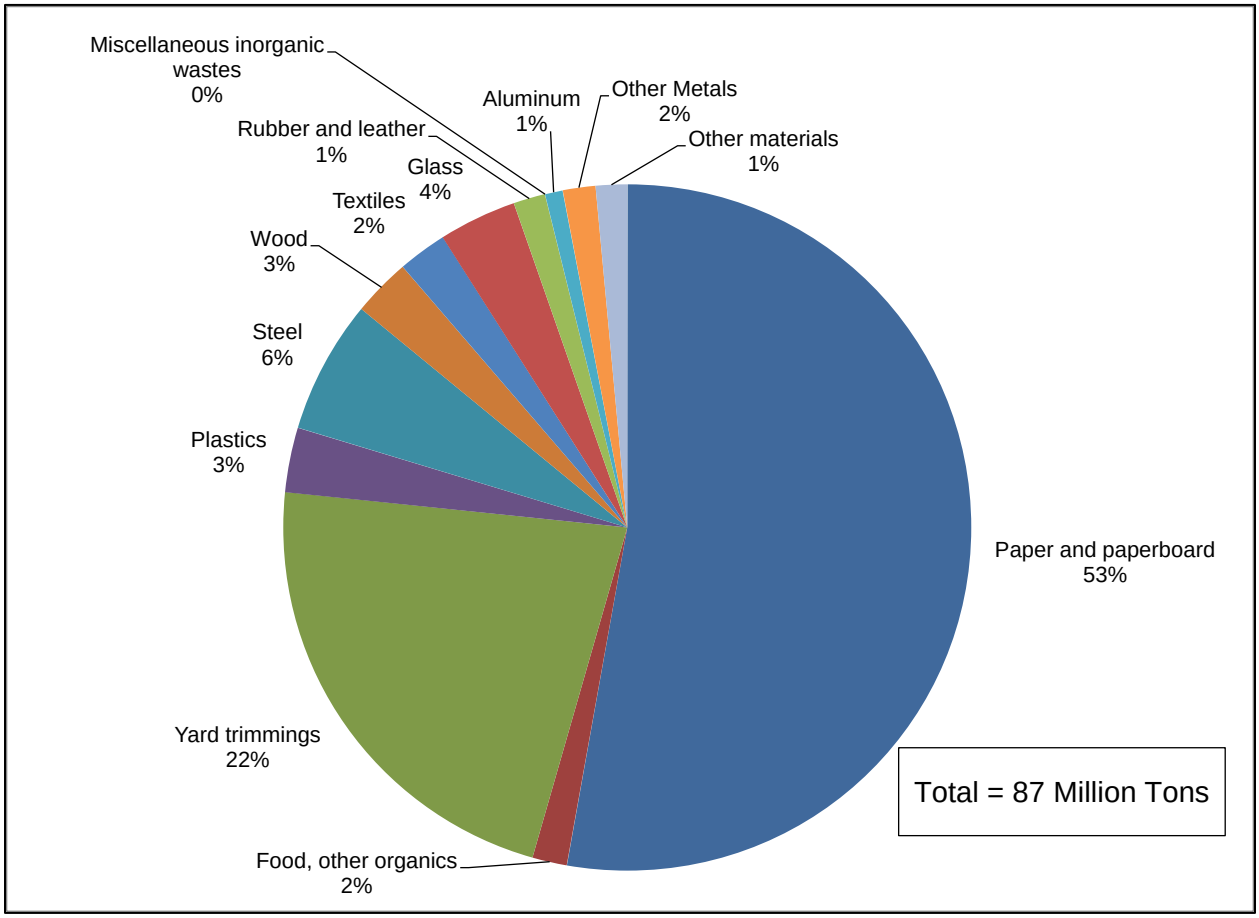
Figure 54. MSW Generation in the United States, 2011



Source: U.S. EPA, May 2013

Figure 55 shows the recovered materials from the MSW stream. In 2011, 87 million tons of the 250 million tons that were generated were recovered. Of the total recovered waste, the five energy-intensive industries accounted for 58 million tons or 67 percent. Paper products accounted for more than half of the total recovered wastes, with 53 percent. Yard trimmings accounted for the second largest share with 22 percent, followed by steel with 6 percent.

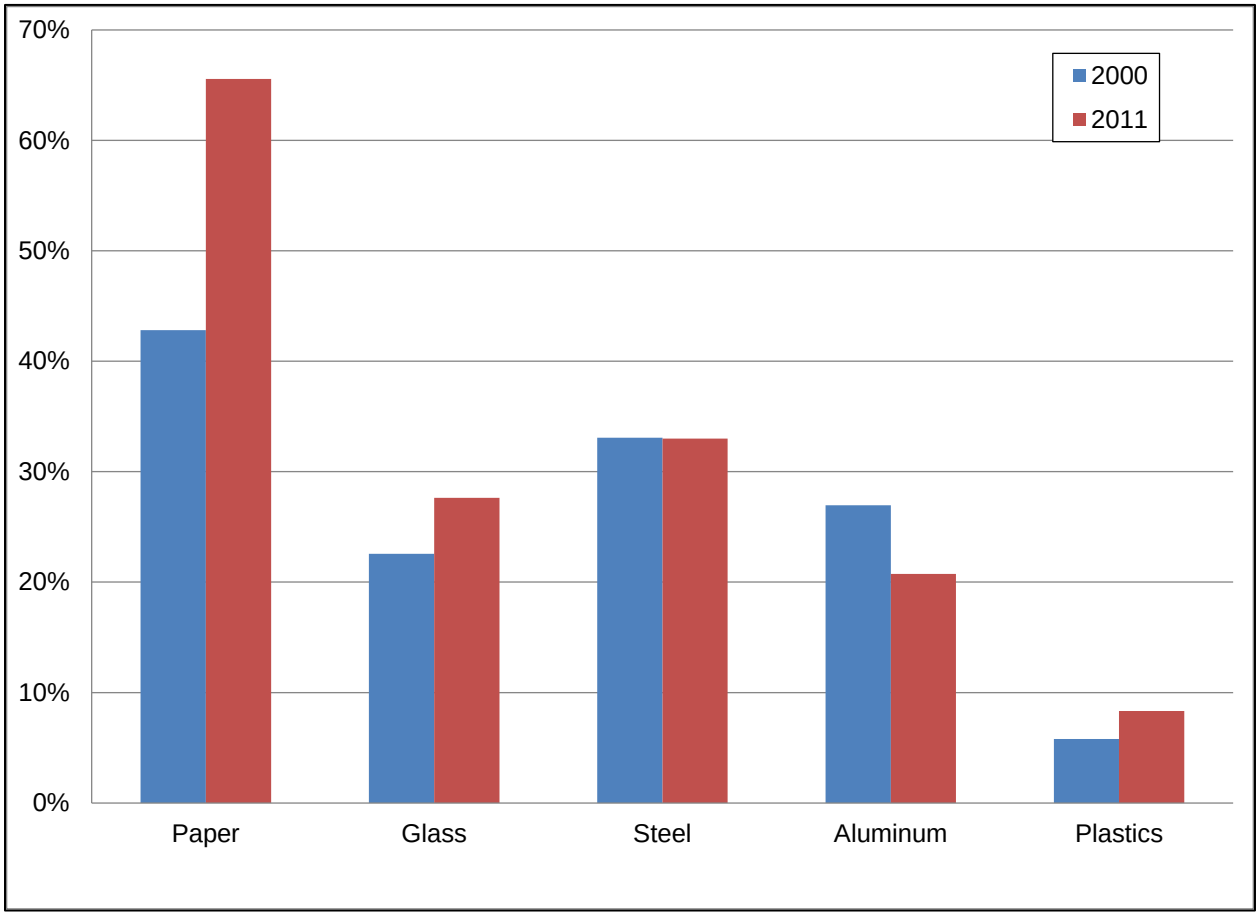
Figure 55. MSW Recovery in the United States, 2011



Source: U.S. EPA, May 2013

Focusing on the five energy-intensive industries**, Figure 56** shows the recovery rates for each industry in 2000 and 2011. Again, it is important to reiterate that the steel data do not include the estimates of scrap from automobiles and engines. The figure shows that in 2011, paper had the highest recovery rate at 66 percent, followed by steel at 33 percent. Glass had a recovery rate of 28 percent and aluminum had a recovery rate of 21 percent. The plastics sector had the lowest recovery rate at 8 percent. Comparing the 2011 recovery rates to the 2000 recovery rates reveals that a significant increase in recovery occurred in the paper industry, with glass and plastics showing modest growth. Steel recovery rates have remained steady, while the aluminum recovery rate has declined. The next section discusses the recycling situation of these energy-intensive industries and identifies issues that can limit improvements of recovery (recycling) rates.

Figure 56. Recovery Rate of Energy-Intensive Products, 2000 and 2011



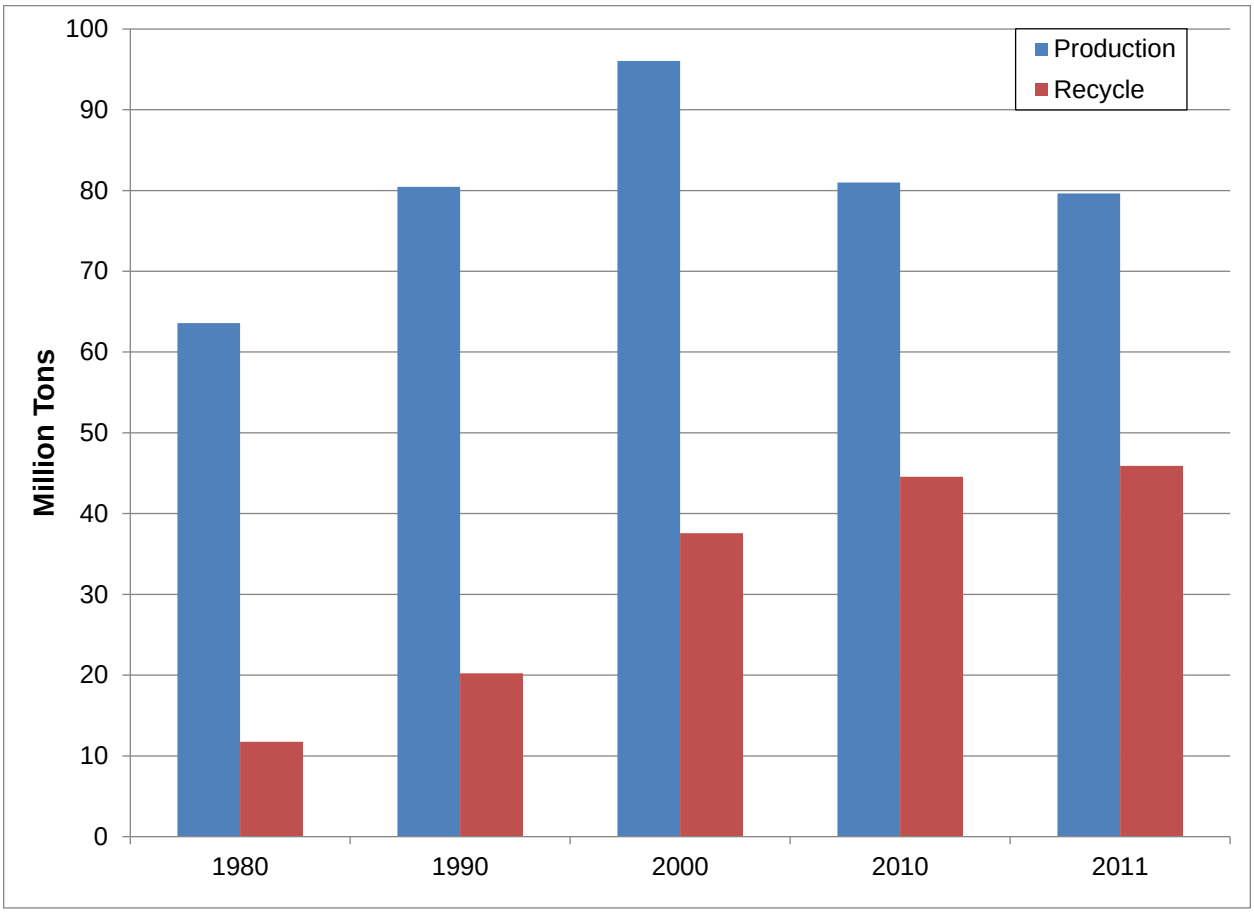
Source: U.S. EPA, May 2013

7.2.1 Paper

Paper (including paperboard products) is the most abundant material in the waste stream, accounting for 28 percent of U.S. municipal solid waste (by weight) in 2011. In 2011, the United States recovered almost 66 percent of total paper, or 45.9 million tons, from waste streams.[22] Another way of looking at the recycling rate is through the reuse rate, which compares the amount of recovered paper (45.9 million tons) to total paper and paperboard production (instead of total paper waste generated in the MSW stream). Given that total paper and paperboard production in 2011 is estimated to be 80 million tons, then the recycling rate, or reuse rate, is 58 percent. **Figure 57** shows the trends in the production and recycling rate of paper and paperboard products. The figure shows that paper and paperboard production in the United States has declined in recent years. The decline was driven by factors that included the economic recession, increased imports, and increased use of digital media. Despite the decline in production, however, in recent years the recovery of paper has actually increased. According to one study, 70 percent is the approximate ceiling for paper recycling (based on production of

paper and paperboard).[23] Several factors prevent the paper industry from reaching higher recycling rates. One factor that has impacted paper recycling is that the price of virgin pulp has been low in recent years, which has reduced the demand for recovered fibers. Another factor is the existence of alternative uses of waste paper (e.g., as fuel), which take waste paper products from the recycling stream. Another factor is that some paper products are not recyclable (e.g., bath tissue). Also, paper used for durable applications, such as books and photographs, does not enter the recycling stream until the product is discarded, which may be several years after initial production. Further, a large portion of the weight of some paper products is composed of non-recyclable materials (brochures, greeting cards, calendars, posters, etc.), which makes them unusable. Also, paper fibers are shortened each time a product is recycled. This degradation eventually makes the fibers unusable. According to one study, each time paper is recycled, it loses 11 to 33 percent of its cellulosic content.[24]

Figure 57. Paper and Paperboard Production and Paper Recycling

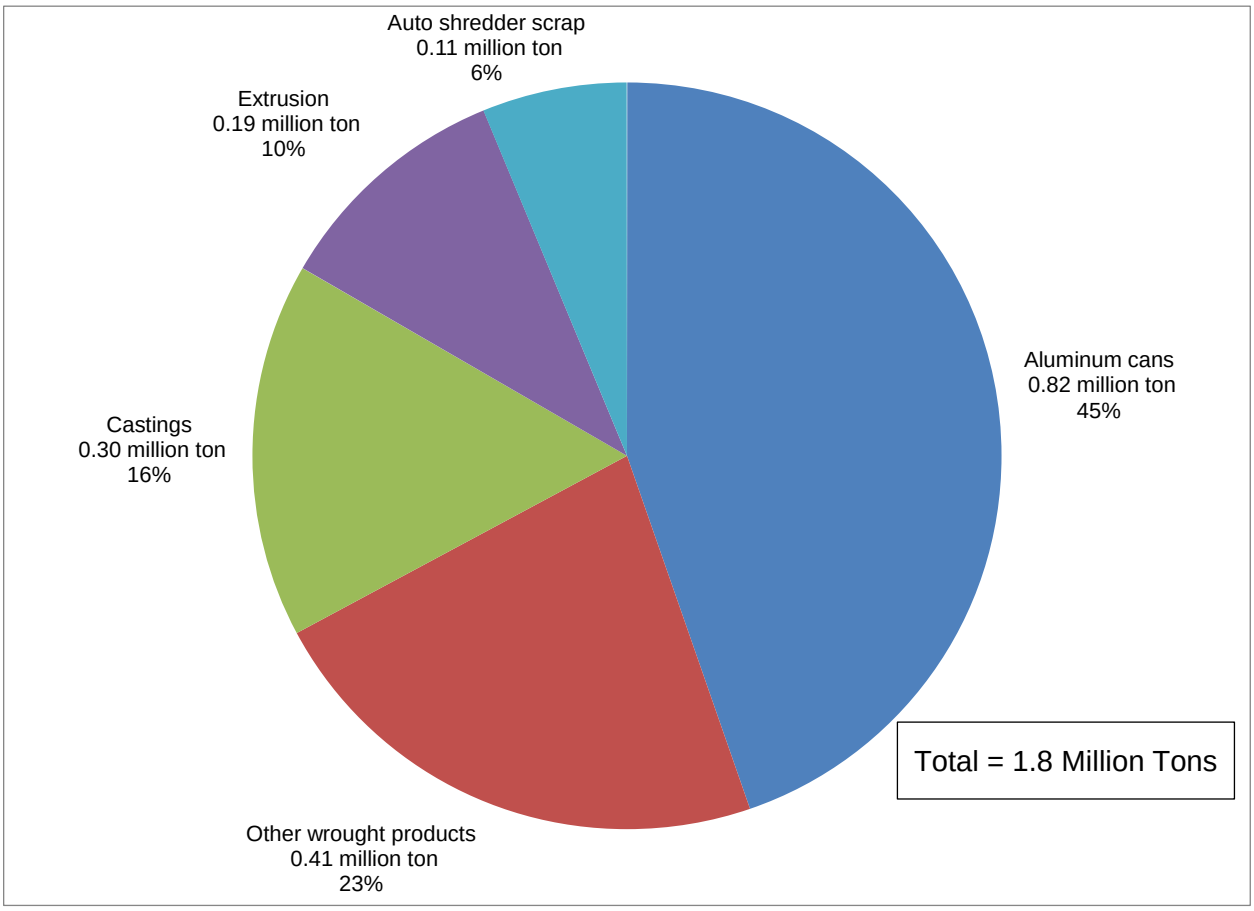


Source: Recycle data: U.S. EPA, May 2013; Production data: U.S. Statistical Abstract

7.2.2 Aluminum

Several aluminum products are recycled. **Figure 58** shows the distribution of these products.[25] The figure shows that the basis of the post-consumer scrap recycling market is the aluminum used beverage can (UBC). In 2011, approximately 44 percent of post-consumer aluminum scrap comes from aluminum UBCs.

Figure 58. Recycled Aluminum Products, 2011



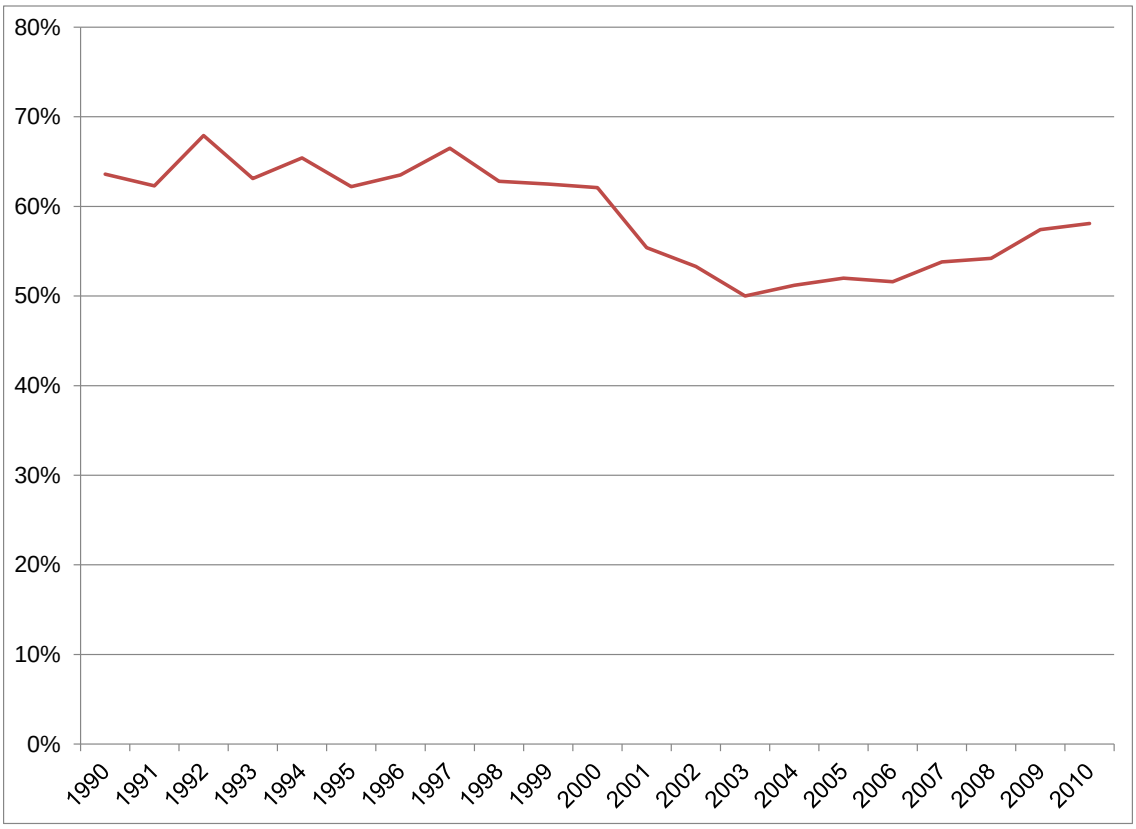
Source: U.S Geological Survey—Aluminum, 2013

If scrap is pre-treated and/or sorted appropriately, the recycled aluminum can be used for almost all aluminum applications, thereby preserving raw materials and making considerable energy savings. **Figure 59** shows the recycling rate for aluminum UBCs from 1990 to 2010 from the Container Recycling Institute and EPA. The figure shows that the recycling rate in the United States for UBCs peaked near 68 percent in 1992 and, since then, has trended downward, although some recovery is seen in the late 2000s. As indicated in **Figure 59**, recycling rates for aluminum UBCs are significantly higher than industry average recycling rates for all types of aluminum scrap (see **Figure 56**). Given the benefits associated with aluminum recycling, it is

interesting that the UBC recycling rate has declined since the early 1990s. Possible factors for this trend include:

- Low price of primary aluminum.
- Lifestyle changes, such as more traveling, which results in lower use of curbside recycling bins.
- Lack of financial incentive for consumers. The deposit in many states has not changed for many years; hence, the value of the deposit has declined in real terms. Deposit amounts range from 2 cents to 15 cents, depending on state and type of bottle.[26]

Figure 59. Recycling Rate Trends for Aluminum Used Beverage Cans

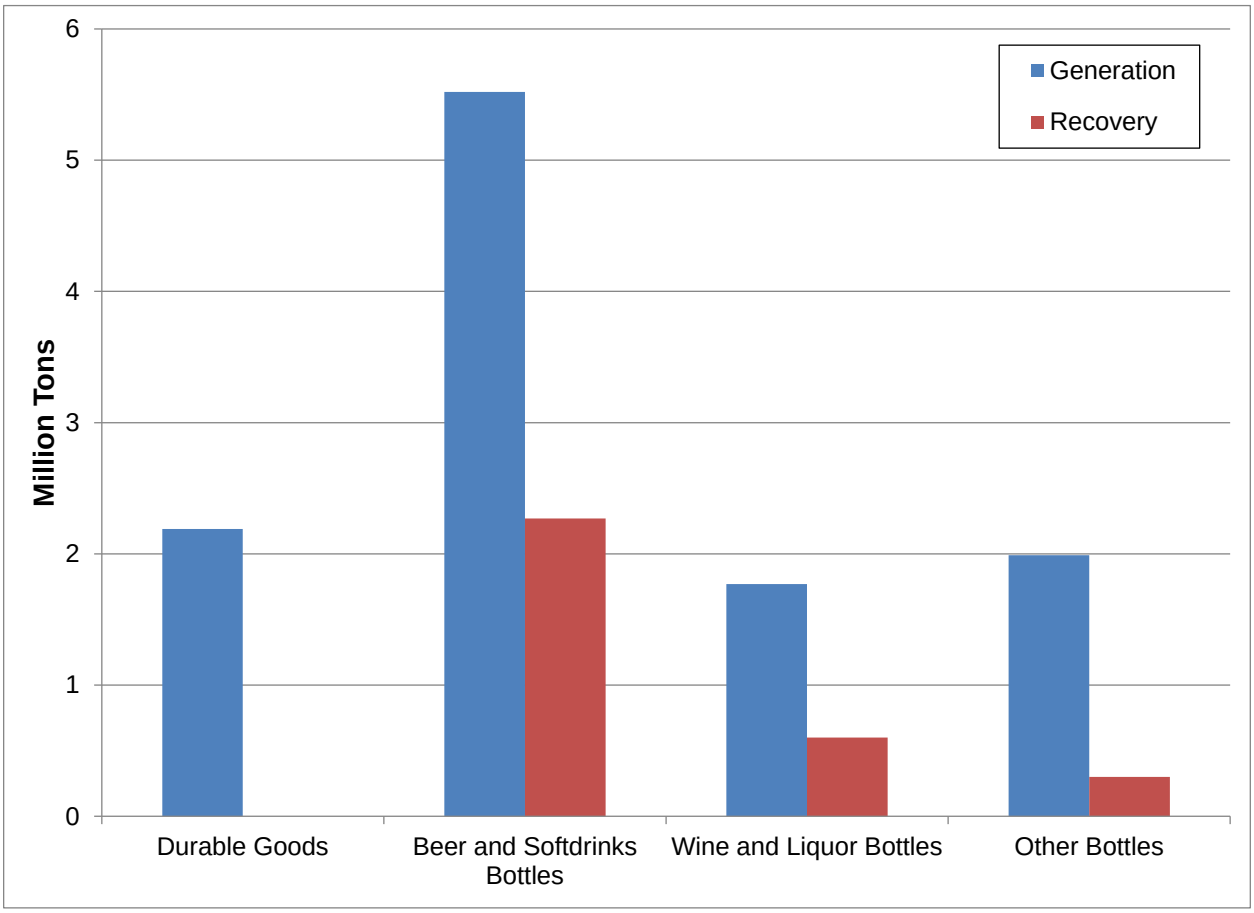


Source: Container Recycling Institute, 2013

7.2.3 Glass

Glass products in the MSW stream consist of glass containers and glass in durable goods such as appliances, furniture, and electronics. **Figure 60** shows the distribution of glass products in the waste stream.[27] Similar to aluminum, the basis of glass recycling is the beverage container. In 2011, glass containers accounted for 81 percent of glass waste and 100 percent of recovered glass.

Figure 60. Glass Recycled Products, 2011

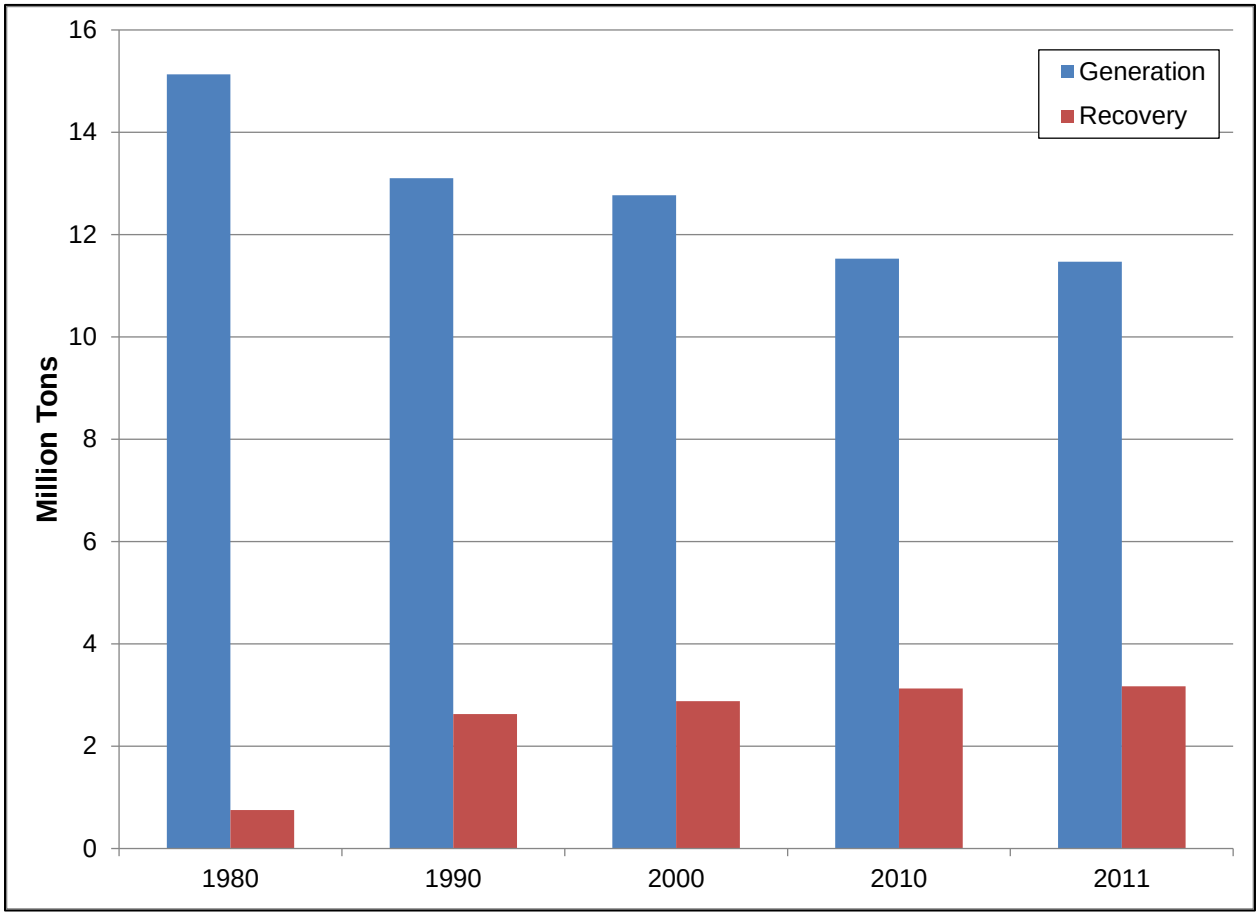


Source: U.S. EPA, May 2013

There has been a steady increase in the recovery of post-consumer glass (see **Figure 61**). Recycling of container glass has increased from around 22 percent in 1990 to 34 percent in 2011. Glass containers are recycled and used to make new containers, and they are also used as raw materials for other glass products such as fiberglass insulation, road construction materials, and tiles. Recycled glass can be used to substitute virgin raw materials in glassmaking up to 90 percent.[28]

Glass recycling helps manufacturers save energy and reduce equipment maintenance and replacement costs. For every 10 percent of recycled glass substituted for raw materials, energy at a glass container plant is reduced by approximately 2 to 3.5 percent. The life of a glass-melting furnace that operates with recycled glass can be increased up to 30 percent due to decreased furnace temperatures required to melt feedstocks that contain recycled glass.[29]

Figure 61. Glass Recycling Trends



Source: U.S. EPA, May 2013

Several barriers impact the use of recycled glass due to quality issues:

- While food and beverage glass containers are 100 percent recyclable and experience no loss in quality or integrity when recycled multiple times, other glass products such as Pyrex, crystal, and ovenware do not have the same qualities. Mixing these materials in the glassmaking process causes production problems and defective products, as they melt at different temperatures and have varying compositions.[30]
- Recycled glass must meet specifications in order to be re-melted into new containers or fiberglass. Recycled glass can contain large quantities of metals, ceramics, gravel, or other contaminants when it is mixed with other material during collection, and it may be cost prohibitive to sort the glass and remove the contaminants.
- There are cases when some recycled glass containers are too contaminated or have been determined to not meet manufacturing specifications, due primarily to recycling collection methods, such as single-stream collection where all recyclable materials are mixed together. This recycled glass is then used for non-container glass products, such

as tile, landfill cover, and road bed aggregate. It should be noted that the majority of these single-use applications are not for use in industrial processes and are not considered primary recycling, which is the focus of this study.

- Glass container customers require specific colors in their products. Thus, color sorting of recycled bottles is important.

The preceding barriers can be overcome with the adoption of advanced technology and market incentive structures. Illustrations include the following:

- The majority of glass-recycling processors have optical sorting equipment to separate colors and ceramic detection technology to help ensure that recycled glass can be used by industrial end markets.

- Data from states demonstrates that container recycling refund programs yield 80 percent recovery among covered containers. There is a strong market for this uncontaminated material and glass manufacturers will transport cullet from states that have these programs to states where manufacturing plants are located.[31]

- When single-stream recycling collection systems are utilized with container recycling refund programs, they are estimated to increase statewide recovery by at least 11 percent over a comprehensive single-stream system and recovery of included beverage containers by 162 percent.[32]

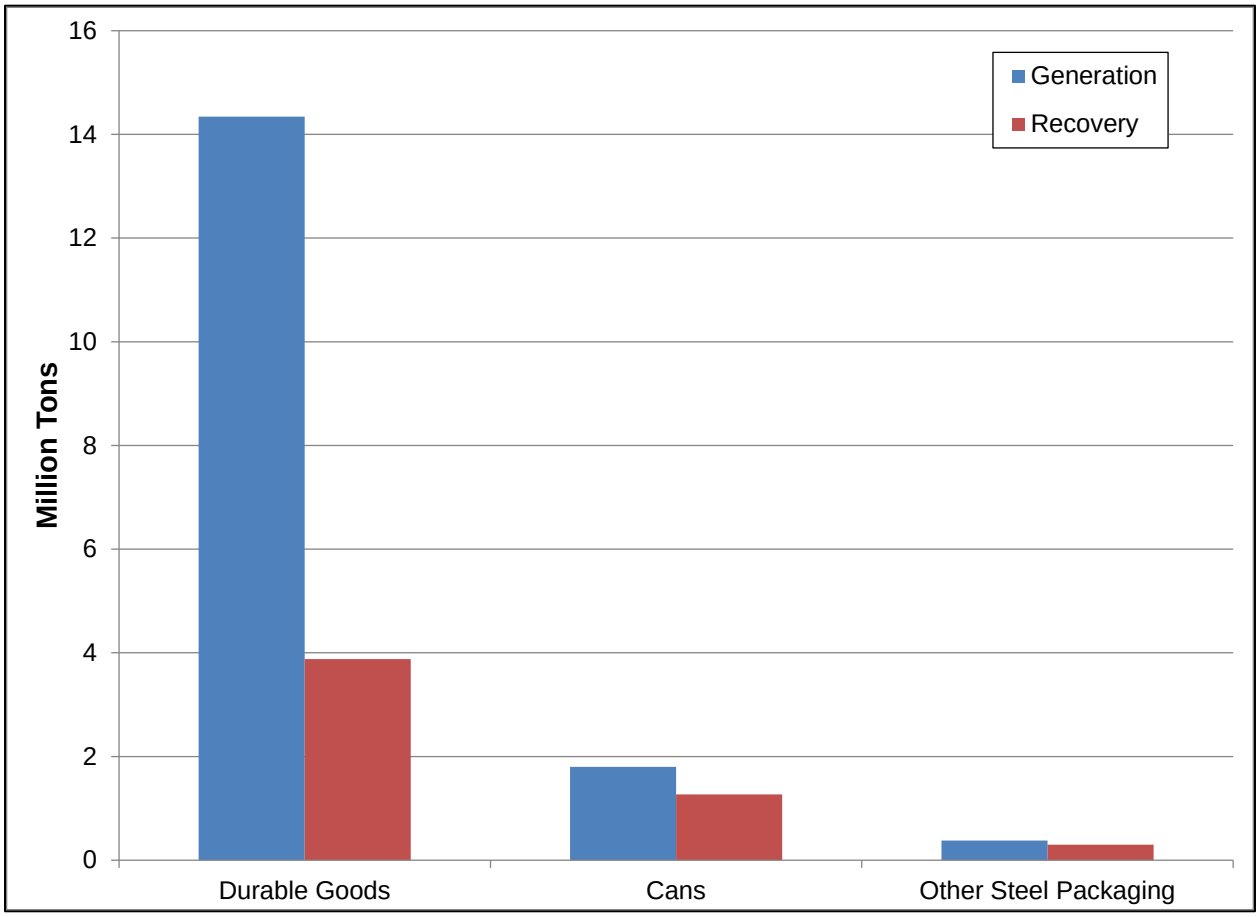
7.2.4 Steel

Steel scrap supply consists of imports (e.g., from other countries such as Canada and Mexico), home scrap, prompt (new) scrap, and obsolete (old) scrap. Home scrap, consisting of trimmings of mill products and defective products, is produced in the mill, particularly during the production of steel. Home scrap supply has been declining, mainly because of the adoption of more efficient casting techniques. New or prompt scrap is the scrap produced from manufacturing steel products. Obsolete, or old, steel scrap results from steel recovered from products that have reached the end of their useful life. Old scrap requires preparation, such as sorting, de-tinning, and de-zincing before it can be used in steelmaking.

EPA reports that old scrap of ferrous (iron and steel) materials in the form of durable goods (e.g., appliances) represents the largest share of ferrous scrap in the United States. Durable goods accounted for 87 percent of total ferrous scrap in the waste stream. It is important to reiterate that these data do not include automobiles and engines that have been scrapped. The rest of the ferrous scrap reported by EPA consists of containers and other steel packaging. **Figure 62** shows the recovery rates of each ferrous scrap type. Although durable goods account

for the most generation, it has the lowest recovery rate at 27 percent. Steel cans have a much higher recovery rate at 71 percent, and other steel packaging has the highest at 79 percent. The overall recovery rate for ferrous scrap is 33 percent.

Figure 62. Iron and Steel Scrap Generation and Recovery



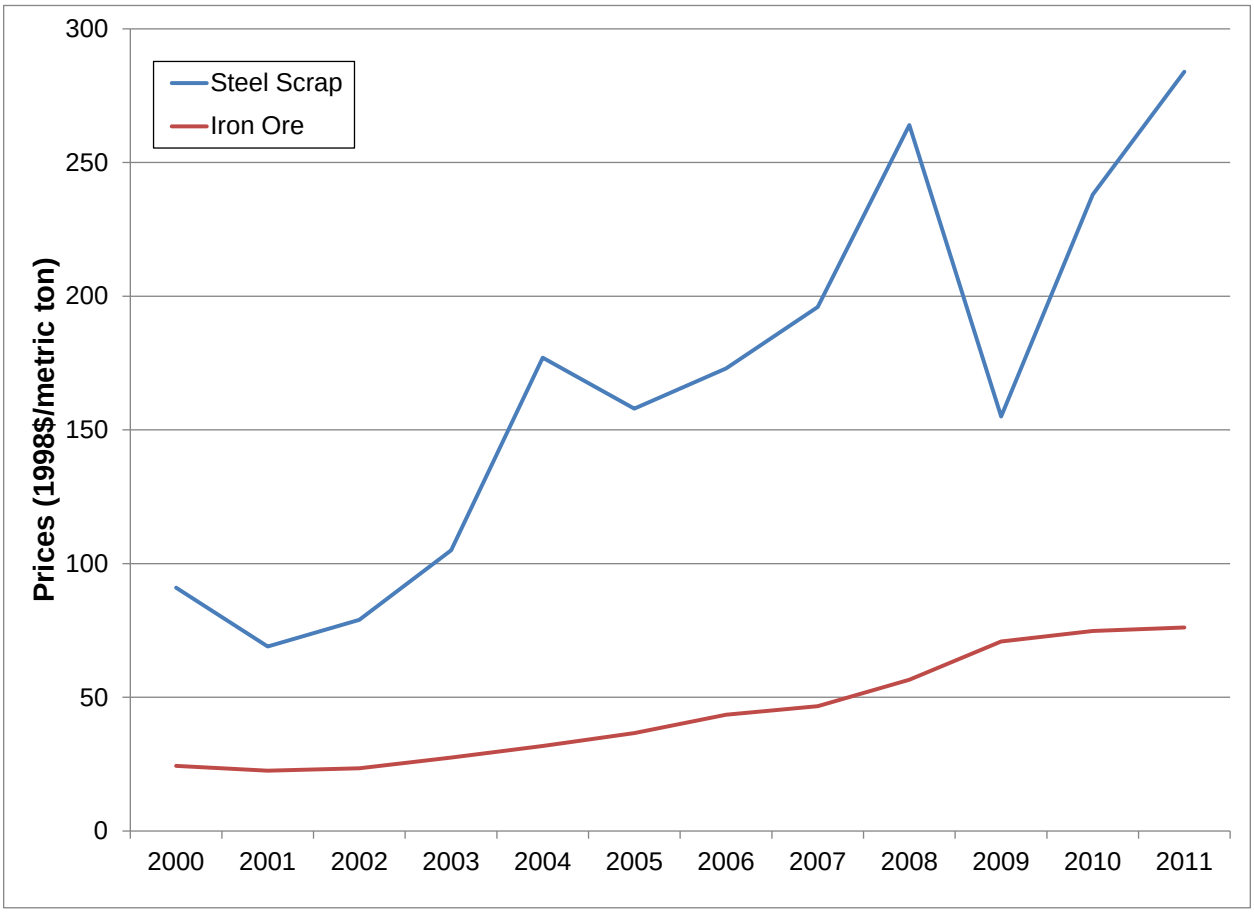
Source: U.S. EPA, May 2013

Two major factors limit the use of recycled steel: (1) the available supply and (2) the price of scrap. Supply constraints stem from the long life of products made from steel—typically in the range of 15–19 years, or even longer. This long product life makes a large portion of steel unavailable for immediate recycling. Another reason for limited supply is the usability of steel products at end of life. For example, a steel barrel, which has typically a life of 6 months, can be reused (for other purposes) instead of ending up in the waste stream.

Another important factor that limits the use of recycled steel is the price of scrap relative to the price of raw materials required to produce steel from iron ore. **Figure 63** shows that, over the last decade, the price of scrap increased significantly as global demand expanded, while the price of iron ore remained steady. Because of the high cost of scrap, some mini-mills have

started using direct reduced iron, instead of scrap, as a source of iron. The cost of scrap is not only driven by the demand for scrap, but also on the difficulty and cost in its collection and treatment (prior to use in EAFs).

Figure 63. Steel Scrap and Iron Ore Prices, 2000–2011

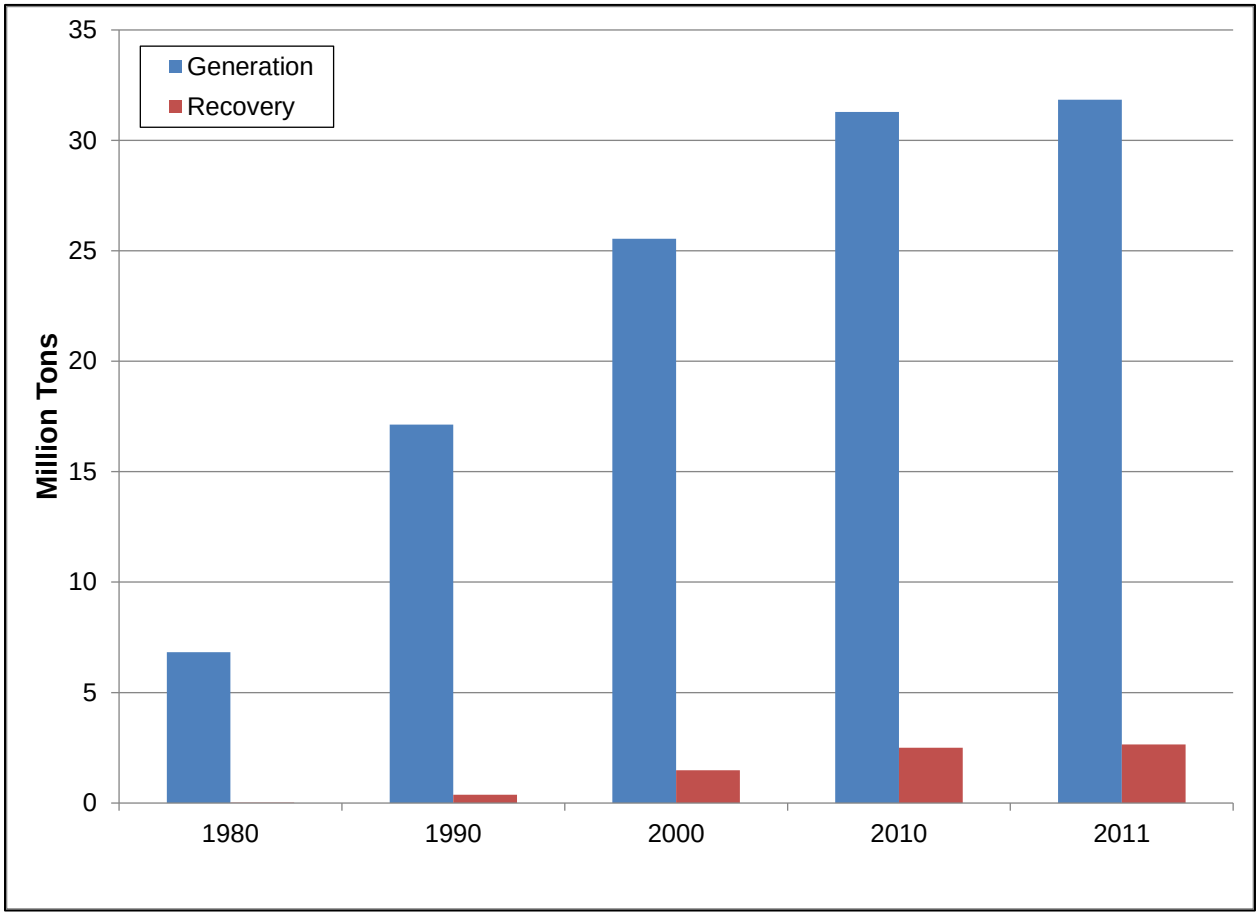


Source: U.S. Geological Survey—Iron Ore and Steel Scrap, 2013

7.2.5 Plastics

Figure 64 shows the amount of plastic waste generated in MSW streams and the amount recovered. The figure shows that, although recovery of plastic products has been growing (from 0.3 percent in 1980 to 8 percent in 2011), it has not paralleled the high growth rate for waste generation. The viability of recycled plastics to replace virgin polymer generally relies on the purity and properties of the polymer of recovered plastic and its compatibility to the requirements of the plastic product being made. With these requirements, post-consumer recycling efforts have been focused on PET soft drink bottles, HDPE milk jugs, and LLDPE/LDPE plastic bags, since they can be easily identified and sorted. Recycling of plastic products with more complex resin combinations is technologically challenging and is therefore limited at this time.

Figure 64. Plastic Products Waste Generation and Recovery, 1980–2011



Source: U.S. EPA, May 2013

As shown previously in **Figure 52**, the recovery rates of even the most recyclable of the plastic resins—HDPE, PET, and LDPE/LLDPE—are also low. Curbside collection of bottles and jugs is the primary source of recyclable plastic products, but at low recovery rates. LDPE film is typically recovered from businesses and not through curbside collection.

7.3 Framework for Analyzing Possible Energy Savings from Increased Recycling

To evaluate how much energy could be saved if recycling is increased using currently deployed technologies, two scenarios were developed for this study: (1) a Modest Scenario and (2) an Aggressive Scenario. The Modest Scenario assumes that recycling rates remain well within the boundaries of existing technology and material availability limitations, while the Aggressive Scenario pushes these boundaries.

Table 31 shows the current recycling rates and the assumptions for recycling rates for the Modest and Aggressive Scenarios. Note that each of the three plastic resins discussed above is handled individually because their generation and recovery rates are different, as well as their

unit energy requirements. It is important to note that the recycling rate assumptions for the moderate and aggressive scenarios are not based on industry data. Rather, the authors of the study considered data on current recycling rates and the technical recycling limits, and developed the recycling rate assumptions for the scenarios within those ranges of data. Explanations on how the recycling rate assumptions used for the scenarios are presented following the table.

Table 31. Current Recycling Rates and Assumed Scenario Rates

Sector	Recycling Rates		
	Current	Modest Scenario	Aggressive Scenario
Paper	58%	60%	65%
Aluminum	65%	75%	90%
Glass	34%	60%	80%
Steel	33%	50%	80%
PET	19%	30%	40%
HDPE	10%	15%	20%
LDPE/LLDPE	5%	7%	10%

- *Paper.* The technical limit in using recycled products is 70 percent. It was assumed that the Aggressive Scenario will be slightly lower at 65 percent. The Modest Scenario was set between the Current and Aggressive Scenarios at 60 percent. It is important to note that these rates are not the rates derived from dividing "recovery" by "generation" for paper and paperboard waste. Rather these rates are based on "recovery" divided by "production" of paper and paperboard.
- *Aluminum.* The aluminum scenarios are limited to an analysis of recycling rates for aluminum beverage cans. The upper limit for reusing aluminum cans is 100 percent. A slightly lower recycling rate of 90 percent was assumed for the Aggressive Scenario, and a 75 percent rate was assumed for the Modest Scenario—a rate between the Current level and the Aggressive value.
- *Glass.* The technical limit in using recycled products is 95 percent. It was assumed that the Aggressive Scenario will be slightly lower at 80 percent. For the Modest Scenario, a recycling rate of 60 percent was established, which is between the Current and Aggressive rates.
- *Steel.* The upper limit was set to the successful recyclability of automobile and engine scraps, which is around 90 percent. This limit follows the current recovery rates of steel durable goods that are not in the MSW stream.[33] Hence, for the Aggressive Scenario, an 80 percent rate was assumed. This 80 percent is applied only to the EPA steel scrap values, which excludes automobile and engine scrap. For the Modest Scenario, a rate of 50 percent was set, which is between the Current and Aggressive rates.

- *Plastics.* There are no established numbers on the technical limits for the use of recycled plastics. For the analytical purposes of this study, it was assumed that the Aggressive Scenario will have recycling rates at twice the Current rates, and the Modest Scenario will have be between the Current and Aggressive rates.

7.4 Estimated Energy Savings from Increased Recycling

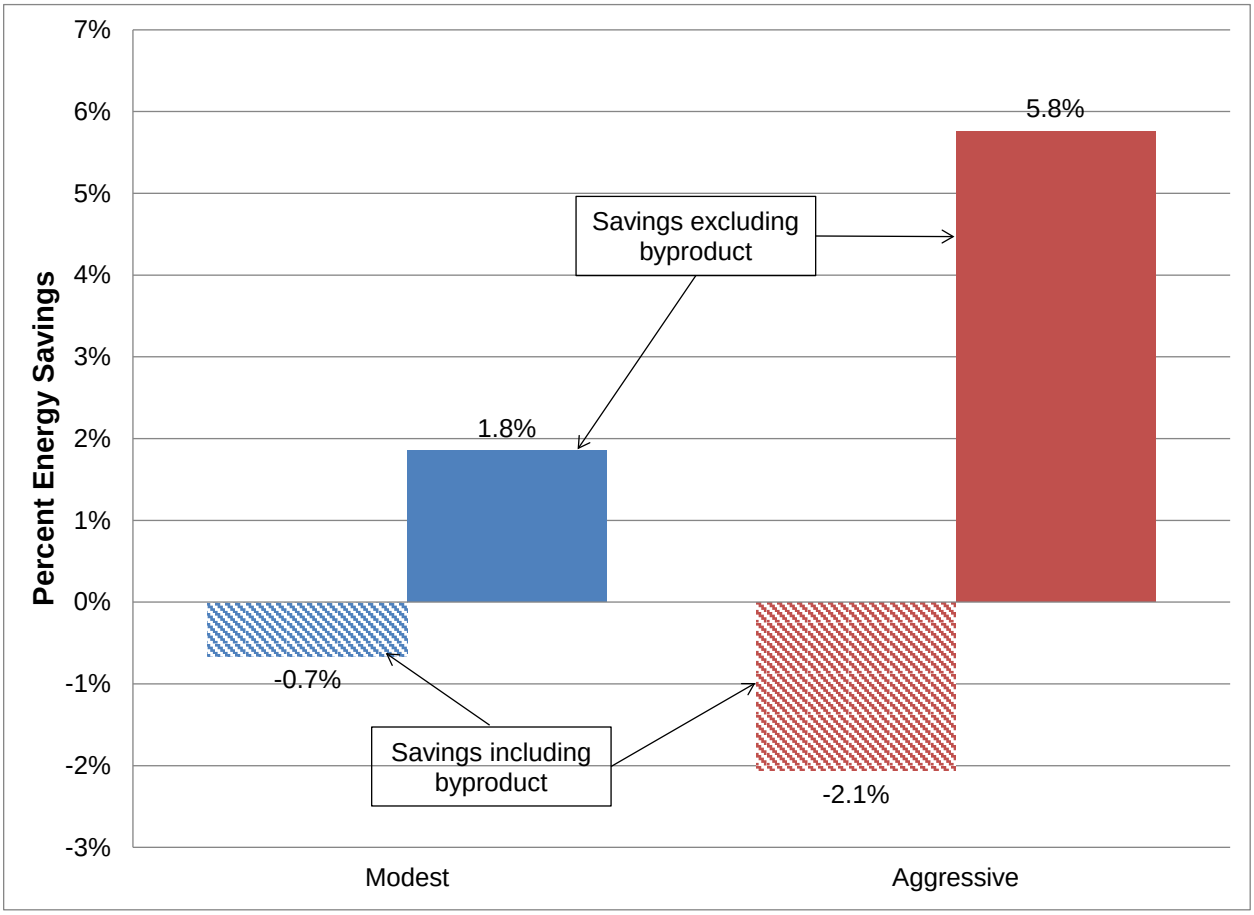
To evaluate the impacts of the increased recycling rates from the Modest and Aggressive Scenarios, energy consumption using the primary and secondary processes was calculated using the unit energy requirements presented in **Section 7.1** and the production and other relevant process information for 2011. An analysis was performed for 2011, looking at the Current, Modest, and Aggressive recycling rates. Given the same total production levels, increasing the recycling rate will decrease the production through the primary processes, while increasing the production using the secondary processes. The results that follow compare the energy consumption for the Current recycling rates in 2011 (the base case) to energy consumption estimates for the Modest and Aggressive Scenarios. It is important to note that the energy savings results from running the scenarios are additional savings to the already achieved energy savings from Current recycling rates. Further, the analysis was not expanded to evaluate the broader impacts of increased recycling such as economic, trade, and global competitiveness impacts. This analysis focuses on direct impacts of increased recycling on energy use of the industries identified in this section.

7.4.1 Paper

Figure 65 shows the potential energy savings at paper mills from increasing recycling rates from a base case of 58 percent (Current) to 60 percent (Modest) and 65 percent (Aggressive). The results for paper mills are interesting given the impacts of byproduct fuels. Because of reduced production using the primary process, there is less byproduct fuel generated, and so overall energy consumption at paper mills would actually increase. The figure shows that when byproduct fuels are not counted, paper mills save almost 2 percent in the Modest Scenario and almost 6 percent in the Aggressive Scenario. If byproduct fuels are included, however, the results show no savings at the mills, but rather an increase in energy consumption when more recycled paper is used. In the Modest case, there is a 7 percent increase and in the Aggressive case there is a 2.1 percent increase.

The paper industry recycling results discussed above are calculated based on energy savings at paper mills. Other studies have examined impacts based on a lifecycle approach, and these studies have shown that recycled paper results in lower energy consumption for scenarios that do not include byproduct fuels as well as scenarios that do include byproduct fuels.[34]

Figure 65. Paper Industry Energy Savings by Scenario

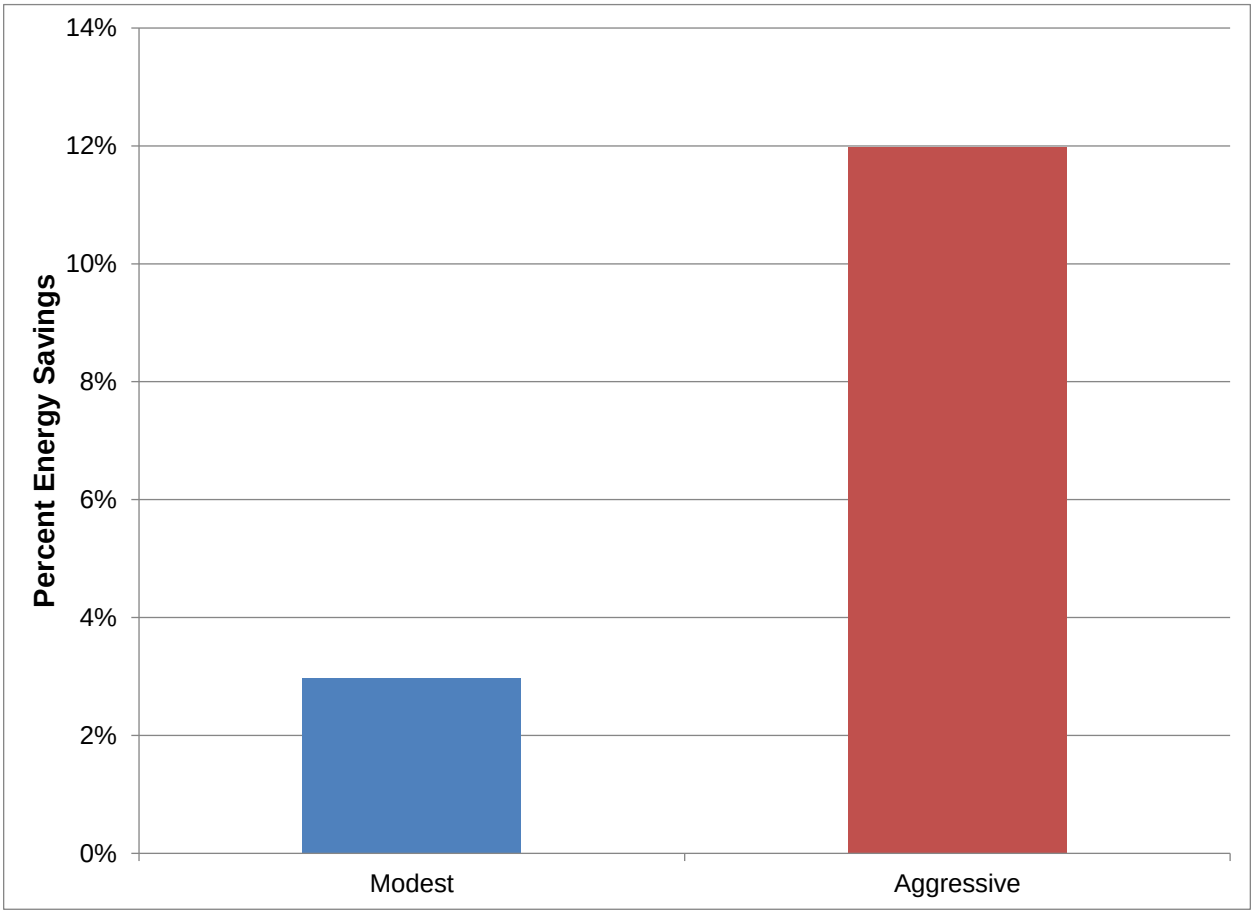


Source: ICF estimate, 2013

7.4.2 Aluminum

Figure 66 shows the estimated additional energy savings from increased recycling of aluminum beverage cans. The Modest Scenario has a recycling rate of 75 percent compared to a recycling rate of 65 percent for the Current case. The results show an additional savings of 3 percent. The Aggressive Scenario increases recycling to 90 percent and shows an additional savings of 12 percent.

Figure 66. Aluminum Industry Energy Savings by Scenario

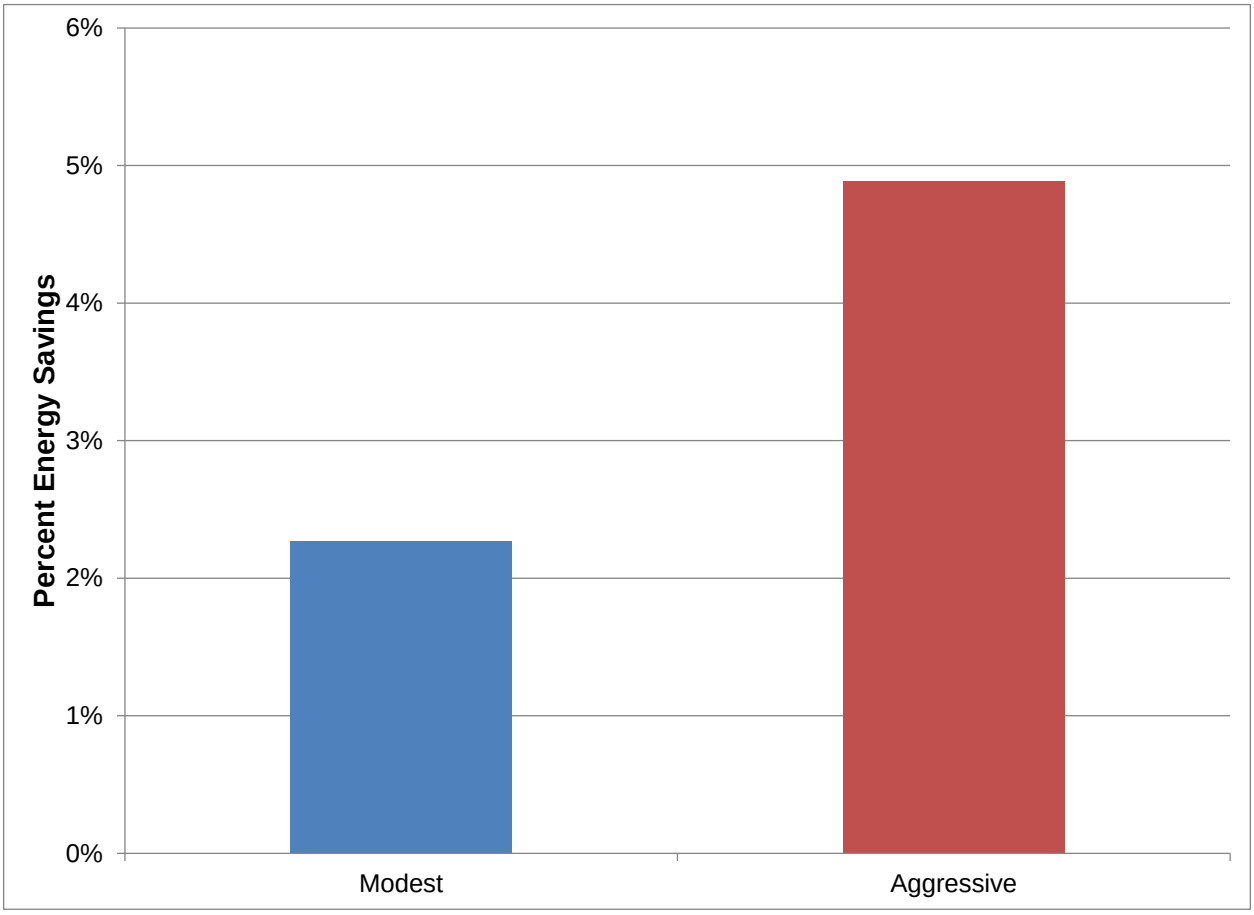


Source: ICF estimate, 2013

7.4.3 Glass

Figure 67 shows the additional energy savings in the glass industry under the Modest and Aggressive Scenarios. With the Modest Scenario, the recycling rate increases from 34 percent (current) to 60 percent. The results show an additional energy savings of around 2 percent. With the Aggressive Scenario, the recycling rate increases further to 80 percent, yielding an additional energy savings of 5 percent.

Figure 67. Glass Industry Energy Savings by Scenario

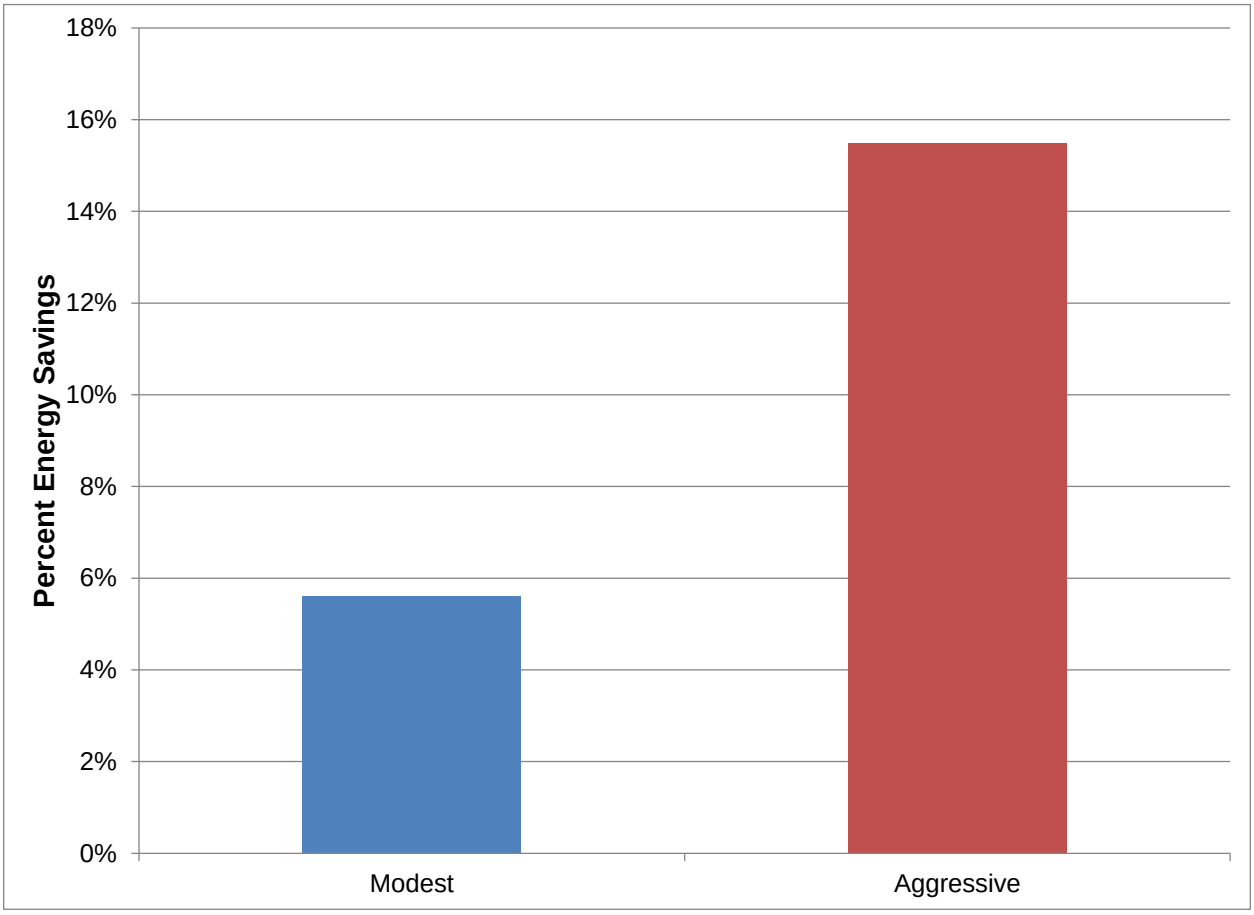


Source: ICF estimate, 2013

7.4.4 Iron and Steel

Figure 68 shows the energy savings results for the Modest and Aggressive Scenarios for the steel industry. The Modest Scenario shows an energy savings of 6 percent when the recycling rate is increased from 33 percent (Current) to 50 percent. The Aggressive Scenario, which assumes an increase to 80 percent, shows an energy savings of 15 percent.

Figure 68. Iron and Steel Energy Savings by Scenario

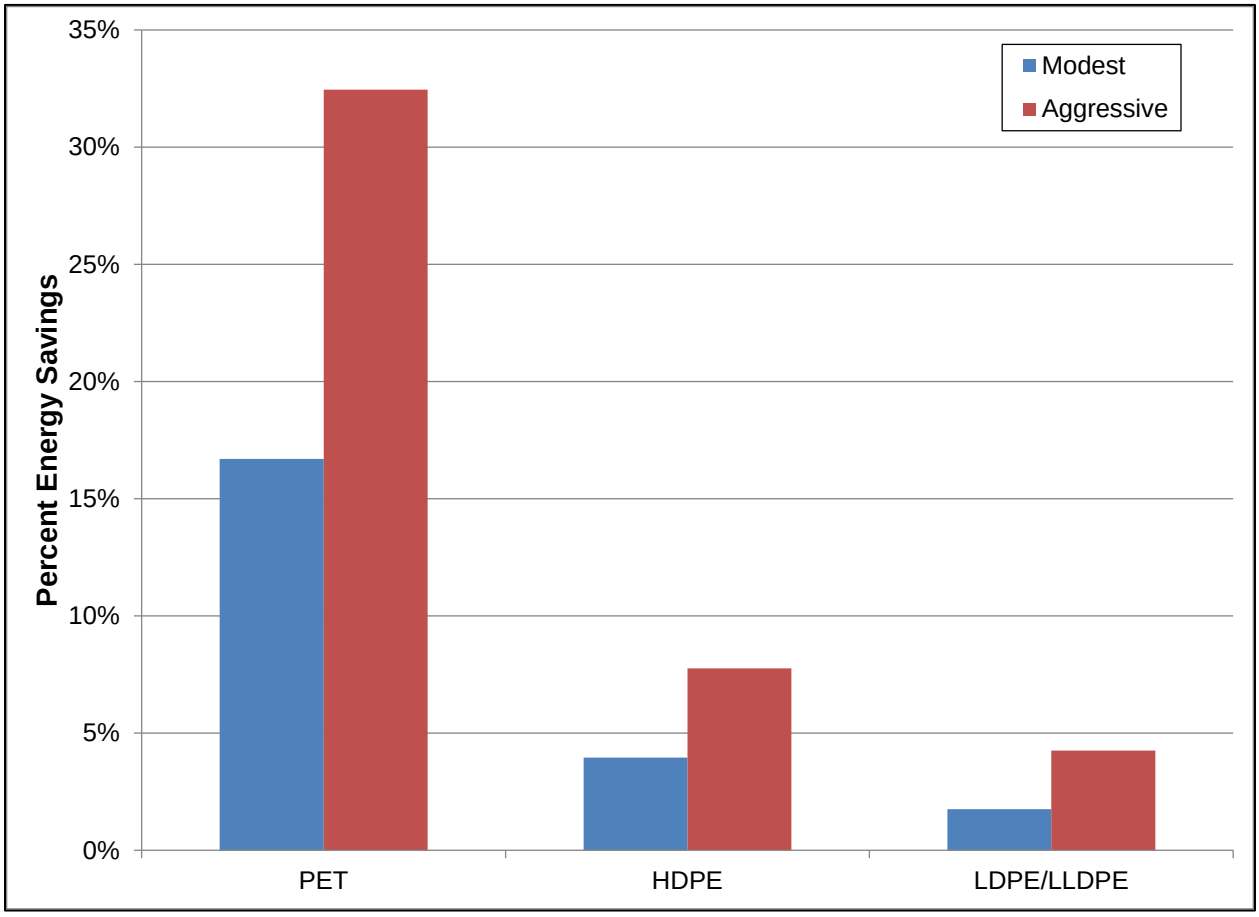


Source: ICF estimate, 2013

7.4.5 Plastics

Figure 69 shows the energy savings from increasing the recycling rates for three types of plastic. PET recycling shows the highest energy savings, with the Modest Scenario saving 14 percent and the Aggressive Scenario saving 27 percent. HDPE and LDPE/LLDPE have lower energy savings. HDPE shows 3 percent energy savings in the Modest Scenario and a 7 percent energy savings in the Aggressive Scenario. LDPE/LLDPE shows a 2 percent energy savings for the Modest Scenario and a 4 percent energy savings for the Aggressive Scenario.

Figure 69. Plastics Industry Energy Savings



Source: ICF estimate, 2013

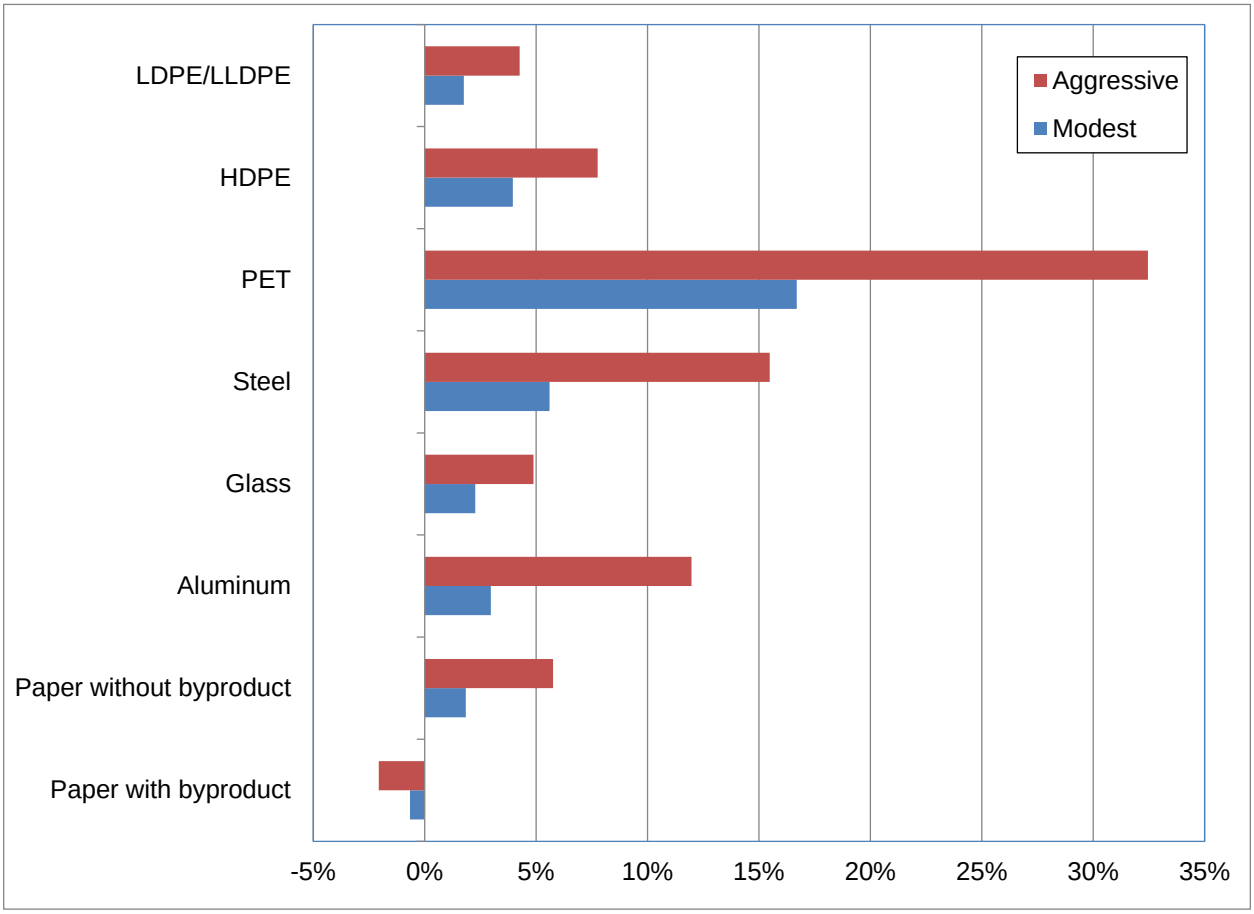
7.5 Summary

The five energy-intensive industries generate substantial waste products. These industries account for 53 percent of total waste products in the MSW stream. However, the products of these industries are also the most recovered, accounting for 67 percent of total MSW recovery. Still, substantial amounts of waste products coming from these industries could be recovered, which could in turn yield significant energy savings.

Figure 70 summarizes the energy savings results under the Modest and Aggressive scenarios. In terms of percentage savings, PET offers the greatest savings in both scenarios, with 17 percent savings in the Modest Scenario and 32 percent savings in the Aggressive Scenario. Steel offers the second largest savings, also in both scenarios, with 6 percent savings in the Modest Scenario and 15 percent in the Aggressive Scenario. The paper industry provides a more complex picture because of its heavy use of byproduct fuels. If byproduct fuels are not counted, the energy savings could be as much as 6 percent (under the Aggressive Scenario). However, if

byproduct fuels are counted, the energy consumption actually increases, which results in negative energy savings.

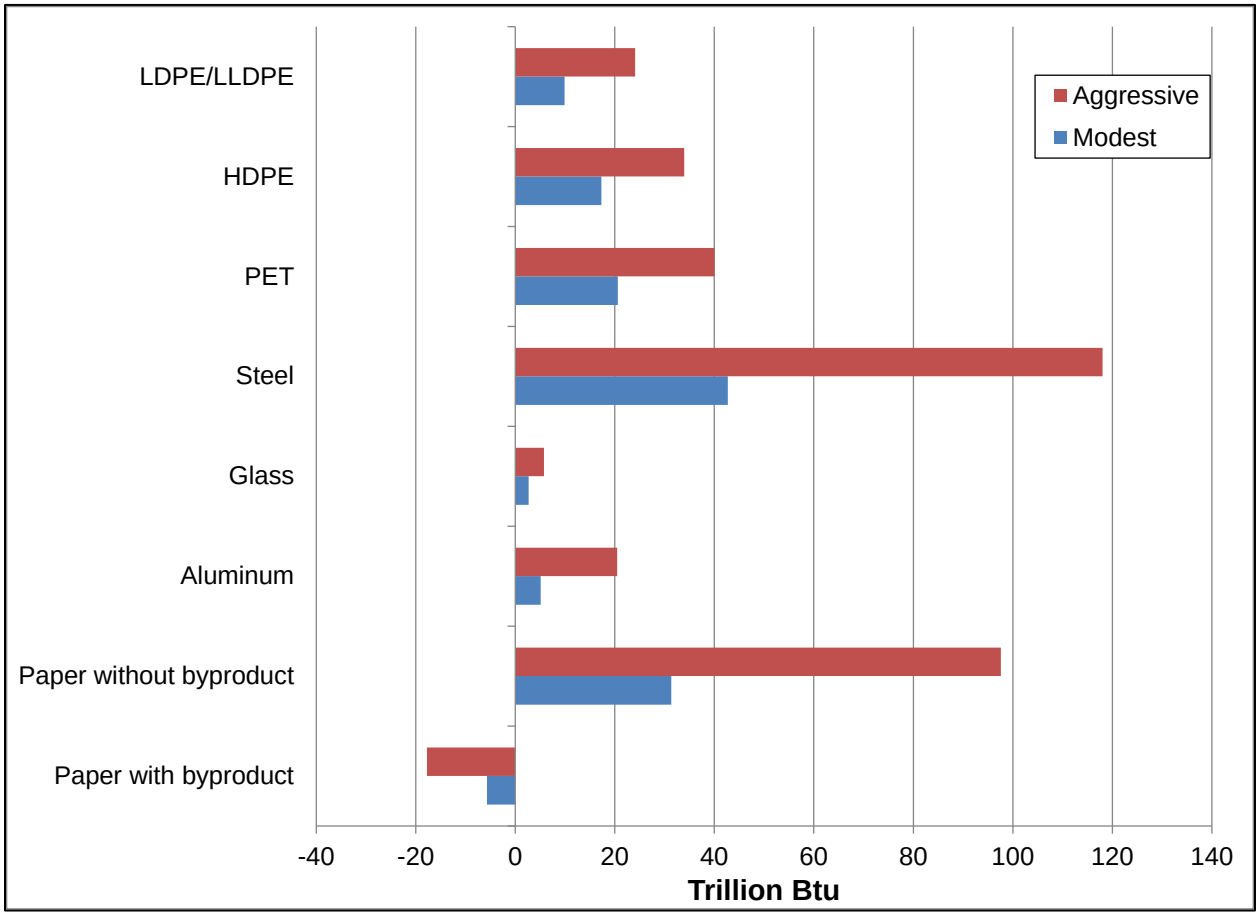
Figure 70. Summary of Energy Savings from Recycling (percent)



Source: ICF estimate, 2013

Figure 71 summarizes the results in trillion Btu (TBtu). To calculate energy consumption in TBtu, the unit energy requirements were multiplied by virgin production and recycled production for 2011. The difference (virgin minus recycled) is the total energy savings. The results show total energy savings under the Modest Scenario of 93 TBtu when byproduct fuels in the paper industry are counted, and 130 TBtu if byproduct fuels are not counted. Under the Aggressive Scenario, total energy savings reach 225 TBtu with byproduct fuels, and 340 TBtu without byproduct fuels. The steel industry has the largest energy savings, with 43 TBtu under the Modest Scenario and 118 TBtu under the Aggressive Scenario. Paper (if byproduct fuels are not counted) has the second largest savings, followed by the three plastics categories (PET, HDPE, and LDPE/LLDPE), aluminum, and glass.

Figure 71. Summary of Energy Savings from Recycling (TBtu)



Source: ICF estimate, 2013

In terms of energy source, most energy savings shown in **Figure 71** are in fuel. Total fuel savings under the Modest Scenario are 89 TBtu when byproduct fuels in the paper industry are counted and 126 TBtu if byproduct fuels are not counted. Under the Aggressive Scenario, total fuel savings are 213 TBtu with byproduct fuels, and 328 TBtu without byproduct fuels. Total electricity savings in the Modest and Aggressive Scenario are 3 and 12 TBtu, respectively.

Endnotes

[1] Section 7 of the Act is contained in the front matter of this study. Economic benefits are discussed in Section 7(b)(2)(C). The complete Act can be accessed at Web link.

[2] U.S. Environmental Protection Agency, 2013. "Recycling Basics," Web link.

[3] U.S. Environmental Protection Agency, 2013. "Common Waste and Materials," Web link.

[4] World Business Council for Sustainable Development, July 2009. "Cement Sustainability Initiative, Recycling Concrete."

[5] The Portland Cement Association provided the estimates of how many tons of alternative fuels and materials are used by the cement industry.

[6] The list of alternative fuels and materials consumed by the industry are from: Schreiber, Yonley & Associates, 2007. "Beneficial Reuse of Materials in the Cement Manufacturing Process," prepared for the Portland Cement Association.

[7] Portland Cement Association, Market Intelligence Group, 2012. "2011 U.S. & Canadian Input Survey."

[8] Hopewell, J., Dvorak, R., and Kosior, E., June 2009. "Plastics Recycling: Challenges and Opportunities." Philosophical Transactions of the Royal Society B, 364, doi: 10.1098/rstb.2008.0311, Web link. Note that Hopewell also identifies a fourth (quaternary) category. Quaternary recycling is where the waste material is used as a fuel in combustion equipment. Quaternary recycling is excluded from this analysis.

[9] Ibid.

[10] Paper Online, 2014. "Types of Pulping Processes." European Paper and Packaging Industries, Web link.

[11] Ibid.

[12] The chemical and mechanical pulping processes generate combustible waste products that are burned as fuel. The chemical process generates black liquor, which is basically a mixture of spent pulping chemicals and dissolved wood. The mechanical process generates wood wastes.

[13] U.S. Geological Survey, November 2013. "2012 Minerals Yearbook (Aluminum)."

[14] Aluminum Association, 2013. "U.S. Aluminum Can Recycling."

[15] Worrell, E., et al., March 2008. "Energy Efficiency Improvement and Cost Saving Opportunities for the Glass Industry, An ENERGY STAR® Guide for Energy and Plant Managers," Lawrence Berkeley National Laboratory.

[16] Ibid.

[17] U.S. Environmental Protection Agency, 2013. "Municipal Solid Wastes in the United States 2011 Facts and Figures," Web link.

[18] Hopewell, J., et al., June 2009. "Plastics recycling: challenges and opportunities," Philosophical Transactions of the Royal Society Biological Sciences.

[19] Franklin Associates, August 2011. "Cradle-to-gate Life Cycle Inventory of Nine Plastic Resins and Four Polyurethane Precursors, Prepared for the Plastics Division of the American Chemical Society," Web link.

[20] U.S. Environmental Protection Agency, 2013. "Municipal Solid Wastes in the United States 2011 Facts and Figures," Web link.

[21] The Steel Recycling Institute's Web site reports that 18 million tons of steel are recovered from automobiles every year. In general, these do not end up in the MSW stream, so are not included in the EPA MSW estimate.

[22] U.S. Environmental Protection Agency, 2013. "Municipal Solid Wastes in the United States 2011 Facts and Figures," Web link.

[23] Bratkovich, S., et al., September 2008. "Paper Recycling in the United States and Beyond: An Update." Dovetail Partners, Inc., Web link.

[24] Ibid.

[25] Extrusions are aluminum products used primarily for construction and buildings. Auto shredder scrap is aluminum recovered from automobiles. Aluminum castings include a variety of cast products such as those used in airplanes, appliances, and engines. Wrought products include rolls and foils.

[26] Bottle Bill Resource Guide, June 2009. "All U.S. Bottle Bills," Web link.

[27] U.S. Environmental Protection Agency, 2013. "Municipal Solid Wastes in the United States 2011 Facts and Figures," Web link.

[28] Glass Packaging Institute. "Glass Recycling Facts.," Web link.

[29] Worrell, E., et al., March 2008. "Energy Efficiency Improvement and Cost Saving Opportunities for the Glass Industry, An ENERGY STAR® Guide for Energy and Plant Managers," Lawrence Berkeley National Laboratory.

[30] Ibid.

[31] Bottle Bill Resource Guide, June 2009. "All U.S. Bottle Bills," Web link.

[32] Resource Recycling Systems (RRS), January, 2014. "Optimized Bottle Bill (OBB) Study," Web link.

[33] The Steel Recycling Institute reports that scrap recovery of automobiles that are not in the MSW stream is around 95 percent. The other steel durable goods outside the MSW stream also have high recovery rates (71 percent for steel packaging, and 90 percent for appliances).

[34] Kinsella, S., April 2012. "Paperwork: Comparing Recycled Paper to Virgin Paper," prepared by Conservatree in collaboration with the Environmental Paper Network's RePaper Project, Web link.

Appendix A. Stakeholder Experts that Collaborated with DOE

Organization	Representative
Alliance for Industrial Efficiency	Jennifer Kefer Vice President *Delegate for* David Gardiner, Executive Director
The Aluminum Association	Charles Johnson Vice-President of Policy *Delegate for* Heidi Biggs Brock, President
American Chemistry Council	Owen Kean Senior Director, Energy Policy *Delegate for* Calvin Dooley, President & CEO
American Council for an Energy Efficient Economy	Neal Elliott Associate Director for Research *Delegate for* Steven Nadel, Executive Director
American Forest and Paper Association	Jerry Schwartz Senior Director, Energy & Environmental Policy *Delegate for* Donna Harman, President & CEO
American Gas Association	Elizabeth Noll Clean Energy Solutions Advocate *Delegate for* Dave McCurdy, President & CEO
American Iron and Steel Institute	Tom Gibson President & CEO
American Public Power Association	Michael Hyland Senior Vice President, Engineering Services *Delegate for* Mark Crisson, President
Association for Demand Response and Smart Grid	Dan Delurey Executive Director
Association of Energy Engineers	George Barksdale Director of Governmental Affairs *Delegate for* Al Thumann, Executive Director
Blue-Green Alliance	Mike Williams Legislative and Policy Director *Delegate for* David Foster, Executive Director
Combined Heat and Power Association	Dale Louda Executive Director
Council of Industrial Boiler Owners	Robert Bessette President
Council on Competitiveness	Deborah Wince-Smith President & CEO
Edison Electric Institute	Eric Ackerman Director, Alternative Regulation *Delegate for* Thomas Kuhn, President & CEO
Electricity Consumers Resource Council	John Anderson President & CEO

Organization	Representative
Environmental Law and Policy Center	Howard Learner President
Federal Energy Regulatory Commission	Jamie Simler Director, Office of Energy Policy & Innovation *Delegate for* Cheryl LaFleur, Chairman
Glass Packaging Institute	Bryan Vickers Government Affairs Liaison *Delegate for* Lynn Bragg, President
Heat is Power	Tobyn Anderson Government Affairs Liaison *Delegate for* Susan Brodie, Executive Director
Industrial Energy Consumers of America	Paul Cicio President
International Association of Heat and Frost Insulators and Allied Workers	Chip Gardiner Director of Government Affairs *Delegate for* James Grogan, President
International District Energy Association	Robert Thornton President & CEO
Institute for Industrial Productivity	Bruce Hedman Technical Director *Delegate for* Jigar Shah, Executive Director
Louroe Electronics	Richard Brent CEO
National Association of Clean Air Agencies	Bill Becker Executive Director
National Association of Energy Service Companies	Donald Gilligan President *Delegate for* Terry Singer, Executive Director
National Association of Manufacturers	Ross Eisenberg Vice President of Energy and Environment *Delegate for* Jay Timmons, CEO
National Association of Regulatory Utility Commissioners	Holly Rachel Smith Assistant General Counsel *Delegate for* Charles Gray, Executive Director
National Association of State Energy Officials	David Terry Executive Director
National Association of State Utility Consumer Advocates	Elin Katz Connecticut Consumer Counsel *Delegate for* Charles Acquard, Executive Director
National Governors Association	Sue Gander Division Director, Environment, Energy & Transportation Division *Delegate for* Dan Crippen, Executive Director
Natural Resources Defense Council	Vignesh Gowrishankar Staff Scientist, Sustainable Energy *Delegate for* Frances Beinecke, President
National Rural Electric Cooperative Association	Mary Ann Ralls Senior Regulatory Counsel *Delegate for* Jo Ann Emerson, CEO

Organization	Representative
The Pew Charitable Trusts	Jessica Frohman Lubetsky Manager, Clean Energy Program *Delegate for* Rebecca Rimel, President & CEO
PJM Interconnection	Susan Covino Senior Consultant, Emerging Markets *Delegate for* W. Terry Boston, President & CEO
Portland Cement Association	Bryan Brendle Director, Environment and Energy Policy *Delegate for* Greg Scott, President & CEO
Regulatory Assistance Project	Carl Linvill Principal *Delegate for* Rich Sedano, Principal and U.S. Programs Director
United States Energy Association	Barry Worthington Executive Director
U.S. Environmental Protection Agency	Beth Craig Director, Climate Protection Partnership Division *Delegate for* Gina McCarthy, Administrator
World Resources Institute	Nate Aden Research Fellow, Climate & Energy Program *Delegate for* Andrew Steer, President & CEO

Appendix B. Results of 50 Percent Cost Share Scenario

The results discussed in Chapter 6 are based on an assumption that industrial manufacturing participants will cost share 80 percent of the total project cost for an energy efficiency project, with the balance funded by a federal grant program. This appendix presents the results of an alternative scenario based on a participant cost share of 50 percent (referred to as "50-50 scenario").

Funding Assumptions

Table 32 shows the total funding and distribution under the 50-50 scenario. As expected, with a fixed federal grant funding level of $5 billion, the funding under the 50-50 scenario is lower than the 80-20 scenario discussed in Chapter 6. The 80-20 scenario has a total funding pool of $25 billion ($12.5 billion for EE/DR programs and $12.5 billion for CHP programs), while the 50-50 scenario has a funding pool of $10 billion ($5 billion for EE/DR and $5 billion for CHP). **Table 33** and **Table 34** show the funding distribution for the EE/DR and CHP programs, respectively.

Table 32. Total Funding, Efficiency/Demand Response and CHP, 50 Percent Cost Share

Description		Technology		Total
		Energy Efficiency/Demand Response	CHP	
Federal Funds	($ billion)	$2.5	$2.5	**$5.0**
	(percent of total project cost)	50%	50%	**50%**
Participant Cost Share	($ billion)	$2.5	$2.5	**$20.0**
	(percent of total project cost)	50%	50%	**50%**
TOTAL	($ billion)	$5.0	$5.0	**$10.0**
	($ billion/year)	$0.5	$0.5	**$1.0**

Note: Unless indicated otherwise, all monetary values are expressed in 2012 dollars.

Table 33. Funding for Energy Efficiency/Demand Response, 50 Percent Cost Share

Description		Scenario		
		1	2	3
Total Funding for Energy Efficiency/Demand Response Measures	($ billion)	$5.0	$5.0	$5.0
Share for Electric Measures	(percent)	20%	50%	80%
	($ billion)	$1.0	$2.5	$4.0
Share for Fuel Measures (natural gas)	(percent)	80%	50%	20%
	($ billion)	$4.0	$2.5	$1.0

Table 34. Funding for CHP Scenarios, 50 Percent Cost Share

Description	CHP Scenario		
	1	2	3
Unit Size (MW)	3.0	12.5	40.0
Deployment Funds (Federal plus participant cost share, $ billion)	$5.0	$5.0	$5.0

End-Use Energy Efficiency and Demand Response Results

Table 35 compares the results of the 50-50 scenario and the 80-20 scenario for EE/DR. The table shows that the energy savings, energy cost savings, CO_2 emissions reductions, jobs creation, and GDP growths are smaller in the 50 percent cost share scenario. These results occur because the investment for EE/DR projects is significantly smaller in the 50 percent cost share scenario compared to the 80 percent cost share scenario.

Table 35. End-Use Energy Efficiency and Demand Response Comparison (50-50 and 80-20 Scenarios)

Description	Scenario					
	1		2		3	
Capacity (MW)	N/A		N/A		N/A	
Funding for Electric Technologies (percent)	20%		50%		80%	
Funding for Natural Gas Technologies (percent)	80%		50%		20%	
Participant Cost Share	80%	50%	80%	50%	80%	50%
Total Investment Over 10 Years ($ billion)	$12.5	$5.0	$12.5	$5.0	$12.5	$5.0
Energy Saved, Source Basis (TBtu/yr)	741	296	744	298	748	299
Energy Saved, Site Basis (TBtu/yr)	642	257	499	199	355	142
Value of Saved Energy to Industrial Customers ($ billion)	$5.00	$2.00	$5.00	$2.00	$5.00	$2.00
Reduced CO_2 Emissions (million MT/yr)	37	15	47	19	58	23
Job-Years	5,871	1,454	5,956	1,476	6,041	1,497
Net Jobs (per $ million invested)	4.7	2.9	4.8	3.0	4.8	3.0
Net GDP ($ million/yr)	$240	$66	$223	$62	$206	$57

Table 36 shows more detailed results on the job impacts. As expected, a $500 million annual investment in the EE/DR program resulted in a significantly lower economic impact in the 50-50 analysis, where the corresponding annual investment amount was $1.25 billion; however, the trends among the three scenarios were similar to the 80-20 analysis. In the EE/DR model, Scenario 1 had the lowest job impact, but the highest GDP; while Scenario 3 had the highest job impact, yet the lowest GDP. On average, approximately 1,480 jobs were created in the 50 percent cost share scenario (range from 1,454 job-years to 1,497 job years). In terms of net

jobs (per $ million invested), the 50-50 scenario results are approximately 37 percent lower compared to the 80-20 scenario (see second row of **Table 36**).

Table 36. End-Use Energy Efficiency and Demand Response Job Impacts

Description	80% Participant Share			50% Participant Share		
	Scenario 1	Scenario 2	Scenario 3	Scenario 1	Scenario 2	Scenario 3
Job-Years over 10 years	5,871	5,956	6,041	1,454	1,476	1,497
Net Jobs per $ million invested	4.7	4.8	4.8	2.9	3.0	3.0
Net GDP ($ million/year)	$240	$223	$206	$66	$62	$57

Table 37 and **Table 38** provide detailed job impacts and GDP impacts results, broken down by direct, indirect, and induced impacts.

Table 37. Net Jobs, Energy Efficiency/ Demand Response Scenarios, 50 Percent Cost Share

Scenario	Annual Net Job Impacts			
	Direct	Indirect	Induced	**Total**
1	896	-50	607	**1,454**
2	907	-42	610	**1,476**
3	918	-35	614	**1,497**

Table 38. Net GDP, Energy Efficiency/Demand Response Scenarios, 50 Percent Cost Share

Scenario	Annual Net GDP Impact ($ Millions)			
	Direct	Indirect	Induced	**Total**
1	$25	-$10	$51	**$66**
2	$17	-$7	$51	**$62**
3	$10	-$4	$51	**$57**

CHP Results

Table 39 presents the results of the 50-50 cost share scenario and the 80-20 scenario for CHP programs. Similar to the EE/DR results, the CHP analysis shows that energy savings, energy costs, CO_2 emissions reductions, jobs creation, and GDP growth are smaller in the 50 percent cost share scenario compared to the 80 percent scenario. These results are expected as the investment for CHP projects is smaller in the 50 percent cost share scenario compared to the 80 percent scenario.

Table 39. CHP Results for 80 Percent and 50 Percent Participant Cost Share

Description	Scenario					
	1		2		3	
Capacity, each CHP system (MW)	3.0		12.5		40.0	
Funding for Electric Technologies (percent)	N/A		N/A		N/A	
Funding for Natural Gas Technologies (percent)	N/A		N/A		N/A	
Participant Cost Share	80%	50%	80%	50%	80%	50%
Total Investment Over 10 Years ($ billion)	$12.5	$5.0	$12.5	$5.0	$12.5	$5.0
Total Installed Capacity, all CHP systems (GW)	5.2	2.1	6.3	2.5	7.9	3.2
Energy Saved, Source Basis (TBtu/yr)	195	78	187	75	297	119
Energy Saved, Site Basis (TBtu/yr)	-42	-17	-118	-47	-116	-46
Value of Saved Energy to Industrial Customers ($ billion)	$1.70	$0.68	$1.68	$0.67	$2.13	$0.85
Reduced CO_2 Emissions (million MT/yr)	11	5	11	4	17	7
Average Simple Payback (years)	9.9	6.2	9.1	5.7	6.11	3.8
Job-Years	5,163	873	4,483	595	3,840	337
Net Jobs (per $ million invested)	4.1	1.7	3.6	1.2	3.1	0.7
Net GDP ($ million/yr)	$212	$56	$189	$45	$168	$37

Table 40 shows detailed results for job and GDP impacts. Like the EE/DR results, the impact on both employment and GDP decreases from Scenario 1 to Scenario 3 in proportion to the number of installed CHP systems. The number of CHP systems is a function of the total funding, thus a $500 million annual investment translates to 70 CHP units in Scenario 1, 20 units in Scenario 2, and 8 units in Scenario 3.

Table 40. CHP Job Impacts

Description	80% Participant Share			50% Participant Share		
	Scenario 1	Scenario 2	Scenario 3	Scenario 1	Scenario 2	Scenario 3
Job-Years over 10 years	5,163	4,483	3,840	873	595	337
Net Jobs (jobs / $ million invested)	4.1	3.6	3.1	1.7	1.2	0.7
Net GDP ($ million / year)	$212	$189	$168	$56	$45	$37

Table 41 and **Table 42** provide detailed job impacts and GDP impacts results, broken down by direct, indirect, and induced impacts.

Table 41. Net Jobs for CHP Scenarios, 50 Percent Cost Share

Scenario	Annual Net Job Impacts			
	Direct	Indirect	Induced	**Total**
1	150	218	503	**873**
2	-87	258	423	**595**
3	-308	294	351	**337**

Table 42. Net GDP for CHP Scenarios, 50 Percent Cost Share

Scenario	Annual Net GDP Impacts ($ millions)			
	Direct	Indirect	Induced	**Total**
1	$24	-$11	$42	**$56**
2	$16	-$6	$35	**$45**
3	$10	-$3	$29	**$37**

Conclusions

Because the federal grant funding level remains constant at $5 billion, the 50-50 scenario has a lower funding pool compared to the 80-20 scenario. In the 50-50 case, the pooled resources total $10 billion, and in the 80-20 scenario the pooled resources total $25 billion. Deployment of industrial energy efficiency technologies reduces energy consumption and reduces energy costs to the manufacturing sector. The 50-50 scenario will stimulate a lower amount of economic activity compared to the 80-20 scenario, and the benefits to the national economy are lower as a result of this reduced economic activity. Furthermore, the IMPLAN analysis shows that the 50-50 scenario produces lower jobs per million dollars invested compared to the 80-20 scenario. These results suggest that the 80-20 scenario will be more beneficial for the national economy compared to the 50-50 scenario, yielding larger energy savings and higher net jobs.

Appendix C. Details for End-Use Energy Efficiency and Demand Response

This appendix includes supporting data related to investments designed to accelerate deployment of end-use energy efficient and demand response technologies.

Table 43. Projected Energy Expenditures by Industry Group, 2015 ($ million)

NAICS		Energy Expenditure		
No.	Description	Electricity	Fuel	Total
311	Food	5,908	4,630	10,538
312	Beverage and Tobacco Products	797	331	1,128
313	Textile Mills	913	327	1,240
314	Textile Product Mills	189	87	277
315	Apparel	112	18	129
316	Leather and Allied Products	32	8	40
321	Wood Products	1,711	819	2,530
322	Paper	3,145	3,549	6,694
323	Printing and Related Support	1,339	268	1,607
324	Petroleum and Coal Products	2,274	5,140	7,414
325	Chemicals	7,932	34,243	42,175
326	Plastics and Rubber Products	3,907	844	4,751
327	Non-metallic Mineral Products	2,896	3,263	6,159
331	Primary Metals	9,906	8,175	18,082
332	Fabricated Metal Products	3,666	1,353	5,019
333	Machinery	2,217	672	2,890
334	Computer and Electronic Products	2,452	266	2,717
335	Electrical Equip., Appliances, and Components	916	281	1,197
336	Transportation Equipment	3,952	1,244	5,197
337	Furniture and Related Products	501	131	633
339	Miscellaneous	789	155	944
31-33	**Total**	**55,553**	**65,806**	**121,359**

Source: EIA, MECS 2010 and AEO 2014

Table 44. Allocation of Funds for Electricity Measures by Scenario, Industry Group

NAICS		Scenario		
No.	Description	1	2	3
311	Food	266	665	1,063
312	Beverage and Tobacco Products	36	90	143
313	Textile Mills	41	103	164
314	Textile Product Mills	9	21	34
315	Apparel	5	13	20
316	Leather and Allied Products	1	4	6
321	Wood Products	77	192	308
322	Paper	142	354	566
323	Printing and Related Support	60	151	241
324	Petroleum and Coal Products	102	256	409
325	Chemicals	357	892	1,428
326	Plastics and Rubber Products	176	440	703
327	Non-metallic Mineral Products	130	326	521
331	Primary Metals	446	1,114	1,783
332	Fabricated Metal Products	165	412	660
333	Machinery	100	249	399
334	Computer and Electronic Products	110	276	441
335	Electrical Equip., Appliances, and Components	41	103	165
336	Transportation Equipment	178	445	711
337	Furniture and Related Products	23	56	90
339	Miscellaneous	36	89	142
31-33	**Total**	**2,500**	**6,250**	**10,000**

Table 45. Allocation of Funds for Fuel Measures by Scenario, Industry Group

NAICS Code		Scenario		
No.	Description	1	2	3
311	Food	704	440	176
312	Beverage and Tobacco Products	50	31	13
313	Textile Mills	50	31	12
314	Textile Product Mills	13	8	3
315	Apparel	3	2	1
316	Leather and Allied Products	1	1	0
321	Wood Products	124	78	31
322	Paper	539	337	135
323	Printing and Related Support	41	25	10
324	Petroleum and Coal Products	781	488	195
325	Chemicals	5,204	3,252	1,301
326	Plastics and Rubber Products	128	80	32
327	Non-metallic Mineral Products	496	310	124
331	Primary Metals	1,242	776	311
332	Fabricated Metal Products	206	128	51
333	Machinery	102	64	26
334	Computer and Electronic Products	40	25	10
335	Electrical Equip., Appliances, and Components	43	27	11
336	Transportation Equipment	189	118	47
337	Furniture and Related Products	20	12	5
339	Miscellaneous	24	15	6
31-33	**Total**	**10,000**	**6,250**	**2,500**

Table 46. Industrial Energy Prices, 2015 ($/MMBtu)

NAICS Code		Energy Price	
No.	Description	Electricity	Fuel
311	Food	21.07	5.37
312	Beverage and Tobacco Products	26.13	6.25
313	Textile Mills	19.29	7.37
314	Textile Product Mills	22.52	6.39
315	Apparel	26.52	7.94
316	Leather and Allied Products	30.52	6.97
321	Wood Products	22.73	10.23
322	Paper	16.85	5.48
323	Printing and Related Support	27.09	6.87
324	Petroleum and Coal Products	16.98	5.22
325	Chemicals	16.65	7.48
326	Plastics and Rubber Products	23.15	6.84
327	Non-metallic Mineral Products	21.10	5.17
331	Primary Metals	14.58	7.71
332	Fabricated Metal Products	25.11	6.76
333	Machinery	25.46	7.27
334	Computer and Electronic Products	23.77	6.04
335	Electrical Equip., Appliances, and Components	23.22	6.77
336	Transportation Equipment	22.29	6.73
337	Furniture and Related Products	28.04	8.53
339	Miscellaneous	28.86	8.27
31-33	**Total**	**19.48**	**6.54**

Source: EIA, MECS 2010; extrapolated to 2012 following overall electricity and fuel price trends.

Table 47. Industrial CO_2 Emission Factors

NAICS Code		Emission Factor (lb of CO_2/MMBtu)
No.	Description	
311	Food	139
312	Beverage and Tobacco Products	137
313	Textile Mills	139
314	Textile Product Mills	140
315	Apparel	117
316	Leather and Allied Products	117
321	Wood Products	129
322	Paper	149
323	Printing and Related Support	120
324	Petroleum and Coal Products	109
325	Chemicals	56
326	Plastics and Rubber Products	107
327	Non-metallic Mineral Products	157
331	Primary Metals	75
332	Fabricated Metal Products	120
333	Machinery	120
334	Computer and Electronic Products	117
335	Electrical Equip., Appliances, and Components	119
336	Transportation Equipment	120
337	Furniture and Related Products	119
339	Miscellaneous	120
31-33	**Total**	**89**

*Note: Electricity CO_2 emissions factor used was 1,874 lb of CO_2/MMBtu. See **Appendix F** for more information.*

Appendix D. Details for Combined Heat and Power

This appendix includes supporting data related to investments designed to accelerate deployment of combined heat and power technologies.

Table 48. Technical Characterization of CHP Systems

Description			CHP System Reference Number		
			1	2	3
Description of CHP System	Prime Mover		Lean Burn Reciprocating Engine with SCR	Gas Turbine with SCR	Gas Turbine with SCR
	Fuel		Natural Gas	Natural Gas	Natural Gas
	Thermal Recovery		Hot water or steam	Hot water or steam	Hot water or steam
Electrical Capacity		(kW)	3,000	12,500	40,000
Usage	Capacity Factor	(percent)	80.0 percent	85.0 percent	92.0 percent
	Equivalent Full Load Hours	(hrs/yr)	7,008	7,446	8,059
Efficiency	Electric	(percent)	35 percent	29 percent	37 percent
	Thermal	(percent)	43 percent	40 percent	35 percent
	Overall CHP	--	78 percent	69 percent	72 percent
	Heat Rate, HHV Basis	(Btu/kWh)	9,800	11,765	9,220
Other Metrics	Thermal Output	(Btu/kWh)	4,200	4,674	3,189
	Power to Heat Ratio	--	0.81	0.73	1.07
Efficiency of Boiler for Avoided Fuel		(percent)	80 percent	80 percent	80 percent
Installed Cost	Total	($/kW)	$2,400	$1,980	$1,580
		($ million)	$7.2	$24.8	$63.2
	Hardware (not including SCR)	(percent)	65.0 percent	75.0 percent	85.0 percent
		($/kW)	$1,560	$1,485	$1,343
	SCR	(percent)	15.0 percent	10.0 percent	5.0 percent
		($/kW)	$360	$198	$79
	Labor	(percent)	20.0 percent	15.0 percent	10.0 percent
		($/kW)	$480	$297	$158
Maintenance Costs		($/kWh)	$0.0160	$0.0088	$0.0050
Life		(yrs)	15	15	20

Source: Characteristics developed by ICF International based on internal data and published reports. One published source "Catalog of CHP Technologies," U.S. Environmental Protection Agency (EPA), 2008. DOE and EPA are currently updating this document.

Table 49. Number of Potential CHP Sites

NAICS Code		Size (MW)			
No.	Description	1-5	5-20	>20	Total
311	Food	4,845	120	0	4,965
312	Beverage and Tobacco Products	77	25	4	106
313	Textile Mills	596	137	0	733
314	Textile Product Mills	27	2	0	29
315	Apparel	22	0	0	22
316	Leather and Allied Products	4	0	0	4
321	Wood Products	1,216	2	0	1,218
322	Paper	957	181	0	1,138
323	Printing and Related Support	231	81	0	312
324	Petroleum and Coal Products	0	110	23	133
325	Chemicals	2,425	319	117	2,861
326	Plastics and Rubber Products	2,203	108	40	2,351
327	Non-metallic Mineral Products	748	217	0	965
331	Primary Metals	651	275	117	1,043
332	Fabricated Metal Products	704	0	21	725
333	Machinery	777	76	0	853
334	Computer and Electronic Products	698	150	0	848
335	Electrical Equip., Appliances, and Components	402	0	0	402
336	Transportation Equipment	674	579	0	1,253
337	Furniture and Related Products	99	0	0	99
339	Miscellaneous	118	0	0	118
31-33	**Total**	**17,474**	**2,382**	**322**	**20,178**

Table 50. Projected Industrial Energy Prices

NAICS Code		**Energy Price** (2015 $/MMBtu)	
No.	Description	Electricity	Natural Gas
311	Food	21.07	5.39
312	Beverage and Tobacco Products	26.13	5.97
313	Textile Mills	19.29	6.40
314	Textile Product Mills	22.52	6.23
315	Apparel	26.52	7.94
316	Leather and Allied Products	30.52	6.97
321	Wood Products	22.73	6.05
322	Paper	16.85	5.11
323	Printing and Related Support	27.09	6.45
324	Petroleum and Coal Products	16.98	4.48
325	Chemicals	16.65	4.48
326	Plastics and Rubber Products	23.15	5.94
327	Non-metallic Mineral Products	21.10	5.43
331	Primary Metals	14.58	4.94
332	Fabricated Metal Products	25.11	6.20
333	Machinery	25.46	6.50
334	Computer and Electronic Products	23.77	6.04
335	Electrical Equipment, Appliances, and Components	23.22	6.24
336	Transportation Equipment	22.29	6.11
337	Furniture and Related Products	28.04	7.93
339	Miscellaneous	28.86	7.66
31-33	**Total**	**19.48**	**4.94**

Source: EIA, MECS 2010; extrapolated to 2015 following overall electricity and gas price trends.

Appendix E. IMPLAN Background

IMPLAN provides the ability to model impacts in 440 sectors, of which 278 are manufacturing sectors (NAICS 31–33). IMPLAN was developed by the Minnesota IMPLAN Group (MIG). The IMPLAN model is a static input-output framework used to analyze the effects of an economic stimulus on a pre-specified economic region, in this case, the United States as a whole. This model is considered static because the impacts calculated by any scenario in IMPLAN estimate the direct, indirect, and induced impacts for one time period. The modeling framework in IMPLAN consists of two components—the descriptive model and the predictive model. The descriptive model defines the economy in the specified modeling region, and includes accounting tables that trace the "flow of dollars from purchasers to producers within the region."[1] It also includes the trade flows that describe the movement of goods and services, both within, and outside of the modeling region (i.e., regional exports and imports with the outside world). In addition, it includes the Social Accounting Matrices (SAM) that traces the flow of money between institutions, such as transfer payments from governments to businesses and households, and taxes paid by households and businesses to governments. The predictive model consists of a set of "local-level multipliers" that can then be used to analyze the changes in final demand and their ripple effects throughout the economy. These multipliers are thus coefficients that "describe the response of the [local] economy to a stimulus (a change in demand or production)."[2] Three types of multipliers are used in IMPLAN:

- Direct—represents the jobs created due to the investments that result in final demand changes, such as investments needed to build and operate a combined heat and power unit.
- Indirect—represents the jobs created due to the industry inter-linkages caused by the iteration of industries purchasing from industries, brought about by the changes in final demands.
- Induced—represents the jobs created in all local industries due to consumers' consumption expenditures arising from the new household incomes that are generated by the direct and indirect effects of the final demand changes.

In this model, the jobs reported are net of a business-as-usual case that takes into account the opportunity cost of the private sector and Federal funds spent through the grant program. The business-as-usual case for each scenario calculates the jobs that would have likely been created had the grant and matching funds been used for other more typical business purposes.

IMPLAN is limited in its ability to model economic impacts from year to year. For example, if an investment in energy efficiency by a manufacturing industry is modeled in 2015, the resulting

job and value added impacts from that input will only be modeled in 2015. For this reason, job impacts are reported on an annual basis rather than as the cumulative effect of the investment over the period 2015–2024.

Endnotes

[1] IMPLAN Pro Version 2.0 User Guide.

[2] Ibid.

Appendix F. Calculation of Electricity Energy Savings and CO_2 Reductions

Electricity Savings

There are two types of electricity savings: delivered and end-use:

- **Delivered electricity** – This is the amount of electricity used at the site. In the analyses in this study, savings of delivered electricity were estimated first since the savings are first incurred on-site. The heat rate value of delivered electricity is 3,412 Btu/kWh.
- **End-use energy** (as applied to electricity) – This is the amount of fuel consumption (Btu) per electricity generation (kWh).

To estimate the heat rate value at the end-use level, the following 2011 EIA data were used:

- Total fuel consumption to generate electricity: 39,049 TBtu[1]
- Total electricity generation: 3,948,186 million kWh[2]
- Heat rate = 39,049 / 3,948,186 = 9,890 Btu/kWh

A sample calculation is shown below:

- Assume delivered electricity savings = 100 TBtu (based on heat rate value of 3,412 Btu/kWh)
- Convert to end-use electricity savings in Trillion Btu:
  - = 100 TBtu X (9890 Btu/kWh) / (3,412 Btu/kWh)
  - = 290 TBtu

CO_2 Reductions

Reductions in CO_2 were calculated using the values shown in **Table 51**. Data sources are shown in the endnotes.

Table 51. Industrial CO_2 Emission Factors

Description			Value
Natural Gas	Higher Heating Values (HHV)	(Btu/scf)	1,020[3]
	CO_2 Emission Factor	(lb/MM scf)	120,000[4]
		(lb/MMBtu)	117.6
Electricity	CO_2 Emission Factor	(lb/MWh)	1,874[5,6]

Endnotes

[1] U.S. EIA, Annual Energy Review 2011, September 2012, Web link.

[2] U.S. EIA, Monthly Energy Review, June 2014, Web link.

[3] Environmental Protection Agency (EPA), "AP-42, Compilation of Air Pollutant Emission Factors," Natural gas HHV from Chapter 1, Section 1.4.1, Web link.

[4] Ibid, Table 1.4-2.

[5] Environmental Protection Agency (EPA), "eGRID2012, Version 1.0, Year 2009 Summary Tables," Table 3, Fossil Fuel Output Emission Rate, Web link.

[6] eGRID CO_2 emission rate (1,743 lb CO_2/MWh) adjusted by 7 percent electric grid loss.

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United States Department of Energy
Washington, DC 20585