CLIMATE CHANGE POLICY PARTNERSHIP

A Convenient Guide to Climate Change Policy and Technology

Prepared by the Nicholas Institute for Environmental Policy Solutions and The Center on Global Change, Duke University

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CLIMATE CHANGE POLICY PARTNERSHIP

VOLUME 1

TECHNOLOGY

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Introduction

Scientific consensus, growing public awareness and political change

may soon drive the United States to a mandatory climate policy. Legislators, regulators and industry executives from a wide array of market sectors increasingly understand that climate change adaptation and mitigation require planning now and action soon.

Fossil fuel-generated electricity accounts for one-third of carbon dioxide emissions in the United States; electric utility companies can therefore provide leadership in technology and policy development through careful investment decisions for future generation capacity. In doing so, climate change mitigation, technological adaptation and innovation merge; forward-looking companies gain the opportunity both to serve the public interest and thrive in a carbon-constrained future.

Electric utilities have a portfolio of mitigation options available, including investment in renewable energy technologies, demand-side management and energy-efficiency programs, nuclear energy generating capacity, natural gas capacity, cleaner coal technologies and carbon capture and storage (CCS). Because coal is an abundant and relatively inexpensive feedstock for energy, reductions and/or offsets of carbon dioxide emissions from coal-fired power plants are particularly important.

The Intergovernmental Panel on Climate Change concluded in 2001 that countries must reduce global greenhouse gas emissions to 25 percent below 1990 emissions by 2050 to reach climate stabilization at 450 parts per million (ppm), or 45 percent above 1990 emissions to reach 550 ppm. Stabilization at either 450 ppm or 550 ppm will be difficult to achieve and may still carry considerable risk of major climate events. While reduction goals for specific countries vary by political proposal, developed countries such as the United States must reduce emissions in the range of 80 percent below 1990 emissions by 2050 for 450 ppm, or 60 percent for 550 ppm.[1]

To meet these targets, all viable options for reducing greenhouse gas emissions must be explored, and as one of the largest contributors to emissions, the electricity sector must play a critical role. The first option for reducing utility-generated greenhouse gas emissions is to address electricity demand through increased energy efficiency and clean distributed generation. A second option is for the United States to repower, optimize, retrofit or co-fire its existing fleet of fossil fuel-powered plants. Alternatively, new fossil fuel, nuclear and renewable energy technologies can be developed and expanded. A third option is to sequester carbon biologically, geologically or in the ocean. The chapters that follow discuss each of these three options in detail and review current technology and performance, cost information, research and development, and future potential.

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1 Reduction targets are from a presentation, "A Comparison of Approaches for International Climate Policy Post 2012," by Nicholas Hoehne of ECOFYS. *http://www.ccap.org/Presentations/FAD/2006/Hoehne-Post%202012%20regimes%20APR%2020.pdf*

Chapter 1 – Electricity Demand

A crucial element in reducing greenhouse gas (GHG) emissions, as well as the need for constructing and deploying new centralized electricity generation capacity, is addressing electricity demand. Increases in energy efficiency can reduce gross electricity demand, thus reducing GHG emissions and delaying or negating the need for expanded generation capacity. Increased use of clean distributed generation (DG) can likewise reduce the need for expanded centralized generation capacity by generating electricity near the end use. This chapter provides an overview of each of these options.

Energy savings in the residential, commercial and industrial sectors can continually be improved by implementing new technologies and practices, as well as by increasing the adoption rate of existing energy-efficient alternatives. Potential electricity savings in the residential, commercial and industrial sectors have been estimated by U.S. Department of Energy (DOE) to be 468-1,377 terawatt hours (TWh) by 2010 and 1,348-2,960 TWh by 2020. Despite this significant potential, a number of informational, institutional, regulatory and financial barriers impede the enabling or adoption rate of energy-efficient technologies or practices. Policies to address these barriers exist at the local, utility, state and federal levels. A discussion and evaluation of these policies can be found in Volume 2 of this report.

In addition to decreasing electricity demand through increased efficiency, clean distributed generation technologies can also be used to supplement or supplant utility-generated electricity. DG technologies generate power at or near the end-use location, and include such technologies as solar photovoltaic (PV) modules, building integrated photovoltaic (BIPV) systems, small wind power systems, combined heat and power (CHP) systems, and fuel cells. Each of these technologies has its own set of drawbacks and benefits, but all of them have the added benefit of defraying the need for additional centralized generating capacity and transmission. Regardless of the DG technology platform chosen, however, any large-scale increase of capacity will require advances and expansions in storage capacity and distribution in the near future. While select DG technologies are introduced and discussed in this chapter, an expanded discussion of solar, wind, and fuel cell technology can be found in Chapter 2: Electricity Supply.

Energy Efficiency

Between 1970 and 1995, energy consumption in the United States dropped from approximately 20 megajoules (MJ) to approximately 14 MJ per (1992) dollar of gross domestic product.[1] Despite this significant improvement in energy efficiency, research indicates that "a very substantial technical, economic and achievable energy efficiency potential remains available in the U.S."[2] In 2000, the DOE estimated potential electricity savings in the residential, commercial and industrial sectors to be 468-1,377 TWh by 2010 and 1,348-2,960 TWh by 2020.[3]

Potential energy savings can be attributed to continued technological advances, increased adoption of existing energy efficient products and the further implementation of energy-efficient practices. However, the overall potential of energy-efficient technologies and practices to bring about energy savings and reductions in carbon emissions will vary among the residential, commercial and industrial sectors; likewise, the specific technologies and practices best suited to bring about these energy savings and emissions reductions will vary as well. In the residential sector, potential near-term electricity savings are predominantly achieved through improvements in energy-efficient lighting and space heating and cooling technology and adoption rates. In the commercial sector, potential near-term savings are driven primarily by improvements in energy-efficient lighting, space cooling and office product technology and adoption rates. In the industrial sector, potential near-term electricity savings are primarily the result of improvements in energy efficient motor, heating and cooling, and lighting technology and adoption rates.

In determining the likelihood of efficiency improvements, analysts must consider adoption and enabling rates along with technical improvements in products, processes or practices, since the existence of a more efficient technology or practice, even if cost effective, does not necessarily mean that it will be used.[4] A number of informational, institutional, regulatory and financial barriers impede the enabling or adoption rate of energy-efficient technologies or practices. In particular, upfront costs of energy-efficient technologies or practices remain a primary barrier to increased use or adoption of high-efficiency products or practices. Likewise, a lack of knowledge of high-efficiency alternatives results in lost opportunities for increased energy savings, regardless of sector.

The presence of barriers to energy efficiency necessitates public policy intervention. The policies or programs best suited to encourage energy efficiency depend on the geographic scale in question (e.g., state, regional, national) and the sectors targeted (e.g., residential, commercial, industrial). The federal government has implemented tax credits and federally backed loan assistance programs to encourage energy efficiency in the home and the workplace. The federal government has also established appliance standards, a branding program called ENERGY STAR for high-efficiency products and model building codes to provide a basis for nationwide minimums in efficiency. Many states have also established their own, more stringent appliance standards and building codes, as well as tax credits and other incentives. Utilities, spurred by state incentives or requirements, have developed demand-side management (DSM) programs to encourage energy efficiency and to aid load management.

This section is intended to provide an overview of demand-side efficiency opportunities. Specifically, the section includes a review of energy-efficient technologies and programs and a description of the barriers to increased

1 Interlaboratory Working Group, 1997.

2 Nadel et al., 2004., p1

3 Interlaboratory Working Group, 2000. Savings estimates are based on scenarios considering various levels of implementation and stringency of policies and programs to encourage energy efficiency, as well as the institution of carbon permit trading fees of $25 and $50 per ton.

4 Nadel et al. (2004) differentiates between three types of energy efficiency potential: technical (all possible measures for improving efficiency without regard to economics), economic (adoption dependent on economic considerations), and achievable (takes into account normal market forces). In fact, the Interlaboratory Working Group (1997) used energy efficient adoption rates of 35 percent to 65 percent in their seminal Five Lab Study, while Beck et al. (2001) used slightly higher adoption rates (60 percent to 70 percent) in their development of a Clean Energy Plan for the South.

energy-efficiency savings. An overview of the complementary policies to encourage energy efficiency is included in Volume 2 of this report. Throughout the discussion below, representative product categories have been selected to provide a generalized cross section of energy-efficient technology. Representative programs and processes were selected on a similar basis. In selecting all products, programs and processes, consideration was given to present and potential future market share and penetration. Aggregate electricity and energy savings are expressed in terms of watthours and joules, respectively. Individual and aggregate avoided greenhouse gas emissions are expressed in terms of pounds and million metric tons (mmt) of carbon dioxide (CO_2) displacement.

TECHNOLOGIES AND PROGRAMS

INTRODUCTION

In 2000, the Department of Energy released a report, "Scenarios for a Clean Energy Future," that described potential 2010 and 2020 energy savings across sectors.[5] The report estimated potential residential electricity reductions of 5.1 percent to 12.3 percent from business as usual, by 2010.[6] By 2020, potential residential-sector electricity reductions increase to 13.3 percent to 27.4 percent from business as usual.[7] In the commercial and industrial sectors, the study estimated similar, if slightly lower, potential savings in 2010 and 2020.[8]

Total potential savings vary at the state and regional level. In California, the state with the lowest per capita energy consumption, Itron Inc. et al. (2006) estimate that continued efforts in energy efficiency can reduce state energy consumption by 16,226-23,974 gigawatt hours (GWh) by 2016.[9] In the Midwest, Synapse Energy Economics (2001) estimates that increased efficiency is capable of reducing average annual electricity load by 0.5 percent between 2000 and 2020 at a cost of approximately 2.4 cents per kilowatt-hour (kWh) and a net benefit of $5.5 billion.[10] In the South, Beck et al. (2001) estimate that aggressive energy-efficiency programs can lower annual increases in electricity demand from 1.8 percent to 0.7 percent, saving approximately 236,000 GWh at a cost of approximately 2.5 cents per kWh and a net benefit of $4.2 billion.[11]

The potential of energy-efficient technologies and practices to bring about energy savings and reductions in carbon emissions varies among the residential, commercial and industrial sectors. Furthermore, the specific technologies and practices employed to bring about energy savings and emissions reductions vary by sector. On a national basis, residential and commercial sectors display greater total achievable energy savings than industrial.[12] In California, the residential sector holds the greatest potential for savings in terms of amounts of energy and demand. Within the Midwest region, the residential sector is capable of achieving the greatest short-term savings, while the industrial sector is capable of much greater long-term savings. In the south, the residential and commercial sectors are capable of greater energy savings than the industrial sector for both near- and long-term time frames (Table 1-1).

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5 Clean Energy Future scenarios included business as usual (1997 base year), moderate efficiency and advanced efficiency. The moderate scenario assumes continued improvement in the implementation of policies and programs to encourage energy efficiency. The advanced scenario assumes greater levels of stringency and penetration of the policies and programs identified under the moderate scenario, as well as the institution of a carbon permit trading fee of $50/ton.

6 Interlaboratory Working Group, 2000.

7 Ibid.

8 Ibid.

9 Itron Inc. et al., 2006.

10 Synapse Energy Economics, 2001. The Midwest includes the states of Illinois, Indiana, Iowa, Michigan, Minnesota, Nebraska, North Dakota, Ohio, South Dakota and Wisconsin.

11 Beck et al., 2001. The South includes the states of Alabama, Florida, Georgia, North Carolina, South Carolina and Tennessee.

12 Nadel et al., 2004.

Table 1-1: Potential energy efficiency savings in the Midwest and South, by sector[13]

Region	Sector	2010 Savings (TWh)	2010 Savings (%)	2010 Reductions (mmt CO_2)*	2020 Savings (TWh)	2020 Savings (%)	2020 Reductions (mmt CO_2)*
Midwest	Residential	61.9	22.3	40.99	107.1	33.8	70.93
	Commercial	39.5	16.5	26.16	72.2	26.4	47.81
	Industrial	48.2	13.4	31.92	110.3	26.8	73.05
	TOTAL	149.6	16.6	99.07	289.7	28.1	191.85
South	Residential	48.04	13.5	31.81	95.92	22.0	63.52
	Commercial	36.44	13.6	24.13	72.77	22.9	48.19
	Industrial	33.84	14.5	22.41	67.57	26.9	44.75
	TOTAL	118.32	13.5	78.36	236.27	22.9	156.47

*mmt: million metric tons – calculated from an estimate of 1.46 pounds of CO_2 emissions per kWh of electricity.

A note on ENERGY STAR

Across sectors, the ENERGY STAR program, a joint effort of the U.S. Environmental Protection Agency (EPA) and DOE, is a recognized leader in the labeling of energy-efficient products. In this section, ENERGY STAR-qualified products are often used as a rough indication of energy-efficient product market penetration, energy savings and emission reductions. The existence of ENERGY STAR specifications for a wide variety of products in the residential, commercial and industrial sectors; the relative availability of ENERGY STAR-qualified product sales data; and the requirement that ENERGY STAR-qualified products meet both product performance and energy-savings criteria makes ENERGY STAR a useful metric in cross-sector comparison and aggregation. That said, ENERGY STAR specifications do not necessarily represent the most energy-efficient technology currently on the market; individual models can and often do exceed minimum ENERGY STAR criteria.

RESIDENTIAL

Year 2005 electricity sales to the residential sector totaled 1,359 TWh,[14] with approximately 26 percent being used for space heating and air conditioning, 13 percent for refrigeration and 9 percent for lighting.[15] DOE's Clean Energy Future study estimated potential residential electricity reductions of 5.1 percent to 12.3 percent from business as usual, by 2010.[16] By 2020, potential residential sector electricity reductions increase to 13.3 percent to 27.4 percent from business as usual.[17] In California, lighting, miscellaneous applications (refrigerators, pool pumps, and dryers) and HVAC have the greatest potential for energy savings.[18] Within the Midwest residential sector, lighting and water heating have the greatest potential for energy savings.[19] In the South, space heating and cooling, water heating, lighting and refrigeration have the greatest potential for energy-efficiency savings.[20]

Policy Drivers

The first energy-efficiency standards in the United States were created in 1974 by the state of California with the State Energy Resources Conservation and Development Act. The standards covered refrigerators, freezers, room air conditioners and central air conditioners. Other states adopted similar standards by the early 1980s. At the federal level, the National Appliance Energy Conservation Act of 1987 (NAECA) was approved and signed into law after many manufacturers expressed concerns about differences among the state standards being created

13 Synapse Energy Economics, 2001
14 Energy Information Administration, 2006.
15 Energy Information Administration, 2005.
16 Interlaboratory Working Group, 2000.
17 Ibid.
18 Itron Inc. et al., 2006.
19 Synapse Energy Economics, 2001.
20 Beck et al., 2001.

in the mid-1980s. NAECA was initially limited in scope to refrigeration, HVAC and other appliances, but was expanded by the Energy Policy Act (EPAct) of 1992 to include lamps, motors and office equipment.

In August 2005, the federal government enacted an updated Energy Policy Act that provided up to $2 billion in tax incentives for energy-efficient and energy-saving technologies. The American Council for an Energy Efficient Economy estimated that the energy-efficiency provisions of the EPAct of 2005 would reduce energy use in the United States by approximately 2 percent of the predicted energy consumption for that year.[21] The EPAct of 2005 also called for the expansion of ENERGY STAR, itself a key driver in energy efficiency savings. Table 1-2 below summarizes the annual energy and CO_2 savings attributed to ENERGY STAR for a selection of products in 2002.

Table 1-2: Annual total energy and CO_2 savings of ENERGY START products in 2002. at target market penetration and at 100 percent market penetration[22]

Product	2002 Market Penetration		Target Market Penetration*		100% Market Penetration*	
	Energy Savings (exajoules)	CO_2 Emissions Avoided (mmt)	Energy Savings (exajoules)	CO_2 Emissions Avoided (mmt)	Energy Savings (exajoules)	CO_2 Emissions Avoided (mmt)
CFLs	0.04	2.49	4.6	245.67	25.3	1,430
Refrigerators	0.009	0.59	0.4	20.17	1.6	84.33
CAC	0.004	0.24	0.07	0.004	1.4	0.08
Heat Pump	0.002	0.15	0.02	1.17	0.9	51.33

* Best estimates of the percent of equipment shipped that is ENERGY STAR.

Building energy efficiency is governed by a series of codes and standards. The International Code Council (ICC) develops model codes for residential and commercial construction.[23] Within the larger body of codes published by the ICC, the International Energy Conservation Code (IECC) pertains directly to energy-efficient design and construction. The American Society of Heating, Refrigerating and Air-Conditioning Engineers likewise develops standards for building and equipment performance, and these standards are often incorporated into energy codes.

Innovation and Energy Efficiency

Individual lighting, refrigeration and HVAC energy-efficient technologies have experienced differing levels of technological innovation, aggregate energy savings and avoided carbon emissions. The same is true for various residential green building programs. For Tables 1-3 to 1-5, CO_2 emission reductions are estimated from annual energy use estimates, assuming 1.46 pounds of CO_2 emissions per kWh of electricity and electricity and gas prices of $0.06/kWh and $0.40/therm, respectively.[24]

Lighting

Lighting efficiency and efficacy has improved over time. The first incandescent light bulb produced five lumens per watt.[25] Current incandescent lamps produce between 10 and 20 lumens per watt, though research indicates that new incandescent filaments could produce up to 25 lumens per watt.[26] Halogen infrared reflecting (HIR) lamps are rated at 25 to 35 lumens per watt. Fluorescent bulbs produce about 40 to 100 lumens per watt,[27] with

21 Nadel, 2005.

22 Webber et al., 2004.. Savings are determined by the number of high-energy-efficiency appliances and products above a baseline market penetration that might be present if the ENERGY STAR program did not exist.

23 While each state adopts its own unique building codes, these are usually based on ICC recommendations.

24 Energy Information Administration, 2002.

25 Higher lumens per watt represent higher luminous efficacy, a measurement of the fraction of energy that is used to produce visible light.

26 Federal Energy Management Program, 2006c.

27 American Council for an Energy-Efficient Economy, n.d.-c.

compact fluorescent lights (CFL) representing a mature, market-ready technology capable of significant energy savings over traditional incandescent lighting (Table 1-3). ENERGY STAR rated CFLs use 66 percent less energy and last up to 10 times longer than traditional incandescents.[28]

Table 1-3: Comparison of energy costs and CO_2 emissions for incandescent and compact fluorescent lighting (CFL)[329]

	Incandescent Bulb Replaced	CFL (6,000 hr life)	Incandescent Bulb Replaced	CFL (10,000 hr life)
Input watts (lumens/watt)	60 W (15)	17 W (60)	60 W (15)	17 W (60)
Annual Energy Use	72 kWh	20 kWh	120 kWh	34 kWh
Annual Energy Cost	$4.30	$1.20	$7.20	$2.00
Lifetime Energy Cost*	$19	$5	$31	$9
Lifetime Energy Cost Savings		$13		$22
Annual CO_2 Emissions	105.1 lbs	29.2 lbs	175.2 lbs	49.6 lbs
Annual CO_2 Emission Savings		75.9 lbs		125.6 lbs

* Lifetime energy cost is the sum of the discounted value of annual energy costs based on average use and an assumed CFL life of five years.

In mid-2000, market share of CFLs was approximately 0.5 percent. By 2002, the market share of CFLs increased to approximately 2 percent.[30] CFLs are most cost-effective in high-use fixtures, however, and market share is assumed to be greatest in high-use applications such as outdoor lighting.[31] Increased market penetration of CFLs is feasible. Despite limits in the number of energy-efficient fixtures and lamp sizes, the variety and selection of CFL bulbs has increased.[32] Recessed CFLs are one variety of CFL identified by DOE as having a large untapped potential market.[33] The DOE's Weatherization Assistance Program has been identified as one mechanism through which up to 500,000 incandescents can be replaced with CFLs annually.[34]

Refrigerators

Refrigerator efficiency has improved over the past 30 years. On average, a new refrigerator with automatic defrost and a top-mounted freezer is over 72 percent more efficient than models produced in 1973. The first federal standards for refrigerator energy efficiency were enacted in 1993 and updated in 2001.[35] Full-sized refrigerators must be at least 15 percent more energy efficient than the federal minimum to meet ENERGY STAR requirements. A comparison of energy savings and emission reductions for refrigerators of various efficiencies is included in Table 1-4.

Table 1-4: Comparison of energy costs and CO_2 emissions for refrigerators of varying efficiency[36]

	Base Model*	Required**	Best Available
Annual Energy Use	489 kWh	440 kWh	387 kWh
Annual Energy Cost	$29	$26	$23
Lifetime Energy Cost +	$387	$347	$307
Lifetime Energy Cost Savings		$40	$80
Annual CO_2 Emissions	713.9 lbs	642.4 lbs	565.0 lbs
Annual CO_2 Emission Savings		71.5 lbs	148.9 lbs

*Minimum allowed by current U.S. DOE appliance standards.
**Minimum required for federal purchase.
+ Lifetime Energy Cost is the sum of the discounted value of the annual energy costs over an assumed product life of 19 years.

28 ENERGY STAR, n.d.-f.
29 Federal Energy Management Program, 2006b.
30 Caldwell & Zugel, 2003.
31 Webber et al., 2004.
32 Ecotope et al., 2003.
33 U.S. Department of Energy, 2005.
34 Bowman, 2005.
35 American Council for an Energy-Efficient Economy, 2005b.
36 Federal Energy Management Program, 2006b.

In 2005, the market penetration of ENERGY STAR refrigerators was nearly 33 percent.[37] However, pre-1993 refrigerators are still in use in approximately 33 million U.S. homes, meaning that significant market penetration potential still remains for newer, more efficient models.[38] Older models from 1993 use an average of 664 kWh per year and models from 1990 use an average of 884 kWh per year.[39]

HVAC

HVAC efficiency has improved over the past 30 years. Shipment weighted efficiency[40] for central air conditioners has improved by over 70 percent from 1970 to 2003. Current electric heat pumps must have a heating seasonal performance factor (HSPF)[41] rating of at least 7.7, while ENERGY STAR heat pumps must have an HSPF rating of at least 8.0.[42] Current central air conditioners must achieve a minimum seasonal energy efficiency ratio (SEER)[43] value of 13, and ENERGY STAR air conditioners must have a SEER greater than 14.[44] A comparison of energy savings and emission reductions for HVAC units of various efficiencies is included in Table 1-5.

Table 1-5: Comparison of energy costs and CO_2 emissions for central AC units of varying efficiency[45]

	Base Model*	Recommended Level	Best Available
Energy Efficiency Ratio (EER)[5]	9.2	11.0	14.5
SEER	10.0	13.0	16.5
Annual Energy Use	3,600 kWh	2,770 kWh	2,000 kWh
Annual Energy Cost	$216	$166	$131
Lifetime Energy Cost +	$2,350	$1,800	$1,420
Lifetime Energy Cost Savings		$550	$930
Annual CO_2 Emissions	5,256 lbs	4,044 lbs	2,920 lbs
Annual CO_2 Emission Savings		1,212 lbs	2,336 lbs

* The EER of 9.2 of the base model shown represents the most common model on the market.

+ Lifetime Energy Cost is the sum of the discounted value of the annual energy costs over an assumed product life of 15 years

Note re: Energy Efficiency Ratio(EER)[4646]

In California, sales of ENERGY STAR heat pumps and central air conditioners during the fourth quarter 2004 were 15 percent and 11 percent of the market, respectively.[47] Aside from improvements in traditional HVAC efficiency, geothermal heat pumps have potential to reduce energy use and carbon emissions significantly. Replacing a conventional HVAC system with a geothermal heat pump could reduce total energy use of a home by 40 percent while simultaneously reducing maintenance costs.[48] The Geothermal Heat Pump Consortium estimates that the installation of 100,000 residential geothermal heat pumps would save consumers $750 million in energy costs while preventing 8.04 mmt of CO_2 emissions over the lifetime of the products.[49]

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37 ENERGY STAR, 2006.

38 ENERGY STAR, 2005b.

39 Energy Information Administration, 2000.

40 Shipment weighted efficiency is the average efficiency of all units shipped within a given year, weighted by the relative number of units in a particular efficiency class.

41 The amount of heat generated divided by the seasonal amount of electricity consumed; the higher the HSPF, the more efficient the heat pump.

42 American Council for an Energy-Efficient Economy, 2006.

43 The cooling output divided by the power input for a hypothetical average U.S. climate; the higher the SEER, the more efficient the air conditioner.

44 American Council for an Energy-Efficient Economy, 2005a.

45 Federal Energy Management Program, 2004.

46 Instantaneous energy efficiency of cooling equipment is the steady-state rate of heat energy removal by the equipment divided by the steady-state rate of energy input to the equipment in watts.

47 Harcharik, 2006.

48 Federal Energy Management Program, 2004.

49 Geothermal Heat Pump Consortium, n.d.

Building Programs

The National Association of Home Builders (NAHB) estimated the 2005 residential green building market at $7.4 billion and 2 percent of housing starts.[50] Overall, the residential green building market is expected to reach $19 billion to $38 billion and 5 percent to 10 percent of construction activity by 2010.[51]

Within the green building market, there are several distinct initiatives and programs. One specific program, the ENERGY STAR Qualified New Homes program, is operated by the EPA and DOE. ENERGY STAR Qualified New Homes are built to be 15 percent more energy efficient than the 2006 IECC, incorporating effective insulation, high performance windows, tight construction and ducts, efficient heating and cooling equipment and ENERGY STAR-qualified lighting and appliances. Beginning in 1995 with only 55 qualified homes, the ENERGY STAR Qualified New Homes program grew to more than 360,000 homes by the end of 2004, cumulatively saving homeowners approximately $200 million in energy costs.[52] By 2005, the number of ENERGY STAR homes increased to 525,000.[53] The program has set a goal of 60 percent nationwide market penetration by 2012. If this target is met, the ENERGY STAR homes program would prevent 33 mmt of CO_2 from being emitted and save homeowners more that $4 billion dollars on energy costs.[54]

Leadership in Energy and Environmental Design (LEED) certifies a variety of commercial building types. Although still in a pilot phase, the residential equivalent, LEED-H, intends to "recognize and reward the 25 percent of new homes that are top performers in terms of resource efficiency and environmental stewardship."[55] LEED-H homes are required to meet the standards for the ENERGY STAR Qualified New Homes and offer additional levels of recognition for those structures exceeding minimum guidelines.[56] Industry groups have also offered their own voluntary green building programs. The 2005 issuance of NAHB's model green home building guidelines is one example.[57] Slated for updating in 2007 to reflect changing technology and standards, NAHB's model guidelines currently require adherence to IECC 2003, correct sizing of HVAC and third-party verification of compliance. To achieve higher levels of recognition under the model green home building guidelines, builders can choose to build at 15 percent, 30 percent or 40 percent above IECC 2003.

The Department of Energy's Building America program employs a systems approach to achieving increased levels of energy efficiency in homes. To date, more than 32,000 homes have been built through Building America projects.[58] The program aims to reduce home energy consumption by 40 percent to 70 percent and is working on developing a zero energy home (ZEH).[59] The ZEH is a highly efficient home built to produce enough on-site renewable energy (e.g., rooftop photovoltaic cells) capable of rendering a net annual home energy consumption of zero.[60] Potential energy savings from ZEH construction can be significant, ranging from 0.45 to 3.14 EJ by 2050 (Table 1-6).

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50 National Association of Home Builders, 2006.

51 Ibid.

52 ENERGY STAR, 2005a.

53 ENERGY STAR, n.d.-d.

54 ENERGY STAR, 2005a.

55 U.S. Green Building Council, 2006.

56 U.S. Green Building Council, 2005c.

57 See, e.g., *http://www.nahb.org/publication_details.aspx?publicationID=1994&sectionID=155*, Retrieved October 5, 2006.

58 U.S. Department of Energy, 2006a.

59 U.S. Department of Energy, 2004.

60 While a ZEH may at times draw electricity from the grid, enough is produced on-site at other times to "reverse-meter" back to the utility, achieving a net annual consumption of zero.

Table 1-6: Estimated impact of zero energy homes from 2010 to 2050[6161]

	2010	2020	2030	2040	2050
Cumulative ZEH Installations					
Reference Case w/ PV	0	0	9,557	608,695	2,816,213
ZEH Integration	0	9,831	806,207	4,959,123	13,178,922
ZEH + 30% tax credit	0	2,673,119	2,673,119	9,793,654	19,584,250
Annual Energy Savings (exajoules)					
Reference Case w/ PV	0.0	0.00	0.002	0.09	0.45
ZEH Integration	0.0	0.001	0.12	0.79	2.11
ZEH + 30% tax credit	0.0	0.03	0.43	1.57	3.14
Annual CO_2 Displacement (MMT)					
Reference Case w/ PV	0.0	0.0	0.18	12.02	55.61
ZEH Integration	0.0	0.18	15.90	97.93	260.22
ZEH + 30% tax credit	0.0	3.32	52.77	193.39	386.71

The reference case with photovoltaics assumes that systems are incorporated into new home building projects using a break-even cashflow analysis (which compares increase monthly mortgage cost versus the decrease monthly utility bills) The ZEH integration case takes into account the benefits of bundling energy efficiency, solar water heating and PV technologies in new homes. The ZEH +30 percent tax credit is a combination of the ZEH integration case with a solar tax credit of 30 percent.

COMMERCIAL

Year 2005 electricity sales to the commercial sector was 1,275 TWh.[62] Approximately 17 percent of all energy consumed in the United States is related to heating, cooling lighting and other energy demands of 67 billion square feet of commercial floor space.[63] Lighting accounts for about 40 percent of the energy used by commercial buildings and is the single largest component of energy use in the commercial sector.[64] The second largest demand for electricity in commercial building is space cooling, which accounts for approximately 15 percent of total commercial energy consumption.[65]

The Clean Energy Future study estimated 2010 potential commercial sector electricity reductions of 4.4 percent to 11.2 percent from business as usual and 2020 potential reductions of 10.8 percent to 22.1 percent.[66] At the national level, office products display significant potential for commercial sector end-use savings.[67] Energy-efficient building construction and management likewise could constitute significant energy savings and emissions reductions. In California's commercial sector, lighting, HVAC and refrigeration have the greatest potential for energy savings.[68] In the Midwest, commercial lighting and space cooling have the greatest potential for energy savings.[69] In the South, lighting, space cooling, office equipment, water heating and refrigeration have the greatest potential for savings.[70]

Policy Drivers

Standards and specifications are key drivers in commercial product efficiency. In 1999, the American Society of Heating, Refrigerating and Air-Conditioning Engineers based its recommended model efficiency guidelines for packaged air conditioning systems on Consortium for Energy Efficiency (CEE) Tier 1 specifications, fostering the widespread transition to Tier 1 energy-efficiency levels.[71] Minimum efficiency standards were adopted by the

61 NAHB Research Center, 2006.
62 Energy Information Administration, 2006.
63 American Council for an Energy-Efficient Economy, n.d.-b.
64 Consortium for Energy Efficiency, n.d.-b.
65 Consortium for Energy Efficiency, n.d.-a.
66 Interlaboratory Working Group, 2000.
67 Nadel et al., 2004.
68 Itron Inc. et al., 2006.
69 Synapse Energy Economics, 2001.
70 Beck et al., 2001.
71 Nadel et al., 2003.

California Energy Commission for reach-in refrigerators and freezers in 2002.[72] The EPAct of 2005 expanded federal minimum standards for commercial air conditioners to include packaged air conditioning equipment with over 20 tons of cooling capacity; these standards were not included in the first EPAct.[73]

Innovation and Energy Efficiency

A description of past technological innovation and future potential for commercial lighting, refrigeration, HVAC, office equipment and building programs is included below. For Tables 1-7 through 1-10, the assumed electricity price is \$0.06/kWh, which represents the average electricity price in the United States. Also, CO_2 emissions were estimated using annual energy usage data and a carbon coefficient of 1.46 pounds of CO_2 emitted per kWh of electricity.

Lighting

Inefficient T12 systems account for about 58 percent of commercial fixtures, while more-efficient T8 lights and ballasts comprise about 23 percent.[74,75] A high-performance T8 system can create electricity savings of 40 percent compared to a standard T12 system.[76] New commercial lighting technology, such as "Super" T8 lamp systems, is capable of achieving a 15 percent to 20 percent improvement in energy efficiency as compared to standard T8 lamps (Table 1-7).[77]

Table 1-7: Comparison of energy costs and CO_2 emissions for fluorescent tube lights[78]

Performance	Base Model	Recommended Level	Best Available
Lamp and Ballast Type	T12,34 watts, magnetic ballast	T8,32 watts, electronic ballast	T8,32 watts, electronic ballast
Related Lamp Output- 2 Lamps	5300 lumens	5600 lumens	6000 lumens
Input Power	82 watts	62 watts	57 watts
Annual Energy Usage	295 kWh	233 kWh	205 kWh
Annual Energy Cost	\$17.70	\$13.40	\$12.30
Annual Energy Cost Savings—2 lamps + ballast		\$4.30	\$5.40
Annual Energy Cost Savings—2 lamps only		\$1.30	\$1.80
Lifetime Energy Cost Savings—per lamp*		\$2.80	\$3.90
Annual CO_2 Emissions	430.7 lbs	340.2 lbs	299.3 lbs
Annual CO_2 Emission Savings		90.5 lbs	131.4 lbs

* Lifetime Energy Cost is the sum of the discounted value of the annual energy costs over an assumed product life of 5 years.

Research is being conducted to develop next-generation fluorescent lamps with improved color rendition and efficiency, as well as to develop advanced technologies such as multiphoton phosphor lighting.[79] A theoretical efficacy potential of 300 lumens per watt has been identified for the latter of these two technologies.[80]

Solid-state lighting, including light-emitting diodes (LEDs) and organic light-emitting diodes (OLEDs), is another emerging technology. LEDs and OLEDs are exceptionally long-lived (+35,000 hours), making them ideally suited for constant-use applications such as exit signs and traffic signals. Research is under way to reduce the per-unit

72 Ibid.

73 Ibid.

74 Consortium for Energy Efficiency, n.d.-b.

75 "T" values for tubular fluorescents refer to the diameter of the lamp, measured in eighths of an inch. Therefore, a T8 lamp is equal to 8*1/8" (1.0") and a T12 is equal to 12*1/8" (1.5").

76 Consortium for Energy Efficiency, n.d.-b.

77 Thorne & Nadel, 2003.

78 Federal Energy Management Program, 2006e.

79 Federal Energy Management Program, 2006a.

80 Gough & Mishra, 2003.

cost and increase the efficiency of LEDs and OLEDs.[81] DOE has set a target market-ready and cost-effective white LED efficacy of 160 lumens per watt by 2025, or nearly 10 times the efficiency of conventional incandescents.[82]

Beyond increases in bulb, lamp and fixture efficiency, recommended levels of general office lighting continue to change and hold the potential for additional energy savings. For example, evolution away from work environments in which most tasks involve handling papers should allow for significant reduction in general office space light intensity, especially when augmented with task lighting.[83]

Refrigerators

In 1996, the average energy use of a solid single door, reach-in commercial refrigerator was approximately 2,300 kWh per year.[84] By 2005, efficiency of a base model solid door, 24-cubic-foot reach-in commercial refrigerator was 1,891 kWh per year, an improvement of nearly 18 percent.[85] ENERGY STAR-qualified solid door, reach-in refrigerators must achieve a level of performance based in part on the volume of refrigerated space. ENERGY STAR-qualified solid door, reach-in refrigerators can achieve as high as 45 percent energy savings compared to standard equipment.[86] Consortium for Energy Efficiency Tier 1 standards for solid door, reach-in refrigerators are similar to ENERGY STAR qualifying criteria, while CEE Tier 2 standards require an additional 40 percent increase in efficiency.[87] A comparison of energy savings and emission reductions for commercial refrigeration units of various efficiencies is included in Table 1-8.

Table 1-8: Comparison of energy costs and CO_2 emmisions for commercial refrigerators[88]

Performance	Base Model	Recommended Level	Best Available
Daily Energy Use	5.2 kWh	4.4 kWh	3.1 kWh
Annual Energy Use	1,891 kWh	1,621 kWh	1,132 kWh
Annual Energy Cost	$113	$97	$70
Lifetime Energy Cost*	$890	$760	$530
Lifetime Energy Cost Savings		$130	$360
Annual CO_2 Emissions	2,761 lbs	2,367 lbs	1,653 lbs
Annual CO_2 Emission Savings		394 lbs	1,108 lbs

* Lifetime Energy Cost is the sum of the discounted value of the annual energy costs over an assumed product life of 10 years.

ENERGY STAR commercial refrigerators comprised roughly 35 percent of total sales in 2003.[89] Past research has determined that commercial refrigeration is capable of achieving annual energy savings of approximately 78 billion kWh, or 29 percent of total consumption, with new equipment payback periods of two years or less.[90]

HVAC

The penetration of high-efficiency commercial air conditioning systems lags behind residential systems.[91] Despite this national lag in installed efficiency, higher-efficiency heat pumps and air conditioners can result in significantly reduced

81 Gustafson, 2006. White LED technology remains comparatively expensive. Current white LED prices are approximately $150.00 per kilolumen; current prices for incandescent and florescent lamps are approximately $0.60 per kilolumen and $0.73 per kilolumen, respectively.

82 U.S. Department of Energy, 2006c.

83 Thorne & Nadel, 2003.

84 Westphalen et al., 1996.

85 Federal Energy Management Program, 2005b. Although energy consumption varies greatly for units of differing size and layout, these two units are assumed to be similar enough in design and operation to allow for a rough approximation of energy efficiency improvement over time.

86 ENERGY STAR, n.d.-a.

87 Consortium for Energy Efficiency, 2003.

88 Federal Energy Management Program, 2005b.

89 Smith et al., 2003.

90 Westphalen et al., 1996.

91 Shugars et al., n.d.

energy costs and CO_2 emissions (Table 1-9). Analysis by DOE's Office of Energy Efficiency and Renewable Energy indicates that increasing minimum energy efficiency ratio (EER) by a little more than 4 percent for 5.5- to 11.25-ton capacity equipment could save nearly 1.3 EJ of energy and $673 million in energy costs between 2004 and 2030.[92]

Table 1-9: Comparison of energy costs and CO2 emissions for commercial heat pumps (120 MBtu/h-10 tons) and unitary air conditioners[93]

Technology	Performance	Base Model	Recommended Level *	Best Available
Heat Pumps	EER	8.9	11.0	11.8
	Annual Energy Use	37,100 kWh	33,800 kWh	26,600 kWh
	Annual Energy Cost	$2,200	$2,050	$1,600
	Lifetime Energy Cost*	$22,200	$20,200	$15,900
	Lifetime Energy Cost Savings		$2,000	$6,3000
	Annual CO_2 Emissions	54,166 lbs	49,348 lbs	38,836 lbs
	Annual CO_2 Emission Savings		4,818 lbs	15,330 lbs
Unitary A/Cs	EER	8.9	11.0	11.8
	Annual Energy Use	19,600 kWh	15,800 kWh	13,800 kWh
	Annual Energy Cost	$1,170	$950	$830
	Lifetime Energy Cost*	$11,700	$9,500	$8,300
	Lifetime Energy Cost Savings		$2,200	$3,400
	Annual CO_2 Emissions	28,616 lbs	23,068 lbs	20,148 lbs
	Annual CO_2 Emission Savings		5,548 lbs	8,468 lbs

* Lifetime Energy Cost is the sum of the discounted value of the annual energy costs over an assumed product life of 15 years.

Office Equipment

Laptops are the most efficient computing platform; they usually draw 15 to 25 watts while in use, compared with an average 150 watts used by a typical PC and monitor. Computers with power management features consume about 70 percent less electricity than computers without such features. ENERGY STAR-labeled computers with an output power rating less than or equal to 200 watts must power down to 15 watts after 30 minutes of inactivity, while computers with a power rating greater than 200 watts must power down to 10 percent of maximum output power. An ENERGY STAR monitor uses 90 percent less electricity than a monitor without power management features that allow it to enter low-power states after periods of inactivity.[94] A comparison of energy savings and emission reductions for office equipment of various efficiencies is included in Table 1-10.

Table 1-10: Comparison of energy costs and CO2 emmisions for computers and monitors[95,96]

Appliance	Performance	Base Model	Recommended
Computers	Annual Energy Use	252 kWh	133 kWh
	Annual Energy Cost	$15	$8
	Lifetime Energy Cost*	$53	$28
	Lifetime Energy Cost Savings		$25
	Annual CO_2 Emissions	367.9 lbs	194.2 lbs
	Annual CO_2 Emission Savings		173.7 lbs
Monitors	Annual Energy Use	370 kWh	100 kWh
	Annual Energy Cost	$22	$6
	Lifetime Energy Cost*	$75	$20
	Lifetime Energy Cost Savings		$55
	Annual CO_2 Emissions	540.2 lbs	146.0 lbs
	Annual CO_2 Emission Savings		394.2 lbs

* Lifetime Energy Cost is the sum of the discounted value of the annual energy costs over an assumed product life of 4 years.

92 Ibid.
93 Federal Energy Management Program, 2005a.
94 American Council for an Energy-Efficient Economy, n.d.-d.
95 Federal Energy Management Program, 2005c.
96 Federal Energy Management Program, 2006d.

The market penetration of ENERGY STAR-qualifying computers and monitors sold in 2000 was 95 percent and 97 percent, respectively. With near market saturation, additional gains must be made through improvement in technology or enabling rates.

Building Programs

ENERGY STAR-labeled buildings use 40 percent less energy than the average U.S. building.[97] In 2002, ENERGY STAR buildings covered 9 billion square feet, or approximately 14 percent of the commercial building market.[98] As an example of the energy savings achievable under the ENERGY STAR Buildings program, Food Lion supermarkets were able to increase total square footage while reducing energy outlays. In 2001, the total square footage of Food Lion stores increased by 6 percent but energy consumption was reduced by 1.3 percent, a savings equal to $50 million in sales. In 2002, Food Lion increased square footage by 2 percent while experiencing a 5 percent drop in energy use, saving $15 million in annualized energy costs.[99]

Another program, the U.S. Green Building Council's LEED certification for New Construction (NC), was launched in 1998. The council has since introduced LEED for Existing Buildings (EB) and for Commercial Interiors (CI). As of November 2005, 3,000 projects, representing more than 390 million square feet of space, were seeking LEED certification.[100] This level of activity represents a 45 percent increase from just one month prior.[101] Built to LEED-Gold standards, the Toyota Motor Sales center in California highlights the benefits of a highly energy efficient HVAC system, achieving a 58.6 percent energy savings over California's state code on energy usage, Title 24.[102] The National Geographic Society Headquarters in Washington, D.C., which was the first LEED-EB certified building, reduced energy use by 20 percent through efficient HVAC and lighting systems. A recent study of 33 LEED-CI certified projects in California estimated an average of 30 percent in designed energy savings.[103] The LEED program aims to continue to guide green building by updating requirements over time.

Looking forward, the EPA estimates that improving energy efficiency by 10 percent in commercial, government and institutional buildings would save approximately $10 billion and reduce CO_2 emissions by more than 78 mmt by 2015.[104] Above and beyond these savings, the EPA's ENERGY STAR Challenge attempts to further improve building efficiency through the conducting of energy audits, the setting of efficiency goals and the recognition of performance leaders (Table 1-11).

97 U.S. Environmental Protection Agency, 2003.
98 Ibid.
99 Ibid.
100 U.S. Green Building Council, 2005a.
101 Projects registered with LEED signify an intent to apply for certification.
102 U.S. Green Building Council, n.d.
103 U.S. Green Building Council, 2005b.
104 ENERGY STAR, n.d.-b.

Table 1-11: Potential CO2 savings from improved building management (estimates based on a 30 percent energy savings)[105]

Market Segment	EPA 2012 Carbon Savings Goals (mmt CO_2 emissions)	Potential Carbon Savings (mmt CO_2 emissions)
Office	19.4	64.2
Retail	11.4	52.4
Education	8.4	27.1
Healthcare	4.8	25.3
Lodging	5.1	21.6
Food Service	4.4	18.0
Food Sales	4.8	11.0
Other *	5.9	57.9
Total	64.2	277.5

* Includes post offices, warehouses, telecommunication centers, wastewater treatment and drinking water facilities.

INDUSTRIAL

Year 2005 electricity sales to the industrial sector was over 1 million GWh,[106] with motors comprising the single largest component of industrial energy consumption. Potential industrial sector primary electricity savings were estimated by the Clean Energy Future study to be 3.8 percent to 13.1 percent from business as usual by 2010 and 7.4 percent to 22.1 percent by 2020.[107] The study also estimated that industrial combined heat and power applications have the potential to save 0.31-1.13 EJ by 2010 and 0.47-2.50 EJ by 2020.[108] Emission reductions attributed to increased use of CHP are estimated at 18.0-95.7 mmt of CO_2 by 2010 and 35.6-145.6 mmt by 2020.[109]

In California, pumps, lighting and compressed air have the greatest energy-saving potential.[110] In the Midwest industrial sector, improved motor efficiency, HVAC and lighting are capable of achieving large energy savings in metals fabrication, rubber and plastics, and primary metals.[111] Ohio has the greatest potential for absolute industrial energy savings. In the South, industrial energy efficiency can be increased by upgrading CHP facilities and steam distribution systems, improving energy recovery, increasing waste recycling, improving motor and drive systems, implementing process controls and performing energy audits.[112]

POLICY DRIVERS

The voluntary National Electrical Manufacturers Association (NEMA) Energy Efficient program, developed in the mid-1980s, was the first motor efficiency specification to define energy efficiency for industrial motors. The Energy Policy Act of 1992 was the first federal legislation to require that motors meet specific efficiency levels. After its passage, the Consortium for Energy Efficiency created a Premium Efficiency Criteria to identify motors that were above the levels required by the federal standards. Eventually, the CEE criteria were adapted to form the NEMA Premium Efficiency Electric Motor Specification that covers a larger range of products than either the EPAct or the original CEE specification.[113]

Innovation and Energy Efficiency

The following section provides an overview of industrial motors, as well as industrial processes and CHP. Motors

105 U.S. Environmental Protection Agency, 2003.
106 Energy Information Administration, 2006.
107 Interlaboratory Working Group, 2000.
108 Ibid.
109 Ibid.
110 Itron Inc. et al., 2006.
111 Synapse Energy Economics, 2001.
112 Beck et al., 2001.
113 Consortium for Energy Efficiency, 2004.

are a driving force in many industrial processes, while the processes themselves are complex, encompass many steps and provide many areas for improvements in energy efficiency.

Motors

Industrial motors represent the single largest use of electricity in the United States, representing approximately one-fifth of all electricity consumption.[114] However, motor system energy use is concentrated in a small percentage of facilities; nearly half of motor system energy is consumed by less than 2 percent of facilities.[115]

Because industrial motors use such large amounts of electricity, even small increases in their energy efficiency can result in large energy savings. In 2000, efficient motors used in industrial facilities saved approximately 3,300 GWh per year, compared with the average efficiency before federal efficiency requirements took effect.[116] Presently, NEMA Premium motors have the potential to save 5,800 GWh of electricity and prevent the emission of nearly 293 mmt of CO_2.[117] In total, mature, cost-effective energy-efficient motor systems have the potential to reduce aggregate industrial motor electricity demand by 11 percent to 18 percent, which would result in savings of \$3 billion to \$5 billion and a displacement of 55 to 95 mmt of CO_2 emissions per year.[118]

In addition, proper motor maintenance and systems level planning can contribute to energy efficiency (Table 1-12). The forest products company Weyerhaeuser, for example, developed a motor plan in the late 1990s for all of its plants; the plan dictates the purchasing of new motors and creates guidelines for repair. In 2000, the company had saved approximately \$2.5 million.[119]

Table 1-12: Systems-level motor energy savings opportunities in manufacturing facilities[120]

Measure	Potential Energy Savings GWh/year*	Midrange Savings as Percent of: Total Motor System GWh	Midrange Savings as Percent of: System-Specific GWh
Motor efficiency upgrades			
Upgrade all integral AC motors to EPAct levels	13,043	2.3%	
Upgrade all integral AC motors to CEE levels	6,756	1.2%	
Improve rewind practices	4,778	0.8%	
Total Motor Efficiency Upgrades	24,577	4.3%	
Systems-level efficiency measures			
Correct motor oversizing	6,786	1.2%	
Pump system improvements	28,681	5.0%	20.1%
Fan system improvements	4,330	0.8%	5.5%
Compressed air system improvements	15,524	2.7%	17.1%
Specialized system improvements	5,259	0.9%	2.0%
Total System Improvements	60,579	10.5%	
Total Potential Savings	**85,157**	**14.8%**	

* Reflects midrange of potential savings.

114 Consortium for Energy Efficiency, n.d.-c.
115 U.S. Department of Energy, 2000.
116 Ibid.
117 National Electrical Manufacturers Association, n.d.
118 Consortium for Energy Efficiency, n.d.-c.
119 Consortium for Energy Efficiency, 2002.
120 U.S. Department of Energy, 2000.

In 2000, approximately 9 percent of motors used in manufacturing facilities met the 1997 federal energy efficiency standards.[121] However, shipments of NEMA Premium motors have experienced recent growth and now comprise 15 percent to 20 percent of the market.[122]

Combined heat and power systems

A CHP system provides heating/cooling energy or electrical power to meet industrial process needs. In 1999, approximately 56 GW of CHP systems were in operation, compared with less than 10 GW in 1980.[123] Total CHP generation in 1999 was 9 percent of all U.S. energy production in that year.[124] CHP applications commonly achieve system efficiencies that exceed 70 percent, reducing energy costs and lowering emission rates. While CHP can be employed cost-effectively outside of the industrial sector (see "Cross-Cutting" below), the technology is predominately used in industrial applications.[125] Within the industrial sector, CHP systems are most common in the chemical, petroleum refining and paper industries. Recent production and installation of smaller CHP systems are making an impact in food, pharmaceutical and light manufacturing industries; in commercial facilities; and on university campuses.[126] Given the role that CHP can play in distributed generation, the technology is also discussed below under "Clean Distributed Generation."

The Clean Energy Future study estimated that industrial CHP applications have the potential to save 298-1,073 TBTUs by 2010 and 450-2,367 TBTUs by 2020.[127] Emission reductions attributed to increased use of CHP are estimated at 18-95 mmt of CO_2 by 2010 and 35-145 mmt by 2020.[128] For the near term, DOE set a goal of doubling CHP capacity in the United States between 2000 and 2010. Meeting this goal would result in 46 GW of additional capacity (27 GW in the industrial sector), $5 billion in energy savings, nearly 1,400 TJ in reduced annual consumption and a 128 mmt reduction in CO_2 emissions.[129] However, even meeting DOE's targets would fall short of total potential industrial capacity (Table 1-13).

Table 1-13: Untapped CHP technical potential for selected industries[130]

Industry	CHP Potential (GW)	Existing CHP (GW)	Untapped Potential (GW)	Untapped Potential (%)
Food & Kindred Products	12.7	4.6	8.1	64%
Paper & Allied Products	34.8	8.6	26.2	75%
Chemicals & Allied Products	27.1	17.7	9.4	35%
Primary Metals Industries	12.4	5.6	6.8	55%
Fabricated Metal Products	5.7	0.08	5.62	99%
Industrial & Transportation Equipment	11.8	0.95	10.85	92%

Processes

ENERGY STAR has recently launched a new designation for plants. The specification is currently used to rate cement manufacturing, corn refining and motor vehicle manufacturing industries. Ratings for petroleum refining and pharmaceutical manufacturing plants are being developed. Furthermore, many companies have developed

121 Ibid.
122 Benkhart, 2006.
123 American Council for an Energy-Efficient Economy, n.d.-a.
124 Ibid.
125 U.S. Department of Energy, 1997.
126 American Council for an Energy-Efficient Economy, n.d.-a.
127 Interlaboratory Working Group, 2000.
128 Ibid.
129 U.S. Combined Heat and Power Association, 2001.
130 Ibid.

extensive individual plans for improving efficiency and reducing greenhouse gas emissions (Table 1-14). British Petroleum, for example, reduced its GHG emissions to 10 percent below 1990 levels within five years of implementing the program. The Global Energy Management System of ExxonMobil has created 12 manuals to describe more than 200 best practices for energy efficiency and has identified practices that could improve energy efficiency by 15 percent at refineries and chemical plants.[131]

Table 1-14: Energy management activities by selected sectors (1998)[132]

Sector	Activities	Establishments	% of Sector
Chemical	Energy Audits	1,692	18.9
	Electricity Load Control	1,706	19.0
	Equipment Installation / Retrofit-Direct Machine Drive	1,710	19.1
	Special Rate Schedule	1,761	19.6
	Power Factor Correction or Improvement	1,549	17.3
	Facilities (Lighting & HVAC)	2,690	30.0
	Compressed Air Systems	1,439	16.1
Petroleum Refining	Facility Lighting	329	18.7
	Steam Production/System	288	16.4
	Special Rate Schedule	357	20.3
	Direct Machine Drive	404	23.0
Aluminum	Energy Audits	1,692	18.9
	Electricity Load Control	1,706	19.0
	Equipment Installation / Retrofit-Direct Machine Drive	1,710	19.1
	Special Rate Schedule	1,761	19.6

Generalized potential for improvements in energy efficiency varies by technology and industry (Table 1-15). Within the chemical and petroleum industries, improved integrated process heater systems have been developed to improve energy efficiency and significantly reduce NO_x emissions. By 2020, the ultra-low-emission and high-efficiency heater systems could potentially save about 0.09 EJ, decrease NO_x emissions by 150,000 tons and decrease CO_2 emissions by nearly 5 mmt per year.[133] In the steelmaking industry, oxygen-enriched furnace systems can be used in a variety of applications where natural gas is burned, including reheat and blast furnaces. The benefits of the advanced furnace systems include reduced air pollutant emissions and energy savings of 25 percent to 30 percent.[134] The cement manufacturing industry also has a number of options for improving energy efficiency. By using high-efficiency roller mills for raw materials preparation, recovering heat in power generation for clinker making and installing high-efficiency classifiers, more than 30 kWh of energy per ton cement can be saved in dry process plants.[135]

131 Worrell, 2005.
132 Energy Information Administration, 2004.
133 U.S. Department of Energy, 2003.
134 U.S. Department of Energy, 2001.
135 Worrell, 2004.

Table 1-15: Generalized potential for improvements in energy efficiency[136]

Industry	Technology/Process	Total Energy Savings [A]	Sector Energy Savings [B]	Simple Payback [C]
Various	Advanced CHP turbine systems	High	High	6.9
Various	Advanced reciprocating engines	High	High	8.3
Various	Fuel cells	High	High	58.6
Various	Microturbines	High	Medium	-
Various	Advanced HVAC	Medium	High	4.0
Various	Advanced lighting (technology)	High	High	1.3
Various	Advanced lighting (design)	High	High	3.0
Various	Advanced compressor controls	Medium	Low	0.0
Various	Compressed air system management	High	High	0.4
Various	Motor diagnostics	Low	Low	Immediate
Various	Improved pump efficiency	High	High	3.0
Various	Switched reluctance motor	Medium	Low	7.4
Various	Advanced lubricants	Medium	Medium	0.1
Various	Anaerobic waste water treatment	Medium	Low	0.8
Various	High-efficiency burners	High	Low	3.1
Various	Membrane technology wastewater	High	Medium	4.7
Various	Process integration	High	Low	2.3
Various	Sensors and controls	High	Medium	2.0
Various	Advanced ASD designs	High	Medium	1.1
Various	Motor system optimization	High	High	1.5
Aluminum	Advanced forming	Medium	Medium	Immediate
Aluminum	Efficient cell retrofit designs	High	High	2.7
Aluminum	Improved recycling technologies	Medium	Medium	4.5
Aluminum	Inert anodes/wetted cathodes	High	High	4.0
Ceramics	Roller kiln	Medium	High	1.9
Chemicals	Gas membrane technologies	Low	Low	10.2
Chemicals	Heat recovery technologies	Medium	Medium	2.4
Chemicals	Levulinic acid from biomass	Low	Low	1.5
Chemicals	Liquid membrane technologies	Low	Low	11.2
Chemicals	New catalysts	Medium	Medium	7.9
Chemicals	Autothermal reforming - ammonia	High	High	3.7
Chemicals	Clean fractionation - cellulose pulp	Low	Low	1.9
Electronics	Continuous melt silicon crystal growth	Medium	High	Immediate
Food	Electron beam sterilization	High	High	19.2
Food	Heat recovery - low temperature	Medium	Medium	4.8
Food	Membrane technology - food	High	High	2.2
Food	Cooling and storage	Medium	Medium	2.6
Glass	100% recycled glass cullet	Medium	High	2.0
Mining	Variable wall mining machine	Low	Low	10.6
Pulp and Paper	Black liquor gasification	High	High	1.5
Pulp and Paper	Condebelt drying	High	Medium	65.2
Pulp and Paper	Direct electrolytic causticizing	Low	Low	-
Pulp and Paper	Dry sheet forming	Medium	Medium	48.3
Pulp and Paper	Heat recovery - paper	High	Medium	3.9
Pulp and Paper	High consistency forming	Medium	Medium	Immediate
Pulp and Paper	Impulse drying	High	Medium	20.3
Petroleum Refining	Biodesulfurization	Medium	Medium	1.8
Petroleum Refining	Fouling minimization	High	High	-
Iron/Steel	BOF gas and sensible heat recovery	Medium	Medium	14.7
Iron/Steel	Near net shape casting/strip casting	High	High	Immediate
Iron/Steel	New EAF furnace processes	High	High	0.3
Iron/Steel	Oxy-fuel combustion in reheat furnace	High	Medium	1.2
Iron/Steel	Smelting reduction processes	High	High	Immediate
Textile	Ultrasonic drying	Medium	Medium	0.3

136 Martin et al., 2000.

Notes:

A. High – >0.1% industry energy savings by 2015; Medium – 0.01%-0.1% energy savings by 2015; Low - <0.01% energy savings by 2015.

B. High – >1% sector energy savings by 2015; Medium – 0.01%-0.1% sector energy savings by 2015; Low - <.01% sector energy savings by 2015.

C. The simple payback period is defined as the initial investment costs divided by the value of energy savings less any changes in operations and maintenance costs.

CROSS-CUTTING

As noted above, there are several products and practices unique to specific sectors. Furthermore, while present in each sector, lighting, HVAC and refrigeration differ somewhat in technology and application across sectors. However, there are a number of technologies and processes that are cross-cutting in nature and applicable to one or more sectors. These cross-cutting technologies include building shell design and construction, the ENERGY STAR labeling program, and CHP and Distributed Generation.

Building shell design and construction

Improved window efficiency is credited with having the single largest impact on building envelope performance between 1970 and 1995.[137] Additional improvements in performance are possible through the use of advanced construction methods and materials, environmental integration and adaptive envelopes, multifunctional equipment and integrated system design, building self-powering, and advanced lighting controls, systems, communications, and measurement.[138] In total, DOE estimates that the buildings sector, comprised of both the residential and commercial sectors, is capable of achieving a nearly 7 percent reduction in electrical energy use and approximately a 3 percent reduction in fossil fuel use by 2010, given sufficient public and private R&D and market transformation efforts.[139] If achieved, the energy savings would equal approximately 2 EJ, generate up to $11 billion in annual energy savings and reduce annual CO_2 emissions by nearly 92 mmt.[140]

Building energy efficiency is governed by a series of codes and standards, as explored further in Volume 2 of this report. In addition to these sets of minimum requirements, there are a number of voluntary building programs and guidelines, including LEED-NC, ENERGY STAR Qualified New Homes and NAHB's model green building guidelines. Individual building shell technologies and programs unique to the residential, commercial or industrial sectors are explored further under their respective sections above. Technologies capable of being transferred across sectors are explored below.

Solar Thermal (Water Heat)

Solar thermal is often used alongside conventional water systems to reduce the need for conventional water heating, thus decreasing water heating bills. Although systems are typically expensive to purchase and install (approximately two to eight times more expensive than conventional electric water heaters, depending on system type and the circumstances of installation),[141] annual cost savings in energy bills can lead to costs savings in the long run. The amount of these savings, though, is based on various factors, including the amount of hot water used, system performance, geographic location, available financing and incentives, cost of conventional fuels and the cost of fuel used for backup.[142]

Two types of solar water heater systems are available: passive and active. In an active system, pumps circulate water through solar collectors and into storage tanks within the home (direct method), or an antifreeze-based

137 Interlaboratory Working Group, 1997.

138 Ibid.

139 Ibid.

140 Ibid. Reported savings are in $1995 and are in excess of any private direct investment costs.

141 Toolbase Services, 2006.

142 Office of Energy Efficiency and Renewable Energy, 2005a.

fluid is circulated through collectors to a heat exchanger located in the home water tank (indirect method). In a passive system, electricity is not used. A basic passive system uses a well-insulated 40 gallon black water tank and allows for natural pressures to move the water to a thermostat-controlled tank.[143] Collection and storage can be combined into one unit (integral collector-storage method) or the natural flow of heated water is used by mounting a tank above a collector so that when the hot water rises, it flows into the tank (thermosiphon method).[144]

These methods can use one of three types of collectors. With a flat-plate system, water flows through tubes within an insulator box and a dark-colored absorber is used to heat the tubes. An evacuated-tube collector uses double-walled glass tubes. A vacuum separates the outer tube from the inner absorber tube. Finally, a batch system uses a glazed, insulated, dark-colored box to heat a water tank that is stored inside.[145]

Passive Solar Building Design

Passive solar technologies incorporate solar geometry and window technology to use the local climate to heat and cool buildings. Based on a fundamental law of energy, these technologies use transfers of heat from warmer materials to cooler ones by utilizing heat-movement and heat-storage mechanisms.[146] These designs make use of conduction (transfer of heat through materials), convection (circulation of heat in liquids and gases), radiation (solar radiation is converted to infrared radiation when it passes through glass but gets trapped on the way out) and thermal capacitance (ability of materials to store heat, especially with regard to thermal mass).[147]

At a basic level, there are five elements incorporated into passive solar design: aperture, absorber, thermal mass, distribution and control.[148] Typically, the aperture is a south-facing window that receives sun exposure from 9 a.m. to 3 p.m. on winter days. The absorber is a hard, dark surface that is exposed to the direct path of sunlight. Below the surface, absorbed heat is retained in the thermal mass. Collected or stored heat will be distributed throughout the house using natural heat transfers (conduction, convection and radiation) or may be mechanically distributed with fans, ducts and blowers. Controls (e.g., roof overhangs, electronic sensing devises, operable vents and dampers, low-emissivity blinds, awnings) are used to provide shade on apertures or aid in improving the effectiveness of the design.

Although retrofitting is possible, most passive solar design is incorporated in the building at inception. Costs are offset by lower annual energy and maintenance costs.[149] Since passive solar building design is an engineering concept, these strategies can be used in both commercial and residential buildings at almost any scale.

ENERGY STAR

ENERGY STAR currently extends to 35,000 labeled products across 40 different product categories, including household appliances, residential heating and cooling, office equipment, lighting and electronics, as well as building design and operation.[150],[151] In 2005, the ENERGY STAR program saved an estimated 4 percent of total

143 Texas State Energy Conservation Office, n.d.
144 Office of Energy Efficiency and Renewable Energy, 2006.
145 Rocky Mountain Institute, 2006.
146 Office of Energy Efficiency and Renewable Energy, 2005c.
147 Ibid.
148 Office of Energy Efficiency and Renewable Energy, 2005b.
149 NAHB Research Center et al., 2000
150 ENERGY STAR, n.d.-e.
151 ENERGY STAR, n.d.-c.

U.S. energy demand.[152] EPA and DOE have set many goals for ENERGY STAR through 2012, including adding new products to the ENERGY STAR label, updating specifications for products already included in the program[153] and raising the public's awareness of the program to 70 percent.[154] Individual ENERGY STAR products and practices unique to the residential, commercial or industrial sectors are explored further in their respective section above.

CHP and DG

By achieving high system efficiencies (greater than 70 percent), CHP applications can result in significant energy savings and emission reductions. While most often used in industrial applications, CHP has the potential to provide energy for other sectors as well. For example, municipalities have used CHP to generate heat for schools and other community buildings, as well as to provide electricity for the surrounding area.[155] As with any form of distributed generation, CHP can reduce the need for expansion of central generation facilities and transmission infrastructure. Furthermore, distributed CHP can encourage the expanded use of biomass feedstocks by providing biopower capability at or near feedstock sources. This application would address one of the key drivers in biomass feedstock price: transportation costs. Biomass and biopower generation is further discussed in Chapter 2: Electricity Supply.

BARRIERS TO ENERGY EFFICIENCY

A number of informational, institutional, regulatory and financial barriers impede the adoption of energy-efficient technologies or practices. Across sectors, higher initial costs of high-efficiency products or practices remain a primary barrier. Likewise, a lack of knowledge of high-efficiency alternatives results in lost opportunities for increased energy savings. These and other impediments are discussed below.

INFORMATIONAL

Customers, builders, landlords and facility managers must be aware of the availability, benefits and operation of energy-efficient products or practices in order for them to be adopted. Unfortunately, a continued lack of knowledge of energy-efficient options and the benefits of conversion to energy-efficient products or practices remains a common barrier to increased energy savings.[156] A lack of information is specifically cited as an impediment to increased use of a wide variety of products and practices, including but not limited to commercial lighting, commercial refrigerators, commercial HVAC, appliances, building practices and industrial motors.[157]

Several programs and policies have been developed to address this information gap. Education and outreach is a key component of demand-side management (DSM), explored in Volume 2 of this report. Labeling requirements, such as those offered by DOE and the Federal Trade Commission's EnergyGuide program, assist consumers in making informed decisions. The ENERGY STAR program uses a highly recognizable branding mechanism to clearly identify high-efficiency products.

152 U.S. Environmental Protection Agency, 2006.

153 Continual updating of specifications is required to maintain the status of the program as more energy-efficient technologies and product models are developed.

154 U.S. Environmental Protection Agency, 2005.

155 Bergman & Zerbe, 2004.

156 Synapse Energy Economics, 2001.

157 Consortium for Energy Efficiency, n.d.-b., Prindle et al., 2003., National Association of Home Builders, 2006., Consortium for Energy Efficiency, n.d.-c.

INSTITUTIONAL

A number of institutional barriers impede improved energy efficiency. These barriers can be expressed in terms of cultural market, and political impediments. Institutional barriers of one form or another are specifically cited as an impediment to increased use of energy-efficient commercial lighting, commercial refrigerators, appliances, building practices, CHP and industrial motors.[158]

Cultural barriers include aesthetic concerns over product design, as well as the availability and variety of suitable products. Zero-energy homes face aesthetic concerns related to the appearance of solar PV panels. Advanced lighting, including CFLs, face continued (albeit diminishing) concerns over product selection and performance.

Various market conditions can impede the adoption of energy-efficient products and practices. In fragmented markets, such as building construction, the large number of individual players or operators makes education and market transformation difficult. In some cases, product distribution remains an impediment, preventing consumers, builders, landlords and facility managers from having access to energy-efficient technologies.[159] In situations where consumers or facility managers may not have an option to conduct extensive research into product performance or to shop around for product availability (e.g., when replacing failed equipment), so-called "panic purchases" may be limited to in-stock items and result in lost opportunities for increased energy efficiency. Business accounting practices can impede adoption of energy-efficient products or practices when upfront costs are weighed disproportionately against reduced life-cycle costs. Staff shortages can lead to backlogs in equipment maintenance, reducing product performance. Utility-imposed interconnection and standby fees can impede the expansion of energy-efficient generation technologies such as CHP. Finally, utilities themselves face a disincentive for investment in end-use energy efficiency to the extent that their revenues depend on increasing sales, or energy "throughput."

Various political institutional barriers remain. Despite the successes achieved by nonutility administration of energy-efficiency programs at the state level (See Energy Efficiency Utility, Volume 2 of this report), questions have been raised regarding the governance and management of nonutility administrators. Traditional energy utilities are subject to oversight and have experience in delivering energy-efficiency programs. Meanwhile, significant capacity building can be required for a newly formed nonutility administrator. To be effective, a nonutility administrator's programming strategy, as well as its methods of evaluating performance, must be carefully considered.[160]

REGULATORY

Increased energy efficiency can be impeded by outdated or unclear standards and specifications. Outdated codes can encourage the continued use of low-efficiency products or practices. The use of energy-saving products or practices can also be discouraged through strictly worded regulations that fail to take into account the ancillary benefits of increased efficiency. Alternatively, emerging technologies or processes may be impeded by the lack of clear approval standards. Regulatory barriers are specifically cited as an impediment to increased use of a wide variety of energy-efficient products and practices, including but not limited to energy-efficient building practices and CHP.[161]

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158 Consortium for Energy Efficiency, n.d.-b., NAHB Research Center, 2006., Prindle et al., 2003., Consortium for Energy Efficiency, n.d.-c., Synapse Energy Economics, 2001.

159 Synapse Energy Economics, 2001.

160 Eto et al., 1998.

161 Prindle et al., 2003., National Association of Home Builders, 2006.

FINANCIAL

Financial barriers impede the increased adoption of energy-efficient products and practices. While increased energy savings can result in lower life-cycle costs for high-efficiency products than for less efficient alternatives, higher upfront costs can deter initial purchase.[162]

Financial barriers are specifically cited as an impediment to increased use of a wide variety of energy-efficient products and practices, including but not limited to commercial lighting, commercial refrigeration, appliances, building practices and CHP.[163] A recent survey of home builders indicated that higher upfront costs and a reluctance of consumers to pay higher prices were "perceived as a barrier [to green building] by 82 percent and 79 percent of the firms surveyed, respectively."[164] Zero-energy homes and CHP are impeded by unfavorable tax treatment and a shortage of other financial incentives.[165] The prices of high-efficiency appliances are oftentimes needlessly increased through bundling with high-end "bells and whistles."[166]

Adoption of energy-efficient products and practices faces financial barriers within companies as well. Many corporations, for example, have a limited pool of capital for internal investment. Potential projects are put forward and evaluated for their rate of return and their relevance to the company's core business function. Although many energy-efficiency investments have a positive rate of return, they may not have a sufficiently high rate of return compared with all other internal investment opportunities; with limited capital, energy-efficiency investments are often not selected. For most companies, investing in efficiency also does not further their core business strategy and may be discounted as a result.

Attempts have been made at the federal level to address financial barriers to energy efficiency; however, the majority of federal tax incentives are set to expire at the end of 2007. Legislation is pending to extend some (but not all) of these tax credits until 2010,[167] but the uncertainty about their future can limit their long-term effectiveness. Another impediment to the effectiveness of incentives is unrealistic goals. For instance, the home builder tax credit is perceived in some regions as unobtainable due to the high level of energy-efficiency required for qualification for the credit.[168] At the state and utility levels, incentives may suffer from uneven distribution, since tax benefits or rebates may not be available in certain states or municipalities.

SPLIT INCENTIVES

Split incentives are encountered when decisions regarding the installation or use of particular products are made by someone other than the individuals who stand to benefit from energy savings. An example of this is a landlord who pays none of the energy bills associated with an appliance or HVAC unit. Split incentives are specifically cited as an impediment to increased use of a wide variety of energy-efficient products and practices, including but not limited to commercial HVAC, appliances and building practices.[169]

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162 Synapse Energy Economics, 2001.

163 National Association of Home Builders, 2006., NAHB Research Center, 2006., U.S. Combined Heat and Power Association, n.d., Consortium for Energy Efficiency, n.d.-b., Prindle et al., 2003.

164 National Association of Home Builders, 2006.

165 See, e.g. NAHB Research Center, 2006., U.S. Combined Heat and Power Association, n.d.

166 Nadel et al., 2006.

167 Alternative Energy Extender Act, 2006.

168 David Reed, Technical Support Specialist for Conservation Programs, JEA, personal communication, August 1, 2006

169 Prindle et al., 2003.

Clean Distributed Generation

Clean distributed generation technologies can be used to supplement or supplant utility-generated electricity by generating power at or near the end-use location. Select DG technologies include solar photovoltaic modules, building integrated photovoltaic systems, and small wind systems. CHP systems, discussed in more detail under "Energy Efficiency" above, represent a mature technology for the generation of on-site electricity and heat in the commercial and industrial sectors. Fuel cells can also be used in DG applications, but are discussed further under Chapter 2: Electricity Supply.

Each DG technology has its own set of drawbacks and benefits, but all DG applications have the added benefit of defraying the need for additional centralized generating capacity and transmission. Specific benefits of PV modules include low maintenance requirements, zero emissions and applicability for remote locations. The disadvantages of low efficiency and high installed cost often overshadow these benefits. BIPV systems, while lower in cost than PV modules, are less efficient and generate less energy. Residential small wind systems are capable of reducing electricity bills by 50 percent to 90 percent, but are economical only when average wind speeds exceed 10 mph and the cost of electricity from utilities is at least 10 cents/kWh. Installed cost of a 5-15 kW residential wind turbine is estimated at $3,500 per kW. Regardless of the DG technology platform chosen, any large-scale increase of DG capacity will require advances and expansions in storage capacity and distribution in the near future.

RESIDENTIAL

SOLAR PV MODULES

A solar photovoltaic module contains a series of solar cells that are wired together and enclosed in glass to protect against the environment. PV system costs depend on the size, equipment used, installation costs, PV provider and PV manufacturer (Table 1-16). Installed costs range from $6,000 to $10,000 per kW. Factory production costs average about $4 per watt. [170]

Table 1-16: DC PV modules pricing[171]

	Manufacturer	Rated Output	Warranty	Listings	¢/kWH (dc)	Price ($ US)
SHR-17 (PV Shingles)	Uni-Solar	17W, 9V	20 years	UL	40	109
ND-72E_U	Sharp	72W, 7V	25 years	UL	35	410
ND-N0ECU	Sharp	142W, 14V	25 years	UL	27	638
ND-162U	Sharp	162W, 16V	25 years	UL	27	717
ND-167U	Sharp	167W, 16V	25 years	UL	27	744
NE-170U	Sharp	170W, 24V	25 years	UL	27	777
NT-175U	Sharp	175W, 24V	25 years	UL	31	899
ND-208U	Sharp	208W, 20V	25 years	UL	27	926
165PC	Shell	165W, 24V	25 years	UL & FM	28	749
175PC	Shell	175W, 24V	25 years	UL & FM	28	805
SW85	SunWize	85W, 12V	25 years	UL & FM	34	472
SW90	SunWize	90W, 12V	25 years	UL & FM	34	499
SW100	SunWize	100W, 12V	25 years	UL & FM		
SW115	SunWize	115W, 12V	25 years	UL & FM		

170 California Energy Commission, 2002b.

171 Modified from *http://nooutage.com/SolarPVMod.htm*, Retrieved December 12, 2006.

Efficiency rates range from 5 percent to 15 percent on commercially available PV systems.[172] Efficiency rate is defined as the ratio of the sunlight energy that hits the cell divided by the electrical energy that the cell produces.[173] Panels generally generate approximately 10 watts per square foot on a clear day.[174] The size of PV systems depends on the application. Small rooftop systems are typically less than 10 kW; medium-sized systems range from 10 to 100 kW; and utility-sized systems produce greater than 100 kW.[175] A one-kilowatt PV system, which can produce 150 kWh per month, prevents 150 pounds of coal from being mined, eliminates 300 pounds of CO_2 from entering the atmosphere and keeps NO and SO_2 from being released into the environment.[176]

BUILDING INTEGRATED PV

Building integrated photovoltaic systems integrate PV panels into roofs or the façade of buildings. Serving a dual function as building materials and power generation, BIPV are incorporated during renovation or new construction. These systems consist of special PV modules, a battery bank, an inverter and other structures (e.g., wiring, harnesses, water-proofing).

The two basic commercial types are thick crystal products and thin-film products. Crystal products are made of crystalline silicon in single or polycrystalline wafer arrangements. Under full sun, these cells can deliver 10 to 12 watts per square foot. Thin-film products use very thin layers of active photovoltaic material atop a glass or metal substrate. Under full sun, these cells can deliver 4 to 5 watts per square foot.[177] Thin-film technology offers lower costs than single-crystal PV, but also has lower efficiencies, thus resulting in less energy production.

SMALL WIND SYSTEMS

Today, the size of localized turbines, as opposed to large wind farms, offers several benefits. Among them, it costs less to integrate small systems into the grid, new turbine technology can add voltage and reactive power, small turbines significantly reduce electrical losses, and small systems enable local communities to take control of electricity generation.[178] According to the American Wind Energy Association, small wind turbines could account for as much as 3 percent of U.S. energy demand, or roughly 50,000 MW.[179]

Residential wind turbines are estimated to reduce electricity bills by 50 percent to 90 percent. The variation depends on the size of the turbine and intensity of average wind speeds. When winds are below cut-in speeds (7-10 mph), grid power is used. However, when cut-in speeds are reached, renewable energy is used. If the generation exceeds the residential demand, the additional electricity can be sold to the utilities. It is estimated that small wind turbines are economical when average wind speeds exceed 10 mph and the cost of electricity from utilities is at least 10 cents/kWh.[180]

Small wind turbines, which are defined as having a generating capacity up to 100 kW (associated with rotor diameters of approximately 60 feet),[181] are currently available from a number of U.S. manufacturers (Table 1-18). Small turbines range in cost from $6,000 to $22,000 installed,[182] with 5- to 15-kW residential turbines typically

172 Ibid.
173 OkSolar.com, n.d.
174 Ibid.
175 California Energy Commission, 2002b.
176 Solar Energy International, n.d.
177 Strong, 2006.
178 Windustry, 2006.
179 American Wind Energy Association, 2002.
180 American Wind Energy Association, 2006.
181 American Wind Energy Association, 2002.
182 American Wind Energy Association, 2006.

costing about $3,500 per installed kilowatt.[183] The price depends on size, application and manufacturer service agreements. Installed costs are estimated to be approximately $4/Watt, with a cost potential of $1.50/W in 2010.[184] Recouping the investment takes about six to 15 years.[185]

Table 1-18: Proven U.S. providers of small wind turbine equipment[186]

Manufacturer	Models (Rated Capacity)
Abundant Renewable Energy	AWP 3.6 (1 kW)
Bergey Windpower Co.	BWC XL.1 (1 kW),
	BWC EXCEL (10 kW)
Entegrity Wind Systems	EW15 (50 kW)
Energy Maintenance Service	E15 (35 kW or 65 kW)
Lorax Energy	FL 25 (25 kW), FL 30 (30 kW),
	FL 100 (100 kW)
Northern Power Systems	NPS 100 (100 kW)
Solar Wind Works	Proven WT600 (600 W), WT2500 (2.5 kW),
	WT6000 (6kW), WT15000 (15kW)
Southwest Windpower Co.	AIRX (400 W), Whisper 100 (900 W),
	Whisper 200 (1 kW), Whisper 500 (3 kW)
Wind Turbine Industries Corp.	23-10 Jacobs (10 kW),
	31-20 Jacobs (20 kW)

COMMERCIAL/INDUSTRIAL

COMBINED HEAT AND POWER

As noted above under "Energy Efficiency," CHP applications (as compared to separate heating and power components) can increase overall efficiencies of power systems. Since two-thirds of the energy content of an input fuel can be lost to heat, the recovery of such "wastes" can help reduce electricity demand, fuel costs and emissions. Small industrial systems range in size from 25 kW to 25 MW. Large and medium industrial systems generate greater than 25 MW.

At the basic level, CHP technologies use gas turbines or microturbines to produce electricity and incorporate heat exchangers to recover heat from the flue gas stream. This heat is then typically converted to thermal energy for use in various applications, including hot water production, space heating, industrial process heat (hot air/steam), space cooling and dry air generation (with the use of a desiccant).[187] Cost and system efficiencies depend largely on system size and technology (Tables 1-19 and 1-20).

183 American Wind Energy Association, 2002.
184 Ibid.
185 American Wind Energy Association, 2006.
186 List of proven U.S. equipment providers is according to the American Wind Energy Association, and is modified from *http://www.awea.org/faq/smsyslst.html*, Retrieved December 12, 2006.
187 California Energy Commission, 2002a.

Table 1-19: Typical performance and cost parameters for microturbine CHP[188]

Cost and Performance Characteristics[1]	System 1	System 2	System 3	System 4
Nominal Electricity Capacity (kW)	30 kW	70 kW	80 kW	100 kW
Net Electrical Capacity (kW)[2]	28	67	76	100
Package Cost (20003 $/kW)[3]	$1,280	$1,070	$1,100	$1,000
Total Installed Cost for Power-only (YR 2003 $/kW)	$2,263	$1,658	$1,663	$1,526
Total Installed Cost for CHP (YR 2003 $/kW)[4]	$2,636	$1,926	$1,932	$1,749
Electric Heat Rate (Btu/kWh), HHV[5]	15,071	13,544	14,103	13,127
Net Electrical Efficiency (%), HHV[6]	22.6%	25.2%	24.2%	26.0%
Fuel Input (MMBtu/hr)	0.423	0.91	1.09	1.31
Required Fuel Gas Pressure (psig)[7]	55	70	85	90
Required Fuel Gas Pressure w/GBC (psig)[8]	0.2-15	0.2-15	0.2-15	0.3-15
CHP Characteristics				
Exhaust Flow (lbs/sec)	0.68	1.6	1.67	1.76
GT Exhaust Temp (degrees F)	530°	450°	500°	520°
Heat Exchanger Exhaust Temp (degrees F)[9]	220°	220°	220°	220°
Heat Output (MMBtu/hr)	0.186	0.325	0.412	0.466
Heat Output (kW equivalent)	54	95	121	136
Total CHP Efficiency (%), HHV[10]	67%	61%	63%	62%
Thermal Output/Fuel Input	0.44	0.36	0.38	0.35
Power/Heat Ratio[11]	0.52	0.7	0.63	0.73
Net Heat Rate (Btu/kWh)[12]	6,795	7,485	7,320	7,300

(1) EEA estimates of characteristics are representative of "typical" commercially available microturbine systems. Table data are based on: Capstone Model 330 -- 30 kW; IR Energy Systems 70LM -- 70 kW (two-shaft); Bowman TG80 -- 80 kW; Turbec T100 -- 100 kw. Performance characteristics are based on ISO standard ambient temperature of 59 degrees F.

(2) Net of parasitic losses from gas boost compressor (GBC) and conversion losses from power conversion equipment.

(3) Microturbine package cost only. The cost for all units except for 30 kW unit includes integral heat recovery water heater. All unit estimates include a fuel gas booster compressor.

(4) Installed costs based on CHP system producing hot water from exhaust recovery. The 70 kW, 80 kW and 100 kW systems are being offered with integral hot water recovery built into the equipment. The 30 kW units are currently built as electric (only) generators and the heat recovery water heater is a separate unit.

(5) All turbine and engine manufacturers quote heat rates in terms of the lower heating value (LHV) of the fuel. On the other hand, the usable energy content of fuels is typically measured on a higher heating value (HHV) basis. In addition, electric utilities measure power plant heat rates in terms of HHV. For natural gas, the average heat content is 1,030 Btu/scf on an HHV basis and 930 Btu/scf on an LHV basis--or about a 10% difference.

(6) Electrical efficiencies are net of parasitic conversion losses. Fuel gas compressor needs based on 1 psi inlet supply.

(7) Fuel gas pressure required at the combustor. This value determines the GBC requirements at a specific site.

(8) Fuel gas pressure required to the gas boost compressor.

(9) Heat recovery calculated based on hot water production (180 to 200 F) and heat recovery unit exhaust temperature of 220 F.

(10) Total CHP Efficiency = (net electric generated + net heat produced for thermal needs)/total system fuel input.

(11) Power/Heat Ratio = CHP electrical power output (BTU)/useful heat output (Btu).

(12) Net Heat Rate = (total fuel input to the CHP system - the fuel that would be normally used to generate the same amount of thermal output as the CHP systems output assuming an efficiency of 80%)/CHP electric output (kW).

188 Modified from *http://www.energysolutionscenter.org/DistGen/AppGuide/DGuideFrameSet.htm* Retrieved December 12, 2006.

Table 1-20: Typical performance and cost parameters for gas turbine CHP[189]

Cost and Performance Characteristics[1]	System 1	System 2	System 3	System 4	System 5
Electricity Capacity (kW)	1,000	5,000	10,000	25,000	40,000
Total Installed Cost (YR 2003 $/kW)[2]	$1,780	$1,010	$970	$860	$785
Electric Heat Rate (Btu/kWh), HHV[3]	15,580	12,590	11,765	9,945	9,220
Electrical Efficiency (%), HHV	22%	27%	29%	34%	37%
Fuel Input (MMBtu/hr)	16	63	118	249	369
Required Fuel Gas Pressure (psig)	95	160	250	340	435
CHP Characteristics					
Exhaust Flow (1000 lbs/hr)	44	162	316	571	954
GT Exhaust Temperature (degrees F)	950	950	915	950	854
HRSG Exhaust Temperature (degrees F)	280	280	280	280	280
Steam Output (MMBtu/hr)	7.1	26.6	49.6	95.6	136.8
Steam Output (1,000 lbs/hr)	6.7	25.0	46.6	89.8	128.5
Steam Output (kW equivalent)	2,080	7,800	14,540	28,020	40,100
Total CHP Efficiency (%), HHV[4]	68%	68%	71%	73%	74%
Power/Heat Ratio[5]	0.48	0.64	0.69	0.89	1.00
Net Heat Rate (Btu/kWh)[6]	6,673	5,947	5,562	5,164	4,944
Effective Electrical Efficiency (%)[7]	51%	57%	61%	66%	69%

(1) Characteristics for "typical" commercially available gas turbine generator system. Data based on: Solar Turbines Saturn 20 --1 MW,; Solar Turbines Taurus 60--5 MW; Solar Turbines Mars 100--10MW; GE LM2500+ -- 25 MW; GE LM6000PD -- 40 MW.
(2) Installed costs based on CHP system producing 150 psig saturated steam with an unfired heat recovery steam generator.
(3) All turbine and engine manufacturers quote heat rates in terms of the lower heating value (LHV) of the fuel. On the other hand, the usable energy content of fuels is typically measured on a higher heating value basis (HHV). In addition, electric utilities measure power plant heat rates in terms of HV. For natural gas, the average heat content of natural gas is 1,030 Btu/scf on an HHV basis and 930 Btu/scf on an LHV basis -- or about a 10% difference.
(4) Total Efficiency = (net electric generated + net steam produced for thermal needs)/total system fuel input.
(5) Power/Heat Ratio = CHP electrical power output (BTU)/useful heat output (Btu).
(6) net Heat Rate = (total fuel input to the CHP system - the fuel that would be normally used to generate the same amount of thermal output as the CHP system output assuming an efficiency of 80%)/CHP electric output (kW).
(7) Effective Electrical Efficiency = (CHP electric power output)/(Total fuel into CHP system -- total heat recovered/0.8); Equivalent to 3,412 Btu/kWh/Net Heat Rate.

The general trend in gas turbine advancement has been toward combining higher temperatures and pressures. The DOE has been working with Capstone, GE, Ingersoll-Rand, Solar Turbines and UTC since 2000 through the Advanced Microturbine Program. Focusing on performance targets to develop the next generation of "ultra-clean, high-efficiency" microturbines, the program is working to develop product designs with conversion efficiencies of 40 percent, NO_x emissions from natural gas of less than 7 ppm, service lives of 45,000 hours with the ability to run at least 11,000 hours, reduced system costs to less than $500 per kW and improved options for fuel flexibility. A Materials Program has also been developed to look at new materials for combustion liners and high-temperature material recuperators.[190]

CONCLUSION

Each DG technology has its own set of drawbacks and benefits, but all DG applications have the added benefit of defraying the need for additional centralized generating capacity and transmission. Still, an increased use of clean DG technology will require additional investment in distribution and storage capacity to take full advantage of the technology's potential.

189 Modified from*http://nooutage.com/SolarPVMod.htm* Retrieved December 12, 2006.
190 U.S. Department of Energy, 2006b.

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Chapter 2 – Electricity Supply

To meet greenhouse gas (GHG) emission targets in a carbon-constrained regulatory environment, utilities must examine all aspects of electricity supply. These strategies include updating the existing fleet of fossil fuel plants; pursuing new advanced fossil fuel, nuclear or renewable technologies; and increasing infrastructure efficiency, capacity and performance. This chapter first introduces each of these strategies and them greatly expands on them.

One option is to reduce GHG emissions from the existing fleet of fossil fuel plants. This approach offers some of the least expensive and quickest mitigation options, including "repowering" retired or unused pulverized coal plants to either advanced coal (integrated gasification combined cycle, or IGCC) or natural gas (natural gas combined cycle, or NGCC) technologies; adding biomass as a co-fired fuel to existing coal plants; increasing maintenance on all plants to optimize efficiency; and retrofitting existing plants to improve environmental performance.

A second option is to invest in new advanced fossil fuel, nuclear or renewable energy technologies. New fossil fuel technologies include supercritical and ultra-supercritical pulverized coal, IGCC, NGCC, fuel cell and natural gas turbine applications. Expanded nuclear capacity can draw on next-generation reactor design to increase performance and safety while reducing costs. Potential renewable energy resources include wind, solar, hydropower, geothermal, ocean, wave, tidal, biomass and landfill gas; where available, these can be cost-competitive alternatives to traditional fossil fuel technologies.

Finally, much of the discussion about the future of energy revolves around generation—facilities, fuels and associated emissions. However, once electricity is generated, it must be transmitted and distributed to end users. Electricity storage is another aspect of electricity infrastructure. Addressing electricity infrastructure, including transmission, distribution, and storage, will be crucial to any future transformation of the U.S. electricity sector in response to federal carbon policy.

EXISTING FLEET

The United States currently has more than 1,500 coal-fired power plants, which generate approximately 50 percent of electricity and produce 85 percent of electricity-generated carbon dioxide (CO_2) emissions.[1] Even in the face of pending carbon emission regulation, retiring all coal-fired power plants and replacing them with less carbon-intensive plants is not economically or politically feasible. With carbon regulation, some coal plants will retire. The remaining coal infrastructure will have to adjust to emissions limits for the remaining life of the capital. Methods for reducing GHG emissions from existing electric power generation offer some of the least expensive and quickest mitigation options. These options include repowering retired or unused pulverized coal plants to either IGCC or NGCC technologies, adding biomass as a co-fired fuel to existing coal plants, increasing maintenance on all plants to optimize efficiency and/or retrofitting existing plants to improve environmental performance.

1 Energy Information Administration, 2006a.

Repowering Coal Plants

Instead of investing in new generation infrastructure, utilities can repower older plants—that is, upgrade current facilities instead of constructing new ones. Repowering existing plants can reduce construction costs and time, including fuel transportation and transmission infrastructure, and lessen the permitting process. Other benefits include increased generation capacity and efficiency at the site, compared to prior plant performance.

Repowering plants normally consists of changing the feed fuel to the boiler or fundamentally upgrading the technology used to generate power. Two leading transformations for repowering plants are from pulverized coal to advanced coal or natural gas technologies, including IGCC and NGCC technologies.

UTILITY EXPERIENCE

One example of utility repowering technology, cost and performance characteristics is the Wabash River Coal Gasification Repowering Project, undertaken jointly by Destec Energy Inc. and PSI Energy Inc. (later Cinergy, then Duke Energy) in the 1990s. The oldest of the original units at the Wabash River Power Plant was a 99 megawatt (MW) coal-fired unit (which later was derated to 90 MW) built in 1952. The repowering project involved refurbishing the existing steam turbine, using existing coal-handling facilities, interconnects and other auxiliaries, along with installing a new integrated gasification combined cycle facility.[2] The new unit, which began operation in November 1995, produces a total of 262 MW, nearly three times the former generation capability. [3]

Costs

The total cost of the project was $417 million, or approximately $1,590 per kilowatt-hour (kW) in 1994 dollars. Estimated costs for a similar greenfield project, which would require additional permitting and equipment, are approximately $1,700/kW, for a total project cost of approximately $445 million[4]. Total cost includes preconstruction studies, equipment procurement, construction, weather- and labor-related delays, start up and escalation costs. By using the existing facility's permits, coal-handling equipment and steam turbine and auxiliaries, the companies were able to save an estimated $30 million to $40 million and one year of project time.[5] Table 2-1 includes the budget breakdown for the project, along with actual expenditure figures.

Table 2-1: Wabash River Coal Gasification Repowering Project costs[6]

Cost Area	Budget *	Actual *
SYNGAS FACILITY		
Engineering and Project Management	29.6	27.3
Equipment Procurement	98.3	84.5
Construction	55.5	106.1
Construction Management	7.9	8.1
ASU	36.9	32.8
Pre-Operations Management	19.8	21.7
POWER BLOCK	121.8	136.2
Total	**369.8**	**416.6**

*$MM, 1994 Average

2 See IGCC section for more on IGCC technology.
3 Troxclair & Stultz, 1997.
4 Wabash River Energy Ltd., 2000.
5 Troxclair & Stultz, 1997.
6 Wabash River Energy Ltd., 2000.

In the demonstration period 1995-1998, nonfuel operating and maintenance costs, for the syngas facility only, accounted for 6.8 percent of installed capacity; annual fuel costs were $15.3 million to 19.2 million[7].

Performance

The repowered plant has achieved at least 75 percent availability, a demonstrated heat rate of 8,900 Btu/kWh or efficiency of 40 percent.[8,9] Table 2-2 and Table 2-3 further detail the plant's performance statistics.

Table 2-2: Wabash River Coal Gasification Repowering Project production statistics[10]

Time Period	On Coal (Hr)	Coal Processed (tons)	On Spec Gas (10^6 Btu)	Steam Produced (10^6 lb)	Power Produced (MWH)	Sulfur Produced (tons)
Start up 1995	505	41,000[a]	230,784	171,613	71,000[a]	559
1996	1,902	184,382	2,769,685	820,624	449,919	3,229
1997	3,885	392,822	6,232,545	1,720,229	1,086,877	8,521
1998	5,279	561,495	8,844,902	2,190,393	1,513,629	12,542
1999[b]	3,496	369,862	5,813,151	1,480,908	1,003,853	8,557
Overall	15,607	1,549,561	23,891,067	6,383,767	4,112,278	33,388

Table 2-3: Wabash River Coal Gasification Repowering Project thermal performance summary[11]

	Design Coal	Actual	
		Coal	Petcoke
Nominal Throughput, tons/day	2,550	2,450	2,000
Syngas Capacity, 10^6 Btu/hr	1,780	1,690	1,690
Combustion Turbine, MWe	192	192	192
Steam Turbine, MWe	105	96	96
Auxiliary Power, MWe	35	36	36
Net Generation, MWe	262	261	261
Plant Efficiency, % (HHV)	37.8	39.7	40.2
Sulfur Removal Efficiency, %	>98	>99	>99

Emissions

One reason to repower older generation facilities is to reduce greenhouse gas emissions in order to comply with federal, state or local standards. As expected, the Wabash River repowered plant significantly reduced emissions. During the project's demonstration phase, sulfur dioxide (SO_2) was captured at more than 99 percent efficiency, nitrogen oxide (NOx) emissions were well within the New Source Performance Standards and carbon monoxide (CO) emissions were within industry standards.[12] As shown in Table 2-4, SO_2 emissions were reduced by more than 96 percent, NOx emissions by more than 88 percent and CO emissions by more than 42 percent, compared with the original unit.

7 U.S. Department of Energy, 2003b.
8 Ibid.
9 Amick et al., 2002.
10 U.S. Department of Energy, 2003b.
11 Ibid.
12 Ibid.

Table 2-4: Emissions from Wabash River IGCC Plant[13]

Emissions	SO_2		NOx		CO		PM-10		VOC	
Units	lb/MWh	lb/MBTu	lb/MWh	lb/MBTu	lb/MWh	lb/MBTu	lb/MWh	lb/MBTu	lb/MWh	lb/MBTu
Pre-Repowering Unit 1 Boiler	38.2	3.1	9.3	0.8	0.64	0.05	0.85	0.07	0.03	0.003
IGCC	1.35	0.10	1.09	0.15	0.37	0.03	ND*	ND*	0.02	0.003

IGCC atmospheric emissions are significantly lower than those from the pre-IGCC repowered boiler. The consequence is a marked improvement in air quality.

* nondetectable

Other projects

Cinergy (now Duke Energy)

The Noblesville Generating Station in Indiana, owned by Cinergy (PSI), was originally built in 1950 as two coal-fired steam turbines, generating about 90 MW of electricity. In about a year and a half (January 2002-June 2003), the company repowered the station to natural gas combined cycle, adding three natural gas combustion turbines and nearly three times as much generation capacity.[14] The repowering project cost approximately $200 million, and the new facility generates close to 300 MW of electricity. Efficiency at the plant increased by 40 percent and overall emissions decreased.[15],[16]

American Electric Power

In September 2001, American Electric Power finished a repowering project at the Northeastern Station plant in Oklahoma. The plant was originally commissioned in 1961 at 160 MW capacity. Two GE combustion turbines and heat recovery steam generators were added, and the existing steam turbine was refurbished. The new unit, with natural gas combined cycle, now contributes 475 MW to the grid. The two-year project cost $135 million.[17]

Pacific Gas & Electric

In April 2006, the Pacific Gas and Electric Company announced plans to repower a nearly 50-year-old natural gas plant to advanced natural gas technology with oil back-up capability. The new plant will produce 163 MW, compared with the current plant's 135 MW. The repowering is expected to increase efficiency by 35 percent and reduce emissions by 90 percent, over a two- to three-year time frame.[18],[19]

Wisconsin Energy

Wisconsin Energy applied to the Public Service Commission of Wisconsin in 2002 to repower the nearly 70-year-old coal-fired Port Washington Power Plant to natural gas combined cycle generation. The first of the two 545 MW units was completed in July 2005, and the second is expected to be finished by summer 2008.[20],[21]

13 U.S. Department of Energy, 2000b.
14 See NGCC section for more information on NGCC technology.
15 Cinergy, 2003b.
16 Cinergy, 2003a.
17 American Electric Power, 2001.
18 Pacific Gas & Electric Company, 2006.
19 Transmission & Distribution World, 2006.
20 Wisconsin Energy, 2002.
21 Wisconsin Energy, 2006.

Imperial Irrigation District, California

In the first half of 2006, Imperial Irrigation District, a community-owned utility in Imperial County, California, submitted a licensing case to the California Energy Commission to repower the 44 MW El Centro Power Plant to natural gas combined cycle generation. The utility plans to replace the existing boiler with a low NOx combustion turbine generator and heat recovery steam generator, adding 84 MW to the unit, for a total of 128 MW.[22]

Reliant Energy/Orion Power

From 2000 to 2002, Orion Power, which became Reliant Energy, repowered three oil-fired single cycle units at the Brunot Island Power Plant, built in 1972, to one natural gas combined cycle plant. The NGCC unit has a net capacity of 262 MW, an increase of more than 80 MW, and is expected to reduce emissions by as much as 80 percent, compared to the former plant.[23],[24]

ADVANCED REPOWERING TECHNOLOGIES[25]

The U.S. Department of Energy's (DOE) National Energy Technology Laboratory (NETL) has begun research projects on repowering to advanced coal technologies such as fluidized bed combustion and high performance power systems. Below are brief descriptions of some projects and anticipated results.[26]

Progress Energy

In September 2000, Progress Energy completed evaluations of repowering its Sutton Station as advanced pressurized fluidized bed combustion (APFBC) technology. At a cost of about $900/kW, Unit 2 is expected to increase production from 106 MW to 226 MW and efficiency from 32 percent to 42.4 percent (Table 2-5).[27]

Table 2-5: Costs and performance Repowering[28]

	High-Efficiency APFBC Repowering	High-Efficiency APFBC Repowering	High-Output APFBC Repowering
Case ID:	Case B APFBC + W501F with MASB	Case S APFBC + W501F with MASB	Case M APFBC + W501F with MASB
Steam turbine(s) repowered with APFBC	Existing reheat Unit 2	Existing reheat Unit 2	Existing non-reheat Unit 1 plus reheat Unit 2
Net plant output	226,491 kWe	226,491 kWe	340,736 kWe
Net plant HHV efficiency	42.4%	42.4%	39.7%
Net plant HHV heat rate	8,041 Btu/kWh	8,041 Btu/kWh	8,601 Btu/kWh
Net plant LHV efficiency	44.1%	44.1%	41.3%
Total Plant Cost	$ 241,674,000 $ 961 / kW	$ 205,242,000 $ 906 / kW	

Note: Total Plant Cost[29]

22 California Energy Commission, 2006.

23 Reliant Energy, 2006.

24 Alexander's Gas & Oil Connections, 2000.

25 All references in this section are taken from U.S. DOE NETL's Fluidized Bed Combustion Repower Project websites, retrieved August 2006 from: *http://www.netl.doe.gov/technologies/coalpower/Combustion/FBC/APFBC/APFBCprojects.html*

26 See Advanced Fossil Fuel Technology section for technology descriptions and performance characteristics.

27 U.S. Department of Energy, 2006d.

28 Ibid.

29 Note on costs: Total plant cost estimates for APFBC repowering show costs similar to those for an all-new pulverized coal plant. However, since an APFBC plant is much more energy efficient and environmentally clean, this means that the total life cycle cost for APFBC is superior, largely due to the fuel savings. The table below gives the estimated costs for an APFBC repowering. Three cases are shown. The first, Case B, is for the high-efficiency APFBC repowering of Unit 2. The Case B option is designed with redundancies typical for owners making decisions using regulated utility investment returns. A plant with similar efficiency, but designed for minimum initial capital expenditure more typical of merchant plant investments, is shown as Case S. Case S has the same energy efficiency level as Case B, but employs a number of design changes that minimize capital investment at the expense of operating or maintenance cost; these

Emissions

Emissions at the repowered Sutton station are expected to significantly drop. CO_2 emissions are expected to drop by 25 percent; SO_2 and particulate emissions are expected to drop up to 96 percent, and NOx reductions are expected to drop by roughly 64 percent. Fuel costs are expected to be reduced by 25 percent.[30]

Duke Power

DOE-NETL studied repowering Duke Power's Dan River Station to APFBC in 1998. The conversion cost less than $800 per kW, while unit efficiency increased almost 7 percent, to 43.2 percent higher heating value (HHV). Output increased from 144 MW to 209 MW, while emissions decreased—CO_2 by about 15 percent, NOx by about 43 percent, and SO_2 and particulates each by more than 95 percent.[31]

AES

Originally built in 1953, the AES Greenidge Plant Unit 4 was studied for repowering to APFBC. Electricity generation nearly doubled with the upgrade, from 106.3 MW to 206.3 MW. Efficiency would also improve, from 34.6 percent to 39.8 percent HHV. Table 2-6 presents emissions comparisons before and after the repowering; significant reductions are expected, especially for SO_2 and particulates.[32]

Table 2-6: APFBC-Modified Greenidge emissions comparison[33]

	Unmodified Unit 4	Repowered with APFBC
Output	106, 310 kW	206, 300 kW
SO_2	3.52 lb/10^6 Btu	0.18 lb/10^6 Btu
	11,296 tons/yr*	1,158 tons/yr*
	34.63 lb/MWh	1.51 lb/MWh
NOx**	0.33 lb/10^6 Btu	0.30 lb/10^6 Btu
	1,060 tons/yr*	1,628 tons/yr*
	3.25 lb/MWh	2.57 lb/MWh
Particulate	0.04 lb/10^6 Btu	0.002 lb/10^6 Btu
	128.5 tons/yr*	10.9 tons/yr*
	0.394 lb/MWh	0.017 lb/MWh
CO_2	202 lb/10^6 Btu	202 lb/10^6 Btu
	648,647 tons/yr*	1,095,572 tons/yr*
	1989 lb/MWh	1731 lb/MWh

*Annual emissions are based on an assumed 70 percent capacity factor.

**Repowering the plant with APFBC with selective non-catalytic reduction (SNCR) further reduced NOx emissions to 0.10 lb/10^6 Btu, 543 tons/yr, and 0.86 lb/MWh.

CONCLUSION

Repowering existing plants takes advantage of capital already paid for and site and transmission capacity already owned. Repowering also can significantly improve environmental performance over the former facility, at much lower cost than constructing a new plant on a greenfield site.

changes include such things as single trains instead of duplicate trains, sized limestone delivery rather than on-site limestone preparation, etc. Case M is another merchant plant repowering, but here, both Unit 1 and Unit 2 are repowered. (http://www.netl.doe.gov/technologies/coalpower/Combustion/FBC/projects/sutton.html)

30 U.S. Department of Energy, 2006d.

31 Ibid.

32 Ibid.

33 Ibid.

Biomass Co-firing at Coal Plants

Another option for reducing emissions at existing coal-fired power plants is to mix biomass, a renewable energy source, with coal. Biomass is plant-derived organic matter, including woody energy crops, agricultural food and feed crops, agricultural crop wastes and residues, wood wastes and other waste materials, including some municipal wastes.[34],[35] The most popular biomass feeds are waste wood and wastepaper,[36] and potential sources include furniture mills, sawmills and construction sites.[37] The pulp and paper industry has used biomass co-firing for decades, taking advantage of waste biomass at processing sites.[38] The primary benefit to adding biomass to the fuel mix in coal-fired power plants is reduced fossil fuel combustion and associated GHG emissions. SO_2 is also reduced, because biomass has lower sulfur content than coal. Changes in NOx emissions depend on the nitrogen content of the biomass compared to the coal. Using renewable, locally produced biomass can also reduce fuel, waste and disposal costs when compared to other emission mitigation options. While co-firing with biomass has many benefits, several key drawbacks, including increased transportation costs and possible triggering of the U.S. Environmental Protection Agency's (EPA) New Source Review requirements, prevent the technology from being used on a larger scale.

HISTORY

From 1996 to 2001, the DOE initiated a series of biomass co-firing demonstration projects, both utility- and industrial-scale (32-469 MW sized plants). Although the program has officially ended, some projects are still in progress. Table 2-7 shows utility-scale tests.

Table 2-7: DOE utility biomass co-firing tests[39]

Utility and Plant	Boiler Capacity and Type	Biomass Heat Input (max)	Biomass Type	Biofuel Feeding
TVA Allen	272 MW cyclone	10%	Sawdust	Blending biomass & coal
TVA Colbert	190 MW wall-fired	1.5%	Sawdust	Blending biomass & coal
NYSEG Greenidge	108 MW tangential	10%	Wood waste	Separate injection
GPU Seward	32 MW wall-fired	10%	Sawdust	Separate injection
MG&E Blount St.	50 MW wall-fired	10%	Switchgrass	Separate injection
NIPSCO Mich. City	469 MW cyclone	6.5%	Urban wood waste	Blending biomass & coal
NIPSCO Bailly	194 MW cyclone	5-10%	Wood	Blending (Tri-fire)
Allegheny Wood Island	188 MW cyclone	5-10%	Sawdust	Blending (Tri-fire)
Allegheny Albright	150 MW tangential	5-10%	Sawdust	Separate injection

The facilities were able to co-fire several different types of biomass with different types of coal, in ranges of 1.5 percent to 10 percent biomass. In general, biomass co-firing proved technically successful and was demonstrated to be a viable option for coal-fired facilities. Co-firing is most commonly done at ranges of 5 percent to 15 percent biomass by heat input, but has been demonstrated to support 20 percent or more biomass using either blending or separate feed systems. Specifications for preparing biomass as fuel for a boiler depend in part on the type of boiler. Biomass sizing requirements range from 3 inches or smaller for stoker and fluidized bed boilers, to one-quarter inch or smaller for pulverized coal (PC) boilers.[40] Utilities can either contract out the biomass processing and delivery or establish on-site facilities.

34 See *http://www1.eere.energy.gov/biomass/feedstock_glossary.html#B* for more info
35 See biomass section for more information on biomass.
36 Federal Energy Management Program, 2004.
37 Foster Wheeler, 1999.
38 Federal Energy Management Program, 2004.
39 Data from Grabowski, 2004.
40 Federal Energy Management Program, 2004.

As coal prices continue to increase and as biomass becomes more developed as an alternative fuel source, biomass co-firing is seen as a relatively inexpensive, quick way to reduce power plant fuel costs and emissions.

TECHNOLOGY

There are two primary options for co-firing biomass in a coal-fired power plant:

1 Mix the biomass with coal before it enters the boiler, and transport the biomass/coal blend to the fuel yard and boiler. This method is least expensive for incorporating biomass into an existing plant; however, this option also allows the smallest amount of co-firing (up to 5 percent biomass) because of biomass particle size and quality as it enters the existing fuel stream. There are no large capital investments necessary to blend biomass with coal before entering the fuel stream; steady supply, transportation and storage capacity is mostly what is needed.

2 Prepare the biomass separately from coal and inject it separately into the boiler. Creating separate fuel injection points is more expensive than blending biomass with coal before injection, but allows for up to 20 percent of biomass to be co-fired depending on boiler type, biomass quantity and quality, etc.[41],[42]

Primary modifications and additions needed to receive biomass include truck tippers and conveyors. In processing biomass, plants need a storage area, conveyors, metal detectors and magnetic scrap metal separators (to remove metal remains from waste materials) and hoggers to grind the waste to acceptable particle sizes. After processing, the biomass can be held in temporary buffer storage for up to 18 hours before being fed to the boiler; appropriate meters and conveyors would need to be added. And lastly, depending on how the plant will inject the biomass into the boiler (either separately or together with coal), modifications will have to be made to the burners.[43]

PLANT IMPACTS

Emissions

One of the primary benefits to incorporating biomass into a coal-fired boiler is the reduced use of nonrenewable fossil fuel resources. Comparing life cycle emissions of a co-fired plant versus an average PC coal plant, the fuel substitution alone (biomass for coal) can reduce a plant's GHG emissions by up to 22 percent CO_2-equivalent when co-firing up to 15 percent biomass.[44]

SO_2 also is reduced by co-firing, because biomass has much lower sulfur content than coal.[45],[46],[47] Table 2-8 compares properties of two types of coal (Black Thunder and Illinois #6) and two types of biomass (sawdust and switchgrass). Note the significantly lower carbon amounts in biomass, higher volatile matter content and lower

41 Ibid.

42 A third option, to gasify the biomass and fire the gas either in a coal-fired boiler as supplementary fuel or in a combined cycle power plant, represents the "next generation" of co-fired power plants, including co-firing biomass with natural gas, which DOE and others are currently studying (see also Foster Wheeler, 1999).

43 Ibid.

44 Mann & Spath, 1999.

45 Haq, 2002.

46 Haq, 2004.

47 Grabowski, 2004.

sulfur. Other elements, such as nitrogen, depend on the type of biomass as to whether or not there will be a reduction in emissions when biomass is incorporated into the boiler fuel.

Table 2-8: Differences of fuel analyses, biomass and coal[48]

Proximate Analysis; %	Sawdust	Switchgrass	Black Thunder (PRB)	Illinois #6
Fixed Carbon (FC); %	9.34	12.19	34.94	44.98
Volatile Matter (VM); %	55.03	65.19	30.72	35.32
Ash; %	0.69	7.63	5.19	7.43
Moisture; %	34.93	15.00	29.15	12.27
Ultimate Analysis				
Carbon; %	32.06	39.68	51.30	66.04
Hydrogen; %	3.86	4.95	2.87	4.38
Oxygen; %	28.17	31.77	10.46	5.66
Nitrogen; %	0.26	0.65	0.68	1.40
Sulfur; %	0.01	0.16	0.35	2.79
Higher Heating Value; Btu/lb	5431	6601	8888	11731
Higher Heating Value; MJ/kg	12.62	15.34	20.66	27.26
FC/VM Ratio	0.17	0.19	1.14	1.27
lb Fuel N/10^6 Btu	0.48	0.98	0.77	1.19
lb Fuel S/10^6 Btu (as SO_2)	0.04	0.48	0.79	4.76

System and Boiler Efficiency

Utility-scale demonstrations of co-fired biomass plants have shown little change in boiler and plant efficiency and rating. Most efficiency losses result because biomass has a lower heating value and higher moisture content than coal. Along with a slight reduction in efficiency comes a decrease in plant output when co-firing biomass. Results of the DOE's Office of the Biomass Program have showed a general trend for reductions in efficiency from 0.5 percent to 1.5 percent, with virtually no loss in efficiency when co-firing 5 percent or less biomass. In fact, co-fired plants are more effective at converting biomass to energy, taking advantage of the existing coal-burning technologies, and are significantly more efficient than stand-alone dedicated biomass plants (33 percent vs. 20 percent, respectively).[49]

According to a National Energy Technology Laboratory life-cycle assessment of co-fired plants, which assumed a decrease in plant output of 2 percent to 3 percent, co-firing with 5 percent biomass can reduce total system energy consumption by 6.4 percent, and co-firing with 15 percent biomass can reduce consumption by 19.8 percent. Reasons for reduced system energy consumption include avoided coal combustion and mining, and less energy used in flue gas scrubbers because of fewer emissions.[50],[51]

Costs

Although one of the least expensive emission mitigation options for utilities, co-firing coal with biomass is not without cost. Some modifications to an existing plant are needed, but co-firing modifications are a fraction of the cost of new plant construction. Minimal adjustments that need to be made, depending on which method of co-firing is used, are changes to the fuel-handling, processing, storage and feed systems. These changes incorporate the biomass into the fuel and increase fuel feeder rates, as biomass has a lower heating value than coal and requires more to generate the same amount of energy.[52]

48 Foster Wheeler, 1999.
49 Clemmer, 1999.
50 Mann & Spath, 1999.
51 Mann & Spath, 2001.
52 Federal Energy Management Program, 2004.

DOE estimates retrofit costs for biomass co-firing at $50-200/kW of biomass capacity,[53],[54] depending on the type of boiler and feeding system. Blending biomass and coal before feeding to the boiler is the least-cost option, requiring additions in transport, storage and handling, for as low as $50/kW of biomass capacity.[55] The $200/kW range is for installing a separate feeding system for biomass, in addition to transport, storage and handling costs.[56],[57]

Table 2-9 shows some of the economics of the DOE test plants. Payback periods on plant modification investments range from less than one year to about 5 years, with net annual cost savings ranging from $140,000 to $700,000.

Table 2-9: Examples of economics of biomass co-firing in power generation applications (vs. 100% coal)[58]

Boiler Type	Example Plant Size (MW)	Heat from Biomass (%)	Biomass Power (MW)	Unit Cost ($/kW)[a]	Total Cost for Co-firing Retrofit ($)	Net Annual Cost Savings ($/yr)[b]	Payback Period (years)	Production Cost, no Co-firing (¢/kWh)[c]	Production Cost, with Co-firing (¢/kWh)[c]
Stoker (low cost)	15	20	3.0	50	150,000	199,760	0.8	5.25	5.03
Stoker (high cost)	15	20	3.0	350	1,050,000	199,760	5.3	5.25	5.03
Fluidized bed	15	15	2.3	50	112,500	149,468	0.8	5.41	5.24
Pulverized coal	100	3	3.0	100	300,000	140,184	2.1	3.26	3.24
Pulverized coal	100	15	15.0	230	3,450,000	700,922	4.9	3.26	3.15

Notes:
[a] Unit costs are on a per kW of biomass power basis (not per kW of total power).
[b] Net annual cost savings=fuel cost savings-increased O&M costs.
[c] Based on data obtained from EPRI's Technical Assessment Guide, 1993, EIA's Costs of Producing Electricity, 1992, UDI's Electric Power Database, EPRI/DOE's Renewable Energy Technology Characterizations, 1997, coal cost of $2,10/MBtu, biomass cost of $1.25/MBtu, and capacity factor of 70%.

Beyond plant modifications, biomass must be processed and transported to the plant facility. Table 2-10 compares physical and economic characteristics of two common types of biomass, urban wood wastes and mill residues. Biomass has a lower heating value than coal, with coal around 10,000 Btu/lb as compared to dry biomass around 8,600 Btu/lb and wet biomass between 4,700 and 7,100 Btu/lb. Biomass must be burned in larger quantities than coal to generate the same amount of electricity; one ton of biomass offsets about 0.61 tons of coal.[59] In addition to collection and processing costs, transportation costs of $12 to $24 per dry ton, depending on distance and type of biomass, need to be considered.[60] Total costs to deliver biomass to a plant could range from $20 to $40 per ton, which is in the range of delivered coal prices. Based on DOE's Biomass Program results, the cost of biomass "must be equal to or less than the cost of coal per unit of heat for co-firing to be economically successful."[61]

Table 2-10: Physical and economic characteristics of urban wood wastes and mill residues[62]

Residue Type	Moisture Content (%)	Heating Value, Wet (Btu/lb)	Heating Value, Dry (Btu/lb)	Collection & Processing Cost ($/Wet Ton)
Bark Residue (Primary Mill)	40	4,697	8,629	4
Wood Residue (Primary Mill)	40	4,661	8,568	4
Woody Yard Trimmings	25	6,150	8,600	12
Construction Residues	15	7,103	8,568	12
Demolition Residues	15	7,103	8,568	12
Other Waste Wood	15	7,103	8,568	12

Source: Antares Group Inc., Biomass Residue Supply Curves for the United States (Update), Report for the U.S. Department of Energy and the National Renewable Energy Laboratory (June 1999).
Note on Collection and Processing Cost[63]

53 Ibid.
54 Grabowski, 2004.
55 Ibid.
56 Ibid.
57 Federal Energy Management Program, 2004.
58 Ibid.
59 Ibid.
60 Haq, 2002.
61 U.S. Department of Energy, 2000a.
62 Haq, 2002.
63 Explanation of costs: While these are average collection and processing costs, the actual costs are expected to range from $0 to $8 per wet ton for mill residues and from $10 to $14 per wet ton for urban residues. A transportation cost is added to the collection and processing costs. The total expenditure in local transportation costs in 1996 was reported to be $122 billion (in 1996 dollars). Local trucking accounted for 506 billion ton-miles in 1996. This implies a

Other costs to utilities may include additional expertise and maintenance, especially when additional feeding systems are involved. Companies could contract out such expertise or develop it in-house.[64]

One category of costs that is avoided through biomass co-firing is waste and landfill fees. "During summer months, waste wood is often sent to the mulch market, which makes the wood unavailable for use as fuel,"[65] but at other times of the year, the waste is delivered to landfills at cost. Using biomass instead for electricity generation replaces coal usage, reduces landfilling and is potentially a new source of revenue for wood recycling and processing companies.

According to DOE's Federal Energy Management Program,[66] several criteria can tip the cost/benefit balance toward biomass co-firing:

- High coal prices.
- Significant annual coal usage.
- Significant local supplies of biomass.
- High landfill tipping fees (charge per ton of delivered waste, in this case, biomass waste).
- Favorable regulation and market conditions for renewable energy use and waste reduction.[67]

national average local freight charge of about $0.24 per ton-mile (1996 dollars). For distances of 50, 75 and 100 miles around a co-firing facility, this would translate to transportation costs of $12, $18 and $24 per dry ton ($0.70, $1.05 and $1.40 per million Btu), respectively. (Haq, 2004)

64 Federal Energy Management Program, 2004.

65 Ibid.

66 See *www.eere.energy.gov/femp/* for more information.

67 Federal Energy Management Program, 2004.

REGULATION AND INCENTIVES

One potentially significant drawback to biomass co-firing is that the coal-biomass ash combustion byproduct may not meet the standards for concrete production for the American Society for Testing and Materials.[68] Sale of fly ash is a significant source of revenue for some utilities, and limiting its sale would be an impediment to including biomass in the fuel mix.[69] Fly ash content depends on the type and share of biomass used in the co-firing mix.

Although the Energy Policy Act of 2005[70] extended a renewable electricity production credit that includes biomass facilities, the definition of qualified biomass facilities excludes co-firing with fossil fuel. Open-loop biomass facilities (a category that includes nearly all co-firing facilities) are eligible for a credit of 0.9 cents per kWh during a 5-year period beginning on the date the facility is placed in service. However, the definition of open-loop biomass "shall not include closed-loop biomass or biomass burned in conjunction with fossil fuel (co-firing) beyond such fossil fuel required for start up and flame stabilization."[71]

In addition, the EPA's New Source Review and other emissions permits may be required when modifying a coal-fired plant to include a separate feed system for biomass. New Source Review, part of the 1977 amendments to the Clean Air Act, requires stationary pollution sources to use "best available control technology" for pollution reduction. Existing plants need to get New Source Review permits if they undergo "major modifications," usually to increase capacity or extend plant life.[72] Because separate biomass injection requires modifications to the burners, among other capital modifications, co-firing plants could fall under New Source Review. Utilities may be more willing to co-fire a smaller percentage of biomass to avoid both capital expenditures and New Source Review permitting. Regarding other emissions permits, DOE has commented:

> Permit requirements vary from site to site, but a facility's emissions permits—even for limited-term demonstration projects—usually have to be modified for co-firing projects. Results from earlier co-firing projects in which emissions were not negatively affected can be helpful during the permit modification process. Air permitting officials also may need detailed chemical analyses of biomass fuel supplies and a fuel supply plan to evaluate the permit requirements for a co-firing project.[73]

According to an Energy Information Administration National Energy Modeling System analysis to 2020, the largest consumption of biomass for co-firing occurs under Renewable Portfolio Standard policies of 10 percent to 20 percent renewable energy, as compared to the reference case and lower-cost case in which renewables gain cost efficiencies without government policy. These modeling results suggest that cost reductions are not enough for biomass co-firing to penetrate the market.[74] Although rising coal and gas costs are beginning to change the cost competitiveness, incentives and standards will help encourage biomass co-firing as an inexpensive, quick GHG mitigation option.

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68 American Society for Testing and Materials, 2005.

69 Federal Energy Management Program, 2004.

70 Government Accountability Office, 2005.

71 Oregon Department of Energy, 2004.

72 For more information, see U.S. EPA's NSR website: http://www.epa.gov/nsr/

73 Federal Energy Management Program, 2004.

74 Haq, 2004.

CONCLUSION

According to a DOE analysis, almost half of the United States has "good" or "high" potential for biomass co-firing, including Indiana, Ohio, North Carolina and South Carolina. The results were based on average coal prices, biomass supply and landfill tipping fees in each state.[75]

Biomass co-firing, as one of the least expensive renewable energy technologies, could be "especially important for certain parts of the country that have significant quantities of coal generation but do not have good wind, solar or geothermal resources, like the industrial Midwest."[76] The Northeast and Northwest, with developed forest products industries, are well-suited to incorporate biomass co-firing; the Southeast has good potential in agricultural and mill residues.[77]

Adding biomass to the fuel mix in coal-fired power plants is a quick, relatively inexpensive way to reduce GHG emissions. With little plant modification, up to 5 percent biomass can replace coal combustion. Increasing coal prices and pressure to reduce emissions make biomass co-firing an attractive mitigation option.

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75 Federal Energy Management Program, 2004.

76 Clemmer, 1999.

77 Zia Haq, U.S. DOE, July 25, 2006, personal communication with H. Knuffman.

Increased Maintenance to Optimize Efficiency for All Plants

Without making changes to the fuel mix or combustion process, existing power-generation plants can still reduce fossil fuel emissions through optimized plant maintenance. Power plant maintenance is an inexact, but improving, science. In keeping with the utility tenet to provide electricity "safely, reliably and at the lowest feasible cost," utility operators have incentive to maintain plants at lowest cost and in ways that cause the smallest interruptions in service.

BACKGROUND AND THEORY

With increased—or, more accurately, improved—maintenance of power plants, plant performance and efficiency can be increased. Historically, plant operations and maintenance (O&M) was based on firsthand operator knowledge and experience and parts manufacturers' recommendations. Recent developments include greater information sharing among utilities and manufacturers of best practices, decision analysis and other theoretical frameworks applied to maintenance schedules, and improved sensory technologies to detect problems before they impact plant performance.

There are generally three options for power plant maintenance:[78]

- Proactive—routine maintenance based on fixed schedules or plant hours of service, regardless of the condition of the equipment.

- Reactive—maintenance performed when equipment fails or begins to impact plant performance.

- Predictive—maintenance needs are detected through advanced equipment monitoring technologies before problems occur, eliminating both proactive and reactive maintenance.

Webster (2004) focuses on five main categories for plant O&M optimization:[79]• Fuel and combustion process optimization, including coal and boiler analyses.

- Performance improvement, including unit performance parameter trends.
- Continual condition assessment;
- Condition based maintenance.
- Life-cycle planning.

The final three categories are part of a trend to holistic, system-based maintenance, as opposed to considering separate plant components.

Ideally, a part will be repaired or replaced just at the point when it begins to impact plant performance, but before it results in severe plant malfunction. Working on equipment on either side of the "maintenance equilibrium" can increase a utility's maintenance costs in parts and labor, as well as affect plant output and time online.

78 Golden, 2004.
79 Webster, 2004.

The importance of keeping a plant in production varies by the type of plant and its usage. Base-load plants are expected to run year-round at close to maximum capacity, with brief scheduled down times. Unexpected maintenance to those plants can disrupt a utility's supply. Load-following plants, on the other hand, have larger maintenance windows and down times, allowing for more flexibility in repair.

INFORMATION SHARING

There are an increasing number of power plant maintenance programs and agreements. Utilities sign maintenance agreements with original equipment manufacturers, who are most familiar with the plant equipment; industry groups organize to share best practices and common maintenance problems. As examples, the Electric Power Research Institute (EPRI) maintains a Reliability Optimization and Plant Maintenance Optimization program.[80] The program gives utilities access to equipment case histories, benchmarking tools, best practices, training modules and other information. In addition, representatives from member organizations meet once a year in a working group to address common problems and share experiential knowledge. General Electric offers a variety of maintenance service contracts through its Global Plant Maintenance division, including reliability, availability and maintainability engineering, and remote monitoring and diagnostics.[81] Wartsila Power, a supplier of decentralized power plant solutions and operation and maintenance services, offers maintenance agreements and field and technical support.[82]

THEORETICAL FRAMEWORKS

Condition-Based Maintenance

Because of the interconnectedness of power plant components, plant O&M is trending toward system analysis. Failure in one part of the plant can lead to a chain reaction; conversely, prevention of failure in one part can prevent multiple failures. In addition, with advanced detection technology, O&M is moving to real-time system analyses. Previous maintenance plans may have called for annual or scheduled review of equipment. With improved monitoring technology, staff can be alerted to a problem, potentially eliminating periodic equipment inspections.

Decision Analysis

There are three decision paths to take in maintenance—do nothing, repair the existing part or replace it. Decision analysis can help O&M staff evaluate the effects of each decision path on plant parameters. Mani (2004) explains how decision analysis was used with one Midwestern utility to evaluate whether to repair or replace a nuclear plant component.[83] Resulting plant variables, such as plant performance, cost to produce electricity and plant reliability, are assigned probabilities and analyzed in each maintenance scenario.

Performance Modeling

Modeling is another tool that O&M staff can use to optimize plant maintenance. Again, ideally using whole system inputs to analyze plant performance, staff can manipulate configurations to model an optimal maintenance strategy. Hines and Usynin (2006) used empirical thermodynamic performance modeling to demonstrate increased steam power cycle efficiency in nuclear power plants. Their simulation results show the potential to save power plants "hundreds of thousands of dollars a year."[84]

80 Electric Power Research Institute, 2006b.
81 General Electric Company, 2006a.
82 Wartsila Power, 2006. See *www.wartsila.com* for more information.
83 Mani, 2004.
84 Hines & Usynin, 2006.

TECHNOLOGICAL ADVANCEMENTS

Recent advancements in maintenance technology include spectral analysis and portable vibration-monitoring equipment, to detect vibrations, and metallurgical sampling and computational fluid dynamics analyses, to detect corrosion and material conditions.[85]

ABB, which specializes in electricity distribution and transmission components, offers plant maintenance management software such as API Pro and the Power Generation Portal, in which separate servers covering different areas of the plant are overlaid to generate graphical status displays.[86]

The Department of Energy offers a series of software tools for plant optimization, including a pumping system assessment tool. Austin Energy used the software in 2004 to assess improvement opportunities at the 405 MW Decker Creek steam turbine plant. The company upgraded components and reconfigured equipment, increasing the circulating water pumps' combined flow rate to 11.5 percent above their design rating, resulting in savings of $1.2 million and 220,000 MMBtu annually.[87]

Among other tools, the Pacific Northwest National Laboratory, part of the DOE, developed DSOM (Decision Support System for Operations and Maintenance). DSOM was originally intended for operators of federal power facilities, but the software can be applied broadly. Using condition-based maintenance management, the software incorporates information from sensors throughout the plant, alerts operators to potential problems and even suggests causes and courses of action. One of the original case studies of DSOM at a Marine Corps Central Heating Plant in the 1990s led to a 30 percent increase in capacity and a 13 percent increase in efficiency for a 15-year-old plant.[88]

Plant intelligence solution software using neural networks to evaluate plant maintenance data was developed by Wonderware, a business unit of Invensys Systems Inc. According to Wonderware, the software installation reduced staff monitoring time, increased plant efficiency and avoided plant downtime at Arizona Public Service's 2,040 MW Four Corners coal-fired plant.[89]

Table 2-11 summarizes potential efficiency improvement measures for coal-fired power plants. Although the information was originally generated for the Australian government, using different coal than is typically used in the United States, the same measures could be considered for U.S. power plants.

85 Golden, 2004.
86 ABB, 2006. See *www.abb.com* for more information.
87 U.S. Department Of Energy, 2006g.
88 Meador, 1995.
89 Wonderware, 2004.

Table 2-11: Measures that may improve the efficiency of coal-fired power plants[90]

Action*	Efficiency Improvement (%)
Restore Plant to Design Conditions	
Minimize boiler tramp air	0.42
Reinstate any feedheaters out of service	0.46 – 1.97
Refurbish feedheaters	0.84
Reduce steam leaks	1.1
Reduce turbine gland leakage	0.84
Changes to Operational Settings	
Low excess air operation	1.22
Improved combustion control	0.84
Retrofit Improvements	
Extra airheater surface in the boiler	2.1
Install new high efficiency turbine blades	0.98
Install variable speed drives**	1.97
Install on-line condenser cleaning system	0.84
Install new cooling tower film pack**	1.97
Install intermittent energisation to ESPs	0.32

* Note that the efficiency improvements expected as a result of these actions may not be additive and the feasibility and improvements associated with each action may vary based on plant configuration.
** The expected efficiency improvements associated with these actions may be overestimated.

Optimization of maintenance in general is very plant- and utility-specific. Efficiency gains can be achieved, and costs avoided, depending on conditions prior to improvements. Maintenance agreements and technical and software services from external companies come at a price, which a utility would have to weigh against potential efficiency and production gains, avoided fuel use and avoided maintenance costs.

90 Perrin Quarles Associates, 2001.

Plant Retrofit

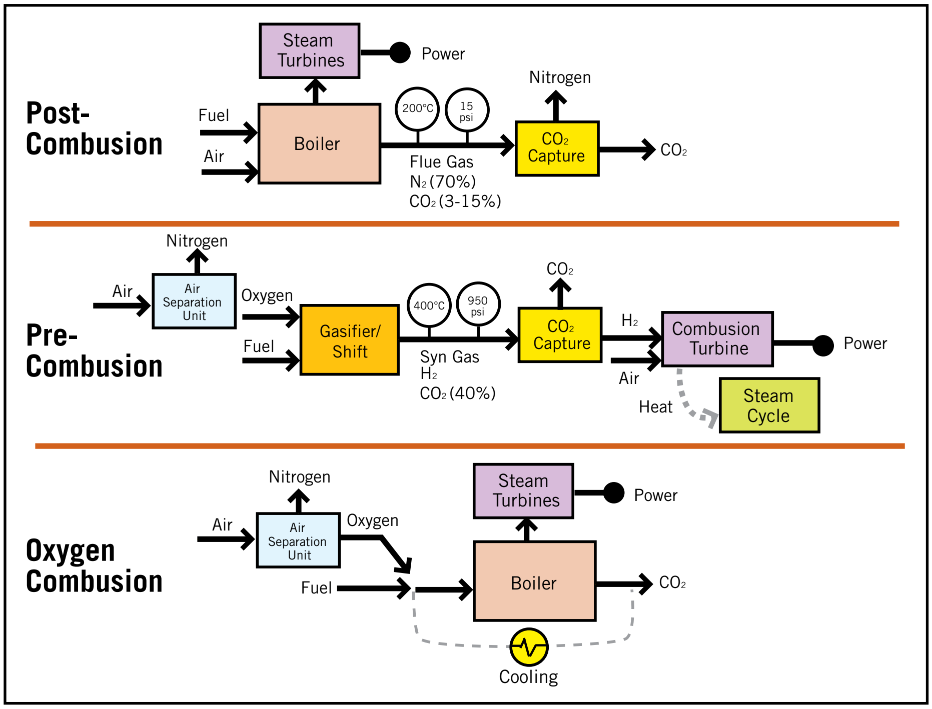
Beyond improving maintenance and monitoring systems, utilities can also achieve efficiency gains by retrofitting existing plants with updated technologies. Retrofitting does not usually change the fundamental systems of the plant; it adds equipment and process steps. As with repowering, retrofitting can be done at lower cost and less time than building a new plant. Most retrofit technologies, because they require electricity to operate or they increase the complexity of the fuel combustion process in boilers (in an effort to capture pollutants), reduce plant performance and increase fuel use and resulting emissions. In addition, retrofit projects can either trigger or be triggered by the EPA's New Source Review policy, which requires updated permitting and adds to delays and costs. Common retrofit technologies are SOx-reducing scrubbers, NOx-reducing selective catalytic reduction (SCR) equipment and updated plant control systems. Retrofit technology research and development focuses on coal-fired power plants and four primary regulated pollutants—NOx, SOx, particulate matter and mercury. CO_2 is also entering the mix as a focus of retrofit technology.

CO_2 RETROFIT TECHNOLOGY

If CO_2 that is normally released to the atmosphere can be removed, purified and compressed, it can be transported and potentially stored. This process is referred to as carbon capture and storage (CCS). Carbon capture requires technologically advanced scrubbers, membranes and compressors, and it can be either pre- or post-combustion or oxyfuel, in which fuel is burned with oxygen.[91],[92],[93] Figure 2-1 presents primary processes for CO_2 capture.

91 Dalton, 2004.
92 Gibbins & Crane, 2004.
93 Heddle et al., 2003.

Figure 2-1: CO_2 capture processes[94]



Coal combustion results in effluent flue gas containing 10 percent to 15 percent CO_2 by volume.[95] Postcombustion methods for carbon capture use a solvent, typically monoethanolamine, to remove the CO_2 from flue gas. Research is under way to develop alternative solvents, sorbents and membranes.[96]

Precombustion CO_2 removal is usually done by mixing coal with steam and air or oxygen to make a syngas of CO and hydrogen. The CO and hydrogen then react with steam again to make CO_2 and more hydrogen. Integrated gasification combined cycle coupled with carbon capture is the most promising precombustion method for removing CO_2 from flue gas. The CO_2 from the syngas produced during IGCC can be separated using absorption or membrane methods.[97]

Oxyfuel combustion systems burn fuel with oxygen to produce steam to run a turbine. The exhaust produced is a combination of water vapor and CO_2, which can then be removed.

PLANT IMPACTS

Because carbon capture adds to the normal power generation process, it requires additional power from the generating plant. Plants with CCS consume 15 percent to 60 percent more energy, with the upper bound for a pulverized coal plant retrofitting with CCS technology.[98] CCS facilities use more fuel and generate more CO_2 emissions; however, if the CO_2 is captured and stored, significantly less is emitted to the atmosphere.[99] CO_2 removal retrofit technologies can remove 80 percent or more of plant CO_2 emissions.

94 U.S. Department of Energy, 2006a.
95 U.S. Department of Energy, 2006b.
96 U.S. Department of Energy, 2006a.
97 Newell & Anderson, 2004.
98 Greenglass, 2006.
99 See "Options for Carbon Sequestration" section for more information on IGCC, CCS and geologic sequestration.

The cost of CO_2 retrofit technology is very site-specific, depending on other pollutant control systems that are already in place (e.g. SO_2 scrubbers, selective catalytic reduction), space available to install new equipment and the original type of plant being retrofitted. Cost estimates range from $30 to $60 per ton of CO_2 avoided.[100],[101],[102] CO_2 capture has been successfully used at industrial plants, such as ammonia production plants and coal- and natural gas-fired power plants, to obtain smaller commercially useful amounts of CO_2.[103] It has not yet been applied to large power plants to capture significant amounts of CO_2 emissions.

REGULATION

Clean Air Act and New Source Review

The EPA's Clean Air Act of 1970 established air quality standards for several pollutants (SO_2, NOx and particulate matter) that all electric utilities must meet. The New Source Performance Standards (NSPS) program created technology-based emission standards for both new facilities and existing facilities undergoing "major modification," which would result in increased capacity or extended plant life. In other words, existing plants had less stringent emissions limits, unless they underwent "major modifications" that modernized the plant; then they would be considered similar to a new plant with stricter emissions limits. In addition, NSPS ensures that plants that have increased emissions as a result of "major modifications" install pollution control equipment to reduce emissions at least to where they were before the modifications. The EPA's New Source Review requires stationary pollution sources to get construction permits specifying the facilities to be built, emissions limits and operation guidelines. The standards require that permitted construction use "best available control technology" for pollution reduction. Some power plant retrofit technologies can be significant enough to trigger New Source Review of the plant. The problem with New Source Review, as it applies to power plant retrofits, is what falls under the category of "major modification." If New Source Review permitting is required on a retrofit project, the process will add time and cost, potentially changing the economics of the project.[104]

100 Simbeck, 2001.
101 Singh et al., 2003.
102 Coal21, 2006.
103 Intergovernmental Panel on Climate Change, 2005.
104 For more information, see U.S. EPA's NSR website: http://www.epa.gov/nsr/

NEW TECHNOLOGIES

Outside of improving performance of the existing fleet of fossil fuel plants, electric utilities such as Duke Energy have a portfolio of GHG mitigation options available. New fossil fuel technologies represent one suite of options. These technologies include supercritical and ultra-supercritical pulverized coal, integrated gasification combined cycle, natural gas combined cycle, fuel cell and natural gas turbine applications. Expanded nuclear generation capacity is a second option for GHG mitigation. Although no nuclear plants have been ordered and constructed in the United States since 1973, anticipation of national climate policy has led to the renewed consideration of nuclear power. A third set of GHG mitigation options includes expanded use of renewable energy resources. Potential renewable energy resources include wind, solar, hydropower, geothermal, ocean, wave, tidal, and biomass and landfill gas.

Choosing among advanced generation technologies will depend on a number of factors, including cost, performance, reliability and fuel source availability. Accordingly, the section below provides a review of current technology and performance, fuel supply, research and development, and future potential, as well as an introduction to the current challenges and barriers facing each technology.

Fossil Fuel Combustion: Pulverized Coal

Humans have used coal as a source of energy for heating, cooking and metal work since antiquity. Use beyond local or domestic needs did not begin until the 18th century with the development of the steam engine by James Watt in 1769. In the United States, the first commercial coal mines sprouted in the late 1740s. Coal use to generate electricity became possible in 1884 when British engineer Charles A. Parson developed a more efficient high-speed steam turbine. Pulverized coal firing technologies were developed in the 1920s. According to the Energy Information Administration, coal consumption in the United States reached an all time high in 2005 at 1,128.3 million short tons.

TECHNICAL OVERVIEW

Pulverized coal units operate by blowing grounded bituminous coal and combustion air (sometimes secondary and tertiary air is added) into a boiler plant through a series of nozzles. The pulverized coal is a fine powder with less than 2 percent content at +300 µm and 70 percent to 75 percent content below 75 µm. This content is needed so that complete combustion can occur within the two to five seconds of particle residence time. Depending on coal rank, combustion takes place at temperatures from 1,300 to 1,700 degrees C and at near-atmospheric pressures. PC is appropriate for most coal types, except for high-ash-content coals.[105]

HISTORIC IMPROVEMENTS AND KEY DRIVERS

Today, technologies to burn coal are well developed. Worldwide, coal-fired production accounts for roughly 38 percent of total electricity production.[106] Pulverized combustion technologies are the most widely used and proven method, accounting for over 90 percent of coal-fired capacity.[105] In the United States, there are 1,338 PC units in operation.[107] As of June 2006, 143 projects have been proposed, accounting for 82,213 MW. Of these projects, 64 percent are PC plants, 18 percent IGCC, 15 percent fluidized bed and 3 percent other.[108] The Energy Information Administration estimates that by 2025, coal generation demand will be between 87,000 and 112,000 MW.[109]

The principal developments involve: [110]

- Increasing plant thermal efficiencies by raising the steam pressure and temperature used at the boiler outlet/steam turbine inlet.
- Ensuring that units can load follow satisfactorily.
- Ensuring that flue gas cleaning units can meet emissions limits and environmental requirements.

105 IEA Clean Coal Centre, 2006.
106 International Energy Agency, 2003.
107 Hewson, 2006.
108 Ibid.
109 Energy Information Administration, 2006a.
110 IEA Clean Coal Centre, 2006.

CURRENT BEST AVAILABLE TECHNOLOGY

Subcritical PC plants are the current best available technology for pulverized fuel combustion technologies. At the subcritical level, steam conditions approximate to 2,400 pounds per square inch gauge with temperatures around 1,000 degrees F using single-reheat steam turbines. Total plant costs can range from $1,230 to $1,378 per KW, and efficiencies range from 34 percent to 36 percent HHV (Table 2-12 and Table 2-13). [111,112]

Costs

Table 2-12: EPRI cost estimates for subcritical pulverized coal[113,114]

	Pittsburgh #8*	Illinois #6**
Total Plant Cost, $/kW	1,230	1290
Total Capital Requirement, $/kW	1,430	
Fixed O&M, $/kW-yr	40.5	
Variable O&M, $/MWh	1.7	
Levelized Fuel Cost, $/MBtu	1.5	1
Levelized COE, $/MWh***	46.3****	44.70*****

*Pittsburgh #8 Bituminous -- HHV =13,260 Btu/lb (30.84 MJ/kg), Ash=7.1%, Sulfur=2.1%
**Illinois #6 Bituminous -- HHV=10,982 Btu/lb (25.54 MJ/kg), Ash=11%, Sulfur=3.3%
***Based on 2003 US$, union wage rates, EPRI TAG methodology, 20-year book life, 80% avg. annual capacity
****($25 capital, $7 O&M, $14 Fuel)
*****($26 capital, $9 O&M, $10 Fuel)

Table 2-13: EPA cost estimates for subcritical pulverized coal[115]

Cost estimates for Subcritical PC*			
Coal type	Bituminous	Subbituminous	Lignite
Total Plant Investment $/kW	1,303	1,343	1,378
Total Capital Requirement $/ kW	1,347	1,387	1,424
Annual Operating Cost ($1,000s)	27,700	28,300	29,640

* All costs are based on 4th Quarter 2004 dollars.

Performance

Heat rate: 34 percent to 36 percent HHV (at 2,400 psig and 35 percent efficiency – 9,751 Btu/kWh) (Table 2-14).[116] Overall thermal efficiencies for older, smaller and poor-quality coal plants can be 30 percent or lower. The capacity factor is 80 percent.[117]

111 Dalton, 2004.
112 U.S. Environmental Protection Agency, 2006b.
113 Dalton, 2004.
114 Booras & Holt, 2004.
115 U.S. Environmental Protection Agency, 2006b.
116 Hewson, 2006.
117 Ibid.

Table 2-14: EPA performance estimates for subcritical pulverized coal[118]

1Performance for Subcritical PC*			
Coal types	Bituminous	Subbituminous	Lignite
Net Thermal Efficiency, % (HHV)	35.9	34.8	33.1
Net Heat Rate, Btu/kWh (HHV)	9,500	9,800	10,300
Gross Power, MW	540	541	544
Internal Power, MW	40	41	44
Fuel Required, lb/h	407,143	556,818	815,906
Net Power, MW	500	500	500

* Numbers based on generation method using boiler and steam turbine cycle. Particulate emissions controlled using fabric filter baghouse. NO_x emissions limited with combustion controls & SCR. SO_2 controlled by wet limestone flue gas desulfurization for bituminous and lignite coals, and lime spray dryer desulfurization followed by fabric filter baghouse and production of solid waste containing SO_2 reaction products and ash for subbituminous coal.

Increasing thermal efficiency could result in higher capital costs with the addition of other design factors. More efficiency does mean that less fuel is needed per unit of electricity produced, so fuel should decrease and emissions reduced from using less coal. Some ways to increase efficiency mentioned in the literature include:[119],[120]

- Higher steam and temperature conditions.
- Double reheat.
- Reduced water and steam system pressure drops.
- Enhanced levels of feed heating.
- Improved turbine performance.
- Reduced auxiliary power.
- Make-up water usage.
- Reducing the excess air ratio.
- Reducing the stack gas exit temperature.
- Decreasing the condenser pressure.

Types and Typical Size

The typical range for PC plants is 500-1,000 MWe.[121] PC plants have been built with outputs between 50 and 1,300 MWe. Economies of scale take effect at 250 to 300 MWe.

Emission Rates

Table 2-15 provides an overview of EPA's estimates of the environmental impact of subcritical pulverized coal.

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118 U.S. Environmental Protection Agency, 2006b.
119 Coal Industry Advisory Board, 1996.
120 IEA Clean Coal Centre, 2006.
121 Coal Industry Advisory Board, 1996.

Table 2-15: EPA estimates of environmental impact of subcritical pulverized coal[122]

	2Environmental Impact (lb/MWh) for Subcritical PC		
Coal type	**Bituminous**	**Subbituminous**	**Lignite**
NO_x (NO_2)	0.528	0.543	0.568
SO_2	0.757	0.589	0.814
CO	0.88	0.906	0.947
Particulate Matter[1]	0.106	0.109	0.114
Volatile Organic Compounds (VOC)	0.021	0.025	0.026
Solid Waste[3]	176	73	331
Raw Water Use	9,260	9,520	9,960
SO_2 Removal Basis, %	98	87[4]	95.84
NO_x Removal Basis[2] (lb/MMBtu)	0.06	0.06	0.06

NOTE: 1. Particulate removal is 99.9% or greater for the IGCC cases and 99.8% for bituminous coal, 99.7% for subbituminous, and 99.9% for lignite for the PC cases. Particulate matter emission rates shown include the overall filterable particulate matter only. 2. A percent removal for NOx cannot be calculated without a basis, i.e. an uncontrolled unit, for the comparison. Also, the PC and IGCC technologies use multiple technologies (e.g., combustion controls, SCR). The NOx emission comparisons are based on emission levels expressed in ppmvd at15% oxygen for IGCC and lb/MMBtu for PC cases. 3. Solid Waste includes slag (not the sulfur product) from the gasifier and coal ash plus the gypsum or lime wastes from the PC system. 4. A relatively low SO_2 removal efficiency of 87% represents low subbituminous coal sulfur content of only 0.22%. Higher removal efficiencies are possible with increased coal sulfur content.

ADVANCED NEAR-TERM TECHNOLOGY

Near-term technologies focus mainly on developing retrofit environmental control technologies. Key areas of research include cost-effective controls of mercury, nitrogen oxides, sulfur dioxide and fine particulate emissions; beneficial uses for coal utilization byproducts; and innovations to minimize the impact of fossil fuel use on water resources.[123]

Supercritical pulverized coal combustion (SPCC) and ultra-supercritical pulverized coal combustion (USPCC) are the near- to mid-term advanced technologies to replace conventional PC power plants. As of 2004, 117 SPCC plants are in operation in the United States.[107] Although there is no commercial experience with USPCC plants in the United States, such plants are operating in Europe and Japan. In the United States, "the technology is considered unproven with potential technical and economic risks," according to an EPA report.[124]

SUPERCRITICAL PULVERIZED COAL

Technical Overview

Supercritical refers to steam condition of 3,500 psig and temperatures up to 1,050 degrees F, both higher than subcritical PC.

Costs

Table 2-16 and Table 2-17 provide cost estimates for supercritical pulverized coal.

122 Ibid.

123 National Energy Technology Laboratory, 2006a.

124 U.S. Environmental Protection Agency, 2006b.

Table 2-16: EPRI cost estimates for supercritical pulverized coal[125],[126]

	Pittsburgh #8*	Illinois #6**
Total Plant Cost, $/kW	1,290	1,340
Total Capital Requirement, $/kW	1,490	
Fixed O&M, $/kW-yr	41.1	
Variable O&M, $/MWh	1.6	
Levelized Fuel Cost, $/MBtu	1.5	
Levelized COE, $/MWh***	46.6****	44.9*****

*Pittsburgh #8 Bituminous -- HHV =13,260 Btu/lb (30.84 MJ/kg), Ash=7.1%, Sulfur=2.1%
**Illinois #6 Bituminous -- HHV=10,982 Btu/lb (25.54 MJ/kg), Ash=11%, Sulfur=3.3%
***Based on 2003 US$, union wage rates, EPRI TAG methodology, 20-year book life, 80% avg. annual capacity
****($25 capital, $7 O&M, $14 Fuel)
*****($26 capital, $9 O&M, $10 Fuel)

Table 2-17: EPA cost estimates for supercritical pulverized coal[127]

Coal type	Bituminous	Subbituminous	Lignite
Total Plant Cost $/ kW	1,261	1,299	1,333
Total Plant Investment $/kW	1,384	1,426	1,463
Total Capital Requirement $/ kW	1,431	1,473	1,511
Annual Operating Cost ($1,000s)	29,000	29,600	30,940

* All costs are based on 4th Quarter 2004 dollars.

Performance

Heat rate: Table 2-18 provides performance estimates for supercritical pulverized coal. Efficiencies range from 36 percent to 42 percent HHV. This range can be further split into supercritical and advanced supercritical. In general, supercritical results in a net energy efficiency of 37 percent and a heat rate HHV of 9,300 Btu/kWh. Advanced supercritical refers to steam conditions of approximately 4,710 psig, and it results in a net energy efficiency of 42 percent and a heat rate HHV of 8,126 Btu/kWh.[107]

125 Dalton, 2004.
126 Booras & Holt, 2004.
127 U.S. Environmental Protection Agency, 2006b.

Table 2-18: EPA performance estimates for supercritical pulverized coal[128]

	Performance for Supercritical PC*		
Coal types	Bituminous	Subbituminous	Lignite
Net Thermal Efficiency, % (HHV)	38.3	37.9	35.9
Net Heat Rate, Btu/kWh (HHV)	8,900	9,000	9,500
Gross Power, MW	540	541	544
Internal Power, MW	40	41	44
Fuel Required, lb/h	381,418	517,045	752,535
Net Power, MW	500	500	500

* Numbers based on generation method using boiler and steam turbine cycle. Particulate emissions controlled using fabric filter baghouse. NO_x emissions limited with combustion controls & SCR. SO_2 controlled by wet limestone flue gas desulfurization for bituminous and lignite coals, and lime spray dryer desulfurization followed by fabric filter baghouse and production of solid waste containing SO_2 reaction products and ash for subbituminous coal.

Emission Rates

Table 2-19 provides estimates of environmental impact for supercritical pulverized coal.

Table 2-19: EPA estimates of environmental impact for supercritical pulverized coal[129]

	Environmental Impact (lb/MWh) for Supercritical PC	
Coal type	Bituminous	Subbituminous
NO_x (NO_2)	0.494	0.5
SO_2	0.709	0.541
CO	0.824	0.832
Particulate Matter[1]	0.099	0.1
Volatile Organic Compounds (VOC)	0.02	0.023
Solid Waste[3]	165	67
Raw Water Use	8,640	8,830
SO_2 Removal Basis, %	98	874
NO_x Removal Basis[2] (lb/MMBtu)	0.06	0.06

NOTE: 1. Particulate removal is 99.9% or greater for the IGCC cases and 99.8% for bituminous coal, 99.7% for subbituminous, and 99.9% for lignite for the PC cases. Particulate matter emission rates shown include the overall filterable particulate matter only. 2. A percent removal for NOx cannot be calculated without a basis, i.e. an uncontrolled unit, for the comparison. Also, the PC and IGCC technologies use multiple technologies (e.g., combustion controls, SCR). The NOx emission comparisons are based on emission levels expressed in ppmvd at15% oxygen for IGCC and lb/MMBtu for PC cases. 3. Solid Waste includes slag (not the sulfur product) from the gasifier and coal ash plus the gypsum or lime wastes from the PC system. 4. A relatively low SO_2 removal efficiency of 87% represents low subbituminous coal sulfur content of only 0.22%. Higher removal efficiencies are possible with increased coal sulfur content.

128 Ibid.
129 Ibid.

ULTRA-SUPERCRITICAL PULVERIZED COAL

Steam temperatures of 1,120 degrees F and pressures of 4,200 psig have been achieved in Europe and Japan. Within the next 10 to 15 years, units with steam pressures up to 1,400 degrees F and pressures up to 5,000 psig are expected to be demonstrated in the United States.[130]

Costs

Table 2-20 provides cost estimates for ultra-supercritical pulverized coal.

Table 2-20 : EPA cost estimates for ultra-supercritical pulverized coal[131]

Cost estimates for Ultra-supercritical PC*			
Coal type	Bituminous	Subbituminous	Lignite
Total Plant Cost $/ kW	1,355	1,395	1,432
Total Plant Investment $/kW	1,482	1,526	1,566
Total Capital Requirement $/ kW	1,529	1,575	1,617
Annual Operating Cost ($1,000s)	30,400	31,100	32,440

* All costs are based on 4th Quarter 2004 dollars.

Performance

Heat rate: Table 2-21 provides performance estimates for ultra-supercritical pulverized coal. Efficiencies are expected to range from 44 percent to 45 percent HHV. At 5,500 psig, with a net energy efficiency of 44 percent, the heat rate is 7,757 Btu/kWh.[132]

Table 2-21: EPA performance estimates for ultra-supercritical coal[133]

5Performance for Ultra-supercritical PC			
Coal types	Bituminous	Subbituminous	Lignite
Net Thermal Efficiency, % (HHV)	42.7	41.9	37.6
Net Heat Rate, Btu/kWh (HHV)	8,000	8,146	9,065
Gross Power, MW	543	543	546
Internal Power, MW	43	43	46
Fuel Required, lb/h	342,863	460,227	720,849
Net Power, MW	500	500	500

Numbers based on generation method using boiler and steam turbine cycle. Particulate emissions controlled using fabric filter baghouse. NO_x emissions limited with combustion controls & SCR. SO_2 controlled by wet limestone flue gas desulfurization for bituminous and lignite coals, and lime spray dryer desulfurization followed by fabric filter baghouse and production of solid waste containing SO_2 reaction products and ash for subbituminous coal.

Emission Rates

In general, ultra-supercritical plants are likely to reduce emission by 15 percent to 20 percent, compared with conventional coal plants (Table 2-22).[134]

130 Moore, 2005.
131 U.S. Environmental Protection Agency, 2006b.
132 Hewson, 2006.
133 U.S. Environmental Protection Agency, 2006b.
134 Ibid.

Table 2-22: EPA estimates of environmental impact for ultra-supercritical pulverized coal[135]

6Environmental Impact (lb/MWh) for Ultra-supercritical PC*			
Coal type	Bituminous	Subbituminous	Lignite
NO_x (NO_2)	0.442	0.45	0.498
SO_2	0.634	0.488	0.714
CO	0.737	0.75	0.83
Particulate Matter[1]	0.088	0.09	0.1
Volatile Organic Compounds (VOC)	0.018	0.02	0.022
Solid Waste[3]	155	60	291
Raw Water Use	7,730	7,870	8,710
SO_2 Removal Basis, %	98	874	95.84
NO_x Removal Basis[2] (lb/MMBtu)	0.06	0.06	0.06

* NOTE: 1. Particulate removal is 99.9% or greater for the IGCC cases and 99.8% for bituminous coal, 99.7% for subbituminous, and 99.9% for lignite for the PC cases. Particulate matter emission rates shown include the overall filterable particulate matter only. 2. A percent removal for NOx cannot be calculated without a basis, i.e. an uncontrolled unit, for the comparison. Also, the PC and IGCC technologies use multiple technologies (e.g., combustion controls, SCR). The NOx emission comparisons are based on emission levels expressed in ppmvd at15% oxygen for IGCC and lb/MMBtu for PC cases. 3. Solid Waste includes slag (not the sulfur product) from the gasifier and coal ash plus the gypsum or lime wastes from the PC system. 4. A relatively low SO_2 removal efficiency of 87% represents low subbituminous coal sulfur content of only 0.22%. Higher removal efficiencies are possible with increased coal sulfur content.

ADVANCED LONG-TERM TECHNOLOGIES

Under the DOE Advanced Systems program for Combustion Systems, development is under way on three major technologies: low emission boiler systems (LEBS), indirect fired cycles (IFC) and pressurized fluidized bed combustion (PFBC).[136] Other advanced central power generation technologies include integrated gasification combined cycle, turbines and combined cycles for application in central power generation.[137]

LOW EMISSION BOILER SYSTEMS

This advanced pulverized coal-fired system benefits from improved performance by integrating environmental controls and using supercritical steam. A 91 MWe proof-of-concept facility, designed by Babcock Borsig Power (formerly D.B. Riley), has been built in Elkhart, Illinois. The plant includes a supercritical steam cycle, a low-NOx, U-fired, slagging combustion system, and a moving-bed copper-oxide flue gas cleanup system for SO_2 and NOx control.[138] Design specifications include a plant thermal efficiency of 42 percent, steam pressures at 4,500 psig and a temperature of 1,100 degrees F, and two reheats, each at 1,100 degrees F. Advances in materials and boiler design are expected to improve the efficiency to 45 percent to 47 percent and increase temperatures to 1,300 to 1,500 degrees F. Test results suggest expected NOx emission levels below 0.2 lb/10^6 Btu and 96 percent to 99.8 percent of SO_2 removal. Total plant costs are estimated to be $137 million.[139]

INDIRECT FIRED CYCLES

IFC technologies are being developed from High Performance Power Systems (HIPPS). A HIPPS plant uses a combined cycle setup by integrating a combustion gas turbine with a heat recovery steam generator. An advanced coal-fired furnace helps transfer the heat of combustion to an air medium that separates combustion gasses. Using a coal pyrolysis system and a flue gas cleanup system, IFCs are able to be highly effective in controlling pollutant emissions. Projected efficiencies are targeted at 55 percent.[140]

135 Ibid.
136 Office of Fossil Energy, 2001.
137 Ibid.
138 National Energy Technology Laboratory, 2006b.
139 Ibid.
140 Office of Fossil Energy, 2001.

FLUIDIZED BED COMBUSTION

Fluidized bed combustion (FBC) technologies exist today at a commercial scale outside of the United States (over 1,000 MW installed in Sweden, Japan and Germany). There are two major types of fluidized bed combustion systems: atmospheric fluidized bed combustion (AFBC) and pressurized fluidized bed combustion (PFBC), with two subcategories, circulating and bubbling. Although AFBC has been commercially deployed, with $8 billion in sales,[141] PFBC will likely be the preferred design choice. According to the National Energy Technology Laboratory, there appears to be "no significant technical roadblocks to integrating carbon capture with oxygen-fired circulating fluidized-bed technology."[142]

FBC works at either atmospheric or pressurized levels to combust powdered coal with some type of sorbent, generally limestone. The sorbent is used to react and capture sulfur dioxide, thus achieving removal rates around 98 percent. Due to the success rate of removing sulphur dioxide, FBC is commonly used for high-sulphur coals. FBC plants burn at lower temperatures, and lower NOx emissions are released. Additionally, longer residence times of coal in the combustion chamber lead to higher efficiencies.[143]

Using a combined cycle approach, the combustion process generates a flue gas that is used to drive a gas turbine, and the exhaust is used to drive a steam turbine. Cyclone separators are used to remove particulate matter.[144] However, a new technology is being developed to integrate a coal pyrolysis unit (carbonizer) to produce a syngas for combustion in the gas turbine. [145]

Research for fluidized bed combustion is examining more efficient sorbents to reduce operating costs and CO_2 emissions; pursuing co-firing of carbon neutral fuels; and conducting systems studies on integrating supercritical steam and fuel cell cycles. [146]

RESEARCH & DEVELOPMENT

Success of PC coal-fired power generation relies on environmental performance and economics, an increase in thermal efficiency and a reduction of emissions. As a result, the National Energy Technology Laboratory has focused its R&D portfolio on developing near-zero-emissions coal technologies. Partnering with the private sector, NETL is working to maximize efficiency and environment performance while reducing driving down the cost for these new technologies. This boils down to eliminating pollutant emissions, managing carbon emissions and allowing coal-based technologies to be cost competitive.[147] According to the Department of Energy, future energy efficiency technology goals expect reduced emission levels and thermal efficiencies of 60 percent within the next 10 years (Table 2-23).

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141 Winfield et al., 2004.
142 National Energy Technology Laboratory, 2005.
143 Winfield et al., 2004.
144 Office of Fossil Energy, 2001.
145 Ibid.
146 Winfield et al., 2004.
147 National Energy Technology Laboratory, 2006a.

Table 2-23: Department of Energy technology goals for pulverized coal[148]

	Technology Goals in the Era of Efficiency				
	2000	2005	2010	2015	Vision 21
Electric Generation Efficiency	42–45%	48–55%	0.55	0.6	60%+
Total Thermal Efficiency	42–45%	48–55%	0.55	0.6	85%+
Pollutant Emissions*	1/3 NSPS	1/4 NSPS	1/10 NSPS	1/10NSPS	Zero
Reduction in CO_2 Emission	0.29	0.42	0.42	0.47	100% with sequestration
Reduction in Cost of Electricity	10–20%	10–20%	10–20%	10–20%	10–20%

* NSPS: New Source Performance Standards

In reference to pulverized coal generation, research is focused on the three categories: coal preparation, combustion and pollution control. "Materials" is a subcategory.

Preparation

Before coal can be combusted, the feedstock must be processed. Grinding, cleaning or altering the chemistry (such as with synthetic fuels) are all ways to help improve combustion. DOE's major focus is on improving and developing new technologies, such as coal cleaning, electrostatic precipitators, coal-water mixture technologies and coal briquetting technology.[149]

Combustion[150]

In general, technologies under development for future power plants include coal gasification, coal liquefaction, advanced turbines, distributed generation, pressurized fluidized bed combustion, atmospheric circulating fluidized bed combustion and fuel cells.[151]

Combustion Turbines

NETL research on coal-based turbine technology focuses largely on combined-cycle plants. In an effort to boost cycle efficiency, reduce capital cost and improve environmental performance, some of the studies involve combustion instability, fuel versatility, and fluid and particle dynamics.[152] NETL is currently working on improving barrier coatings for turbine blades and adjusting acoustic properties caused in low-emission operating conditions.[153]

Improvements in Sensor Technology

Improved sensor technology is needed to monitor combustion parameters to assure reliable performance, optimum plant efficiency and lower emissions. Understanding operating conditions can help prevent plant failures, lengthen the lifetime of power turbines and help reduce operating costs.[154]

148 Modified from Office of Fossil Energy, 2001.
149 National Energy Technology Laboratory, 2006a.
150 Ibid.
151 National Energy Technology Laboratory, 2006b.
152 National Energy Technology Laboratory, 2005.
153 Ibid.
154 Ibid.

Materials

Increases in steam pressures and temperatures require new material engineering to sustain performance, minimize corrosion and reduce costs and emissions.[155] NETL is managing a consortium called the Fossil Energy Materials Program that is evaluating and developing advanced materials for advanced steam cycles in coal-based power plants. The consortium includes ALSTOM Power, Babcock & Wilcox, Foster Wheeler and Riley Power, with support from the Energy Industries of Ohio, the Electric Power Research Institute and Oak Ridge National Laboratory.[156]

Pollution Control[157]

For pollution control, NETL is focusing on flue gas desulfurization (FGD), utilizing fly ash and coal refuse, and measures for industrial boilers and kilns (NOx reduction technologies as selective catalytic reduction and low NOx burners).

NETL also believes technologies for carbon capture and storage can be an economic and environmentally acceptable route to a low-carbon future and can enable coal to form the basis of a future hydrogen economy.[158]

Developmental Programs for Future Coal Generation

Clean Coal Demonstration Projects. This is a 10-year, $2 billion program in which the government provides up to 50 percent of the cost to demonstrate new and promising technologies.[159]

Clean Coal Technology demonstration program. This is a $5.2 billion government/industry partnership addressing environmental concerns associated with coal use. The program is involved in the Innovations for Existing Plants and Advanced Systems efforts under the Central Power Systems program. Currently, 38 projects are active, including 18 environmental control projects, one advanced electric power generation projects and nine coal processing projects.[160]

Power Plant Improvement Initiative. This initiative was established in October 2000 to further the commercial-scale demonstration of clean-coal technologies at existing and new electric generating facilities.[161]

FutureGen Industrial Alliance. Announced in February 2003, the Integrated Sequestration and Hydrogen Research Initiative will design, build and operate the world's first nearly zero-emissions coal-fired electric and hydrogen production plant.[162] The 275 MW (net equivalent output) prototype plant is estimated to cost $1 billion, and will be built using both public and private funds. Taking an estimated 10 years to complete, the plant will "establish the technical and economic feasibility of producing electricity and hydrogen from coal (the lowest cost and most abundant domestic energy resource), while capturing and sequestering the carbon dioxide generated in the process."[163] The plant will be based on coal gasification technology integrated with combined cycle

155 Ibid.
156 Ibid.
157 National Energy Technology Laboratory, 2006a.
158 Ibid.
159 Ibid.
160 Office of Fossil Energy, 2001.
161 National Energy Technology Laboratory, 2006a.
162 U.S. Department of Energy, 2003a.
163 U.S. Department of Energy, 2006e.

electricity generation and carbon sequestration.[164] FutureGen is a joint public-private venture that includes the Department of Energy, the FutureGen Industrial Alliance (which represents some of the world's largest coal companies and electric utilities), and a few foreign countries. Construction of the plant is expected to be completed by 2012, and the plant is expected to be in full operation by 2013.[165]

Vision 21 Program. This DOE program seeks to develop and implement new-generation technologies that expand fuel resources to wastes and renewables, provide high-value products, significantly improve efficiency, obtain near-zero emissions and facilitate CO_2 capture and sequestration.[166]

By 2015, the DOE expects electricity generation efficiencies of 60 percent for coal-based systems and 75 percent for natural gas-based systems; combined heat and power thermal efficiencies above 85 percent; near-zero emissions of sulfur and nitrogen oxides, particulate matter, trace elements, and organic compounds; 75 percent fuels utilization efficiency when producing fuels such as hydrogen or liquid transportation fuels alone from coal; and reductions in CO_2 emissions of 40 percent to 50 percent through efficiency improvements, with 100 percent reductions with sequestration.[167]

164 Ibid.
165 FutureGen Alliance, 2006.
166 Office of Fossil Energy, 2001.
167 Ibid.

Fossil Fuel Combustion: IGCC

Integrated gasification combined cycle offers a cleaner and more efficient technology option to use fossil fuels for electric power generation.[168] IGCC is a well-proven technology that, when coupled with carbon capture and storage, can reduce nearly 90 percent of CO_2 emissions into the atmosphere from coal combustion. IGCC with CCS may be a viable approach to fossil-fuel-based electricity in a carbon-constrained economy. IGCC converts fuel stock such as coal, petroleum coke, orimulsion, biomass or municipal waste to low heating value, high-hydrogen gas in a process called gasification. The gas is then used as the primary fuel for a gas turbine, which generates electric power. Heat generated during the process is also captured to power steam turbines, which in turn produce additional power.[169]

TECHNICAL OVERVIEW

IGCC consists of four basic steps:

1. Gasification
   Feedstock such as coal or petroleum coke is pulverized and fed into the gasifier (reactor) along with oxygen that is produced in an on-site air separation unit. The combination of heat, pressure and steam breaks down the feedstock and creates chemical reactions that produce hydrogen, carbon monoxide and synthesis gas (or syngas). Feedstock minerals become an inert, glassy slag product that can be used in road beds, landfill cover and other applications.

2. Syngas Cleanup
   Syngas must be purified before it can be used as a gas turbine fuel. Syngas purification results in high-pressure steam. This cleanup process removes sulphur compounds, mercury, ammonia, metals, alkalytes, ash and particulates to meet the turbine's fuel gas specifications. These compounds can, in turn, be used to manufacture commercial products such as elemental sulphur, methanol, ammonia, fertilizers and other chemicals. Hydrogen also can be separated and recovered at this point for further energy production.[170]

   As a result of this purification process, CO_2 is 80 percent to 90 percent concentrated (volume/volume) within the flue stream and can be vented to the atmosphere or sequestered (see "Geologic Sequestration" section below).[171]

3. Power Generation: Gas Turbine Combined Cycle
   Following purification, syngas flows to the gas turbine, where it is burned to drive the turbine and generate power. The nitrogen from the air separation unit is expanded through the turbine to increase power production and reduce NOx emissions. The steam from gasification is combined with steam produced in the gas turbine heat recovery unit and fed to a steam turbine-generator.

4. Cryogenic Air Separation
   A cryogenic air separation unit provides pure oxygen back into the gasification reactor.[172]

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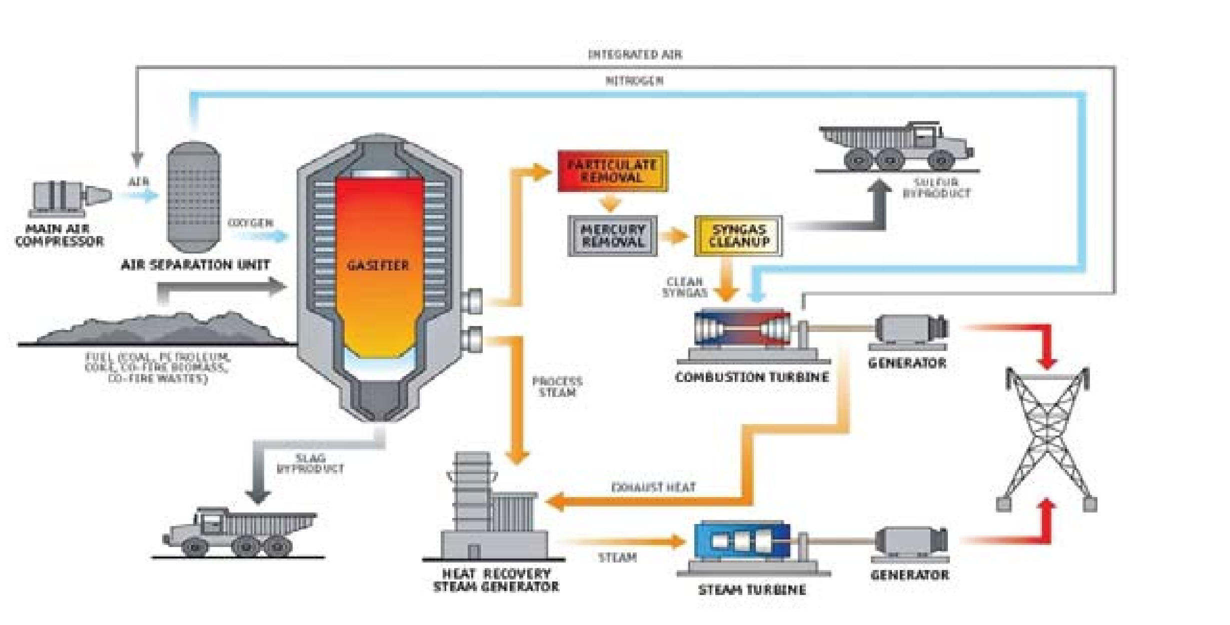
168 See *http://www.energy.gov/energysources/coal.htm* for more information
169 The Energy Blog, 2005.
170 Joshi & Lee, 1996.
171 GE Energy, 2006c.
172 Ibid.

Figure 2-2 summarizes the major components of the process:[173]

Figure 2-2: Simplified IGCC flow diagram



PLANT CONSIDERATIONS

The physical IGCC plant is comparable in size to a conventional coal-fired power plant; unlike a conventional coal plant, an IGCC plant does not require additional area for scrubber sludge treatment or ash dewatering. An IGCC plant's water consumption is approximately 30 percent lower than in a conventional coal plant. Also, lime or limestone is not required for desulphurization.[174]

In a IGCC plant, SO_x, NOx and particulate emissions are fractions of those produced by conventional pulverized coal boiler power plants. IGCC gas turbines do not require expensive back-end flue gas mercury removal systems. Activated carbon bed filters in syngas and recycled water streams remove 90 percent to 95 percent of the mercury, at a cost of $20 to $30 per kW installed.[175]

As mentioned in process step 2, above, IGCC plants enable carbon removal before combustion to create a hydrogen-rich fuel. In conventional boiler plants, carbon is removed from the exhaust gas after combustion, making the process less efficient and more expensive due to the larger gas volume from postcombustion cleanup. To remove CO_2, the syngas is combined with steam in a shift reactor to produce additional hydrogen and CO_2. This highly purified carbon dioxide (approximately 80 percent to 90 percent purity) can be captured and used for commercial applications or sequestered in a geologic reservoir to reduce the level of greenhouse emissions resulting from fossil fuel-based power generation. The remaining 10 percent to 20 percent of CO_2 is released to the atmosphere.

173 Pashos, 2006.
174 GE Energy, 2006c.
175 GE Energy, 2006b.

Costs

Because IGCC is such a new technology, the cost is not well established. Most analysts believe that the capital cost of IGCC, even without CCS, is slightly more than that of new pulverized coal technology. IGCC capital cost depends on a number of factors, including the technology vendor (and relationship between buyer and vendor), the type of coal, whether it is CCS-ready, and whether or not the plant will be co-located with another coal plant, repowered at an existing site or built on a greenfield site. Table 2-24 shows a range of cost estimates by various government agencies and institutions.

Table 2-24: Reported IGCC costs[176],[177]

	EPA		EIA - 2005		EIA nth-of-a-kind		DOE, EPRI Parsons		IEA - Shell		IEA - GE	
	IGCC	with CCS	IGCC	with CCS	IGCC	with CCS	IGCC	with CCS	IGCC	with CCS	IGCC	with CCS
Cost ($/Kw)	1670	2455	1443	2065	1251	1844	1251	1844	1371	1859	1187	1494
Fixed O&M	n/a	n/a	35.21	41.44	27.5	33	27.5	33	57.6	60.3	52.5	59.7
Var O&M	n/a	n/a	2.65	4.04	3	4	3	4	n/a	n/a	n/a	n/a
Heat rate	8167	9555	8309	9713	7200	7920	7915	9226	7916	9890	8979	10832

Generally speaking, most analysts assume that the capital cost of IGCC is about 15 percent greater than pulverized coal. After accounting for lower fuel costs from improved efficiency and lower criteria pollutant emissions (and less need for expensive allowances), the cost of IGCC compared to PC plants begins to even out. With a value for carbon, either under a cap-and-trade system or with a GHG tax, the total cost of IGCC begins to look favorable compared to pulverized coal. Higher monetary values of carbon can make carbon capture and storage in conjunction with IGCC economically competitive.

CURRENT STATUS

Several IGCC pilot and demonstration plants operate across the United States and abroad to convert synthetic gas to power (see Table 2-25). According to the Gasification Technologies Council, the largest percentage growth for using gasification technologies in 2005 occurred in the power-generation sector; the other sectors include chemicals, fuels and gas.[178] With four IGCC plants in operation today to convert synthetic gas to power, only one, the Polk County plant, is coal-fired.

176 U.S. Environmental Protection Agency, 2006b.
177 Energy Information Administration, 2006c.
178 Gasification Technologies Council, 2005b.

Table 2-25: Operating IGCC plants[179,180,181,182,183]

Project	Year On-Line	Net Output (MW)	Primary feedstock	Design efficiency	Capital cost
Polk County IGCC Project	1996	250	Coal	42%	$1650/KW $424 Million
Wabash River Energy Ltd	1995	260	Petcoke	38%	$1660/KW $430 Million
Delaware Clean Energy Cogeneration Project	2002	160	Fluid petcoke	No data	$380 Million
El Dorado Gasification Power Plant	1996	35	Petcoke, natural gas, refinery waste	No data	$2150/kW $80 Million
ISAB Energy (Italy)	1999	512	Asphalt		$1200 Million
Falconara Marittima (Italy)	2000	550	Heavy oil	38%	$1530/KW $444 Million
Elcogas Puertollano (Spain)		335	High ash coal, petroleum coke	47%	$894 Million
Nippon Oil Negishi (Japan)	2003	342	Asphalt residue	39%	$1,000/kW
William Alexander Plant (Netherlands)	1994	253	Bit. coal	43%	

Operating IGCC Plants: Syngas for Power

Polk County IGCC Project

Tampa Electric Company (TECO) runs the Polk County IGCC Project in Mulberry, Fl.; the plant produces syngas for power. Construction began on the 250 MWe net plant in 1994, and the plant became operational in October 1996. An additional operating unit was installed in 1998, and a spare unit was installed in 1999. Using GE Gasification technologies, coal is used as the primary feedstock. Approximately 2,200 metric tons per day of coal is used to produce 451.10 MWt of syngas output that produces roughly 250 MWe net (enough for 75,000 homes).[184] To produce the power, the plant uses two GE 7FA gas turbines, each with 192 MW output.[185] The plant is able to capture and remove 96 percent of sulfur[186] and 90 percent of nitrogen[187] that would otherwise be released to the atmosphere. The oxygen-blown, wet-feed-entrained flow process has a design efficiency of 41.7 percent.[188] The total capital cost was $424 million, or $1,650/kW.[189] Including site acquisition and development, construction management, start up, operator training, project management, permitting and preliminary

179 The Energy Blog, 2005.
180 Gasification Technologies Council, 2005a.
181 Smith, 2003.
182 CRE Group Ltd, 1999.
183 Schimmoller, 2005.
184 Gasification Technologies Council, 2005a.
185 Ibid.
186 CRE Group Ltd., 1999.
187 Gasification Technologies Council, 2005a.
188 CRE Group Ltd., 1999.
189 Smith, 2003.

engineering and coal truck loading facility construction, the total cost was $2,430/kW.[190] Capital costs were partially offset with a $120 million award from the Department of Energy.[191]

Wabash River Energy Ltd.

Global Energy Inc. operates the Wabash River Energy Ltd. Plant in West Terre Haute, Ind. Operating since December 1995, the 262 MWe net plant is a single-train facility that uses the ConocoPhillips E-GAS (Destec/Dow) Gasification Process to produce syngas for power. Two gasifiers are present at the facility, one in operation and one as a spare. Fueled by petcoke, 2,000 mt/d are used to produce a syngas output of 590.60 MWt.[192] The GE 7FA gas turbine has 192 MW output.[193] The oxygen-blown, wet-feed-entrained flow process has a design efficiency of 38 percent.[194] Capital costs exceeded $430 million, which equates to $1,660 KWe.[195] (The facility operated from December 1995 to January 2000 as the Wabash River Coal Gasification Repowering Project, a joint venture between Dynegy Power and PSI Energy, with support from the Department of Energy.)[196]

Delaware Clean Energy Cogeneration Project

Premcor Inc. operates the Delaware Clean Energy Cogeneration Project in Delaware City, Del. Started in 2002, the plant has two operating gasifiers that produce 160 MW net of electricity. Fluid petcoke is used as the feedstock at a rate of 2,100 mt/d. Syngas output is 519.50 MWt. The two GE 6 FA gas turbines produce 180 MW output.[197]

El Dorado Gasification Power Plant

Frontier Oil and Refining Co. has been operating the El Dorado Gasification Power Plant in El Dorado, Kansas, since September 1996. Using GE Gasification Technology, the commercial refinery facility generates 35 MW of power. Feedstocks used are petcoke (150.6 mt/d), refinery waste (13.6 mt/d) and natural gas (7,000 MMBtu/d). Syngas output is 11 MWt.[198]

Pinon Pine Power Project

The Pinon Pine Power Project was funded by the Sierra Pacific Power Company and the Department of Energy, at a total cost of $336 million.[199] Located near Reno, Nevada, a Kellogg/Rust/Westinghouse (KRW) gasifier was used in association with a GE Frame 6FA combustion turbine to achieve a design efficiency of 43 percent.[200] Expected to use 880.6 tons of coal per day and produce 104 MW of electricity, the plant never operated in a steady-state.[201] WPS Power Development Inc. purchased the plant from Sierra Pacific Power Company in 2000.

Developmental Phase IGCC Plants: Syngas to Power

As of May 2006, 17 plants have been proposed in the United States to create power from synthetic gas (Table

190 Ibid.
191 Ibid.
192 CRE Group Ltd., 1999.
193 Gasification Technologies Council, 2005a.
194 CRE Group Ltd., 1999.
195 Ibid.
196 Gasification Technologies Council, 2005a.
197 Ibid.
198 Ibid.
199 National Energy Technology Laboratory, 2003.
200 CRE Group Ltd., 1999.
201 National Energy Technology Laboratory, 2003.

2-26). According to the Gasification Technologies Council, however, only three plants (the Lima Energy IGCC Plant, the Mesaba Energy Project and the Southern Illinois Clean Energy Center) are registered as developmental plants to produce syngas to power.[202]

Table 2-26: IGCC under development in the United States[203]

Sponsor	State	Size (MW)	Start up	Estimated total plant cost (millions)	Fuel Type	DOE Clean Coal Power Initiative Funding
Orlando Utilities Comm.	FL	285	2010	$750	Bit. Coal	$235 million
Southeast Idaho Energy	ID	520	2010	$850	Bit. Coal	
Clean Coal Power Resources	IL	2,400	TBD	$2,800	Pet coke	
Madison Power Corp.	IL	545	TBD	$2,000	Bit. Coal	
Erora Group	IL	677	TBD	$700	Bit. Coal	
Steelhead Energy Co.	IL	545	TBD	$600		
Cinergy	IN	600	TBD	$900	Bit. Coal	
Tondu Corp	IN	640	TBD	$1,000	Bit. Coal	
Global - Kentucky Pioneer	KY	540	TBD	$520	Coal, refuse derived fuel	
Synfuel	OK	600	2004	$600		
Excelsior Energy, Mesaba Energy Project	MN	531	2011	$1,200	Bit. Coal	$36 Million
American Electric Power	OH	600	2010	$1,288	Coal, some pet coke	
Global Energy	OH	580	2007	$575	Bit. Coal	
DKRW	WY	350	2008	$2,500	Bit. Coal	
Waste Management and Processors Inc. (WMPI)	PA	41	2008	$612	Bit. Coal	$100 million
FirstEnergy/Consol	OH or PA	TBD	TBD	TBD		
Energy Northwest	WA	600	2011	$950		

Mesaba Energy Project

Excelsior Energy is in the developmental stage of the Mesaba Energy Project in Minnesota. A gasification plant to produce syngas for power, Mesaba will use the ConocoPhillips E-GAS (Destec/Dow) Gasification Process. The plant will have two operating gasifiers and one spare. Using coal as the feedstock at a rate of 5,000 t/d, electricity production is valued at 530 MW net. [204] Operation is expected to begin in 2011. The DOE has provided $36 million for the project.[205]

Southern Illinois Clean Energy Center

Madison Power Corp. is in the development stages of putting a syngas for power gasification plant in Williamson County, Ill., in 2010. The facility's name will be Steelhead Energy. Using the E-GAS (Destec/Dow) Gasification Process, two gasifiers will be used. Coal will be the feedstock with a rate of 10,000 t/d. The facility will produce 545 MW of power.[206] A $2.5 million grant has been awarded by the Illinois Clean Coal Review Board for the initial phase of detailed engineering design.[207]

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202 Gasification Technologies Council, 2005a.
203 Modified from Falsetti, 2006.
204 Gasification Technologies Council, 2005a.
205 Jorgensen, 2005.
206 Gasification Technologies Council, 2005a.
207 ArcLight Capital Partners LLC, 2004.

Lima Energy IGCC Plant

Global Energy Inc. is in the developmental stages of the Lima Energy IGCC Plant in Lima, Ohio. Using the E-Gas (Destec/Dow) Gasification Process, a single gasifier is expected to produce 1,005.7 MWt of syngas output. The power plant will be a 530 MW plant using feedstocks of coal and municipal solid wastes.[208]

American Electric Power

AEP signed with GE Energy and Bechtel in September 2005 to begin engineering and designing an approximate 600 MWe gasification plant.[209] Two plants are projected to be built, one in Meigs County, Ohio, and one most likely in West Virginia. In Ohio, AEP expects to obtain permits, finalize engineering and begin construction by 2007, and expects the plant to be operational by 2010.[210] The company intends to build the West Virginia plant to serve its eastern operating area by 2013.[211]

Duke Energy

Cinergy/PSI (now Duke Energy) signed an agreement with GE Energy and Bechtel in March 2006 to begin front-end engineering design of an approximate 600 MWe IGCC plant. Estimated to cost $900 million,[212] the plant location will most likely be at the Edwardsport coal-fired generating station near Vincennes, Indiana. Vectren Energy Delivery of Indiana is also participating in the preliminary work.

RESEARCH & DEVELOPMENT

The Department of Energy's research on IGCC focuses on reducing emissions and capital costs and on improving operating efficiencies, both in process and turbine technology.

In the early 1990s, turbine systems had efficiencies of approximately 50 percent. As of 2006, systems typically operate in the 57 percent to 58 percent efficiency range. Turbines with 60 percent efficiency ratings are planned for future IGCC plants, such as the Mesaba project in Minnesota, due on-line in 2011 (Table 2).

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208 Gasification Technologies Council, 2005a.
209 American Electric Power, 2005.
210 American Electric Power, 2006b.
211 American Electric Power, 2005.
212 LCG Consulting, 2005.

Other areas of DOE research include:

- New, lower-cost configuration gasifiers;
- New energy efficient technologies for oxygen separation;
- New, inexpensive membranes that can selectively remove hydrogen from syngas, making it available as a fuel for future fuel cells or refineries;
- Fuel cell or fuel cell-gas turbine hybrids with higher operating efficiencies.

CHALLENGES OF IGCC

Integrated gasification combined cycle is not a large-scale, commercially developed technology. Under some favorable conditions, IGCC could mature to meet baseload demand. Several conditions may help advance the deployment of IGCC. First and foremost, legislation covering a number of pollutants and establishing a carbon constraint is paramount.[213] Under a carbon constraint, IGCC technologies become more economical than PC plants to reduce carbon, NOx, SOx and mercury pollutants. Second, the recent volatility and high prices of natural gas have led many analysts to question its role as a low-cost energy source.[214] Despite low capital costs, high natural gas prices offset initial expenditures. Known abundances of coal and relatively low prices will help balance the risk of constructing IGCC plants. Third, significant technology progression of gasification and turbine technologies will favor IGCC deployment.[215] And fourth, public opinion is increasingly worried about the United States' reliance on foreign sources of energy and the effect humans have on the environment.[216] IGCC technologies can help alleviate these concerns by increasing U.S. reliance on domestic sources of energy and burning coal more cleanly. With 200 to 300 years worth of coal reserves, this resource is more likely, at least in the near- and medium term, to meet baseload demand instead of intermittent renewable energy sources.

IGCC still has some challenges to overcome before much confidence is placed in this technology.

Achieving Cost Reductions

IGCC ranges from 10 percent to 20 percent more expensive in terms of capital costs than conventional PC plants. One reason for this premium involves economies of scales.[217] None of the IGCC plants in operation today are at the size needed by utility companies to meet baseload demand. Since a 500 to 600 MW plant has not been built, cost estimates are based on smaller plants. Learning lessons from the first generation of IGCC plants and making significant investments in value engineering will help improve and mature IGCC technology. Additionally, when factoring in the long-term environmental benefits from fewer emissions and potential sequestration, the benefits are expected to outweigh the costs, especially under a carbon price.[218]

213 Schimmoller, 2005.
214 Ibid.
215 Ibid.
216 Ibid.
217 Ibid.
218 Ibid.

Improving Availability/Reliability and Establishing Performance Guarantees

Poor plant availability has created uncertainty about reliance on an immature technology for baseload capacity. Plants with spare gasifiers have operated at above 95 percent capacity, but plants without backup have experienced poor availability.[219] Although spare gasifiers are beneficial, they are not a long-term solution to the engineering problems; furthermore, spare gasifiers increase capital costs. Lack of performance guarantees (either for the gasifier or final cost) from technology providers is the most significant problem with building an IGCC plant today.[220] Plants must be able to meet design specifications continually without complications to build confidence in using IGCC. Vendors are now guaranteeing gasifier performance with eastern coal, but not with western coal. Field demonstration of large-capacity gasifiers and carbon capture and storage technologies is needed. Since current demonstration plants "do not have the reliability needed to be competitive with other existing coal technology" and utilities are hesitant to take the risk to finance such plants,[221] some experts believe that IGCC technologies will not be competitive with PC plants until FutureGen proves successful.[222]

Federal Funding for IGCC

In an effort to address some of the challenges outlined above, Congress included a number of incentives for IGCC in the Energy Policy Act of 2005 (EPAct 2005). EPAct 2005 offers a 20 percent investment tax credit for the gasification portion of an IGCC plant, which amounts to a 14 percent overall credit for the entire project. EPAct 2005 provides a limit of $800 million in tax credits, implying support for approximately six IGCC plants.[223] This funding will likely be highly competitive.

219 O'Brien et al., 2004.
220 Ibid.7
221 Ibid.
222 Schimmoller, 2005.
223 Wilson, 2005.

Fossil: Natural Gas Combined Cycle

TECHNICAL OVERVIEW

The natural gas combined cycle design is the most efficient commercial technology for central station power-only generation.[224] An NGCC plant uses gas turbine generators with heat recovery steam generators (HRSG) to capture heat from turbine exhaust to generate steam to power steam turbine generators, thus producing additional electric power. Using this configuration helps improve efficiencies over simple and single-cycle gas turbines. "FA-class" combustion turbines are the most common technology for large, single-train combined cycle plants (one gas turbine generator, a HRSG and a steam turbine generator). These plants can produce about 270 MW of capacity. Conventional plants can convert about 50 percent of the chemical energy of natural gas into electricity on a HHV basis.[225] Variations in efficiency is a function of altitude (cycle efficiency decreases by 0.3 percent for every 100 feet in elevation above sea level), ambient temperatures and age.[226] When technologies are added to capture, transport and store carbon emissions, NGCC power plants have high incremental capital cost and high energy requirements (0.354 kWh/kg of CO_2 processed). This is a result of low CO_2 concentrations (around 3 percent) in the flue gas.[227]

HISTORIC IMPROVEMENTS AND KEY DRIVERS

Prior to the 1990s, gas turbines were used primarily for peaking capacity or industrial usage.[228] During the 1990s, combined cycle gas turbines became the choice for bulk power generation as a result of power companies' needs to address load growth, enter new markets and replace retiring plants.[229] Other benefits include high thermal efficiencies, low initial costs, high reliability, relatively low gas prices and low air emissions.[230] At low and constant fuel prices, natural gas generally is more competitive than coal for both reference (NGCC only) and capture (NGCC with CCS) plants. The rise and volatility of gas prices, however, is bringing IGCC capture plants into competition with NGCC capture plants.[231] The key drivers of using NGCC versus coal-fired systems include differences in efficiencies, the availability and price of natural gas, and current and future environmental regulations.[232]

CURRENT BEST AVAILABLE TECHNOLOGY

Costs

Table 2-27 and Table 2-28 indicate cost estimates for NGCC and cost of carbon capture from NGCC.

224 Energy and Enivronmental Analysis Inc & Exergy Partners Corp., 2004.
225 Northwest Power Planning Council, 2002.
226 Burke & Statnick, 1997.
227 David & Herzog, 2000.
228 Electric Power Research Institute, 2006a.
229 Ibid.
230 Northwest Power Planning Council, 2002.
231 David & Herzog, 2000.
232 Burke & Statnick, 1997.

Table 2-27: Cost estimates for NGCC[233]

Total Plant Cost	440
Total Capital Requirement, $/kW	475
Fixed O&M, $/kW-yr	5.1
Variable O&M, $/MWh	2.1
Ave. Heat Rate, Btu/kWh (HHV)	7,200
Capacity Factor, %	80/40
Levelized Fuel Cost, $/MBtu	5
Levelized COE, $/MWh (2003$)	47.3/56.5

Table 2-28: Cost of carbon capture from NGCC[234]

Cost Model for Capture Plants, in 2000 and 2012		
Cycle	**NGCC**	**NGCC**
Data Description	**2000**	**2012**
Input		
Capital Cost, $/kW	542	525
O&M, mills/kWh	2.5	2.4
Heat Rate (LHV), Btu/kWh	6,201	5,677
Incremental Capital Cost, $/(kg/h)	921	829
Incremental O&M, mills/kg	5.2	4.68
Energy Requirements, kWh/kg	0.354	0.297
Basis		
Yearly Operating Hours, hrs/yr	6,570	6,570
Capital Charge Rate, %/yr	15	15
Fuel Cost (LHV), $/MMBtu	2.93	2.93
Capture Efficiency, %	90	90
Reference Plant		
CO_2 Emitted, kg/kWh	0.368	0.337
coe: CAPITAL, mills/kWh	12.4	12
coe: FUEL, mills/KWh	18.2	16.6
coe: O&M, mills/kWh	2.5	2.4
Cost of Electricity, ¢/kWh	3.3	3.1
Thermal Efficiency)LHV), %	55	60.1
Capture Plant		
Relative Power Output, %	87	90
Heat Rate (LHV), Btu/kWh	7,131	6,308
Capital Cost, $/kW	1,013	894
CO_2 Emitted, kg/kWh	0.042	0.037
coe: CAPITAL, mills/kWh	23.1	20.4
coe: FUEL, mills/KWh	20.9	18.5
coe: O&M, mills/kWh	5.1	4.4
Cost of Electricity, ¢/kWh	4.91	4.33
Thermal Efficiency (LHV), %	47.8	54.1
Comparison		
Incremental coe, ¢/kWh	1.61	1.23
Energy Penalty, %	13	10
Mitigation Cost, Capture vs. Ref., $/tonne of CO_2 avoided.	49	41

233 Dalton, 2004.
234 David & Herzog, 2000.

Emission Rates

Emission rates are discussed below in the "Natural Gas Turbines" section.

RESEARCH & DEVELOPMENT

The design characteristics of NGCC technology have been well implemented. As a result, recent research and development has focused more on improving gas turbine materials and operating temperatures to increase efficiencies. See R&D Efforts in the "Natural Gas Turbines" section for more detail.

An increase in gas prices has led to more research focusing on IGCC and hydrogen technologies. At $2.50/Million Btu, NGCC was believed to have had a slight advantage over IGCC with coal at $1.50/Million Btu. At prices above $4.00/Million Btu, IGCC plants are believed to provide the lower cost of electricity.[235] With current natural gas prices ranging from approximately $6 to $8/Million Btu, NGCC does not look as promising. Additionally, precombustion removal of CO_2 from syngas is cheaper than the postcombustion CO_2 removal that is required for NGCC plants.

235 Future Options for Generation of Electricity from Coal, 2003.

Fossil Fuel Combustion: Fuel Cells

TECHNICAL OVERVIEW

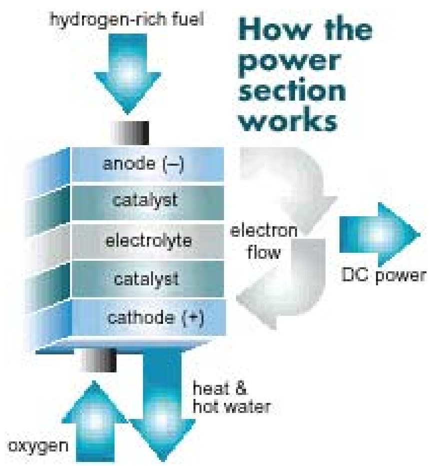
A fuel cell is an electrochemical conversion device that converts the chemical energy of a fuel into electricity and heat. Fuel cells are similar to batteries in that electrons flow between positive (cathode) and negative (anode) electrodes. Unlike batteries that have a stored amount of energy, fuel cells use a constantly flowing, easily oxidized fuel substance such as hydrogen. Compared to combustion technologies, fuel cells are more efficient, have no moving parts, have essentially no NOx emissions due to lower temperatures, have no sulfur emissions because a desulfurized fuel must be used and have byproducts of water and heat.[236]

As shown in Figure 2-10, the basic design of a fuel cell involves an anode, a cathode, a catalyst to speed up reactions and an electrolyte (a proton exchange membrane). The process works by feeding a hydrogen mix fuel into the anode and oxygen into the cathode. The anode and cathode are divided by an electrolyte that will allow only protons to flow through it. In the anode, a catalyst encourages the hydrogen atoms to split into protons and free electrons. The protons then travel through the electrolyte to combine with the oxygen and free electrons in the cathode. Since the electrons cannot pass through the electrolyte, they flow through a separate electrical circuit. A direct current is formed and a load is placed on the flowing electrons to be used for power generation. What electrons are not used travel back to the cathode to recombine with hydrogen and oxygen to form water molecules.[237] Fuel cells that use aqueous solutions or liquid electrolytes have a plate-like configuration (likely because liquids cannot hold form), but fuel cells that use solid electrolytes can have different configurations. Multiple fuel cells are combined into stacks to meet the desired electrical current and voltage required for application. To produce electricity, an entire fuel cell system is needed.

There are three basic components to a fuel cell system. The fuel processor combines gas with system generated steam to produce a hydrogen-rich fuel; the power section combines the fuel mix with oxygen to produce electricity; and the power conditioner converts the direct current power to alternating current.[238]

236 Siemens AG, 2006.
237 American Gas Foundation, 2000.
238 Ibid.

Figure 2--3: Fuel cell chemistry[239]



The basic chemical reaction is:

Anode side: $2H_2 \Rightarrow 4H^+ + 4e^-$

Cathode side: $O_2 + 4H^+ + 4e^- \Rightarrow 2H_2O$

Net reaction: $2H_2 + O_2 \Rightarrow 2H_2O$

CURRENT TECHNOLOGIES

Fuel cells are classified by the type of electrolyte used. The five most common types are polymer electrolyte membrane fuel cells (PEMs), alkaline fuel cells (AFC), phosphoric acid fuel cells (PAFC), molten carbonate fuel cells (MCFC) and solid oxide fuel cells (SOFC).

Polymer Electrolyte Membrane Fuel Cells

PEMs, also known as proton exchange membrane fuel cells, are generally lower in weight and smaller in volume than other fuel cells, and thus they typically have a high power density. They operate at relatively low temperatures, around 176 degrees F (80 degrees C), which requires less warm-up time and results in better durability because there is less wear on system components. Only pure hydrogen, oxygen and water are needed to operate the fuel cell. The design components include a solid polymer as the electrolyte, carbon electrodes and a platinum catalyst. An additional reactor is needed to reduce CO in the fuel gas because the platinum catalyst is sensitive to CO poisoning (it binds with the platinum and reduces efficiencies). Due to their fast start up time, low sensitivity to orientation and favorable power-to-weight ratio, PEMs are used primarily for transportation applications and some stationary applications in residential or small commercial buildings.[240] Fuel cell systems range in size from 1 kW to 250 kW.[241]

Alkaline Fuel Cells

One of the first fuel cell technologies developed, AFCs were developed in the 1960s to be used in the U.S. space program. Most of these fuel cells operate at temperatures between 212 and 482 degrees F (100 and 250 degrees C); newer designs, though, operate at lower temperatures of roughly 74 to 158 degrees F (23 to 70 degrees C).[242] Due to the rate at which chemical reactions occur in the fuel cells, AFCs have proven efficiencies near 60 percent in space applications. The design components include an aqueous solution of potassium hydroxide as the electrolyte and a variety of nonprecious metals for catalysts in the anode and cathode. The disadvantages of AFCs include their extreme susceptibility to carbon dioxide poisoning, required purification of both hydrogen

239 Ibid.
240 Office of Energy Efficiency and Renewable Energy, 2006h.
241 IdaTech LLC, 2006.
242 Ibid.

and oxygen to eliminate carbon dioxide, the potential cell poisoning and poor operating flexibility (shown to maintain operations for over 8,000 hours; must exceed 40,000 hours to be economically viable). Currently the technology is not cost-effective, a major barrier to AFC commercialization.[243]

Phosphoric Acid Fuel Cells

The most commercially developed of all fuel cells, PAFCs are typically large, heavy and less powerful than other fuel cells, and they operate at higher temperatures (requiring longer start up times). The design components include a liquid phosphoric acid as an electrolyte (contained in a Teflon-bonded silicon carbide matrix), porous carbon electrodes and a platinum catalyst. PAFCs are expensive, with typical costs between $4,000 and $4,500 per kilowatt. PAFCs can achieve up to 85 percent efficiencies when used for cogeneration. When used only for electricity production, efficiencies range from 37 percent to 42 percent. This type of fuel cell is typically used for mid-size (approximately 200 kW) stationary power generation in building such as hospitals, nursing homes, hotels, offices, schools and, in one instance, an airport terminal), but they also may be used in larger vehicles such as buses and locomotives.[244]

Molten Carbonate Fuel Cells

MCFCs are high-temperature fuel cells that operate at extremely high temperatures of 1,200 degrees F (650 degrees C). The high-temperatures allow for steam generation from byproduct heat. The design components include a molten carbonate salt mixture (lithium, sodium and/or potassium) suspended in a porous, chemically inert ceramic lithium aluminum oxide ($LiAlO_2$) matrix and a nonprecious metal for the catalysts.[245] Efficiencies range from 60 percent to 85 percent, depending on whether waste heat is captured and used. Since MCFCs operate at higher temperatures—fuels are converted to hydrogen through a process called internal reforming, thus eliminating the need for an external reformer and reducing costs—they are not prone to carbon monoxide or carbon dioxide poisoning. This advantage may also mean that dirtier fuels with sulfur and particulates might be used. Durability of the fuel cells is the major disadvantage. The higher temperatures and corrosive nature of the electrolyte used result in component breakdown and corrosion. Best suited for large stationary power generators (as baseload capacity), MCFCs are being developed for natural gas- and coal-based power plants.[246]

Solid Oxide Fuel Cells

Best suited for large-scale stationary power generation, SOFCs operate at high temperatures around 1,830 degrees F (1,000 degrees C). When converting fuel to electricity, SOFCs are expected to achieve around 50 percent to 60 percent efficiencies; when used for cogeneration, overall fuel use efficiencies could reach 80 percent to 85 percent. The design components include hard, nonporous ceramic compounds for the electrolyte and nonprecious metals for the catalysts. Unlike other fuel cells, the solid electrolyte allows for SOFCs to deviate from the typical plate-like configuration (tubular configuration is being designed by Siemens). The high temperature operation eliminates the need for a precious-metal catalyst and an external reformer (because internal combustion produces hydrogen) and enables the use of a variety of fuels (such as propane and natural gas), all thereby reducing cost. Some disadvantages to the high temperature operation include slow start up, stringent durability requirements on materials and need for thermal shielding. Reducing costs for materials with high durability is the key challenge facing SOFC commercialization. There are efforts to develop lower-temperature (at or below 800°C) SOFCs.[247] Size ranges from 25 kW to 100 kW. [248]

243 Nice, 2006.
244 Nice, 2006.
245 Nice, 2006.
246 Ibid.
247 Nice, 2006.
248 IdaTech LLC, 2006.

An overview of various fuel cell technologies can be found in Table 2-29. Companies currently working to develop fuel cells for building applications can be found in Table 2-30.

Table 2-29: Comparison of fuel cell technologies[249]

Fuel Cell Type	Common Electrolyte	Operating Temperature	System Output	Efficiency	Applications	Advantages	Disadvantages
Polymer Electrolyte Membrane (PEM)*	Solid organic polymer poly-perfluorosulfonic acid	50 - 100°C	<1kW-250 kW	50-60% electric	•Back-up power •Portable power •DG •Transportation	•Solid Electrolyte reduces corrosion & maintenance problems •Low temperature •Quick start up	•Requires expensive catalysts •High sensitivity to fuel impurities •Low temp waste heat
Alkaline (AFC)	Aqueous solution of potassium hydroxide	90 - 100°C	10kW-250kw	60-70% electric	•Military •Space	Cathode reaction faster; high performance	Expensive removal of CO_2 from fuel & air streams required
Phosphoric Acid (PAFC)	Liquid phosphoric acid	150 - 200°C	50kw-1MW (250kW typical)	80-85% overall with CHP; 36 - 42% electric only	Distributed generation	•High efficiency •Increased tolerance to impurities in hydrogen •Suitable for CHP	•Requires platinum catalysts •Low current & power •Large size/weight
Molten Carbonate (MCFC)	Liquid solution of lithium, sodium, and/or potassium carbonates	600 - 700°C	<1kW-1MW (250kW typical)	85% overall with CHP (60% elec-tric)	•Electric utility •Large DG	•High efficiency •Fuel flexibility •Can use variety of catalysts •Suitable for CHP	•High temperature speeds breakdown •Complex electrolyte management •Slow start
Solid Oxide (SOFC)	Solid zirconium oxide	650 - 1000°C	5kW - 3MW	85% overall with CHP (60% electricity)	•Auxiliary power •Electric Utility • Large DG	•High efficiency •Fuel flexibility •Catalyst flexibility •Fewer electrolyte issues •Suitable for CHP	•High temperature speeds breakdown •Slow start

*Direct Methanol Fuel Cells (DMFC) are a subset of PEM typically used for small portable power applications with a size range of about a subwatt to 100W and operating at 60 - 90°C

249 Office of Energy Efficiency and Renewable Energy, 2006a.

Table 2-30: Companies developing fuel cells for building applications[250]

Fuel Cell Type	Fuel Type	Application	Company
PEM	Natural Gas	Residential	Teledyne
PEM	Multi-fuel	Commercial Residential Transportation	Plug Power, LLC
PEM	Multi-fuel	Light Commercial Residential Emergency Back-up Portable (using their fuel flexible reformer system)	IdaTech
PEM	Multi-fuel	Light Commercial (up to 50kW) Residential	Nuvera Fuel Cells
PEM	Hydrogen	Modular	ReliOn (formerly Avista Labs)
PAFC	Natural Gas	Commercial Institutional (Only commercially available building-scale fuel cell)	UTC Fuel Cells
MCFC	Natural Gas	Commercial	Fuel Cell Energy
SOFC	Natural Gas	Commercial Industrial	Siemens Westinghouse—Power Generation
AFC	Natural Gas	Light Commercial Residential	Apollo Energy Systems
SOFC	Natural Gas	Commercial	Ceramic Fuel Cells Limited
SOFC	Multi-fuel	Residential Light Commercial	Fuel Cell Technologies LTD
PEM	Hydrogen	Light Commercial	General Motors
SOFC	Multi-fuel	Commercial Industrial	ZTEK Corporation

FUEL PROCESSING FOR FUEL CELLS

Hydrogen is the typical fuel used in fuel cells. Although hydrogen can be produced from renewables, reforming is the most likely option for supplying hydrogen in the foreseeable future.

To obtain hydrogen, the element must be reformed from various fuel sources. The major potential sources mentioned in the literature include natural gas, gasoline, propane, diesel, ethanol, methanol, landfill gas, biogas, methane and water (using electrolysis, solar or wind power). A reformer can be internal or external. Internal reformers have advantages of using dirtier fuels and achieving higher efficiency, all while simplifying the process. Externally, the reforming process involves catalytically reacting vaporized feedstocks with water vapor to produce hydrogen and carbon oxides (this process is often referred to as steam reforming). Hydrogen separated from gaseous hydrocarbons (natural gas and propane) must be desulfurized before entering the fuel cell. Hydrogen gas must be further purified to remove impurities from the product stream through a series of membranes and catalytic beds before fueling the fuel cell. Rejected carbon oxides, hydrogen and unconverted feedstocks are fed into the combustor to provide heat for the reforming process.[251]

250 Walsh & Wichert, 2006.
251 IdaTech LLC, 2006.

BENEFITS OF FUEL CELLS

The benefits of fuel cells include:

- Clean.
- Most efficient technology to generate electricity from fossil fuels.
- Lack of combustion results is much less production of pollutants and byproducts of electricity (water and heat).
- Flexibility; cells can be stacked to the obtain the level of power needed.

MAJOR BARRIERS

The major barriers to wider adoption of fuel cells include:

- Technology affordability (cost-effective).
- Reliability.
- Cost-effective fuel infrastructure needed.

Costs

Fuel cells today range in price from $3,000 to $4,000 per kW. In order to be competitive with conventional technologies, the price would need to drop between $1,000 and $2,500 per kW installed. Some of the factors involved in the life-cycle cost include the relative price of electricity and the fuel used, the value of waste heat generated, maintenance costs, the anticipated life of the fuel cell, cost savings due to reliability gains, and avoided transmission and distribution system costs.[252] Reliability also is an important variable in certain niche applications, such as on-site power for computer systems handling credit card or other financial transactions; a single power outage in these critical applications can cost considerably more than the cost of installing and operating fuel cells.

ADVANCED LONG-TERM TECHNOLOGY

Direct Methanol Fuel Cells

Direct methanol fuel cells (DMFC) are similar to PEM cells in that they use a polymer membrane as the electrolyte, but DMFCs differ in that there is no need for a fuel reformer because the anode catalyst draws the hydrogen directly from liquid methanol. These cells generally operate between temperatures of 120 to 190 degrees F, achieving efficiencies in the range of 35 percent to 40 percent. A low-range technology, these cells will likely be used for mid-sized applications such as use in cellular phones, laptops or powering military electronic equipment in the field.[253]

252 Walsh & Wichert, 2006.

253 American Gas Foundation, 2000.

Regenerative Fuel Cells

Currently being researched by NASA, regenerative fuel cell (RFC) technology is a closed-loop form of power generation that uses a solar-powered electrolyser to separate water into hydrogen and oxygen (the separation is known as electrolysis). Hydrogen and oxygen are fed into the fuel cell and the water byproduct is recirculated back to the electrolyser.[254]

Zinc-Air Fuel Cells

Zinc-air fuel cells (ZAFCs) are being commercialized by Powerzinc, a company located in southern California. The typical design components include a zinc/air fuel cell, a gas diffusion electrode (permeable membrane that allows atmospheric oxygen to pass through it), a zinc anode separated by electrolyte and some form of mechanical separators. This process shares some characteristics with batteries in which electricity is generated as zinc and oxygen mix to create zinc oxide. Once the fuel is used up, the stored energy can be added to the grid. This concept is a "reversing" process in that once electricity is put into the grid, recharging takes only about five minutes. ZAFCs are closed-loop systems that have low material costs due to the abundance of zinc. Due to their high specific energy, ZAFCs are used to power electric vehicles, consumer electronics and military needs.[255]

Protonic Ceramic Fuel Cells

Primarily researched by CoorsTek, protonic ceramic fuel cells (PCFCs) combine the high temperatures (up to 700 degrees C) with proton conduction by using a ceramic electrolyte. This type of fuel cell does not use a reforming process and the electrolyte cannot dry out or leak (as might occur with PEMs or PAFCs).[256]

RESEARCH AND DEVELOPMENT

The Department of Energy's Office of Fossil Energy is partnering with private-sector fuel cell developers through the Stationary Power Fuel Cell Program. The funding ratio of the program, which focuses primarily on central power and distributed generation, is roughly 60/40 government/industry. The aim is to develop a much lower cost fuel cell, as cost is the major barrier for their widespread use. The target is $400 per kilowatt. Currently, fuel cell costs per kilowatt range between $4,000 and $4,500.[257]

Solid State Energy Conversion Alliance

Formed by the DOE, the Solid State Energy Conversion Alliance (SECA) has the goal of producing a solid-state fuel cell module with costs less than $400/kW, which would make the cells cost-competitive with gas turbines and diesel generators. The key to cost reduction is mass production. To build a standard model of three to 10 kilowatts, clusters of stacks could be used for central- or distributed generation or auxiliary systems. Administered by National Energy Technology Laboratory and the Pacific Northwest National Laboratory, SECA comprises various stakeholders, including fuel cell developers, small businesses, universities and national laboratories. Major industrial leaders include FuelCell Energy, Delphi, General Electric, Siemens Power Generation, Acumentrics and Cummins Power Generation.[258]

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254 Ibid.
255 Breakthrough Technologies Institute, 2006.
256 Ibid.
257 Office of Fossil Energy, 2006a.
258 Ibid.

SECA directs much of its attention to coal-based fuel cell systems. Most commonly referenced as a hybrid system, this process combines fuel cells with gas turbines. Small-scale demonstrations have been effective in determining the benefits and feasibility of these systems. Commercialization scale (greater than 100 MW) facilities will not be demonstrated until the FutureGen project is complete. Cost-effectiveness of fuel cells and scalability are two obstacles that large plants must overcome to be economical.[259]

High Temperature Electrochemistry Center Advanced Research Program

Based at the Pacific Northwest National Laboratory, the High Temperature Electrochemistry Center (HiTEC) Advanced Research Program provides multidisciplinary research support for SECA, FutureGen and coal-based fuel cell systems. HiTEC focuses on coal-based power production systems that incorporate SOFC technology. The aim is to achieve higher efficiencies and lower emissions over conventional plants and to exploit the potentials of energy storage with high temperature electrochemical systems.[260]

259 Ibid.
260 Ibid.

Fossil Fuel Combustion: Natural Gas Turbines

TECHNICAL OVERVIEW

Natural gas turbines use a thermodynamic cycle, known as the Brayton cycle, in which atmospheric air is compressed, heated and then expanded to be used for power generation.[261] Only about one-third of the shaft power produced in a combustion engine is used for electrical power; the rest is used to run the compressor.[262] Gas turbine configurations can be used for simple cycle operation in which a single gas turbine is used solely to produce power; combined heat and power operation in which a heat exchanger is added to a simple cycle gas turbine to form steam or hot water; or combined cycle operation in which additional power is created from high pressure steam generated from recovered exhaust heat.[263]

The main design sections of a simple cycle gas turbine include the air intake, compression, combustion, turbine, exhaust and exhaust diffuser sections. The cycle begins with a compressor reducing the volume of space occupied by atmospheric air. A gaseous or liquid fuel is injected and combusted in the combustor, thus increasing the volume of air as it expands. This expansion flows through the turbine to produce electricity. When released as exhaust, the volume of air decreases (and thus temperature decreases) as heat is absorbed into the atmosphere. Plants without thermal requirements, such as single or simple cycle systems used for peaking, vent exhausts directly into the atmosphere. Since these plants focus on electrical power, recuperators (and/or larger size turbines) are often used to maximize efficiencies. Recovering exhaust heat, however, helps improve efficiency. Higher electrical efficiencies result in lower amounts of available thermal energy in the exhaust.[264] A duct burner is sometimes used to help boost the total available thermal energy in the exhaust. Located in the turbine exhaust stream, the boosted exhaust is directed into a waste heat boiler called a heat recovery steam generator (HRSG), which uses the heat to re-create steam. Additional electricity is produced from the steam in a combined cycle configuration.[265]

Three additions to improve overall efficiencies include regeneration, intercooling and reheating:

Regeneration

Regeneration involves the installation of a heat exchanger through which the turbine exhaust gases pass. The compressed air is then reheated in an exhaust gas heat exchanger before entering the combustor. Adding regenerators to the simple cycle can improve efficiency by 5 percent to 6 percent. Efficiency gains are achieved by effectively recuperating heat and minimizing pressure drops. Although regenerators have relatively high costs, they still may be cost-effective.[266]

Intercooling

Intercooling uses a heat exchanger to cool compressor gasses during the compression process. If an intercooler is used between a low pressure and high pressure compressor, efficiency gains can be made by decreasing the work necessary for compression in the high-pressure compressor. Atmospheric air or water is often used as the cooling fluid.[267]

261 Energy and Environmental Analysis Inc & Exergy Partners Corp, 2004.
262 Fegan, 2002.
263 Energy and Environmental Analysis Inc & Exergy Partners Corp, 2004.
264 Ibid.
265 Ibid.
266 Ibid.
267 Ibid.

Reheating

In reheating, a second combustor is used between a high-pressure and low-pressure turbine. As air passes through the high-pressure turbine, work is done so the temperature and pressure of the flow decreases. By adding another combustor, the flow can be reheated to recover more power from a low-pressure turbine. Doing so can increase efficiency by 1 percent to 3 percent.[268]

HISTORIC IMPROVEMENTS AND KEY DRIVERS

The history of combustion turbine advancement can be summed up as a general trend toward use of higher temperatures and pressures. Increasing the optimum pressure ratio results in higher efficiency and greater specific power. Although technological advancements to meet such goals have increased upfront costs, the additional output gains have led to net economic benefits.[269]

Combustion turbines typically are separated into two different categories based on size and usage: industrial usage and stationary power production. Industrial turbines were developed based on jet propulsion engine designs. Ranging in size from 500 kW to 40 MW for on-site power generation and for use as mechanical drivers, industrial and institutional usage began in the early 1980s. Gas turbines are popular in industry because they require little maintenance and the high-quality waste heat systems achieve efficiencies of 70 percent to 80 percent.[270]

For stationary power production, utilities have used larger-grade and microturbines primarily for peaking capacity. However, changes in the industry and advancements in technology have allowed gas turbine technologies to be used for baseload power generation.[271] Success of combustion turbines have resulted from their relatively low installation costs, low emissions, high heat recovery and infrequent maintenance requirements. Low electric efficiencies have been the major disadvantage.[272] This disadvantage can be lessened with cogeneration or combined cycle configurations.

CURRENT BEST AVAILABLE TECHNOLOGY

Efficiency

Efficiency and capacity vary according to inlet air temperature and local altitude and atmospheric conditions. A typical heat rate is around 11,000 Btu, with an efficiency of 31 percent. Smaller, single or simple-cycle turbines without recuperators achieve efficiencies around 25 percent, while larger turbines with recuperators achieve efficiencies around 40 percent. Though they may be larger, simple-cycle turbines with recuperators are smaller than combined cycle units with heat recovery steam generators. Combined thermal and electric efficiency turbine plants average in the 60 percent range. Using duct burners can increase overall system efficiencies to nearly 80 percent efficiency.[273]

268 Fegan, 2002.
269 Energy and Environmental Analysis Inc. & Exergy Partners Corp., 2004.
270 Ibid.
271 Ibid.
272 Fegan, 2002.
273 Ibid.

Emission Rates

Primary pollutants from natural gas turbines include nitrogen oxides, carbon monoxide and volatile organic compounds. Other pollutants of concern include sulfur oxides, particulate matter and carbon dioxide. Sulfur emissions and particulate matter are primarily of concern only when heavy oils are used instead of natural gas. Other emission levels are based on load conditions. Since gas turbines achieve maximum efficiency and optimum combustion at high loads (high temperatures), NOx emissions are higher. At lower temperatures, when incomplete combustion occurs, emissions of carbon monoxide and volatile organic compounds are more abundant.[274]

NOx emissions are of greatest concern for combustion turbines. Water injection to reduce combustion temperatures and selective catalytic reduction (SCR) are the most common methods to reduce NOx emissions.[275]

SCR works by injecting ammonia into the flue gas to produce N_2 and water. High-temperature SCR systems, operating in temperature ranges from 800 to 1,100 degrees F, are used on peaking capacity and base-loaded simple-cycle gas turbines where there is no heat recovery steam generator. This system is often located downstream of the turbine exhaust flange. Mid-temperature SCR systems are typically located in the HRSG and range in operating temperatures from 400 to 800 degree F. Low-temperature SCR systems, operating in the 300 to 400 degree F temperature range, are ideal for retrofit applications since they can be located downstream of the HRSG, avoiding costly retrofitting of the HRSG. Since SCRs are very expensive, they are not economically feasible for smaller gas turbines. However, significant cost reductions have come as a result of catalyst innovations that have reduced the volume of catalyst needed.[276]

RESEARCH & DEVELOPMENT

The Department of Energy has been conducting intensive R&D on gas turbines since 1992. These efforts have led to production of turbine systems that can operate at temperatures above 2,600 degrees F, achieve efficiencies in excess of 60 percent and limit nitrogen oxide emissions with new combustion techniques. The advancements resulted from changes in cooling technologies and advanced materials.[277]

Advanced R&D today is focused on developing integrated gasification combined cycle turbines that can burn coal-derived synthesis gas and hydrogen fuels cleanly and efficiently. The Clean Coal Technology Program has been successful in commercial deployment of coal-derived syngas at Tampa Electric's Polk Station and at the Wabash River Coal Gasification Repowering Project. More advanced, near-zero emission turbines will be deployed in FutureGen plants.[278]

274 Energy and Environmental Analysis Inc & Exergy Partners Corp., 2004.
275 Fegan, 2002.
276 Energy and Environmental Analysis Inc & Exergy Partners Corp., 2004.
277 Office of Fossil Energy, 2006b.
278 Ibid.

Nuclear Energy

In 1954, the chairman of the U.S. Atomic Energy Commission—forerunner of the U.S. Nuclear Regulatory Commission (NRC)—famously declared that nuclear power would be "too cheap to meter."[279] The commission also predicted that 1,000 nuclear plants would be operating in the United States by the year 2000.[280] Although existing nuclear plants have direct operating costs on the low end of the spectrum of generation (average, in 2005, of 1.72 cents per kWh, compared with 2.21 cents per kWh for coal[281]), the cost is clearly not too cheap to meter. As of 2004, only 104 commercial reactors were in operation.[282] A number of factors contributed to nuclear power's failing to live up to the early enthusiasm of its proponents, including an overestimate of the demand for electricity and corresponding need for 1,000 reactors, construction delays and cost overruns, and public opposition stemming from accidents at Three Mile Island and, later, at Chernobyl.

Although the first commercial nuclear power plant in the United States began operation in 1957, utilities did not build nuclear plants in earnest until the mid-1960s. New reactor construction starts continued until 1977 (the last reactor coming on-line, in 1996, began construction in 1972) See Figure 2-4 for more information.[283] Although the accident at Three Mile Island fueled public opposition to nuclear power that thwarted plans for a number of reactors in various stages of development (the last *successfully completed* order for a nuclear reactor came in 1973), the electricity industry was beginning to slow its investment in nuclear, as evidenced by the last order (not completed) for a nuclear reactor in 1978, a full year before Three Mile Island.

279 Wikipedia, 2006.

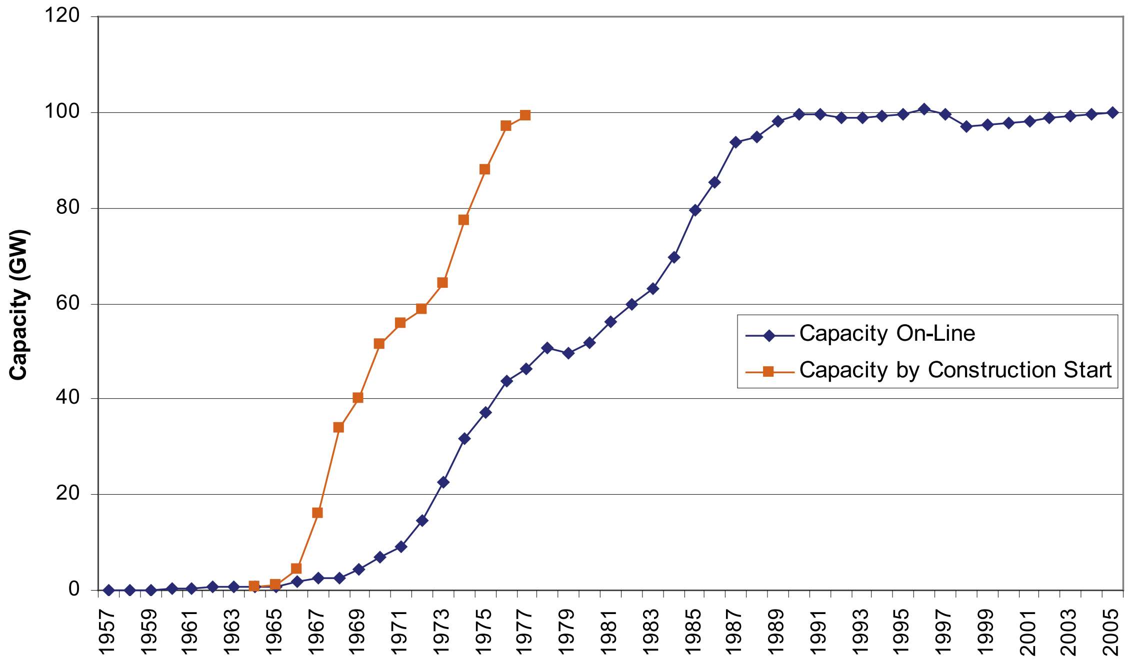
280 International Atomic Energy Agency, 2004.

281 Nuclear Energy Institute, 2006a.

282 Energy Information Administration, 2006f.

283 Energy Information Administration, 2004.

Figure 2-4: U.S. nuclear capacity by on-line year and construction start[284]



NOTE: 'Capacity by Construction Start' includes only plants still in operation at current capacities; 'Capacity On-Line' reflects all capacity, including retirements and uprates

Nuclear plants play a pivotal role in the current portfolio of generation resources, delivering 19.3 percent of U.S. net electricity generation in 2005 while comprising only 10.2 percent of total generating capacity. Utilities specializing in efficient operation of nuclear power plants have largely consolidated nuclear plant ownership, lowering costs and reducing outages.[285] The average capacity factor for the nuclear fleet has improved steadily, from 66 percent in 1990 to 89.4 percent in 2005.[286]

Nuclear power does not result in any direct GHG emissions and has among the lowest lifecycle GHG emissions of all electricity generating technologies.[287] For this reason, in expectation of national climate policy, the electricity industry is once again considering building new nuclear reactors.

CURRENT TECHNOLOGY

The next round of new U.S. nuclear plants will likely be based on three designs: Westinghouse's AP1000, GE's Advanced Boiling Water Reactor (ABWR), and GE's Economic and Simplified Boiling Water Reactor (ESBWR). Each of these designs is more technologically advanced than the reactors in U.S. plants operating today. The Nuclear Regulatory Commission has certified the AP1000 and ABWR designs, and the companies are now ready to build. NRC is reviewing the ESBWR design and is expected to certify it by late 2007, in time for Construction and Operating License submissions that would support the commercial operation of new ESBWRs by 2014 or 2015.

284 Ibid.

285 Gertner, 2006.

286 Energy Information Administration, 2006f.

287 UK Parliamentary Office of Science and Technology, 2006.

AP1000

The AP1000 is a pressurized water reactor (PWR) in which water, heated by nuclear energy, is kept at high pressure to prevent the water from boiling. The pressurized water transfers heat from the core to an exchanger. Steam is then generated in a secondary loop. The AP1000 is a Generation III+ design[288] with a 1,117 MW capacity, featuring "50 percent fewer valves, 83 percent less piping, 87 percent less control cable, 35 percent fewer pumps and 50 percent less seismic building volume than a similarly sized conventional plant."[289] The AP1000 design has larger safety margins and promises to be less operator-intensive, reducing the hundreds of control room knobs and buttons to a few computers and a large screen.[290] The design employs passive safety features, such as gravity, natural circulation, condensation and evaporation and stored energy, to maximize accident prevention. These features provide safety injection, residual heat removal and containment cooling.[291] No pumps, fans, diesels, chillers or other rotating machinery are needed in the passive safety subsystems. Simplifying the plant's systems allows for reduced construction and operation costs and increased safety.

Another cost-saving feature is that all AP1000s will be built uniformly and modularly, with many more of the components being constructed offsite and transported in. Previously, entire temporary industrial complexes were often built at each nuclear plant site.[292] Uniformity will also lower maintenance costs because spare parts can be manufactured and made available for any AP1000 reactor. In addition, modular construction will lower total project time to five years (36 months from "first concrete to fuel load").[293]

DOE estimates the cost at $1,365/kw for the first unit, assuming two units are built, in 2000 dollars (equivalent to $1,560/kw in 2006 dollars).[294] However, Westinghouse estimates the cost to range from $1,500 to $1,800/kw as of mid-2006.[295] Critics suggest that the costs are higher, citing as evidence the Tennessee Valley Authority's decision to refurbish a unit at its Brown's Ferry nuclear plant at a cost of $1,500/kw. If the cost of a new plant were in the $1,500/kw range, critics argue, TVA would have chosen to build a new plant rather than refurbish an existing one.[296] But other factors almost certainly influenced TVA's decision, such as public perception and potential opposition to a new plant, the effort and time to site and license a new plant, and economies of scale for maintenance and operation (TVA is refurbishing a dormant unit at an active plant).

GE's ABWR

GE's Economic and Simplified Boiling Water Reactor is a Generation III design with a capacity of 1,380 MW. In the reactor, water is used as both coolant and moderator. The water is allowed to boil in the core, and the resulting steam can be used directly to drive a turbine to generate electricity.

Four ABWR units are operating in Japan, three are under construction in Japan and Taiwan, and nine additional units are planned in Japan.[297] Like the AP1000, the ABWR design has fewer systems and greater operator margins, and provides benefits from streamlined maintenance. However, the ABWR still relies on active safety

288 All commercially operating nuclear plants in the United States are Generation II. Generation III is the next generation of nuclear plants. Generation III+ offers refinements over Generation III, such as passive safety and improved economics. Generation IV is the future generation of plants that will not be available at least until 2015 and perhaps not by 2030.
289 Westinghouse Electric Company, 2004.
290 Gertner, 2006.
291 U.S. Nuclear Regulatory Commission, 2004.
292 Ibid.
293 Matzie & Worrall, 2004.
294 Office of Nuclear Energy, 2001.
295 Uranium Information Centre, 2006b.
296 Gertner, 2006.
297 GE Energy, 2006a.

features. According to the DOE, ABWR costs $1,400/kw to $1,600/kw.[298] The first units built in Japan actually cost around $2,000/kw.[299] In anticipation of increased demand for nuclear construction services, GE has increased its cost estimate to $1,850/kw as of mid-2006.[300] Experience from Japan shows that these plants take roughly 48 months to build, though GE claims 39 months for new ABWR units.

GE's ESBWR

GE's Economic and Simplified Boiling Water Reactor is a Generation III+ design with a capacity of 1,500 MW. The design builds on the ABWR design, with added natural circulation and passive safety features to enhance safety and lower costs. As with the AP1000, modular construction offers to reduce construction time and costs. GE quotes a cost of $1,600/kw as of mid-2006 for ESBWR plants, $250/kw less than an ABWR.[301]

CURRENT ECONOMICS OF NUCLEAR POWER PLANT TECHNOLOGY

The Levelized Cost of Electricity (LCOE) combines the capital and operating costs of a power plant into a single, flat $/MWh value that can be compared across plants with different shares of capital and operating costs. The LCOE represents the minimum real price of electricity over the life of the plant needed to cover all costs. Many factors go into the LCOE for nuclear plants, as well as other energy sources, including construction time, plant life, capacity factor, cost of debt, cost of equity, debt term, deprecation schedule, tax rate, fuel costs, decommissioning costs, operation and maintenance, waste fees and overnight capital costs (Table 2-31). Capital cost is the single most important factor for nuclear; capital contributes one-third of the LCOE, and the interest paid adds another quarter.[302]

Table 2-31: Effects of capacity factor, construction period, on first plant nuclear LCOEs for three reactor costs, $/MWh, 2003 prices[303]

Capacity Factor %	Mature Design Overnight Costs $1200/kW (no FOEKE)	New Design Overnight Costs $1500/kW (FOEKE included)	Advanced New Design Overnight Costs $1800/kW (FOEKE included)
	5 year construction period		
85	$47	$54	$62
90	$44	$51	$58
95	$42	$49	$56
	7 year construction period		
85	$53	$62	$71
90	$50	$58	$67
95	$47	$56	$64

One hurdle that investors hoping to build new nuclear plants in the United States currently encounter is "First of a Kind Engineering" (FOAKE) costs, which represent extra costs that plants with new designs will incur due to unforeseen challenges in initial construction. FOAKE costs will decline with each new plant until costs reach the Nth plant, a stable, proven cost that is expected to be achieved after the first few new nuclear plants of a given design. According to the University of Chicago study, FOAKE costs can raise the overnight costs of the first plant built by up to 35 percent.[304] The seller of the technology can choose whether the incremental FOAKE costs will all be applied to the first plant or whether they will be spread out among the first several plants. A plant design

298 Office of Nuclear Energy, 2001.
299 Nuclear Power Education, 2006.
300 Uranium Information Centre, 2006b.
301 Uranium Information Centre, 2006b.
302 Tolley & Jones, 2004.
303 Ibid. p. S-8
304 Ibid. pg S-5

such as the AP1000, which has never been built, will likely incur higher FOAKE costs than a plant such as GE's ABWR, which has already been built in Japan.

In estimating the LCOE for new nuclear plants in the United States, an MIT study judged overnight costs to be $2,000/kw (in 2002 dollars). See Table 2--32 for key assumptions of the study. Given a five-year construction period, 85 percent capacity factor, operations and maintenance costs of 1.5 cents/kwh, and no regulatory assistance or carbon policy, the study found that nuclear power is not cost competitive with coal or natural gas. Nuclear is 2.6 cents kWe-hr more expensive than coal over a 25-year span and 2.5 cents/kWe-hr more over a 40-year span.[305]

Table 2--32: MIT study base assumption model[306]

Overnight Cost	Construction Time	O&M Costs	Economic life-cycle	Real Levelized Cents/kwh (85% Capacity, 25 years)	Real Levelized Cents/kwh (85% Capacity, 40 years)	Real Levelized Cents/kwh (75% Capacity, 25 years)	Real Levelized Cents/kwh (75% Capacity, 25 years)
$2000/kw	5 years	1.5cents/kwh	25-40 years	7.0	6.7	7.9	7.5

A University of Chicago study made three separate overnight cost assumptions: $1,200/kw for a mature design, $1,500/kw for a new design, and $1,800/kw for an advanced new design (all in 2003 dollars). The added costs in the last two assumptions take into account FOAKE costs. According to the study, new nuclear power plants coming online have LCOEs ranging from $47 MWh to $71/MWh without government assistance. The full range is shown in Table 2-33.

At these prices, nuclear is not competitive with other traditional sources of electricity. According to the MIT study, coal's real levelized cost is estimated to be 4.8 cents to 4.6 cents. Natural gas generation is higher (and depends on the price natural gas), but still is lower than nuclear, even in the case of high natural gas prices and improved nuclear efficiency. However, if carbon taxes were to be implemented, nuclear becomes much more competitive. The study estimated a $50/ton tax on carbon (equivalent to $13.7 per ton CO_2), which would raise the price of coal to 5.8-6.0 cents/kwh. A $200/ton carbon tax ($54.5 per ton CO_2) would raise the cost of coal to 9.6/9.4 cents/kwh, the only scenario in which nuclear can be competitive with coal or gas. (Table 2-33)

Table 2-33: Effect of a carbon tax on electrical generation[307]

Fuel (25 yrs/40 yrs)	No Carbon Tax	$50/ton carbon	$100/ton carbon	$200/ton carbon
Nuclear (75% Cap)	7.9/7.5 cents/kwh	7.9/7.5 cents/kwh	7.9/7.5 cents/kwh	7.9/7.5 cents/kwh
Coal	4.8/4.6 cents/kwh	6.0/5.8 cents/kwh	7.2/7.0 cents/kwh	9.6/9.4 cents/kwh
Nat Gas (low)	4.0/3.9 cents/kwh	4.5/4.4 cents/kwh	5.0/5.0 cents/kwh	6.0/6.0 cents/kwh
Nat Gas (med)	4.2/4.3 cents/kwh	4.7/4.8 cents/kwh	5.3/5.3 cents/kwh	6.3/6.4 cents/kwh
Nat Gas (high)	5.5.5.7 cents/kwh	6.0/6.3 cents/kwh	6.5/6.8 cents/kwh	7.5/7.8 cents/kwh

Both studies lay out a series of recommendations that would help make nuclear power cost competitive. New nuclear technologies are expected to have lower generation costs than the previous generation. The MIT study states that with a 25 percent reduction in construction costs, a four-year construction time instead of five, and with the right regulatory conditions, nuclear power can be competitive. The study recommends a production tax credit of up to $200/kw for the first 10 plants built and the inclusion of nuclear credits in state or federal "carbon free" portfolio policies.[308] The study was done before passage of the EPAct 2005, which contains incentives that are expected to make qualified new nuclear units cost-competitive.

The University of Chicago study makes similar recommendations, proposing an $18/MWh production tax credit

305 Beckjord et al., 2003., p. 42
306 Data from Ibid., pp. 42-43
307 Ibid., p. 42
308 Ibid. p. 8

and a 20 percent investment tax credit for the first nuclear plants built. These policies would bring the LCOEs down to a level competitive with coal (Table 2-34).

Table 2-34: Effects of combined $18 per MWh 8-Year production tax credits and 20 percent investment tax credits on nuclear power plant LCOEs, $/MWh, 2003 prices[309]

	Mature Design $1200/kW		New Design $1500/kW		Advanced New Design $1800/kW	
Construction Time	5 Years	7 years	5 Years	7 years	5 Years	7 years
No Policies	47	53	54	62	62	71
Combination of Policies	26	31	31	38	37	46

Both of these recommendations take into account the FOAKE costs currently associated with building nuclear power plants. The study quantifies the reduction in costs associated with the learning curve involved in building new plants. The learning rate is the percent reduction in cost resulting from doubling the number of plants built. Applying this learning rate results in a considerable reduction in the LCOE. In addition, as construction becomes more efficient, construction time is expected to drop. Investors become more confident in the projects, so the interest rate on debt and the rate of equity drop, resulting in further savings. This pattern can be seen in Table 2-35 and Table 2-36.[310]

Table 2-35: LCOE for the 5th nuclear plant, no policy assistance, 7-year construction time, 10 percent interest rate on debt, 15 percent rate of equity in dollars per MWh (2003)

Learning Rate (Percent for Doubling Plants Built)	Initial Overnight Cost, $/kW	
	1,200 and 1,500	1,800
3	50	58
5	48	56
10	44	52

Table 2-36: LCOE for the 5th nuclear plant, no policy assistance, 5-year construction time, 7 percent interest rate on debt, 12 percent rate of equity in dollars per MWh (2003)

Learning Rate (Percent for Doubling Plants Built)	Initial Overnight Cost, $/kW	
	1,200 and 1,500	1,800
3	35	40
5	34	39
10	32	36

The Energy Policy Act of 2005 included provisions similar to the recommendations in the MIT and University of Chicago reports. One provision, titled the Emergency Loan Guarantee Fund, calls for a loan guarantee of up to 80 percent of the cost of a plant, at the discretion of the Secretary of Energy. A production tax credit of 1.8 cents/kwh for the first six gigawatts of new capacity is offered. This credit is good for the first eight years of operation and applies to any new nuclear plant placed into operation prior to 2021, provided it is among the first six GW. In addition, the bill states that the federal government would pay the cost of delays beyond the industry's control for the first plants built.[311] These provisions were included in order to help offset the high FOAKE costs and encourage investment in nuclear power.

CHALLENGES TO NEW NUCLEAR CONSTRUCTION IN THE UNITED STATES

Given that no nuclear plants have been ordered and ultimately constructed in the United States since 1973,

309 Tolley & Jones, 2004. pg S-14
310 Ibid. pg S-15
311 Nuclear Energy Institute, 2005.

nuclear faces a number of formidable challenges to further development. Challenges include uranium supply, waste disposal, financing, licensing, public opposition, security and demand-driven cost increases.

Uranium Supply

Military interest has always distorted the market for uranium. U.S. policy drove mining and enrichment in the 1970s, resulting in the production of more uranium than used until 1985.[312] Coinciding with the halt in building new nuclear plants, the industry retained a large stockpile of fuel. Starting in the early 1990s, nuclear fuel, converted from weapons, began to arrive from Russia. As a result of these combined factors, the uranium market was depressed from the 1980s to the 2000s.[313] Mining companies contracted, as did their trained and experienced workforce. As new nuclear plants are being built worldwide and are expected to be built in the United States soon, a short-term deficit in fuel supplies is also expected.[314] Current annual world reactor consumption is 172 million pounds, but supply is 104 million pounds. Uranium prices are expected to rise significantly and grow more volatile.[315]

The World Nuclear Association has developed three nuclear capacity forecast scenarios: low, reference and high (Error! Reference source not found.). Based on known resources, Ross McCracken, editor of Platts Energy Economist, estimates that the low-demand scenario will exhaust known resources 50 years from 2025. The high-growth scenario will deplete known resources 35 years after 2025, falling well short of the expected 60-year lifetime for new plants built in the 2015-2025 period. Undiscovered resources could fill the gap, but the net energy (and GHG benefit) from those resources may decline as uranium ore becomes more difficult and energy-intensive to mine.[316]

Storage of Nuclear Waste

Civilian nuclear power plant reactors are refueled approximately every 18 months. The spent fuel consists mainly of Uranium-238, Plutonium-239 and some unused U-235 isotopes. The waste remains highly radioactive for several thousand years and poses a significant risk to human health. The safe, secure storage of spent fuel adds further costs to nuclear power generation.

Spent nuclear fuel is classified by the NRC as high-level waste.[317] Approximately 2,000 metric tons of spent nuclear fuel is generated annually in the United States. Fifty-four thousand metric tons have accumulated over the past four decades and are stored onsite at 125 nuclear facilities across the country.[318] Currently, the nuclear industry pays a fee of 0.01 cent/kWh dedicated to nuclear fuel disposal. In exchange for paying this fee, nuclear-plant owners have a standard contract with the Department of Energy for it to remove and store nuclear waste. The contract calls for DOE to have removed waste by 1998. A number of utilities are suing and winning over DOE's failure to do so.

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312 Uranium mining methods are open-pit, underground and in situ. Open-pit consists of digging open holes in the ground, physically removing the ore and injecting it with solvent to extract the uranium oxide (U3O8). Underground mining involves the same process except that underground tunnels are used instead of above ground pits. Both of these types of mines are referred to as mills. Mills produce a considerable amount of waste referred to as "tailings." Tailings from uranium mines amount to the largest quantity of waste in the nuclear fuel cycle. The major isotope of concern is Radon-226. The in situ method involves injecting the ore deposit directly with solvent. A system of pipes is placed in the deposit to recover the uranium oxide removed from the ore. This method reduces the environmental footprint of a uranium mine and the amount of tailings produced. However, if not properly controlled, there is a risk ofgroundwater contamination. In the United States, in situ is the preferred method of uranium mining. (Energy Information Administration, 2006g.)

313 World Nuclear Association as cited in Platts, 2006.

314 Hargreave Hale as cited in Ibid.

315 U.S. Department of Energy, 2006c.

316 U.S. Department of Energy, 2006c.

317 Reprocessed nuclear fuel is also classified as high-level waste. Reprocessing is covered in a section below.

318 Nuclear Energy Institute, 2006b.

Reactor owners in the United States store spent fuel in two ways. One storage method is spent fuel pools, which are intended to house spent fuel for 10 to 20 years after use. Pools function to cool and shield the still-hot radioactive fuel and are located onsite adjacent to the reactors. A drained fuel pool could cause an uncontrolled nuclear reaction, so reactor operators must constantly monitor the pools and provide the highest level of security. The absence of a permanent repository is straining the current system; the NRC estimates that the pools will reach 100 percent capacity by the year 2015.[319]

The other storage method is dry cask storage. After spent fuel is cooled in the fuel pool for at least 10 years, it can be stored above ground in a concrete cask. Dry cask storage is more secure and poses less risk than spent fuel pools. Dry casks offer a better option for long-term storage. Twenty-eight dry cask storage facilities operate in the United States. [320]

In 2002, the DOE recommended, and Congress approved, a long-term storage repository at Yucca Mountain, located 100 miles northwest of Las Vegas. The site would occupy 230 square miles of surrounding land. Congress authorized the facility to hold 70,000 metric tons, but the Nuclear Energy Institute believes that it can hold up to 120,000 metric tons.[321] The repository is scheduled to open in 2017, but many observers suspect that the project will be delayed, if not ultimately abandoned.

The DOE estimates that the fuel stored at Yucca Mountain will need to be stored for approximately 10,000 years.[322] This enormous time frame poses tremendous geologic, engineering and security issues. The effect of an earthquake, corrosion, human intrusion, groundwater contamination or a host of other possibilities have been considered. The DOE has been studying Yucca Mountain since the late 1970s. Los Alamos, Sandia, Lawrence Berkley and Oak Ridge national laboratories have done extensive studies on all aspects of Yucca Mountain. Based on their reports, the DOE has determined that the site is adequate for long-term storage on the scale required.[323] However, many observers argue that fully qualifying the effects of a project given the time span is impossible.

The project faces significant opposition in Nevada among the public and within state government. The state has sued the Department of Energy several times over issues relating to the project. In addition, Nevada's congressional delegation, including the Democratic Senate Minority Leader, Harry Reid, is opposed to the project. Although the DOE has released several scientific studies verifying the safety of the project, many citizens remain unconvinced. This lack of public confidence and political opposition is a major factor in the construction timeline and the project's future itself.

Even assuming Yucca Mountain opened in 2007, at the current rate of spent fuel production (plus accumulated waste), it would be filled in 12 years. The site cannot provide the single solution to the spent nuclear fuel problem. The MIT study provides a set of recommendations for dealing with the spent fuel problem. The first recommendation is to expand the interim storage facilities in order to be prepared for further delays in Yucca Mountain construction. The study also proposes that the 0.01 cent/kwh fee that generators pay for waste disposal be increased in order to provide incentives to switch to high burn-up fuel and more efficient methods that would provide the same amount of power and produce less waste. It also suggests continuing R&D in repository and storage technology.[324]

Despite the problems at Yucca Mountain, the United States is considerably ahead of other countries in address-

319 U.S. Department of Energy as cited in U.S. Nuclear Regulatory Commission, 2003b.
320 U.S. Nuclear Regulatory Commission, 2003a.
321 Uranium Information Centre, 2006c.
322 Eckhardt, 2000.
323 Office of Civilian Radioactive Waste Management, 2006b.
324 Beckjord et al., 2003. p. 55

ing the spent fuel problem. France, whose nuclear program is seen as a success story, does not yet have a comprehensive strategy to deal with its waste. When the French government began to look for long-term repository sites in the early 1990s, it was met with widespread opposition from the public, and the project halted. France is still looking into several sites, but for now the waste continues to be stored at La Hague, one of its two reprocessing facilities.[325] Japan, Russia, China, India, the United Kingdom and Switzerland are still only in the exploratory stages of building a long-term spent fuel facility.[326] If opened, Yucca Mountain will be the first facility of its kind in the world, and its fate will likely determine that of similar projects in other countries.

Reprocessing

One way to reduce the amount of spent fuel waste is to reprocess it. Uranium with 3 percent enrichment will produce waste containing 1 percent uranium and 1 percent plutonium. Reprocessing consists of separating the remaining uranium and plutonium. The uranium can be enriched and used again as fuel in light water reactors. The plutonium can be used in fast breeder reactors (FBRs), as discussed below. The disadvantages of reprocessing are that the plutonium produced could pose a significant nuclear weapons proliferation problem, and the final waste has a longer half-life than directly disposed spent fuel. Although the volume of the final waste is less, it still poses the same problems as spent fuel that has not been reprocessed.

France, the United Kingdom, Russia and Japan currently have the civilian capacity to reprocess 2,940 tons of spent fuel per year. Japan is building a plant with a capacity to reprocess 800 tons per year. The United States does not have a civilian reprocessing operation, but the DOE is developing a comprehensive plan to build such a facility. In the budget for fiscal year 2006, $250 million was allocated for the Global Nuclear Energy Partnership, which will work with countries that have advanced reprocessing systems and assist developing countries in developing small-scale reactors. The partnership also aims to fund advanced fuel-cycle technologies to reduce nuclear waste worldwide.

A 2003 Harvard study analyzed the economics of reprocessing nuclear fuel in the United States. The study estimated that the current reprocessing price would be $1,000/kg of waste (about $2.65 per MWh). The cost of current direct disposal was estimated at $360/kg. The study projected that reprocessing would increase spent nuclear fuel management costs by 80 percent, yet it did not include either capital costs associated with building the reprocessing facilities or the costs of security measures that will be needed. The study concluded that reprocessing is not currently an economically competitive option in the United States without considerable government intervention.[327]

Breeder Reactors

Fast breeder reactors use a mixed oxide fuel consisting of approximately 20 percent of a plutonium oxide called PuO_2 and 80 percent of a uranium oxide called UO_2, both of which can be obtained by reprocessing spent uranium. Therefore, the reactor "breeds" its own fuel. This phenomenon occurs in all nuclear reactions. However, a breeder reactor is specifically designed to produce more fissile material than it consumes.[328]

Fast breeder reactors have been operating for decades on a small scale. The largest commercial FBR developed to date was the 1,250 MW Superphoenix in France. The plant was closed in 1998 because of poor economic

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325 Klein, 2002.
326 Office of Civilian Radioactive Waste Management, 2006a.
327 Bunn et al., 2005.
328 International Atomic Energy Agency, 1998.

competitiveness. Currently, there are a number of research and prototype FBRs around the world but no large-scale commercial plants.[329] Considerable interest remains in FBRs, and research to improve cost and performance will continue.

Nuclear Power Plant Financing

According to the DOE Secretary of Energy Advisory Board, "Construction of the first new nuclear power plants in the United States is regarded as a relatively high-risk undertaking by both the electric power industry and the financial community." [330] The risk is largely due to unforeseen interruptions in prior nuclear plant construction in the 1970s and `80s. Utilities lost considerable investments due to a host of factors, including a poorly designed regulatory and licensing process, changing regulatory standards and requirements, the absence of design standardization and modular construction practices, the nascent stage of technological maturity and construction mismanagement.[331]

Higher interest rates on debt and a greater return on equity will be demanded for risky projects, such as a new nuclear plant. Interest rates on financing will depend on the credit quality of the company building and operating the plant. Factors affecting credit rating include debt to equity ratios, strength of future revenues, liquidity and overall financial strength. Lenders' concerns about nuclear exposure limit liquidity in the bank market, making it harder for lenders in a nuclear-related transaction to partner with other banks and pool capital.[332] This pooling is known as syndicate financing, where a lead bank lends part of the debt, but involves other banks to share the credit risk. This arrangement is especially common in very large deals (such as nuclear plant finance). The financing of a new nuclear plant will likely be achieved by a well-capitalized entity with a strong cash flow necessary to develop such a facility.

Participants in financial markets tend to classify the financing of a new nuclear power plant in three distinct phases. Development is the first phase and occurs prior to construction. The project developer—typically, a utility or consortium of utilities—bears all costs in this phase. During the construction phase, when the majority of expenditures take place, third-party lenders begin funding after a closing of the transaction. Interest on project funding is typically capitalized during this period, since the project is unable to generate revenues to repay loans. In the case of a regulated utility, where the rate-base covers the utility's costs, the financing can be structured with interest paid currently. The final phase of commissioning takes two years, as the facility is ramped up to full production capacity.[333]

Regulated Utilities

A utility operating in a state that has not deregulated its utilities will have the opportunity to build a new nuclear plant under cost-of-service rate regulation. In this scenario, the utility will charge ratepayers for any increased expense of added nuclear power to meet the authorized rate of return for the utility. In some states, the utility can put into the rate-base the cost of construction from the beginning of the project, rather than at the completion of construction. Debt and equity financiers prefer projects that have the greatest potential for cost recovery through rate-base. Financiers will have recourse to all of the utility's assets and revenues both during and after construction. The traditional debt-to-equity ratio for financing projects in regulated utilities is 50/50.[334] Scully Capital has said that these types of integrated utilities will be the first to finance and build a new nuclear power plant.[335]

329 Uranium Information Centre, 2006a.
330 Secretary of Energy Advisory Board, 2005.
331 Ibid.
332 Scully Capital, 2002.
333 Ibid.
334 Secretary of Energy Advisory Board, 2005.
335 Scully Capital, 2002.

Unregulated Utilities and Merchant Generators

In deregulated power markets, merchant generating companies, rather than regulated utilities, would mostly likely build and operate new nuclear facilities. A merchant generating company can be either an affiliate of one or more regulated utilities within a holding company corporate structure or a stand-alone company. Such businesses will generally require a less leveraged balance sheet (more equity and less debt) than a regulated utility to achieve an equivalent credit rating and, therefore, similar financing terms.[336] Although utilities seek to shelter their existing assets by creating a dedicated merchant company to own and operate a nuclear plant, the financial community will almost certainly demand that utilities put up their existing assets as collateral anyway. The increased risk associated with a merchant generator will require a higher return on equity and could benefit from government loan guarantees (discussed later). The ability of the merchant company to attract debt financing will depend on the asset base, the revenues available and the extent of any parent company support.[337] The traditional debt-to-equity ratio for financing projects in unregulated utilities and merchant projects is 50/50.[338]

Non-Recourse Financing

In the case of non-recourse financing, lenders work with a single-purpose entity whose only asset is the new power plant and whose only revenues will be derived from future sales of the electricity produced. This type of structure is attractive to the generating company if a consortium of companies pool assets into a business specifically to build a new nuclear facility. Their other assets can be insulated from claims by the project lenders in the event of a default. Consequently, this is the riskiest structure for nuclear power plant financing from the perspective of the financial community. "The financial community has indicated that debt investors will be unwilling to lend under a non-recourse project finance structure to a new nuclear project, absent other protection against the risk of a default."[339] Non-recourse project finance capital structure can be up to 80 percent debt and 20 percent equity and are generally much more structured deals.[340] The equity will come from the members of the consortium, and the debt from banks, institutional investors and other sources.[341] In the past, financial markets have provided the debt funds for many gas-fired power plants structured using the non-recourse project finance model. The difference for nuclear plants is that lenders perceive regulatory risks to be significantly greater in the case of a new nuclear plant than those of a gas-fired plant. The extra risk arises from such factors as cost overruns, delays, changes in design and litigation.[342] According to Scully Capital, non-recourse project financing for power-generation assets has become a much less attractive financing option. The cost of "off-balance sheet" financing has become much more expensive relative to the cost of corporate (regulated utility) financing.[343] Scully Capital stressed that off-balance sheet, non-recourse project financing would not be feasible for a new nuclear power plant, given the unique risks inherent in a nuclear power facility, the large capital costs and limited liquidity in the market.

Subsidies Available

The Energy Policy Act of 2005 provides numerous incentives to build new nuclear power plants. These incentives were requested by the nuclear and financial communities to make nuclear power cost competitive and to mitigate the risk associated with such large capital projects. The Secretary of Energy directed an advisory board,

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336 Secretary of Energy Advisory Board, 2005.
337 Ibid.
338 Ibid.
339 Ibid.
340 Ibid.
341 Carroll & Matthews, 2005.
342 Ibid.
343 Scully Capital, 2002.

the Nuclear Energy Task Force, to assess impediments to building new nuclear power plants. In its report of January 10, 2005, the task force identified the unavailability of financing as a significant obstacle to new plant construction. Many of the subsidies in the EPAct were an outcome of this task force's suggestions.[344] One important improvement was a 20-year extension of the Price-Anderson Act, which provides insurance protection to the public in the event of a nuclear reactor accident.[345] Construction subsidies contained in the EPAct include up to $750 million due to permit delays, and up to $1.25 billion from 2006 through 2015 for the construction of plants that produce both hydrogen and electricity.[346]

One of the critical economic subsidies obtained by the sector is a production incentive of 1.8 cents/kWh for an eight-year period. The tax credit is subject to an annual cap of $125 million per facility for each 1,000 MW of generating capacity.[347] A federal loan guarantee was made available for up to 80 percent of a new project's eligible costs. This guarantee was put in place to make lenders more comfortable in all three types of financing situations, but especially for unregulated utilities and merchant generators. According to the Secretary of Energy Advisory Board, a federal loan guarantee appears to have relatively low value for regulated utility financing, medium- to high value for the unregulated merchant generating company, and high value for non-recourse project financing.[348]

The outcome of financing the first nuclear plants will depend greatly on how the provisions of the EPAct are implemented. James Asselstine, managing director at Lehman Brothers, said in his testimony to the U.S. Senate on May 22, 2006, that "the methodology for determining the cost of the loan guarantee to the project sponsor will be a factor in assessing the availability and value of the loan guarantee. For these reasons, the Department's implementation of the loan guarantee provision is likely to be an important component in ensuring the availability of financing for the initial plants."[349]

CONCLUSION

In addition to subsidies, many lenders would prefer to see completion and performance risk mitigated through fixed-price, turnkey "engineer-procure-construct" contracts with engineering and construction firms. Also, extended warranties from equipment vendors delivering the new reactor design packages may be required to help mitigate the risk of nonperformance.[350] Another risk-mitigation strategy for new operators is long-term power purchase agreements, which will assure lenders that there is a market for the additional electricity expected to be produced.

Licensing Process

The NRC's licensing process has been revised to reduce the financial risks incurred by delays due to the previous cumbersome regulatory structure. Under the old licensing rules, the NRC would issue two separate permits, one before construction and one when the project was approaching completion. Each process consisted of a complete individual site and engineering review as well as mandatory public hearings. The process ensured a complete evaluation of all issues involved in the site construction. However, it often resulted in construction delays and retrofitting that dramatically increased the final cost of construction. Investors saw the uncertainty of the final costs as a deterrent to financing further plants.

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344 Carroll & Matthews, 2005.
345 Implementation of the Provisions Of The Energy Policy Act Of 2005: Nuclear Power Provisions, 2006.
346 U.S. Energy Policy Act of 2005, § 635 and 638.
347 Ibid., §§ 1300-1364.
348 Secretary of Energy Advisory Board, 2005.
349 Implementation of the Provisions Of The Energy Policy Act Of 2005: Nuclear Power Provisions, 2006.
350 Scully Capital, 2002.

The NRC's new licensing process seeks to maintain the same level of diligence while reducing the financial risks incurred in the process. By front-loading as much of the regulatory hurdles before construction begins, the NRC hopes to decrease the costs incurred due to retrofitting and resulting delays. The shift from site-specific reactors to generic reactors will likely help speed the regulatory process. The NRC has already started to approve specific reactor designs before any plant was scheduled to be built. Settling reactor design issues before construction begins is expected to save a significant amounts of time during construction.

Another key feature of the new licensing process is early site permits (ESPs). An applicant seeks approval to build a facility on a specific site before any construction begins. Any issues regarding the site location, ranging from public concern to environmental impact, are raised before significant capital resources are put into a plant's construction. Front-loading these issues also helps reduce the regulatory risks. A site permit is valid for 20 years. As of August, 2006, the NRC is reviewing four ESP applications.

Construction and Operating Licenses authorize both the construction and operation of the specific plant. The combined process ensures that a project meets the Design Certification for the reactor and the ESP for the site. At least 180 days prior to initial fuel loading, the NRC must publish a notice of intended operation. A public hearing is initiated and final certification is subject to judicial review. No Construction and Operating License has been sought as of yet, though the first applications are expected in 2007. The NRC is still working out the final details of the process. Although the process was designed to front-load as much of the legal hurdles as possible, significant delays and increased costs are still a possibility. Since the process has yet to be tested, it still presents financial risks to potential investors.[351]

The Price-Anderson Act of 1957 established the framework for payments to the public in the case of a nuclear accident. The act was renewed as part of the EPAct of 2005. The law requires each facility to purchase the maximum insurance available, which amounts to coverage of $300 million per reactor.[352] A secondary fund consisting of money from all operators is used to cover additional costs from an accident. Each operator is required to pay $95.8 million per reactor in case of an accident. This secondary fund would make available over $10 billion. After this cap, the nuclear industry is no longer liable. Price-Anderson is seen as a significant subsidy to the nuclear industry because it puts a specific value on the liability the nuclear industry would incur in the case of an accident.[353]

Public Opinion

Public opinion will play a crucial role in any future development of the nuclear industry. After Three Mile Island and Chernobyl, public confidence in nuclear power dropped to an all-time low. The negative perceptions played a key role in the de facto moratorium on new nuclear power plant construction in the United States. The public has the power to place pressure on regulatory agencies, as well as to file lawsuits that can cripple already expensive projects.

Recent polling on nuclear power shows that the public is less antagonistic to nuclear power than in the past, but still holds a great deal of reservations. A Los Angeles Times/Bloomberg poll taken in July 2006 found that 61 percent of respondents would support the increased deployment of nuclear power if that would lead to reducing U.S. dependence on foreign sources of energy and reducing emissions of greenhouse gases.[354] However, the MIT study found that 75 percent of respondents believed that a major nuclear accident in the United States is likely

351 Secretary of Energy Advisory Board, 2005.
352 U.S. Nuclear Regulatory Commission, 2005b.
353 Nuclear Energy Institute, 2005.
354 Los Angeles Times/Bloomberg, 2006.

to occur within the next 10 years.[355] Along the same lines, the study found that 64 percent believed that nuclear waste could not be stored safely over the long term. The overall picture shows that while the public's perception of the nuclear industry has improved, the industry has a long way to go to present a favorable public image [356]

The submitted early site permits are for sites already containing operating nuclear power plants. Having operating nuclear facilities and infrastructure adjacent to the new construction sites will greatly reduce the cost and complexity of construction and operation. Using existing sites is also easier to gain public approval for a new reactor. The Not in My Back Yard attitude will almost certainly present a substantial barrier to any new nuclear site. Continued safe operation of existing facilities and incident-free new construction is imperative for the successful completion of planned new reactors. A single incident could jeopardize the future of the industry.

France is the most notable country where nuclear power enjoys widespread public support. Currently, France gets approximately 76 percent of its electricity from nuclear power. When the French government decided to invest heavily in a nuclear strategy, it sold its decision to the public as a security issue. "No coal, no oil, no gas, no choice" is a popular phrase used by the French to explain their reliance on nuclear power. Polls consistently show nuclear power enjoys widespread support, on the order of 66 percent. However, the spent fuel issue has shown to be contentious in France as well. In the early 1990s, the French government began to explore for underground sites for long-term storage. The search was met by widespread opposition from the French public, especially in the countryside. The project was put on hold. As in the United States, the spent-fuel problem continues to be a major public concern.[357]

Security

After the events of September 11, 2001, the issue of nuclear plant security became an important factor in the nuclear debate. A successful terrorist attack on a nuclear power plant could have catastrophic results, especially if it were located near a major population center. Nuclear facilities are designed to withstand catastrophic natural events such as hurricanes, tornadoes, earthquakes and fires. The Electric Power Research Institute showed that a commercial airline crash would not compromise the integrity of a plant's containment vessel.[358] The NRC also is looking closely at this issue. Still, restrictions currently are in place as to how close airplanes can fly to nuclear plants. In addition, the NRC has increased its oversight of plant security and required reactor owners to tighten security. The NRC works closely with federal, state and local law enforcement agencies to help identify potential threats.[359]

Despite the increases in security at nuclear power plants since 9/11, there are still legitimate concerns about nuclear security. The Union of Concerned Scientists points to the fact that 37 of 81 nuclear sites inspected by the NRC failed their security drills.[360] Such performance, or lack thereof, is not likely to inspire the confidence of the public and investors. Security also represents another added cost. However, nuclear power is likely to remain a major energy source well into the 21st century, and the NRC and federal government as a whole have correctly deemed nuclear power plant security a vital homeland defense issue. Security issues will certainly play a crucial role in the design, licensing and construction of new reactors.[361]

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355 Beckjord et al., 2003, p. 169.
356 Ibid.
357 Klein, 2002.
358 Beckjord et al., 2003.
359 U.S. Nuclear Regulatory Commission, 2005a.
360 Union of Concerned Scientists, 2003.
361 Beckjord et al., 2003.

Renewable Energy: Wind

Capturing energy from the movement of wind is an ancient concept. The first windmill is believed to have been built around 2000 B.C. in ancient Babylon. By the 10th century A.D., windmills were used to grind grain in the areas around what is now known as eastern Iran and Afghanistan. The earliest written record of wind machines dates from the 12th century, when they also were used for milling grain. A few hundred years later, windmills pumped water to reclaim much of Holland from the sea.

In the 1930s and 1940s, wind turbines generated power in remote areas of the United States to charge storage batteries, operate radio receivers and power lights. The Rural Electrification Administration virtually eliminated the market for these machines in the early 1950s with the extension of the central power grid, leaving the industry dormant for the next two decades.

Interest in wind energy resurfaced in the early 1970s in response to climbing energy prices following the OPEC Oil Embargo. With new federal and state tax incentives, government research programs stimulated new wind turbine designs. By the 1970s, there were nearly 50 wind turbine manufacturers in the United States. Fewer than a dozen domestic manufacturers remained in 1997, as a result of industry consolidation that followed the expiration of the tax incentives in the mid-1980s and the easing of the energy crisis.

In 1978, Congress passed the Public Utility Regulatory Policies Act, which required utilities to buy electricity from private, nonutility individuals and developers. As a result, "wind farms" emerged in the early 1980s, primarily in California due to appealing electricity buy-back rates and the availability of windy, sparsely populated mountain passes.

Since the early 1980s, research programs such as those sponsored by the Department of Energy have helped reduce the cost of wind energy from 80 cents (current dollars) per kWh to between 4 and 6 cents per kWh. As the cost of the technology continues to decline and urgency grows to lower GHG emissions, interest in wind energy has increased significantly across the United States. Wind energy is today widely considered the nation's most technically advanced and commercially viable source of renewable energy. The U.S. wind energy industry is expected to install a record 2,750 MW of generating capacity in 2006.

TECHNICAL OVERVIEW

Three characteristics of wind are critical to wind turbine development and siting: the relationship of wind energy and speed, the importance of height above ground and the importance of surface terrain. Wind energy increases at the cube of its speed, such that a doubling of wind speed results in an eightfold increase in the potential power that can be generated from it.[362]

Wind speed also increases with altitude as the effect of ground drag is diminished. As a general rule, wind speed increases as the 1/7th power of the height above ground.[363] Based on this rule, the theoretical increase in wind is illustrated as a function of increasing height.

As an example, two feet above the ground (the "surface") would indicate a factor of approximately 1.1; increasing height to 20 feet would indicate a factor of approximately 1.54. If the wind speed at 2 feet is 10 mph, the predicted wind speed at 20 feet equals:

10 mph X 1.54/1.1 = 14 mph.

362 Reeves & Beck, 2003.
363 Rainbow Power Company, 2006.

Wind energy and wind turbine output are proportional to the cube of the wind speed. If wind speed doubles, the power increases by a factor of eight. In practice, however, power output of a wind turbine and wind speed do not necessarily follow a cubic relationship. Below certain minimum wind speeds, turbines do not function. Above a certain speed—typically 25 meters per second (m/s) turbines shut down to prevent excessive wear and damage.

Terrain also strongly affects wind speed. The rougher the surface, the more turbulent the air and the less horizontal velocity wind is able to maintain.

The modern wind energy industry has developed larger and taller turbines to take advantage of stronger and steadier winds at higher altitudes. The industry also carefully sites wind turbines in areas with optimal wind energy characteristics, such as the sparsely populated mountain passes in California.

CURRENT TECHNOLOGIES

Horizontal-Axis Wind Turbines

All new commercial grid-connected wind turbines have a horizontal rotor atop a tall tower to which three blades are attached. The rotor is connected to a long shaft that runs through a nacelle, which houses the turbine's gearbox and electrical generator, which sit atop the tower. The turbine blades capture the horizontal kinetic energy of the wind and translate it into rotational energy that spins the turbine's rotor, which in turn powers the electrical generator and creates electricity.

The circular area swept by a turbine's rotor grows at the square of the blade length, which is the radius of the swept area. Consequently, the doubling of a turbine's blade length will quadruple the swept area of the turbine and result in a proportional increase in the potential power output of the wind turbine. Therefore, wind turbine designers strive to build larger turbines to sweep larger areas of air with fewer turbines.

In the past 25 years, utility-scale wind turbines (+75 kW) have grown significantly in size and power capacity as a result of technological advancements. Typical utility-scale turbines installed today have a power-generating capacity between 700 kW and 2.5 MW with rotor diameters between 50 and 90 meters. Wind energy systems can reach as high as 135 meters and have blades that sweep areas greater than a Boeing 747's wing span or length.[364]

The major technical barrier to creating ever larger wind turbines is mechanical stress on the blades, gearbox and generator. At the same time, the blades of a turbine need to be as light as possible so that the maximum amount of energy from the wind can be converted into electricity.[365] This balance between weight and strength has resulted in the development of complex composite materials that are used in wind turbine blades.

Modern wind turbines are typically available to produce electricity 97 percent to 99 percent of the time, with the remaining time devoted to scheduled or unscheduled maintenance. Because the winds do not blow constantly, wind turbines tend to generate electricity between 65 percent and 90 percent of the time, depending on the characteristics of the wind resource. Depending on the model, some wind turbines may operate at 100 percent of capacity only in winds above approximately 14 m/s. The end result is that the capacity factor of wind turbines ranges between 25 percent and 40 percent, depending on the wind resource.[366]

364 American Wind Energy Association, 2004b.
365 Mandell et al., 1998.
366 American Wind Energy Association, 2004b.

Turbines are placed as high above ground as possible to take advantage of the strata of air with the least turbulence and highest wind speeds. Ideally, developers place wind turbines in areas with minimal wind turbulence (away from buildings, trees, elevation changes and other obstacles[367]) in order to reduce stress on the blades and tower. However, turbines are typically sited on hills and ridgelines despite the turbulence. Wind speeds are typically greater and more constant in these locations due to air pressure differences between the windward and leeward sides of the hill or ridge and in narrow mountain passes, where winds are compressed and funneled through the gaps.[368]

Vertical-Axis Wind Turbines

While horizontal-axis wind turbines place the gearbox and electrical generator well above ground, vertical-axis wind turbines (VAWTs) keep these components on the ground while typically using vertical blades to catch the wind. VAWTs have many benefits; they are easier to construct and maintain and they are omnidirectional (they do not need to be oriented into the wind).

VAWTs have not yet significantly penetrated the commercial wind turbine market.[369] They are difficult to mount on high towers to capture stronger, steadier winds. They are therefore more suited for use at ground level or on rooftops in densely populated areas. Although this limits their potential, VAWTs may offer advantages for distributed generation of electrical power over taller horizontal-axis wind turbines. However, their placement closer to ground level exposes them to lower, more turbulent winds, producing less electricity and increasing the cost of maintenance and repair. A number of private companies are doing research on VAWTs, but none has yet progressed to large-scale commercial production in the United States after nearly a decade of development.[370]

ECONOMICS OF WIND ENERGY

The federal government provides two incentives to stimulate growth in the wind power sector. The first is the Federal Renewable Electricity Production Tax Credit (REPC), which provides 1.9 cents per kWh for wind and various other renewable technologies. This credit is available to the commercial and industrial sectors. The credit is adjusted annually for inflation and applies to the first 10 years of a facility's operation. REPC funds entrepreneurial wind farms developed by investors who will then sell electricity to utilities or other end-users or distributors.

The role this tax credit plays can be seen in the amount of wind energy capacity installed annually.[371] When the tax credit is about to expire, there is a rush to get wind power developments installed in time to take advantage of the credit; the following year, few installations are made as the industry waits for the tax credit to be retroactively renewed. This boom-and-bust cycle adds additional costs to the development of wind power as suppliers and installers need to carry sufficient financial reserves to make it through the biannual lean years. At the same time, wind turbine suppliers are unwilling to commit to investments to expand production in the absence of a long-term tax incentive. The result is that during booms, the price of wind turbines increases due to increased demand and limited supply, eroding some of the benefit from the tax credit. Another benefit of the tax credit would be to drive down turbine prices by increasing manufacturing capacity, improving economies of scale and increasing experience; yet, since short-term tax credits do not lead to significant manufacturing capacity expansion, much of the potential for cost-lowering is not achieved. As part of the Energy Policy Act of 2005, the REPC was extended through December 31, 2007.

367 Reeves & Beck, 2003.
368 Danish Wind Industry Association, 2003.
369 American Wind Energy Association, 2004a.
370 Ibid.
371 American Wind Energy Association, 2006.

The second federal incentive for wind power, the Renewable Energy Production Incentive (REPI), is particularly important to municipalities. The REPI provides financial incentive payments of 1.5 cents per /kWh (in 1993 dollars indexed for inflation, currently 1.9 cents per kWh) for electricity produced and sold by new qualifying renewable energy generation facilities. Eligible sectors include tribal governments, municipal utilities, rural electric cooperatives, and state and local governments that sell electricity.

ONSHORE WIND

The levelized cost of onshore wind power varies from approximately 2 to 6 cents per kWh. (Levelized cost is the present value of the total cost of building and operating a generating plant over its economic life, converted to equal annual payments. Costs are levelized in real dollars—that is, adjusted to remove the impact of inflation.) The variation is due to differences in scale of equipment and project size, quality of wind resource and cost of financing.[372] In 1999, the Colorado Public Utility Commission determined that wind "is justified on purely economic grounds, without weighing other benefits of wind generation that could be considered …"[373] Currently, new wind power developments in areas with good wind resources and access to the grid cost less per kWh generated than combined cycle natural gas power plants, so long as natural gas costs are more than $5 per MMbtu (during winter 2006-07, futures markets were selling natural gas for delivery at prices above $7 per MMbtu).[374]

Onshore, wind power can generate electricity for less than five cents per kWh in a class 5 or higher wind area.[375] The projected levelized electricity costs of producing new wind plants is on par with traditional forms of electricity generation.[376]

The cost of wind energy has decreased by almost 90 percent since the 1980s.[377] Because wind energy has no fuel costs, most of the cost of wind energy is comprised of capital expenditures. As the industry has matured, technological advancements have allowed wind turbines to grow consistently larger and more efficient. This progression toward multimegawatt machines has provided cost savings by reducing the cost of a wind turbine per kWh generated. In addition, the increasing popularity of wind power, especially in Europe, has allowed production of wind turbines to expand, achieving economies of scale not possible when the industry was first developing. The cost of financing is also decreasing as lenders gain confidence in the technology. Wind power should become increasingly competitive as conventional fossil fuel costs increase.[378]

The capital outlays of building a wind farm account for approximately 70 percent of the total cost of energy produced; the costs include the turbine, tower, power equipment, construction of access roads and foundations, connection to the grid and installation. The remaining 30 percent consists of maintenance (20 percent) and general and administrative costs (10 percent). Though much of the maintenance is unscheduled, the cost can still be forecasted because it is roughly proportional to energy production, around $0.005/kWh for large wind farms (+40 MW). In 2003, total capital costs were on average less than $1,000 per kW of generating capacity for large wind farms.[379]

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372 Reeves & Beck, 2003.
373 Lehr et al., 2001.
374 Demeo, 2004.
375 New Jersey Board of Public Utilities, 2005.
376 Energy Information Administration, 2006a.
377 American Wind Energy Association, 2004c.
378 British Wind Energy Association, 2006.
379 Reeves & Beck, 2003.

The four main factors that affect the levelized cost of wind energy are:

- The size of the wind farm. Larger wind farms typically have lower per MW costs due to economies of scale.
- The wind speed at the site. Greater wind resources increase the amount of electricity generated in a year, allowing for the cost of the project to be spread out over a larger amount of electricity.
- The cost of installing the turbines and connecting them to the utility grid. More remote or challenging terrain can significantly drive up the cost of a wind farm.
- The presence of a production tax credit or other government subsidy.

In summary, wind industry experts agree that the cost of generating electricity will continue to drop for onshore wind in the next 15 years as the industry continues to grow, achieving further economies of scale and developing advanced technologies and materials to increase the efficiency and durability of the next generation of wind turbines while reducing the costs of materials and financing. The European Wind Energy Association estimates that generation costs for onshore wind energy will decrease by 20 percent to 25 percent by 2020 as capital and operational costs decrease and efficiencies are gained both from larger projects and improved turbine designs.[380]

OFFSHORE WIND

Offshore wind energy is an untapped resource in the United States. Because average wind speeds over the open ocean are often 20 percent higher than over nearby locations on land, energy generation from comparable offshore wind turbines can be 50 percent to 73 percent higher. Wind variation with altitude and turbulence are less over the ocean, thus reducing wear, operating costs and maintenance on the turbine. Some estimates put the life span of offshore wind turbines at 25 to 30 years versus 20 years on land.[381]

Offshore siting of wind energy may facilitate increases in wind energy capacity. Onshore wind energy faces transportation and installation constraints that may limit future growth. Offshore wind farms may increase in size and density relatively close to major population centers. This proximity decreases the need for the addition of lengthy transmission lines and associated infrastructure costs.[382]

One major technical limitation for U.S. offshore wind farms is the required location of monopile platforms in waters shallower than 30 meters. Offshore wind power is therefore capital-intensive due to high installation, transmission, and operating and maintenance costs.[383] New technology using floating platforms in deeper water may decrease some of these costs and accelerate the acceptance and growth of offshore wind power.

Domestic historical cost data are not available for offshore wind in the United States. A 100 MW offshore wind energy facility, located in an area with class 6 winds (average wind speed above 8 m/s at 50 meters above the ground) and a capacity factor (the total energy actually produced divided by the energy potential at full capacity) between 32 and 35, is projected to cost between 8.5 and 8.9 cents per kWh.384

380 European Wind Energy Association, 2005.
381 Krohn, 1998.
382 Musial, 2005.
383 Reeves & Beck, 2003.
384 New Jersey Board of Public Utilities, 2005.

As of the end of 2004, over two-thirds of the world's installed offshore wind energy capacity was located off the coast of Denmark, while an additional 20 percent was located along the United Kingdom coastline.[385] Based on the experiences across Europe with offshore wind energy, the European Wind Energy Association estimated in 2004 that the generation costs of offshore wind energy range between 8.5 and 12.5 cents per kWh. These costs are expected to decrease by 40 percent in the next 15 years as the market for offshore wind energy technology and the infrastructure mature and achieve economies of scale.[386]

Offshore wind generation is expected to play an increasing role in European renewable power generation due to higher costs of land and amenable ocean-siting conditions (e.g., the topography of the ocean bottom). In addition, visual aesthetics do not appear to be a major obstacle in Europe, as evidenced by the broad public acceptance of land-based wind turbines. The near-future offshore potential of wind energy in the United States appears to be somewhat more limited due to an abundance of undeveloped land with high average winds, combined with a Not-in-My-Backyard cultural mind-set. The potential detrimental effect of this NIMBY mind-set on wind power project planning was evidenced during the debate over the proposed Cape Wind offshore wind farm in Massachusetts, which has been delayed for more than five years due to permitting disputes.[387]

WIND POWER CAPACITY

Wind power is currently the world's fastest growing source of electricity, as measured by growth rates. Generating capacity grew at an average annual rate of 25 percent between 1990 and 2000.[388] In 2005, worldwide generating capacity grew 24 percent with the addition of 11,310 MW of capacity, bringing the total world wind power capacity to 58,982 MW.[389] Wind energy experts expect world wind energy capacity to reach 120,000 MW by the end of 2010.[390]

A small number of European Union countries have invested resources in R&D on utility-scale wind farms, resulting in a leadership role reflected by installed capacity for wind energy. At the end of 2005, Europe was the world's frontrunner, with 69.6 percent of global installed capacity. Germany has the most capacity, with 18,428 MW, followed by Spain, with 10,027 MW, and Denmark, with 3,128 MW.[391] Despite its small population, Denmark ranks fifth worldwide in installed wind power capacity, deriving 20 percent of its total electricity generation from wind. The total is expected to reach 25 percent by 2007 as new wind farms come online.[392]

Worldwide, there are currently 24 offshore wind projects in eight countries, with an aggregate capacity of 805 MW. The first offshore wind farm, Vindeby, built in 1991 as a research project in Denmark, is still in operation today. The most recent offshore wind farm to go online is Barrow in the United Kingdom. Barrow has 30 3 MW wind turbines, for a total capacity of 90 MW. The largest offshore farm is Nysted in Denmark, which has a total capacity of 165.5 MW. The United States does not have any offshore wind farms, though there are sites under consideration and evaluation.[393]

With the addition of 2,400 MW of wind energy in 2005, the United States reached 9,149 MW of wind energy in operation across the country. In 2006, these wind turbines will generate 25 billion kWh of electricity.[394] The rapid

385 Musial, 2005.
386 European Wind Energy Association, 2005.
387 Cape Wind Associates LLC, 2006.
388 Worldwatch Institute, 2001.
389 World Wind Energy Association, 2006.
390 Ibid.
391 Ibid.
392 Danish Wind Industry Association, 2006.
393 Wind Service Holland, 2006.
394 American Wind Energy Association, 2006.

growth of the wind energy industry in the past decade has been impressive, but the amount of electricity generated by wind energy remains insignificant comparison with the 3,675 billion kWh of total electricity generation projected for 2006. U.S. wind power generation for 2006 was forecasted to be 0.7 percent (up from 0.4 percent in 2004) of total generation.[395]

Views on potential capacity growth in the U.S. wind power industry differ widely. The Energy Information Administration forecasts wind power generation to increase to only 1.1 percent of total U.S. electrical power generation by 2030.[396] At the other end of the range, the American Wind Energy Association projects that by 2030, installations of wind power will have increased to the point that 10,000 MW of wind power capacity are added annually.[397] Such an annual addition would result in an approximate annual generation of 29 billion kWh (assuming a 33 percent capacity factor), which would account for 0.5 percent of the forecasted 5,341 billion kWh of 2030 electricity generation.[398] Such a growth rate for one year would likely necessitate a total market penetration for wind power in the 5 percent to 10 percent range.

Recent trade industry projections estimate that approximately 2,700 MW of additional wind capacity would be installed in 2006 (all onshore), with a similar expansion of capacity projected for installation in 2007.[399] The federal production tax credit for renewable sources of energy is set to expire at the end of 2007. Despite uncertainty about the status of federal subsidies after 2007, wind power installations in the United States are still expected to grow significantly over the next 10 years. This growth is, in part, the result of 20 states having enacted renewable energy portfolio standards requiring utilities to purchase increasing amounts of electricity generated via renewable energy.[400,401]

Long-term predictions for offshore wind power development in the United States are difficult at this time, due to the uncertainty of permitting and public acceptance. As a result of the hotly contested Cape Wind project in Massachusetts, the regulatory oversight process for offshore wind development is uncertain. Because of these uncertainties, Europe will likely continue its leadership role in the adoption of new approaches and technologies in this arena.

RESEARCH & DEVELOPMENT

The technologies listed below are particular areas of focus for R&D efforts in both the public and private sectors.

Low Wind Speed Technologies

Currently, most wind turbines are designed for class 6 sites, where wind speeds average above 8.0 m/s at 50 meters above ground. There are a number of class 6 wind sites in the United States, but they tend to be in remote regions, limiting their potential. The federal government is researching low wind speed technologies that will allow wind turbines to efficiently generate electricity at wind speeds currently considered marginal. DOE's Office of Energy Efficiency and Renewable Energy is seeking to reduce the cost of generation in class 4 sites (average wind speed above 6.4 m/s at 50 meters above ground) to 3 cents per kWh for onshore systems and 4 cents per kWh for offshore systems.[402] The aim is to make it economically viable to install wind power across the Midwest where class 4 wind sites are common.

395 Energy Information Administration, 2006a.
396 Energy Information Administration, 2006a.
397 American Wind Energy Association, 2006.
398 Energy Information Administration, 2006a.
399 American Wind Energy Association, 2006.
400 Energy Information Administration, 2006a.
401 Union of Concerned Scientists, 2006.
402 Office of Energy Efficiency and Renewable Energy, 2005c.

Increased Capacity

A major area of research for wind turbine companies is on increasing the capacity of turbines by increasing the size of blades and generators. This research is primarily focused on developing technologies for application offshore, because there are no noise restrictions offshore and fewer spatial, transportation and installation constraints. Some larger wind turbines, such as GE's 3.6 MW turbine, are already commercially available for offshore use, while many other, still larger, wind turbine designs, such as Vestas' 4.5 MW model, will be commercially available in the near future.

Offshore Wind Platforms

Current design options allow only for the development of offshore wind power in waters shallower than 30 meters, due to the need for a foundation that is anchored to the ocean floor (e.g., a monopole, or piled foundation, on which the turbine is mounted). This limitation is significant for many areas of the world, including much of the U.S. coastline, where the continental shelf is deeper than and does not extend as far out as in Europe. Europe is developing plans for significant expansions of offshore wind power between 2006 and 2010. New platform designs are being developed to maximize stability, lower costs and make deep-water turbines possible. A major milestone goal within this field is the development of an effective, inexpensive floating platform foundation that would allow for wind farms to be located in waters deeper than 80 meters.[403] By developing cost-effective platform technologies, wind farms can move farther off the coast in order to access more and stronger wind resources and to further avoid aesthetic issues that have proven to be a problem in the United States.

Grid Integration Technologies

As wind power becomes a larger source of electricity generation, power quality will need to be improved to avoid burdensome integration costs. Because winds fluctuate in strength from minute to minute and throughout the day, the wind power industry has been trying over the past two decades to smooth out power and voltage fluctuations to improve the quality of electricity provided to the electrical grid. A number of technologies designed to improve power quality have begun to enter commercial application. As these technologies and others yet to be developed make it into the marketplace, integration costs for supplying power to the electricity grid will decrease, and utilities can rely on wind farms to provide services (e.g., spinning reserves) similar to those provided by more traditional power plants.

Researchers also are trying to develop better methods of forecasting wind speeds. Reducing uncertainty about how much power a wind farm is going to produce at a given time will help improve the value of the resource for utilities planning their generation mix.[404]

Energy Storage

Theoretical and real-world studies of the interaction of wind power with the larger electricity system have shown that wind power can achieve a market penetration of 10 percent to 20 percent of total electricity generation without placing significant burdens on the electrical grid.[405] In order to expand wind energy beyond this level, methods of dealing with the variability of wind power will need to be adopted. Cost-effective energy storage

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403 Musial, 2005.
404 European Wind Energy Association, 2005.
405 Ibid.

technologies, if they can be developed, would be an ideal enabler for the more effective use of variable renewable energy technologies such as wind power.

Currently, the governments of the United States, the European Union, and Japan are funding research into a wide array of storage technologies, including conventional and advanced batteries, fuel cells, pumped hydro, compressed gas, superconducting magnetic energy storage, flywheels and ultracapacitors (Table 2-37).

Table 2-37: Comparison of storage technologies[406]

Technology	Efficiency (%)	Energy Density (Wh/kg)	Power Density (kW/kg)	Size (MWh)	Applications	Limitations
Compressed Gas	70	0	Low	250-2,200	Location specific	Inefficient
Superconducting Magnets	90+	0	High	$20	Power quality, transmission stability	Expensive, still cutting edge
Batteries	70-84	30-50	0.2-0.4	17-40	Load leveling	Expensive, bulky, durability concerns for some advanced batteries
Flywheels	90+	15-30	38720	0.0001-0.02	Power quality, transmission stability	Insufficient capacity, friction energy losses
Ultracapacitors	90+	38758	High	0.0001-0.0005	Power quality, transmission stability	Insufficient capacity, expensive

None of the storage technologies has been used on a utility scale, although sodium-sulfur batteries have begun to be used in Japan for load leveling.[407] Recent successes with improving the energy density (100 Wh/kg) and recharge time of lithium-ion batteries have increased interest in this technology, but issues of expense will likely limit the technology to portable and transportation applications for the foreseeable future.[408]

Transmission Upgrades

As the United States continues to increase its electrical power consumption, the transmission infrastructure is being placed under increased strain. Constraints on the transmission of electricity due to insufficient infrastructure has the potential to be a serious issue for wind power in the future, as onshore wind power resources typically have long distances to travel in order to reach load centers. Identifying the best methods to upgrade the transmission network in a manner that provides the optimal benefit to the wind power industry is an important area of both research and public policy. Currently, the federal government is conducting research to try to develop high-temperature superconductive materials that are both durable and inexpensive to be used in next-generation transmission lines. If adopted, superconductive transmission lines would dramatically increase the capacity of the transmission grid and also significantly reduce the heat losses associated with the transmission of electricity.[409]

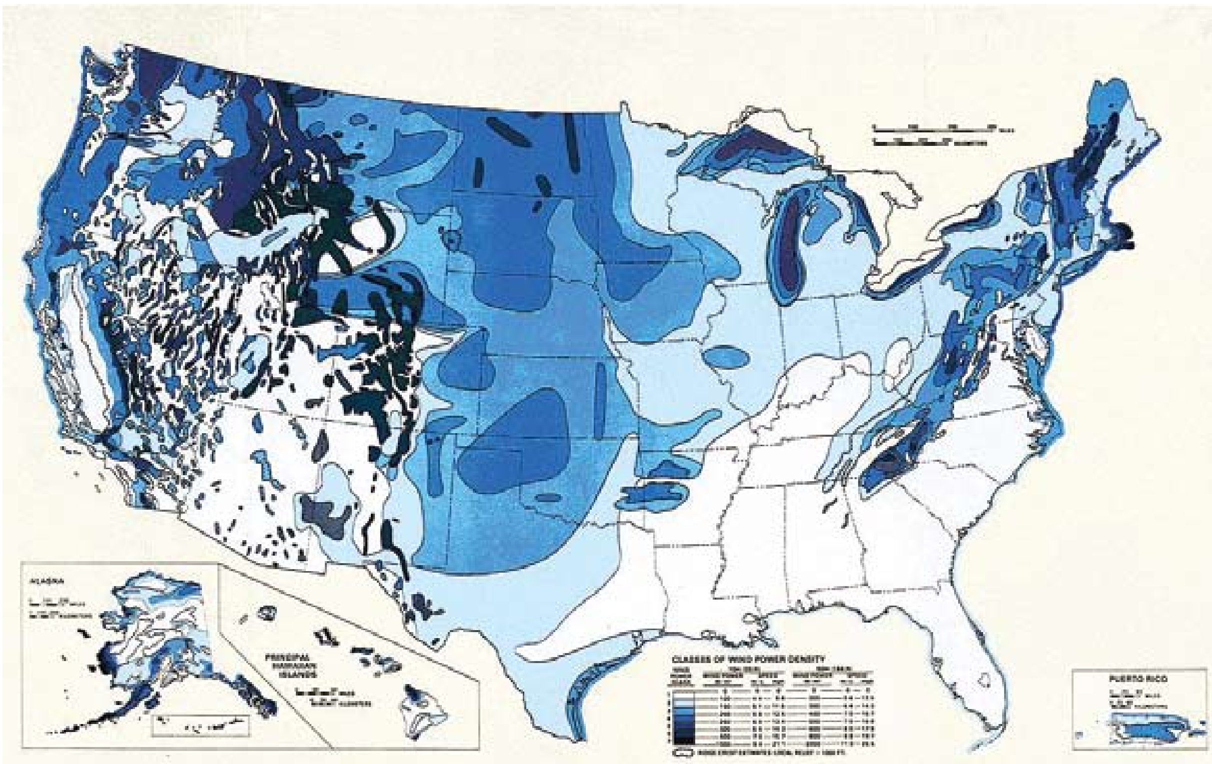
RESOURCE AVAILABILITY

In general, cost-effective development of wind energy requires a sufficient strong wind resource (a rating of 3 or greater). Figure 2-5 provides an overview of U.S. wind energy resources. The map shows the excellent wind resources located in the central plains; however, most of these resources are located at a considerable distance from the country's population and load centers. Transmission lines and national infrastructure would have to be improved in order to capture the full benefit of these wind resources. However, the Midwest does have the opportunity to test

406 U.S. Climate Change Technology Program, 2005.
407 Ibid.
408 European Commission, 2006.
409 U.S. Climate Change Technology Program, 2006.

higher levels of wind power penetration into local grids to determine optimal sustainable levels and provide important research for the rest of the country. In the long term, the Midwest has the potential wind resources to supply the majority of U.S. power needs, if issues surrounding infrastructure, transmission and storage can be addressed. For example, North Dakota, the state with the highest total wind resources, has the potential to generate 1,210 billion kWh of power, or one-third of current U.S. electricity consumption, from its class 3 or better wind resources.[410]

Figure 2-5: United States annual average wind power[411]



CHALLENGES

Cost

Most renewable forms of energy production cost more than conventional forms of energy generation. Some of the cost difference could be mitigated by accounting for the full direct and indirect lifecycle costs of using energy resources. By considering and quantifying the intangible effects or external costs of various energy resources, such as long-term impacts on health and environment, the full cost of utilizing a power supply can be internalized into the cost structure of the resource. Internalizing these costs will provide appropriate price signals to energy markets, deterring the use of energy resources that have large external costs that are borne by other areas of the economy. Although wind energy is already economically competitive with conventional forms of energy production in areas with good wind resources, by taking into account the external costs of energy production, wind energy becomes even more competitive.

410 American Wind Energy Association, 2005a.

411 Pacific Northwest Laboratory, 1985.

Transmission and Storage

Offshore wind farms offer the potential to locate wind energy generation capacity close to population centers in the United States. As of 1998, more than 53 percent of residents live in coastal counties that comprise 17 percent of the country's land mass.[412] The major onshore wind resources are located in the Rockies and in the Midwest, well away from this portion of the population. If wind energy is to become a major contributor to the nation's power supply, either offshore wind energy will need to be widely adopted or major transmissions projects will need to be undertaken by public or private interests in order to transmit wind power generation from its source to the major population and load centers.

Electricity storage has not been commercially feasible up to this point. Two and a half percent of the nation's electricity capacity has storage capability, almost all through the use of pumped storage hydroelectric plants. Another technology currently in use for daily load shifting is compressed-air energy storage, which uses electrically driven compressors to fill an underground reservoir during off-peak hours. When needed, air is discharged from the reservoir into an expansion turbine connected to a generator. Germany has a 290 MW plant of this type that has been operating since 1978 to store energy generated by a wind plant in close proximity.[413]

Various types of batteries have been used to store energy, though they can have high energy losses, are expensive and carry especially steep maintenance costs. However, they are commercially available and can be advantageous with distributed generation. One promising new technology that could be applied on the utility scale is superconducting magnetic energy storage. In this system, energy is stored in the magnetic fields produced by continuously circulating current in a direct-current superconducting coil. Today's technology designs are in the 10 to 100 MW range and have theoretical efficiencies approaching 95 percent. These systems are ideal for fast discharge, with 1 to 3 MW systems capable of discharging more than 1kWh in about one second.[414] Because of its fast discharge rate, this technology is best used for power quality and transmission stability purposes rather than long-term energy storage for load leveling.

Aesthetic/NIMBY Issues

People living near proposed large-scale wind farms often bring up the visual and noise concerns that they associate with such facilities, concluding that wind generated energy is acceptable so long as it is NIMBY. To counteract such objections, wind turbine manufacturers have developed surface coatings for turbine blades that can reduce their visual impact. Various technologies and noise proofing materials also have been developed to help reduce sound output to a minimum. The sound of a working wind farm is actually less than normal road traffic or an office; 35 to 45 decibels from 350 meters away.[415] Even with these advances, a number of communities, both in the United States and internationally, oppose the development of wind energy near their locations or near other cherished lands.

Many of the excellent wind resources of the United States are located in rural areas where aesthetic issues would logically be minimized. In practice, this has not always proved true, as the lower density of human occupation is counteracted by stronger opposition to the introduction of massive and highly visible industrial technology into an area that is perceived to be naturally or aesthetically pristine. While the most familiar case for offshore wind development focuses on the defeat of the proposed offshore wind initiative in Massachusetts, NIMBY issues for offshore wind farms might be managed by placing wind turbines further from shore; however, platform and

412 Culliton, 1998.
413 Moore & Douglas, 2006.
414 Ibid.
415 British Wind Energy Association, 2000.

transmission costs increase with increased distance from the shoreline, emphasizing the need for thorough cost-benefit analysis during site consideration.

Avian deaths were considered a significant side effect of wind power development in the 1980s and `90s, after an unusually high number of raptor deaths at the Altamont Pass wind farm in California. Numerous studies have been conducted over the past two decades in response to this event. The majority of the studies concluded that the wind turbines were not well placed; for example, a recent study commissioned by the state of California determined that better future placement of turbines could avoid common flight paths of birds.[416] Indeed, avian deaths at the same site have decreased as wind turbine technology has progressed. As wind turbines have grown in size over the past 25 years, their rotors now make fewer revolutions per minute, making the blades easier for birds to see and avoid. Avian mortality from wind turbines can also be reduced through proper risk assessment and site placement.

Regulatory

One of the largest obstacles for wind farm developers is obtaining the various development and operational permits from local, state and federal governments, depending on the location of the proposed site.[417] Interconnection studies are required for each new site request as well. As a result of current rules, the same level of study is required for a small wind plant as for a large coal-fired plant; due to the ever-changing nature of inputs to the grid, a new project renders an earlier study invalid.

Offshore regulatory approval processes are still in development. Currently, individual states have authority over waters within three miles of their shores, and the federal government controls waters from that point up to 200 miles out. Most offshore projects will require review from the Army Corps of Engineers, the U.S. Fish and Wildlife Service, the U.S. Coast Guard and potentially other agencies, depending on the site specific impacts.[418]

Intermittency of Supply

One of the critical issues for future success of wind energy is the challenge of intermittency. Though electricity-storage technologies are under development, wind energy cannot currently be controlled or stored; U.S. power companies typically do not place any value on its capacity. Utilities are required to have enough available capacity to more than meet peak demands. Having this capacity available, even when some of it is not generating electricity, is valuable, but only if the capacity can be counted on to generate electricity when needed. Utilities and power companies view wind in the same category as demand, in that they cannot fully predict or control it. In the United States and regions of Europe, wind energy is viewed more as a "negative load" than a supply resource. If a utility cannot fully count on wind as capacity to maintain reliability, the utility must have additional capacity available. The need for additional reserve capacity in order to meet full capacity demand, as is required by regulatory authorities, results in additional costs to the system.

A shift in perspective and regulatory approach may help resolve concerns around wind intermittency. Addressing capacity concerns are important; yet, wind energy is an unconventional method of power generation. Wind power is predominately an energy resource. The intermittency of wind power is, in many cases, no different in its effects on the electrical grid than the intermittency of load, and therefore wind power can be (and is) managed productively.

The means by which a power company manages load intermittency also apply to wind energy. The aggregate load of an electrical grid typically has a high degree of randomness and uncertainty. In order to minimize this un-

416 Smallwood & Neher, 2004.
417 For specific state information visit: http://www.nationalwind.org/publications/siting/Siting_Factsheets.pdf
418 Renewable Energy Policy Project, 2003.

certainty, grid controllers create day-ahead forecasts that are continually updated as the load period approaches. Because load demands are uncertain, grid controllers have developed methods to respond to load changes as they occur, thus ensuring the reliability of the electrical grid. This same approach facilitates wind energy transfer to an electrical grid intermittently without significantly increasing operating costs.

Power purchasing agreements in both the United States and Europe typically acknowledge the negative load characteristics of wind power and allow wind energy transfers to the electrical grid to fluctuate from planned output levels. German wind power generators are guaranteed €0.0836 for each kWh generated for five years for a wind turbine installed in 2006 and €0.0528 for all following years.[419]

In California, many wind power purchasing contracts are still Standard Offer contracts of the type developed back in the 1980s in response to federal and California regulations that required that the state's utilities accept and pay for all renewable energy generated. In Texas, utilities typically have followed this precedent by accepting all wind energy generated by contracted power generators unless exceptional events (primarily transmission constraints) require that turbines be shut down. More recently, power purchasing contracts in California have begun to include penalties for undersupplying wind power but not oversupplying. This change has presented an additional cost to wind power producers, but not one that has significantly changed the economic competitiveness of wind power generation.

In exchange for allowing power generation to fluctuate without penalty, U.S. utilities expect wind power generators to provide accurate day-ahead forecasts of planned power generation in order to better predict the load that utilities will need to meet using conventional power generation. Meteorological forecasting and modeling to manage load has facilitated more effective and efficient management of wind intermittency, which is strongly influenced by shifts in weather. Wind energy contributions to the grid's reliability vary depending on the wind resource used and the characteristics of peak load in the region. Forecasting and probabilistic modeling are used to manage this variability and uncertainty. These tools enable day-ahead forecasts of wind power generation levels by forecasting services that achieve average margins of error between 13 percent and 21 percent.[420] Wind forecasts are updated periodically up to 20 minutes before the generation period begins in order to refine the forecasted wind levels. In this time frame, uncertainty in the wind forecast is very low for a typical wind resource.

German wind energy providers use similar forecasting methods, including a forecasting tool known as Wind Power Management System to predict hourly wind power output. The tool has a 9 percent margin of error for 24-hour ahead forecasts, and this margin of error decreases to 8 percent for eight hours ahead and 2 percent for one hour ahead.[421] By following the changes in wind power forecasts and taking into account the margin of error within the forecasts, German electrical grid managers can adjust planned generation accordingly and minimize the amount of reserve capacity contracted. This process is largely the same as that used by U.S. electrical grid managers.

Nevertheless, wind does have some capacity value, particularly with large wind farms or multiple wind farms geographically dispersed on the same system. When spatially diverse wind farms are used, large energy fluctuations tend to be further moderated by the statistically random fluctuations of individual wind turbines,[422] while the catastrophic sudden loss of wind power generation "is not a credible event."[423] A single wind turbine may briefly stop producing electricity altogether and would not be considered to have any capacity value. The more turbines at different locations within the same system, the greater the likelihood that a percentage of wind

419 German WindEnergy Association, 2006.
420 UWIG, 2003
421 International Energy Agency, 2005b.
422 Ibid.
423 Utility Wind Integration Group, 2006.

capacity will be generating electricity at all times. According to Hannele Holttinen at the Technical Research Centre of Finland, geographically dispersed wind power will reduce variability, increase predictability and decrease the occasions with near zero or peak output. Holttinen concludes that hourly variations in large-scale wind power production in Denmark and Nordic countries are "91% – 94% of the time within ±5% of capacity and 99% of the time between ±10% of capacity."[424]

The American Wind Energy Association suggests as a general rule of thumb that 35 percent (or the specific capacity factor for an installation) of a wind farm's rated capacity be considered firm capacity.[425] The Colorado Public Utility Commission determined that Xcel Energy's Lamar wind farm, with a generating capacity of 162 MW, has an equivalent firm capacity of 48 MW and, therefore, was eligible to count as capacity for reliability reasons and receive capacity payments.

Two significant studies on the cost of integrating wind power to the grid were conducted in recent years by the Bonneville Power Authority and Xcel Energy. In 2002, the power authority completed a study which concluded that 1,000 MW of wind power modeled on existing wind power installations operated in the region would cost the utility $0.19/MWh of wind power generation in power regulation services (assuming $11/MWh of regulation services) and $0.28/MWh of wind power generation in spinning reserves (assuming $5/MWh of spinning reserves).[426] In comparison, the Xcel study found that adding 1,500 MW of wind power capacity to the Minnesota grid would cost $0.23/MWh of wind power generation for regulation requirements, negligible cost increases per MWh for load-following services and $4.37/MWh for average hourly integration costs. The Xcel study also calculated that the current 400 MW of wind power in Minnesota had an effective load carrying capacity of 135 MW, while an addition of 1,500 MW of wind power capacity would improve the system's effective load carrying capacity by another 400 MW.[427]

In general, the U.S. and European consensus is that at low levels of market penetration (1 percent to 3 percent), the intermittent generation of wind energy poses indiscernibly small costs to the reliable operation of the electrical grid; fluctuations in wind energy generation are completely drowned in the "noise" of random load shifts and the contingency plans developed to address these load shifts. Costs to the electrical grid increase as wind energy penetration increases; at market penetration levels between 10 percent and 20 percent, the additional operating cost are less than $5/MWh and are largely the result of uncertainty in the day-ahead forecasts and the need for additional standby generation for ramping requirements.[428],[429]

424 Holttinen, 2005.
425 American Wind Energy Association, 2004b.
426 Hirst, 2002.
427 Zavadil et al., 2004.
428 Utility Wind Integration Group, 2006.
429 Smith, 2005.

Renewable Energy: Solar

Solar energy can be harnessed for electricity generation using photovoltaic cells (PV) or concentrating solar power technologies (CSP). With PV, semiconducting materials convert sunlight directly to electricity, while CSP concentrates energy from the sun to power a turbine or generator. Both of these technologies can be used for either utility-scale generation or distributed generation, though PV is better suited today to distributed generation and niche applications and CSP to utility-scale generation.

SOLAR PV: CRYSTALLINE SILICON AND THIN FILM TECHNOLOGIES

Crystalline Silicon

PV cells typically consist of a glass or plastic cover, an antireflective layer, a front contact to allow electrons to enter a circuit, a back contact to allow them to complete the circuit and several layers of semiconductor material where electrons are "freed" from their atoms and electric current is created. Although PV cells can be based on other photoreactive materials, silicon is dominant, being used in 98 percent of PV cell production.[430] Other photoreactive materials, such as gallium arsenide and cadmium telluride (CdTe), convert energy much more efficiently than silicon; however, the cost per kWh is significantly higher, forcing them into critical applications, such as space vehicles, where maximizing electric output is more important than minimizing cost.

Crystalline silicon can either be in a single-crystal state or multicrystalline. Single-crystal silicon is made by melting high-purity silicon and reforming it to adapt to the pattern of the initial single-crystal seed, resulting in a uniform molecular structure. Multicrystalline silicon can be made with refined lower-grade silicon rather than the semiconductor grade required for single-crystal material. Multicrystalline silicon devices are generally less efficient than those of single-crystal silicon, but they can be less expensive to produce.[431]

Cost

Like other renewable energy technologies that rely on naturally occurring energy resources, crystalline silicon PV has high initial capital costs and very low operating and maintenance costs. The equipment and physical solar cells of a typical 3 kW grid-tied system will account for approximately 85 percent of the project's total cost, with the remaining 15 percent coming from the design and installation of the system. Operating and maintenance costs for an installation of this size are estimated to be $0.01 per kWh.[432] Scheduled maintenance usually consists of washing the solar panels to remove dust and dirt that collect on the panels in many climates and applications. Technical problems with the solar panel modules are rare, and inverters, though once problematic, are showing improved performance and reliability.[433]

World PV market installations reached a record high of 1,460 MW in 2005, representing annual growth of 34 percent.[434] This growth, which largely occurred in Germany and Japan, made solar panels relatively scarce in the United States during 2005, as the global supply of high-grade silicon was significantly outstripped by silicon demand in the electronics and solar cell industries. In the coming years, additional high-grade silicon purification plants will begin operations, but the two to three year lag times for commercial production drives up the capital

430 National Renewable Energy Laboratory, 2006f.
431 Office of Energy Efficiency and Renewable Energy, 2006g.
432 Public Renewables Partnership, 2006.
433 Ibid.
434 Solarbuzz LLC, 2006b.

cost of solar panels, likely on a temporary basis. Despite current silicon shortages, prices for PV are expected to continue their downward trend in the near future.[435]

New materials for PV construction, such as thin films, will reduce the pressure on demand for crystalline silicon in coming years while allowing the solar energy industry to continue to grow. Because of the infancy of thin films, the production of crystalline silicon PV will likely continue to dominate the solar energy market for the next several years.[436]

Due to the cost of silicon and scarcity of high-grade silicon, it is expected that other PV materials and technologies will emerge in the long term. As solar energy conversion efficiencies of thin film PV increase and concentrating technologies based on copper indium diselenide (CIS, or CIGS, when gallium arsenide is added) and cadmium telluride come to market, they will likely provide a more cost effective alternative to silicon, especially for large applications (over 20 kW).[437]

Research & Development

Although the United States produces only about 12 percent of the world's PV cells, it has been a leader in PV research due to government and commercial support as well as the excellent solar resources in the U.S. Southwest.[438] In particular, the Energy Policy Act of 2005 authorized $590 million to be devoted exclusively to solar research. One major research program being funded by the federal government for solar PV is the National Renewable Energy Laboratory's High-Performance PV Program, which is exploring the performance limitations of PV. The aim is to double the sunlight-to-electricity conversion efficiency of PV devices while dramatically cutting the cost of solar energy.

Multijunction concentrators have been one focus of high performance research. This technology uses relatively inexpensive optics to concentrate sunlight onto a small area of high-efficiency multijunction cells. Notably, Boeing-Spectrolab achieved an efficiency of 39.3 percent for one of its multijunction cells.[439]

PV researchers are employing nanotechnology as well. An NREL team found that tiny "nanocrystals," also known as "quantum dots," produce as many as three electrons from one high energy photon of sunlight. When today's PV cells absorb a photon of sunlight, the energy gets converted to, at most, one electron, and the rest is lost as heat. Research has shown that solar cells based on quantum dots theoretically could convert more than 65 percent of solar energy into electricity, approximately doubling the efficiency of today's highest efficiency solar cells.[440]

Thin Film

Thin film technology refers to the method used to deposit thin layers of photoreactive material on a substrate. Instead of a metal grid for the top electrical contact, thin film uses a thin layer of a transparent conducting oxide. One advantage of thin films is how little material they use; the cell's active area is usually only 1 to 10 micrometers thick, whereas conventional cells typically are 100 to 300 micrometers thick. Thin film cells can usually be manufactured in an automated, continuous production process. These advantages support the long-term cost competitiveness of thin film cells. In addition, thin films can be deposited on flexible substrate materials (e.g., roofing materials) and can be made as a single unit instead of individual panels interconnected into a module.[441]

435 National Renewable Energy Laboratory, 2005c.
436 Malsch, 2003.
437 von Roedern et al., 2006.
438 International Energy Agency, 2005a, pp. 16-17.
439 National Renewable Energy Laboratory, 2006b.
440 National Renewable Energy Laboratory, 2005b.
441 Office of Energy Efficiency and Renewable Energy, 2006g.

Thin films are the fastest growing segment of the PV market and can be made with a variety of semiconductor materials. The three most common are amorphous silicon (a-Si), CdTe, and CIS or CIGS. Amorphous silicon was heralded in the 1980s as the technology of choice, but fell out of favor due to its instability and low energy conversion efficiency. Multijunction cell configurations have helped solve these problems by layering different semiconductor materials in specific ways to allow each layer to produce electricity from a different region of the solar spectrum. In the near term, a-Si modules with 6 percent to 8 percent efficiencies are expected.[442]

One of the major benefits of CdTe and CIGS technologies is that they do not have the same material limitations as silicon, making these technologies competitive with crystalline silicon in today's market of silicon scarcity. CdTe thin-film technology has progressed to the point of commercial production. CdTe cell efficiencies are over 16 percent in the laboratory, while commercial module efficiencies are in the 7 percent to 10 percent range in the first manufacturing plants. Fabrication of these cells is inexpensive, and there are more than a dozen ways to make cells that are 10 percent efficient. These characteristics provide the potential for high-efficiency modules with low-cost manufacturing processes.

With 19.5 percent efficiency under standard test conditions, the best CIS cell is about as efficient as the best polycrystalline-silicon cell. The potential for high module efficiencies and low cost has led to a large increase in private investment. Currently, the technology is making the transition to first-time manufacturing.[443] Research indicates that CIS and CdTe module technology presently offer the best approach for significantly exceeding the cost/performance levels established by crystalline silicon technologies.[444]

Increased thin film production will lower PV prices, helping them compete with other renewable generation. According to the Thin Film Partnership at NREL, future module efficiencies are expected to climb close to that of today's state-of-the-art cells, which have achieved energy conversion efficiencies of 10 percent to 16 percent. Costs are expected to drop to below \$100 per square meter ($m^{2)}$ in volume production, and could cost less than \$50/m^2 when fully optimized. At these levels, thin film modules will cost less than 50 cents per watt (\$500 per KW) to manufacture, opening new markets such as cost-effective distributed power and utility production to thin-film electricity generation.[445] In order to achieve this goal, additional testing and improving 30-year outdoor warrantable lifetimes will be necessary in order to compete with the excellent reliability of current silicon based PV. Reducing cost is one of the most important R&D efforts for all renewable energy technologies, and thin film PV is no exception, with a long-term goal of \$0.06/kWh.[446]

CONCENTRATING SOLAR POWER

Concentrating solar power plants produce electric power by converting the sun's energy into heat using various mirror configurations; the heat energy is then channeled through a conventional generator to produce electrical power. CSP plants are best suited for utility-scale applications in the 10 to 400 MW range. Current CSP technologies include dish/engine systems, power towers and solar troughs. CSP technologies can incorporate cost-effective thermal storage techniques or be part of a hybrid power system, in which one part runs on fossil fuels, allowing the plant to generate power during periods of low solar energy.

442 National Renewable Energy Laboratory, 2006g.
443 Ibid.
444 von Roedern et al., 2005.
445 National Renewable Energy Laboratory, 2006g.
446 Frantzis & Mints, 2006; U.S. Climate Change Technology Program, 2005. Page 2.3-5

Dish/Engine Systems

A solar dish/engine system is an electric generator that uses sunlight to produce electricity via a solar concentrator and power conversion unit. The concentrator, or dish, collects the solar energy and focuses it on a receiver. Silver/glass mirrors are often used, as they reflect approximately 92 percent of the sunlight, are relatively inexpensive, durable and easy to maintain. The dish structure tracks the sun on two axes, allowing it left/right and up/down rotations. The thermal receiver absorbs the concentrated beam, converts it to heat and transfers the heat to the engine/generator. The thermal receiver is typically a bank of tubes with a cooling fluid, usually hydrogen or helium. This cooling fluid transfers heat and is the working fluid for an engine. Alternate thermal receivers are heat pipes wherein the boiling and condensing of an intermediate fluid is used to transfer the heat to the engine. The engine/generator uses the heat from the thermal receiver to produce electricity.[447]

Dish/engine technology is the oldest of the solar technologies, dating to the 1800s when a number of companies demonstrated solar powered steam-Rankine and Stirling-based systems. Modern technology was developed in the late 1970s and early `80s. The dish/engines of this time were already recording conversion efficiencies of 29.4 percent.[448] A number of companies tested various dish/engines into the mid-1990s without any commercial success. In August 2005, Stirling Energy Systems Inc. signed an agreement with a subsidiary of San Diego Gas and Electric (SDG&E) to sell energy produced on a 4,500 acre dish/Stirling farm in the Mojave Desert. The initial phase will consist of a 500 MW solar farm produced from 20,000 25 kW dish arrays built over four years, with an option to expand to 850 MW. A second contract was signed with SDG&E one month later to build another dish/Stirling farm projected to have an initial capacity of 300 MW, with the potential to increase to 900 MW.[449]

Dish/engine systems look likely to become a cost-competitive method of electricity generation over the next 10 years. The conversion rate is much higher than with trough systems (see below) and costs are expected to fall exponentially as more commercial applications are added. (Current costs of $150K per 25 kW dish are expected to drop to as low as $50K/dish, according to Stirling Energy Systems Inc.)[450] The performance of the two upcoming projects in California will be critical for the industry's success and are a result of California's goal to have 20 percent of its energy from renewable sources by 2010.[451]

Researchers are developing advanced reflective materials to replace the silver/glass mirrors that comprise the dishes in this type of system. Some polymer films and stretched membranes may have greater reflectivity and be more cost-efficient than the glass materials used currently. As was noted in the PV section, if fully funded, the Energy Policy Act of 2005 should have a positive impact on all types of solar research by devoting $590M exclusively to solar research.[452]

Power Tower Systems

Solar power towers generate electric power from sunlight by focusing concentrated solar radiation on a tower-mounted heat exchanger (receiver). Hundreds to thousands of sun-tracking mirrors (heliostats) are used to reflect the incident sunlight onto the receiver. Power towers can be integrated with a molten-salt pump system to store energy to be used when solar radiation is low, maintaining full capacity for up to 13 hours. In a typical installation, solar energy collection occurs at a rate that exceeds the maximum required to provide steam to the

447 Sun-Lab, 2001.
448 Sun-Lab, 2001.
449 Stirling Energy Systems Inc., 2005.
450 Gnatek, 2005.
451 Database of State Incentives for Renewable Energy, 2006b.
452 U.S. Energy Policy Act of 2005.

turbine so that a thermal storage system can be charged at the same time that the plant is producing power at full capacity. Tower systems with energy storage capability have been shown to have a capacity factor of about 65 percent. Without storage, the capacity factor is about 25 percent, although typically more power is generated through this method due to the energy penalty that results from thermal storage.[453]

Experimental towers have been in production for 25 years, though no large-scale power towers have been built to date. The Department of Energy was a pioneer in solar power tower technology, with its Solar One and Solar Two projects. Operation for Solar One began in 1981 and aimed to prove that large-scale power production with power towers was feasible. Solar One used a water/steam thermal storage system that proved ineffective and spurred study of molten-salt power towers. Solar Two operated from 1996 to 1998. It was a redesign of Solar One using molten-salt for power storage and updated materials for the salt transfer.[454]

Spain built the first commercial tower, called PS10, an 11 MW project with a small one-hour storage capacity. This tower uses water stored in thermally clad tanks for storage instead of a molten salt system. The hot water does not require the high temperatures needed in the molten salt systems, reducing the overall wear and increasing generator life.[455]

Also in Spain, a larger commercial solar power tower plant is set to begin construction in 2006. The generation plant will have a 50 MW capacity and use a molten salt thermal storage system to extend daily electricity generation to over 12 hours in winter and up to 20 hours in summer.[456] Cost estimates are unavailable at this time.

There are a number of R&D efforts under way to improve technology and reduce costs associated with power towers. NREL and SunLab are conducting research on higher reflectivity mirrors made from lighter glass or films, receiver enhancements in materials and parts to reduce radiative loss, and advanced molten salt to lower the salt's freezing point in order to decrease parasitic power consumption.[457]

Trough Systems

Trough systems concentrate the sun's energy with parabolically curved, trough-shaped reflectors focused onto a receiver pipe running along the area surrounded by the curved surface. This energy heats synthetic oil flowing through the pipe to temperatures approaching 400 degrees C, and the heat energy is then used to generate electricity in a conventional steam generator. A collector field comprises many troughs in parallel rows aligned on a north-south axis. This configuration enables the single-axis troughs that ensure the sun is continuously focused on the receiver pipes. The heated fluid is used to generate high-pressure superheated steam, which is fed into a conventional reheat steam turbine/generator to produce electricity. Currently all U.S. trough plants are hybrids, using natural gas to supplement output during periods of low solar radiation.[458] This approach ensures consistency in power supply and allows both capacity and energy payments, similar to proposals for wind power.

Historic Improvements and Key Drivers

A 64 MW trough solar system currently under construction in Nevada has an estimated levelized power cost of between 9 and 13 cents per kWh.[459] NREL worked closely with Solargenix, the solar technology company in

453 Office of Utility Technologies, 1997.
454 Ibid.
455 Stirzaker, 2006.
456 Environment News Service, 2006.
457 Sargent & Lundy LLC Consulting Group, 2003, pp. 5-2 -- 5-3.
458 Sandia National Laboratories, 2006a.
459 Broehl, 2006.

charge of the project, to assess the optical performance of Solargenix's parabolic-trough concentrators. Testing included how accurately the mirror shape follows the optimal parabolic shape and the accuracy of aligning the mirrors so that reflected sunlight hits the receiver tube. The Solargenix SGX-1 collector design uses an aluminum hub system to create a structure that is 30 percent lighter, has 50 percent fewer pieces and requires substantially fewer fasteners than earlier designs. The aluminum structure provides better corrosion resistance and has been designed so that the mirrors are mounted directly to the structure and do not require any alignment in the field. The collector uses a new receiver, featuring a number of improvements that increase receiver useful life and performance.

Recently, DOE launched the U.S.A. Trough Initiative in order to bring industry partners together for the purpose of advancing state-of-the-art parabolic-trough technology, integration, analysis and services to improve the competitiveness of the technology in the U.S. power market. Specific activities within the initiative are intended to lower costs, improve performance and reliability, and reduce commercial risk.[460]

Current Cost

Similar to other renewable technologies, including PV Solar, the cost of energy for CSP has decreased steadily over time, yet it is projected to level off after 2015 as additional technical and economic efficiencies become integrated into the market. Studies vary in their cost estimates for new CSP plants, as a result of only limited commercial development up to this point.

One study conducted for NREL in 2004 found that the levelized cost of energy for a new parabolic trough CSP plant was between $99 and $120 per MWh. The same study estimated that the 2004 LCOE for a solar tower CSP plant was between $114 and $143 per MWh.[461] A more recent study done for NREL estimated that the 2007 LCOE for a 150 to 200 MW parabolic trough CSP plant with six hours of thermal storage is $140/MWh.[462] Dish/engine solar power systems are estimated to currently have a LCOE above $400 per MWh.[463]

RESOURCE CAPACITY

Solar PV Technologies

Crystalline Silicon

The installed PV capacity in the United States increased by 105 MW in 2005[464] to reach a total of 479 MW.[465] Worldwide, cumulative installed solar PV has surpassed 5 GW, after growing in capacity by 39 percent in 2005.[466] At the end of 2004, Japan was the world leader in PV capacity, with over 1.1 GW installed, and Germany followed with 794 MW.[467] Japan has invested heavily in PV, due to its adequate solar resources, a commitment to energy independence and limited land available to construct fossil fuel power plants. Japan has ample rooftop space and the majority (over 90 percent) of its PV power comes from distributed generation sources.[468]

460 National Renewable Energy Laboratory, 2006h.
461 Sargent & Lundy LLC Consulting Group, 2003.
462 Stoddard et al., 2006. The figure utilizes a 30 percent investment tax credit.
463 National Renewable Energy Laboratory, 2004d.
464 Solarbuzz LLC, 2006a.
465 International Energy Agency, 2005a.
466 Solarbuzz LLC, 2006b.
467 International Energy Agency, 2005a.
468 Ibid.

Thin Film

Currently there are no existing capacity data for thin film PV.

Dish/Engine Systems

Although a number of small experimental projects on the 1 MW scale have been completed, there are no commercial dish/engine systems in operation to date. As noted above, in 2005 Stirling Energy Systems Inc. signed power purchasing agreements with San Diego Gas and Electric to purchase power generated by 500 MW and 300 MW Dish/Stirling solar farms to be constructed in the Mojave desert.[469] If completed, these projects will not only be the first dish/engine farms, but also the largest solar projects in the United States.

Power Tower Systems

Experimental towers have been in production for 25 years, though no large-scale power towers have been built to date. On a smaller scale, Spain has built a commercial tower—an 11 MW project with a one-hour storage capacity.[470] A generation plant in the city of Granada in southern Spain will have a 50 MW capacity and use a molten salt thermal storage system to extend daily electricity generation to more than 12 hours in the winter and up to 20 hours in the summer.[471]

Trough Systems

Private industry built 354 MW of commercial solar trough plants between the mid-1980s and early 1990s. All nine of these plants in the Mohave Desert are still in operation.[472] In December 2005, Arizona initiated construction a 1 MW plant. In Nevada, a 64 MW plant is under construction and scheduled to come online in March 2007.[473]

RESOURCE AVAILABILITY

Figure 2-6 and Figure 2-7 show a distinct difference in resource availability for PV versus CSP technologies. Solar PV has a much broader application range across the country than CSP. Solar resources are at least 5 to 6 kWh/M^2/day for the vast majority of the country, making solar PV a more cost effective technology in the Midwest and the Southeast than CSP. This same resource level (5 to 6 kWh/M^2/day) for CSP is concentrated almost exclusively in the Southwest.

Photovoltaic systems are installed in the Northwest and Northeast in areas with resources of 4 to 5 kWh/M^2/day. At this time, CSP's viability is limited to a large area centered in the Southwest with resources of 7 or more kWh/ M^2/day. Currently, the strong solar resources of California, Arizona and Utah are beginning to be tapped for power generation using CSP.

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469 Stirling Energy Systems Inc., 2005.

470 Stirzaker, 2006.

471 Environment News Service, 2006.

472 National Renewable Energy Laboratory, 2003d.

473 Menand, 2006.

Figure 2-6: Solar photovoltaic resource potential in the United States [474]

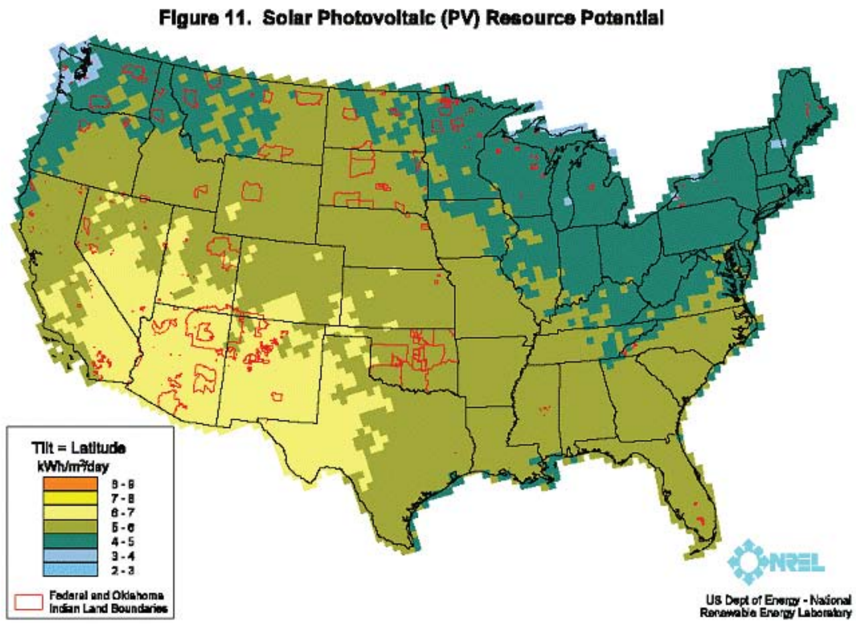
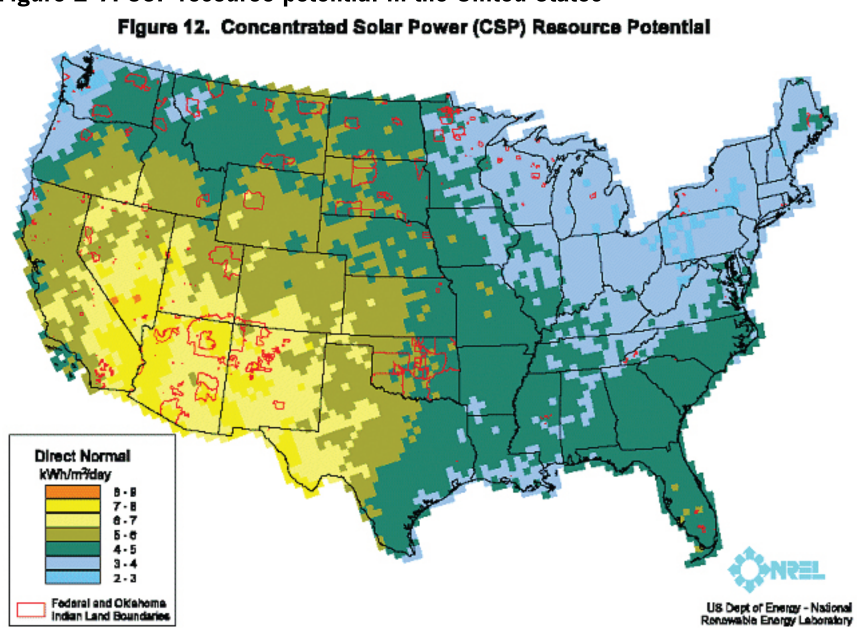


Figure 2-7: CSP resource potential in the United States [475]



CHALLENGES

A major challenge for solar power is the cost of electricity. Currently, all forms of solar power generation produce costs per kWh that are above competing power generation technologies for utility-scale applications; solar PV, for example, is competitive in niche off-grid applications. In order to achieve a significant penetration level within the U.S. electricity market, costs per kWh of generated electricity must come down to levels closer to competing forms of renewable and conventional power generation.

474 National Renewable Energy Laboratory, 2003b.
475 National Renewable Energy Laboratory, 2003c.

The global demand for PV has caused material shortages in the silicon industry. Some of this demand will be alleviated by solar technologies using materials other than silicon. Analysts' views of silicon availability vary widely, but all show a limitation on the growth of the PV industry due to material constraints. Projected growth rates of silicon-based PV in 2006 vary from 5 percent to 25 percent, based on differing views of supply constraints.[476] The ability of the industry to expand the production capacity of high-grade silicon and bring non- and low-silicon solar technologies to market rapidly will be crucial in determining the future growth of the industry.

A perceived challenge to the PV industry has been the use of cadmium, which has been questioned by some in the environmental community who do not believe that using cadmium in PV production is environmentally sensitive. However, some observers believe this challenge is overstated, as the use of cadmium in PV cells is improving a current environmental problem rather than exacerbating one. Cadmium is a byproduct of zinc mining and would be treated as a source waste by mining companies if PV manufacturers did not use it as a resource. Cadmium usually ends up in a slag heap or in NiCd batteries, half of which eventually end up in landfills. PV modules seal the cadmium for the life of the module (20 to 30 years), at which time the cadmium can be recycled.[477] Given appropriate procedures and precautions, the use of cadmium should not negatively effect the environment and may actually reduce the amount of cadmium left uncaptured from zinc mining. In addition, a CdTe PV module contains less than 0.1 percent cadmium by weight, making the overall levels of cadmium used very small. One 8-square-foot module contains less cadmium than one Size-C NiCd flashlight battery, and the cadmium in the module is in a much more environmentally stable form (i.e., a compound rather than a metal).[478]

ECONOMIC POTENTIAL AND POLICY INITIATIVES

Solar PV

The Energy Policy Act of 2005 increased the business tax credit for PV from 10 percent to 30 percent, which is applicable to all system and installation costs for corporate entities that install PV as distributed generators in utility-scale plants. This tax credit increase is scheduled to cease at the end of 2007, at which time the tax credit will return to 10 percent.[479]

An analysis by Navigant Consulting, shown below, calculates the cost of solar PV (average, without respect to material used) without incentives and what each incentive does to decrease the price. On a levelized basis, solar PV is completely dependent on incentives to make the technology competitive with fossil fuel generation. The analysis is based on a case in Phoenix, Ariz., and includes rebates by the Phoenix utility SRP.

In certain commercial installations, solar PV has achieved cost levels that beat retail utility rates on a levelized cost basis. For example, the California Construction Authority, owner of the Silver Dollar Fairgrounds in Chico, Calif., installed a 112 kW amorphous silicon system for \$2.21/watt (\$4.41/watt pre-rebate). The authority achieved this low cost output by purchasing the solar panels in bulk (bundling 5 MW of projects), bidding labor and materials separately, and using the 50 percent rebate from the California Public Utility Commission.[480]

For residential electricity consumers who want to install PV systems, there are federal, state and utility incentives as well. The major federal incentive is the residential solar tax credit, which gives the purchaser of a residential PV system a 30 percent tax credit up to \$2,000 on the cost of materials and installation.[481]

476 Li, 2006.
477 National Renewable Energy Laboratory, 2003a.
478 Ibid.
479 Database of State Incentives for Renewable Energy, 2006a.
480 Solar Electric Power Association, 2003.
481 Database of State Incentives for Renewable Energy, 2006a.

Net metering also can play a role in the economics of residential PV. If homeowners are paid fair rates for the electricity they generated but did not use, they can often recoup the costs of their solar system much faster.[482]

Concentrating Solar Power

The Energy Policy Act of 2005 increased the business tax credit for CSP from 10 percent to 30 percent, which is applicable to all system and installation costs for corporate entities that install solar thermal electric and solar thermal process, including utility-scale plants. The credit is scheduled to go back to 10 percent at the end of 2007.[483]

As with current costs, there is a wide variance in the projections for the future cost of CSP technologies. A 2004 study conducted for NREL calculated that the LCOE for solar trough CSP plants would range between $43 and $62 per MWh in 2020. The same study estimated that the LCOE for a solar tower CSP plant in 2020 would range between $35 and $55 per MWh.[484] A 2006 study conducted for NREL estimated that the LCOE for a trough CSP plant would be $120 per MWh in 2009 and $93 per MWh in 2015.[485] The scarcity of sizable dish/engine test facilities and the lack of any commercial developments make estimating the LCOE potential for dish/engine solar systems difficult to predict at this time, but a goal has been set to get the technology's LCOE under $200 per MWh with the beginning of commercial development, with an ultimate goal of $60 per MWh.[486]

The projected cost reductions will be brought about by efficiency gains in energy conversion, reductions in the materials used, the generation of economies of scale and additional technological advancements.

The potential market penetration for the various CSP technologies will be heavily driven by future technological advancements, cost reductions and public policy choices. Assuming that current cost and technological advancement trends continue and that the federal government's investment tax credit is allowed to decrease from 30 percent to 10 percent at the end of 2007, CSP technologies may not achieve capacity additions beyond 1 to 2 GW until the late 2010s or 2020s. But the time when CSP technologies are broadly utilized can be moved forward by a decade or more if CSP research is able to bring the LCOE for the technologies down by 50 percent and/or the 30 percent investment tax credit is renewed for an additional five to ten years. If these hurdles can be overcome, CSP capacity could reach 20 GW by 2020.[487]

482 A list of net metering standards by state is available at *http://www.solarelectricpower.org/docs/IREC%206_2006%20net_metering.pdf*

483 Database of State Incentives for Renewable Energy, 2006a.

484 Sargent & Lundy LLC Consulting Group, 2003.

485 Stoddard et al., 2006. The 2009 figure is arrived at using a 30 percenet investment tax credit, while the 2015 figure assumes a 10 percent investment tax credit.

486 National Renewable Energy Laboratory, 2004d.

487 Blair et al., 2006.

Renewable Energy: Hydroelectric Power

Water has been used as a source of energy for thousands of years. Water first generated electricity in 1882 to provide power to two U.S. paper mills; hydroelectric power units installed in 1891 in Whiting, Wisc., are still operational today. Hydroelectric power is considered a renewable energy resource by the federal government, utility companies, their trade associations and some nongovernmental organizations. Hydroelectric generation is emission-free, and the power source is generally considered constant (as long as water is readily available) and nonpolluting. Large conventional dams affect the environment in many ways, are not considered environmentally sustainable and are not anticipated as new future projects in the United States. However, small, relatively low impact run-of-river ("in-stream") and "low-head" projects are under evaluation at various sites around the country; such projects would avoid many of the environmental concerns associated with large, conventional hydroelectric projects.

Advanced turbine designs may maximize the use of hydropower and potentially minimize adverse environmental effects.[488] Hydroelectric power generation does not emit greenhouse gases. However, there are environmental impacts associated with large dam projects. After an area is flooded to create a dam, vegetation rots underwater and emits methane for a period, perhaps up to a decade, depending on a variety of local environmental factors. [489] Large dams are also well-known for their effects on fish from passage through turbines, as well as their detrimental effects on the quality of downstream water and other impacts on plant and animal species. A variety of mitigation techniques are now in use, and environmentally friendly turbines are under development. Legal and institutional issues include federal licensing as well as state and local permits, laws for historic and cultural preservation, and recreational requirements.

TECHNICAL OVERVIEW

Hydroelectric generating units operate by harnessing the force of moving water. Water held in a reservoir or lake behind the dam is released and spins the blades of turbines that are connected to a generator that produces electricity.

Types of Hydropower Facilities

Impoundment

Impoundment facilities, also known as "high-head" plants, typically are large hydropower systems that use dams to store river water in reservoirs and take advantage of the force of falling water. The water is released either to meet changing electricity needs or to maintain a constant reservoir level.

Diversion

Diversion facilities, sometimes called "run-of-river" plants, channel a portion of a river through a canal or penstock. These facilities may not require the use of a dam and therefore typically have a smaller environmental impact than high-head plants. However, they also provide far less electrical capacity than impoundment facilities.

488 U.S. Department of Energy, 2006f.
489 New Scientist, 2005

Pumped Storage

A pumped-storage plant uses two reservoirs, one located at a much higher elevation than the other. During periods of low demand for electricity, such as nights and weekends, energy is stored by reversing the turbines and pumping water from the lower to the upper reservoir. The stored water can later be released to turn the turbines and generate electricity as it flows back into the lower reservoir.

Sizes of Hydropower Plants

Facilities range in size from large power plants that supply many consumers with electricity to small and micro plants that individuals operate for their own energy needs or to sell power to utilities. These facilities include:

- Large Hydropower. Facilities that provide more than 30 MW.
- Small Hydropower. Facilities that provide 0.1 to 30 MW.
- Micro Hydropower. Facilities that provide up to 100 kilowatts (0.1 MW).

Turbine Technologies

There are many types of turbines used for hydropower, and they are chosen based on their particular application and the height of standing water ("head") available to drive them. The turning part of the turbine is called the runner. The most common turbines are as follows:

- Pelton Turbines. These turbines have one or more jets of water impinging on the buckets of a runner that resembles a water wheel. Pelton turbines are used for high-head sites (50 feet to 6,000 feet) and can be as large as 200 MW.
- Francis Turbines. These turbines use a runner with fixed vanes, usually nine or more. The water enters the turbine in a radial direction with respect to the shaft and is discharged in an axial direction. Francis turbines will operate from 10 feet to 2,000 feet of head and can be as large as 800 MW.
- Propeller Turbines. These turbines use a runner with three to six fixed blades, similar to a boat propeller. The water passes through the runner and drives the blades. Propeller turbines can operate from 10 feet to 300 feet of head and can be as large as 100 MW. A Kaplan turbine is a type of propeller turbine in which the pitch of the blades can be changed to improve performance. Kaplan turbines can be as large as 400 MW.

COST OF ENERGY

Cost information on conventional hydropower must be used cautiously. Even for projects with the same capacity to generate electricity, the costs of building a hydroelectric project can vary dramatically. Examples of variables include engineering considerations unique to each project site; the developer's ability to transfer electricity generated to the power grid or end user location and potential environmental mitigation needs.

According to the Department of Energy, based on 21 hydroelectric plants that commenced operation during 1993, the average capital cost for construction was $2,000 per kW of capacity.[490] These projects ranged in size from 125 kW to 32.4 MW, averaging 4.81 MW of capacity. The capital cost per kW ranged from $735 to $4,778. The capital cost per kW for nine of the projects was within $300 of the average of $2,000. As a mature technology, the cost in real terms is not expected to change significantly over time.

According to the Energy Information Administration, based on 1996 data, the operation and maintenance of hydropower was 0.7 cents per kWh of electricity.

RESEARCH & DEVELOPMENT

Recent research activities in hydropower resource assessment have focused on unconventional turbine designs, such as free flow turbines or designs for low-head (30 feet or less) sites that have a capacity of 1 MW or less.[491] Generally, low-head sites have fewer environmental challenges, although individual sites may have specific environmental issues that must be assessed and managed appropriately. Generally, development of low-head/low-power sites tends to be uneconomic due to constraints of using conventional turbine technologies. The Idaho National Engineering and Environmental Laboratory is quantifying these types of hydropower resources in regional studies in partnership with the U.S. Geological Survey.[492] New turbine designs have been developed that promise lower environmental impacts. New areas for research include technology to exploit the low-head/low-power resource.

Advanced R&D activity for hydroelectric power is supported by the Department of Energy and the Army Corp of Engineers, in conjunction with industry partners. There are three primary areas of research and development:

- Testing a new generation of large turbines in the field to demonstrate that these turbines are commercially viable, compatible with today's environmental standards and capable of balancing environmental, technical, operational and cost considerations.

- Developing new tools to improve water use efficiency and operations optimization within hydropower units, plants and river systems with multiple hydropower facilities.

- Identifying improved practices that can be applied at hydropower plants to mitigate for environmental effects of hydro development and operation.[493]

DOE's R&D goal is to enable a 10 percent increase in hydropower generation at existing dams, with net benefits to the environmental quality of U.S. rivers. Traditional hydropower is associated with adverse environmental impacts, particularly with respect to fish passage and survival, water quality in reservoirs and downstream from dams, and altered flow regimes that may degrade physical habitat for fish below dams. Advanced research on new turbine designs has been supported jointly by DOE and industry for several years, with the intent to improve environmental performance of turbines without sacrificing energy generation. The advanced turbine research to date has produced two types of new conceptual designs. The two types involve modifications to existing Kaplan and Francis turbines, and an innovative turbine runner with a helical screw shape, patterned after centrifugal pumps.

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490 U.S. Department of Energy, 2005c.
491 U.S. Department of Energy, 2005b.
492 Ibid.
493 Energy Efficiency and Renewable Energy, 2005

Biological design criteria also have been developed in laboratory tests of fish response to physical stresses, such as hydraulic shear and pressure changes. Through the combination of laboratory, field and computational studies, new solutions to environmental problems at hydropower projects are being found. Much of this work is cost-shared between the DOE, the Army Corps of Engineers and industry partners.

The specific actions needed for optimizing operations at hydropower projects are highly project-specific. Operational changes to improve energy and environmental performance include:

- Better monitoring and control of individual turbine units.
- Better monitoring and control of sets of units.
- Coordination of total reservoir releases in a river basin.

Three sets of research projects are being supported under DOE's Hydropower Resource Assessment program: large turbine testing, water use and operations optimization, and improved environmental mitigation.

Large Turbine Testing

Efforts are under way to evaluate a new generation of large turbines in the field to demonstrate commercially viability, compatibility with today's environmental standards and capability of balancing environmental, technical, operational and cost considerations. Test results are designed to determine whether and to what degree the new generation turbines:

- Operate more efficiently and generate more electricity.
- Improve water quality during operation.
- Provide improved conditions within the turbine to safely pass increasing numbers of fish.

Water Use/Operations Optimization

Efforts are focused on developing and demonstrating new tools to improve how available water is used within hydropower units, plants and river systems with multiple hydropower facilities, to generate more electricity with less water and greater environmental benefits.

Energy production from hydropower projects is determined by the type of hardware installed at a site (e.g., turbines, generators), the civil works configuration (e.g., dam structures, reservoir capacity) and the operation of the plant (e.g., timing and mode of water releases, hardware settings).

Generation can be increased at a given plant by optimizing a number of different aspects of plant operations. These include settings of individual units, multiple unit operations and release patterns from multiple reservoirs. Optimizing operations is a potentially new research direction that is responsive to requests from industry and environmental interests. Significant technical challenges remain, including improved hydraulic measurements.

Improved Mitigation Practices

Projects in this area are focused on studying the benefits, costs and overall effectiveness of environmental mitigation practices and developing guidance that will enable best-available technology to be used in hydro development and operation.

The program is currently supporting several environmental mitigation studies, focused on in-stream flow issues and on fish passage requirements at hydropower projects, but progress on mitigation studies has been limited in the past several years by congressional appropriations and by the DOE program emphasis on advance turbine research.

Operational changes to conform to regulatory requirements can have a substantial adverse affect on power generation and power values at individual projects. Therefore, the current mitigation research being conducted is focusing on in-stream flow requirements that constrain peaking operations, such as ramping rates. Additional studies are planned on the effectiveness of fish passage technology at hydropower projects.

Department of Energy hydro-testing in the areas described above was completed by mid-2006, and a detailed report was slated to be available by the end of the year. However, Congress in 2006 ended funding of DOE's hydropower research initiatives, ordering the agency to "complete all research programs in 2006."[494] Lack of continuing federal support is reportedly due to a lower priority assigned to hydro-based electric power generation relative to competing interests for other uses of water for irrigation, recreation and drinking.

RESOURCE CAPACITY

Hydroelectric stations currently supply approximately 20 percent of the world's demand for electric power. Some mountainous nations, such as Switzerland and New Zealand, meet as much as 50 percent of their domestic electric demand through hydroelectric power.

The Department of Energy reports that existing "hydroelectric power facilities in the United States can generate enough power to supply 28 million households with electricity, the equivalent of nearly 500 million barrels of oil."[495] Total U.S. hydropower capacity—including pumped storage facilities—is about 95,000 MW, or roughly 10 percent of U.S. electric energy needs. More than 80 percent of existing hydropower projects could be upgraded for increases in efficiency and capacity, according to a 1991 report by the Oak Ridge National Laboratory. The estimate of potential includes 15 to 20 GW at existing dams and more than 30 GW of undeveloped hydropower. Retrofitting advanced technology and optimizing system operations at existing facilities would lead to at least a 6 percent increase in energy output; once installed, this would equate to 5 GW and 18,600 GWh of new energy production.[496]

A DOE initiative in the early 1990s proposed upgrading existing dams and retrofitting existing hydropower plants to increase capacity by 16 GW. As the Oak Ridge National Laboratory noted in its study, such an increase would replace approximately 1.2 percent of predicted fossil fuel increases between 1990 and 2030. Upgrading and retrofitting existing dams and hydroelectric sites is believed to have relatively minor environmental impacts, since disruption occurred during construction and installation of the original project. The most likely environmental impacts are predicted to occur as a result of increasing water flow rates at a given site; these effects are considered manageable using accepted mitigation techniques and are thought to be minor relative to environmental benefits of increased water quality and reduced fossil fuel emissions.

The Idaho National Engineering Laboratory, in conjunction with DOE's Hydropower Resource Assessment program, designed the Hydropower Evaluation Software (HES) to evaluate the potential of undeveloped conventional hydropower in over 30 states (pumped storage is not included).[497] In 1997, the researchers classified potential hydropower development at new sites and additional capacity at sites already with hydropower, but

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494 Personal communication, Jim Ahlgrimm, Department of Energy, Hydropower Research Team Leader, May, 2006

495 U.S. Department of Energy, 2006

496 U.S. Climate Change Technology Program, 2003

497 Idaho National Laboratory

not developed to their full potential. Modeling of undeveloped U.S. hydropower resources, based on environmental, legal and institutional constraints, identified 5,677 sites that have a total undeveloped capacity of about 30,000 megawatts.[498]

The 10 largest hydropower projects in the United States account for almost 23 GW of installed capacity (Table 2-38). Of these projects, four are located in the Pacific Northwest and produce 13 GW of electrical power, or approximately 50 percent of the region's energy load requirements.[499]

Table 2-38: Largest hydroelectric projects in the United States[500]

Dam Name	River	State	MW
Grand Coulee	Columbia	Washington	6,180
Chief Joseph	Columbia	Washington	2,457
John Day	Columbia	Oregon	2,160
Bath County P/S	Little Back Creek	Virginia	2,100
Robert Moses - Niagara	Niagara	New York	1,950
The Dalles	Columbia	Oregon	1,805
Ludington	Lake Michigan	Michigan	1,872
Raccoon Mountain	Tennessee River	Tennessee	1,530
Hoover	Colorado	Nevada	1,434
Pyramid	California Aqueduct	California	1,250

Reflective of the large resource and capacity of the Northwestern region, one example of retrofitting and upgrading commonly cited pertains to the Clatskanie Public Utility District of Idaho and Oregon. This region has the third lowest residential power rate in the nation and is continuing its efforts to find alternative low-cost energy sources. The Public Utility District and five Idaho and Oregon irrigation districts have agreed to jointly develop a 15-megawatt hydroelectric project on the existing Arrowrock Dam northeast of Boise, Idaho. The project is expected to cost $41 million and produce an average of 81,000 megawatt hours of electricity per year, which will be purchased by the Clatskanie Public Utility District. The project will place two 7.5-megawatt turbines on existing dam outlets and reconstruct a 5.5-mile power line to a substation. When completed in 2008, it is expected to provide about 8 percent of the Clatskanie district's energy needs.[501] Another new 8.3 MW plant is planned in Oregon at an Army Corps of Engineers dam. [502]

RESOURCE AVAILABILITY

Hydroelectric power is typically considered more reliable in the short term than other renewable energy sources, such as solar and wind. The renewable nature of hydroelectric power may be influenced by long-term climate change impacts on precipitation patterns and hydrological cycles. Climate models indicate that certain regions of the United States could experience higher temperatures and significant decreases in precipitation in coming years, which will decrease stream flow and water levels at impoundment sites. Atmospheric warming also contributes to faster evaporation rates from reservoirs, compounding the effects of prolonged drought on hydroelectric power capacity. Recent reports of drought-related impacts on hydroelectric generating capacity include:

- In February 2006, Tanzania introduced daytime power cuts, after drought lowered water levels in dams.[503]

498 Idaho National Laboratory, 1997
499 Robinson, 2006.
500 Subcommittee on Water and Power, 2006.
501 Manny, 2006.
502 The Register-Guard, 2005.
503 BBC News, 2006.

- In January 2005, Uganda reported that prolonged drought "significantly affected water levels on Lake Victoria, reducing hydroelectric power generation capacity and increasing power shortages across the country."504

- In December 2002, The New York Times reported that drought reduced generation of hydroelectric power in the United States by 23 percent, resulting in overall decline of energy consumption from "renewable sources" in 2001. The Bonneville Power Administration, which with other federal agencies oversees operation of the Federal Columbia River Power System, reported an average decline of 2,500 MW as a result of the 2000-2001 drought in the western United States.

- In 1998, The New York Times reported that drought reduced hydroelectric production in Ghana by 40 percent, "crippling its economy at a time when it was just beginning to emerge from poverty."

Analysts expect no growth for new conventional hydro power in the Southeastern United States through 2020. Currently, only 2 percent of the dams in the United States produce electricity.

CHALLENGES

The shift in some states toward deregulation of electricity markets has made the high capital cost and regulatory burden of new, conventional hydropower projects prohibitive. Accordingly, new impoundment and diversion projects are not currently planned in the United States because of construction costs and concerns over environmental impact. In fact, some public stakeholder groups are advocating dismantling older dams at the end of their useful life cycle in order to restore dam project areas to original pre-dam habitat.

Power supplied by conventional hydro electric projects will likely decrease as a result of regional declines in precipitation and stream flow, by as much as 50 percent in some areas; new environmental requirements under hydro project relicensing require that minimum levels of stream flow be maintained to protect downstream water quality and natural habitat, thereby limiting the capacity available for power generation. The share of hydro in total U.S. electricity generation will also decline as other sources of generation increase.

504 Integrated Regional Information Networks News, 2005.

Renewable Energy: Geothermal

Geothermal power plants use heat from the earth's interior to heat water that drives a steam turbine generator. Geothermal reservoirs are formed by fractures in the earth's crust that are near enough to the surface to allow hot water or steam to accumulate.[505] Temperatures in these reservoirs can range up to 360 degrees C, with most plants operating at temperatures between 80 and 250 degrees C.[506] Electric power production from geothermal resources is relatively clean when compared to traditional fossil fuel generation and has a minimal impact on the environment. Although some geothermal reservoirs have reduced their output over time, enhanced geothermal systems (EGS) can mitigate reduced temperatures and pressures in older fields, as well as make additional reservoirs viable for commercial output.

TYPES OF GEOTHERMAL POWER PLANTS

Three types of plants are in operation: dry steam, flash steam and binary.[507] Each uses geothermal in a different way, allowing developers to choose the design that best fits the characteristics of the target reservoir. The temperature-pressure relationship is a key driver behind the generation technology that is chosen at a particular site. Dry steam power plants use low pressure, high temperature steam (around 250 degrees C[508]); flash steam uses higher pressure, lower temperature steam (180 degrees C); binary plants tend to run on high pressure, low temperature steam (100 to 150 degrees C).

Dry steam geothermal power plants operate by drawing hot, dry steam from the reservoir and running it through a turbine. The steam is then condensed, usually by a water-based cooling tower, and reinjected into the well to prevent land subsidence and maintain the pressure of the reservoir.[509] The first geothermal plant used dry steam; it was built in Larderello, Italy, in 1904. The oldest operating geothermal power plant in the United States—the only dry steam plant in the United States—was built in 1960 at The Geysers site in California. The water-based cooling mechanism causes approximately 50 percent of the water taken from the geothermal reservoir to be lost into the atmosphere. The other 50 percent is injected back into the well.[510] The Geysers project, which now suffers from significantly reduced reservoir pressure, also injects 11 million gallons of treated waste water per day from the nearby town of Santa Rosa. This operation has helped ensure the long-term sustainability of the geothermal resource.[510]

More common than dry steam facilities, flash steam geothermal power plants use water at temperatures exceeding 182 degrees C (under high pressure) to produce steam that can be sent through a turbine to generate electricity. Once the pressure is reduced from the extremely hot water (or brine), the liquid "flashes" into steam that, once passed through the turbine, is cooled and disposed of in a manner similar to that of a dry steam plant.[511] Additionally, a second flash tank can be added so that hot water that is not initially vaporized enters a tank with even lower pressure than the first flash tank, increasing the power output of the facility by driving a second turbine.[512] This technology is limited to use with aqueous reservoirs with very high temperatures, usually found at depths exceeding 2 kilometers.[513] Since the capital cost of a geothermal power plant depends heavily

505 Idaho National Laboratory, 2005.
506 Office of Geothermal Technologies, 1998.
507 Office of Energy Efficiency and Renewable Energy, 2006e.
508 Reed & Renner, 1995, Chapter 2.
509 National Renewable Energy Laboratory, 2004b.
510 Kagel et al., 2005.
511 McLarty & Reed, 1992.
512 Office of Energy Efficiency and Renewable Energy, 2006e.
513 Reed & Renner, 1995, Chapter 2.

on drilling costs,[514] reaching reservoirs suitable for flash steam generation can be more expensive than reaching the shallower resources used for dry steam and binary power plants.

Lower reservoir temperatures (below 150 degrees C) necessitate the use of binary geothermal technology. In a binary plant, the hot, pressurized water is passed through a heat exchanger where a working fluid that has a lower boiling point than water is gasified and passed through a turbine.[515] Unlike dry steam and flash steam plants, there are no emissions that result from evaporation of the gases trapped inside the geothermal resource (e.g., carbon dioxide, hydrogen sulfide). Rather, the geothermal water is reinjected back into the ground without coming in contact with the atmosphere.[516] Additionally, since the geothermal water is not used in the cooling process, the condenser may be cooled through an air-cooling system if an ample supply of water is not readily available. Water cooling systems are generally less costly, more efficient and more reliable than air cooling systems (plant output can fluctuate as much as 20 percent to 25 percent between cooler and warmer seasons).[517] However, as most geothermal resources in the United States are located in the arid Southwest, air cooling systems may become more attractive. Research for binary geothermal power plants continues to focus on improving the efficiency of heat exchangers, as well as on developing piping that can withstand the corrosive geothermal brines.[518]

HISTORIC IMPROVEMENTS AND KEY DRIVERS

The use of geothermal resources in the United States for large-scale public use began in the late 19th century in the form of direct use district heating and hot water systems in Boise, Idaho, Klamath Falls, Ore. Geothermal-based electricity production was pioneered in 1921 by John D. Grant, who built a 250 kW facility across the valley from what is now The Geysers site in California. However, this system was not cost-competitive with other forms of electricity production and stopped being used. The modern development of geothermal electricity in the United States began at The Geysers in 1960, when Pacific Gas and Electric brought an 11 MW dry steam geothermal power plant on-line. [519]

The major move toward the commercial development of geothermal electric production can be attributed to two key events in the late 1970s: the energy shortage in the United States and the passage of the Public Utility Regulatory Policy Act of 1978 (PURPA).[520] The energy shortage drove R&D on domestic sources of energy, while PURPA provided geothermal and other renewable investors with financial stability through mandatory power purchases and grid interconnection.[521] Acting in the spirit of PURPA, the California Energy Commission required all utilities to establish long-term purchase contracts with independent power producers (IPPs) that set the price of geothermal-based electricity "at the utility's full avoided cost of new baseload capacity."[522] In addition, the 1974 Geothermal Energy Research, Development and Demonstration Act provided guaranteed loans for geothermal development.[523]

Using incentives provided to geothermal developers by PURPA, the first water-dominated geothermal power plant was built on the East Mesa field in California's Imperial Valley. This plant used a binary system with an iso

514 Hance, 2005.
515 National Renewable Energy Laboratory, 2004b.
516 Kagel et al., 2005.
517 Hance, 2005.
518 National Renewable Energy Laboratory, 2006d.
519 Office of Energy Efficiency and Renewable Energy, 2006c.
520 McLarty & Reed, 1992.
521 Office of Energy Efficiency and Renewable Energy, 2006c.
522 McLarty & Reed, 1992.
523 Office of Energy Efficiency and Renewable Energy, 2006c.

butene working fluid to drive a 10 MW turbine.[511] The provisions in PURPA that require utilities to connect IPPs to the grid and to purchase power from qualified facilities led to an increase in geothermal power plant ownership by IPPs. PURPA implementation led to a sharp increase in IPP-owned geothermal power plants.

More recently, a geothermal research program, GeoPowering the West, has taken steps to remove barriers to geothermal development by working with the U.S. Bureau of Land Management and the U.S. Department of Interior to reduce the backlog of land lease applications that has slowed the growth of geothermal development.[524] Also, in conjunction with facilities such as the Idaho National Laboratory, GeoPowering the West is seeking to improve the industry's ability to accurately predict where geothermal resources can be used for electricity generation, as well as for direct use applications.[525] Currently, research is under way to improve the durability, efficiency and environmental compatibility of geothermal electricity production.[526]

ADVANCED TECHNOLOGIES: ENHANCED GEOTHERMAL SYSTEMS

Enhanced geothermal systems can serve to increase the lifespan of an existing geothermal resource or make a previously unusable reservoir viable for electricity production. Although temperatures at a particular site may be sufficiently hot for a geothermal power plant, the tectonic fractures in the underground rock may have sealed over time through secondary mineralization processes. A report published by DOE's Office of Energy Efficiency and Renewable Energy details how a previously unproductive geothermal field can be tapped for the energy captured in the subsurface rocks:

> Through a combination of hydraulic, thermal, and chemical processes, the target EGS reservoir can be 'stimulated,' causing the fractures to open, extend, and interconnect. This results in the creation of a conductive fracture network and a reservoir that is indistinguishable from conventional geothermal reservoirs. EGS technology could serve to extend the margins of existing geothermal systems or create entirely new ones, wherever appropriate thermal and tectonic conditions exist.

One reason why geothermal power plants reduce their output over time is that the geothermal well loses pressure, decreasing the temperature as well as the flow rate of the production well. Pressure loss is related to hydrothermal fluid temperature for different power outputs.[527] As temperature increases, the well can handle less pressure loss. Thus, it becomes important for high temperature resources such as The Geysers to retain their pressure.

Output from The Geysers field peaked in 1987, entering a state of gradual decline. The total number of homes that the field can serve has dropped by 700,000. EGS techniques are now being employed at the site, by pumping treated wastewater from the nearby town of Santa Rosa into the underground wells at depths of 7,000 to 10,000 feet. This project will increase the electrical output from facilities at The Geysers by a total of 85 MW, enough power for 85,000 homes.

Another geologic survey suggests that there may be possible geothermal resources available in the Gulf Coast, by tapping the heat from dry oil fields with EGS techniques.[528] The study indicates that while there are many costs related to geothermal reservoir exploration in the west, such costs are avoidable in the Gulf Coast region.

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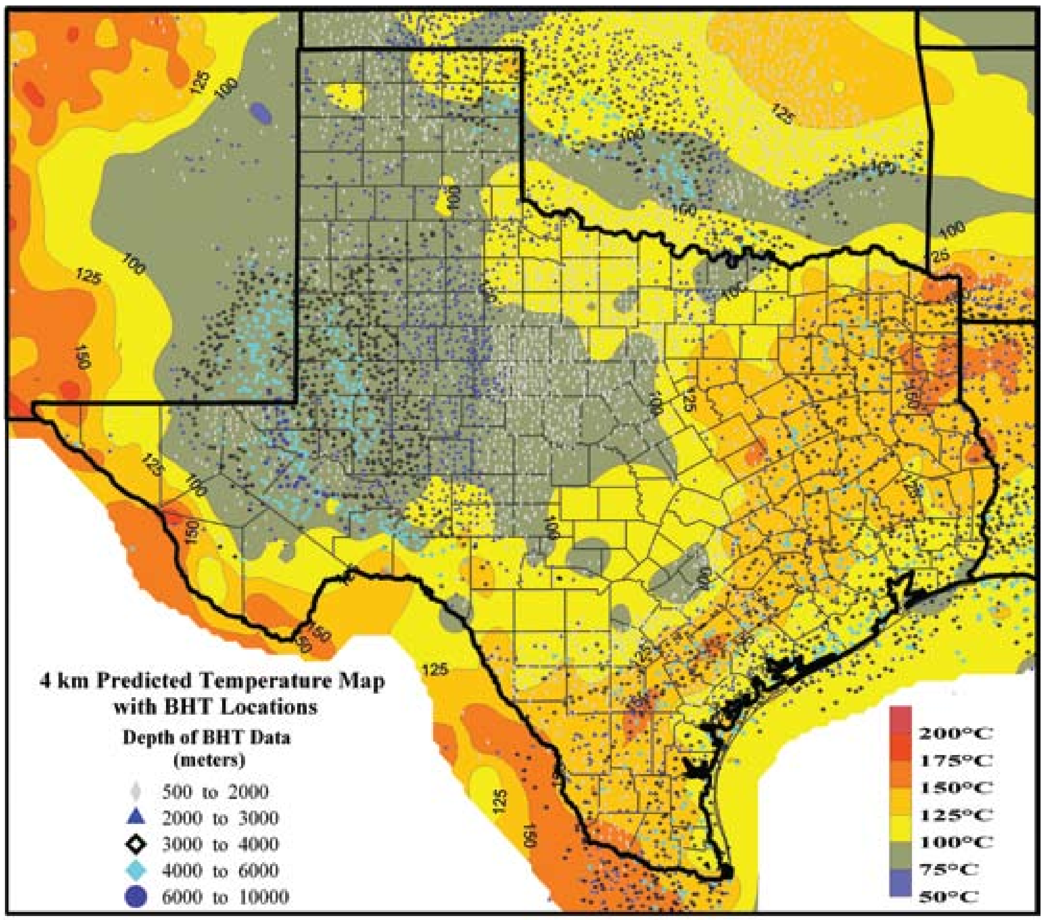
524 Farhar & Heimiller, 2003.
525 Office of Energy Efficiency and Renewable Energy, 2006d.
526 National Renewable Energy Laboratory, 2006d.
527 Xie et al., 2005.
528 McKenna et al., 2005.

Existing infrastructure, high-permeability engineered reservoirs and high temperatures (up to 200 degrees C) allow for economically viable EGS development in the region that would be too expensive and risky in the west. Figure 2-8 shows that there are sufficient temperatures in eastern Texas to produce electricity with a binary geothermal power plant. In addition to having sufficient temperatures, the wells have sufficient permeability to allow flow rates that exceed the minimum requirement for power production. Estimates of the total available resource in the Gulf Coast area exceed 10,000 MW.[528] Cost estimates to capture this resource potential are not available at this time. With the exception of areas that have significant existing infrastructure and resource knowledge in place, EGS projects may be limited to expanding the life of existing wells through additional water injection. Especially in the arid western United States, a major barrier to EGS development remains the lack of water supply and investors' aversion to devoting large amounts of equity to new fields that need EGS to become productive.

Figure 2-8: Gulf Coast temperatures at 4 kilometers[529]



ADVANCED TECHNOLOGIES: SUPERCRITICAL STEAM

Another geothermal resource that holds potential for the future is supercritical steam. Supercritical steam generally reaches temperatures between 430 and 550 degrees C (twice the temperature of traditional geothermal reservoirs) and pressures of 230 to 260 bar (eight times the pressure of traditional reservoirs). Geothermal power plants that use this resource have the potential to produce 10 times more electricity than a traditional binary

529 Ibid.

cycle. Supercritical steam is found deeper within the earth and therefore is more expensive to reach due to increased drilling costs, the hardness of the rock typically surrounding a supercritical reservoir and the engineering necessary to support this extremely hot steam of an unknown mineral composition.[530]

The Iceland Deep Drilling Project (IDDP) has completed phase 1 of a supercritical well in Reykjanes; this is a test well with a depth of 3,082 meters. The project, expected to be completed by 2010, will yield a test well of over 5 kilometers in depth and provide researchers with elaborate flow tests and mineral composition studies that are necessary to develop the corresponding power plant technologies. The total cost of the project is approximately $20 million.[531] The research of supercritical steam as an advanced geothermal technology may lead to a resource that can be harnessed to dramatically improve the power output and efficiency of geothermal power plants. In the United States, there is a large potential for the use of supercritical steam in Alaska's Aleutian Islands; this region may not have a great demand for electricity, but it may provide the opportunity for Alaska to emerge as a leading supplier of hydrogen.[532]

ENVIRONMENTAL IMPACTS OF GEOTHERMAL POWER PRODUCTION

The main environmental concerns associated with geothermal energy production include air pollution, groundwater pollution, noise pollution and land use. The two major gases that are emitted into the atmosphere as a result of geothermal power production are carbon dioxide and hydrogen sulfide. These gases are not produced as a byproduct of combustion, as they are in fossil fuel-based facilities. Rather, they exist in the geothermal fluid as noncondensable gases. When the pressure on these fluids is released and the steam passes through the power plant and into the atmosphere, generally 5 percent of the steam is made up of gases such as carbon dioxide, hydrogen sulfide, ammonia and methane. However, the concentrations of the latter two compounds are generally very small.[533] The carbon dioxide that is released in the geothermal steam is a very small percentage of what would be released from a coal-fired or natural gas power plant.

The other main pollutant of concern is hydrogen sulfide. One problem caused by hydrogen sulfide emissions is a localized "rotten egg" smell. Another concern is that hydrogen sulfide can be toxic to humans in moderate amounts.[534] There have been claims that hydrogen sulfide will oxidize into sulfur dioxide (a main byproduct of fossil fuel combustion and a cause of acid rain), although current research indicates that most of the hydrogen sulfide washes out of the steam and precipitates into the environment as elemental sulfur.[535] Most geothermal power plants in the United States are currently required to install hydrogen sulfide abatement equipment that converts 99.9 percent of the hydrogen sulfide contained in geothermal fluids into elemental sulfur, which can be used as a fertilizer feedstock.[536]

Although geothermal electric power plants do emit pollutants into the atmosphere, they typically are gases that would have eventually entered the atmosphere without any production from the field. The natural CO_2 emission flow rate from Icelandic geothermal fields is greater than the rate of CO_2 emissions from power-producing fields. Additionally, emissions of air pollutants from geothermal facilities are far less than what is expected from fossil fuel facilities (Table 2-39), and it is possible to add abatement equipment that can further reduce the environmental impacts of air emissions from geothermal-based electricity production.

530 Fridleifsson et al., 2005.
531 Ibid.
532 National Renewable Energy Laboratory, 2005a.
533 Kagel et al., 2005.
534 Kagel et al., 2005.
535 Kristmannsdottir & Armannsson, 2003.
536 Kagel et al., 2005.

Table 2-39: Air emissions summary[537]

Pounds per megawatt hour:	Nitrogen Oxides	Sulfur Dioxide	Carbon Dioxide	Particulate Matter
Coal	4.31	10.39	2191	2.23
Coal, life cycle emissions	7.38	14.8	not available	20.3
Oil	4	12	1672	not available
Natural gas	2.96	0.22	1212	0.14
EPA listed average of all U.S. power plants	2.96	6.04	1392.5	not available
Geothermal (flash)	0	0.35	60	0
Geothermal (binary and flash/binary)	0	0	0	negligible
Geothermal (Geysers steam)	.00104	.000215	88.8	negligible

Geothermal power plants require very little land, compared with other means of electricity generation. When the total life cycle land use for electricity generation is considered, including the land used for mining the resource, geothermal power production proves to use only a fraction of the land required for traditional resources.[538] Geothermal power plants also have a low profile, minimizing the visual impacts on their surroundings. The primary impairment of the local view is the steam plume that rises from water-cooled facilities.[539]

RESEARCH & DEVELOPMENT

Research programs under way at the National Renewable Energy Laboratory as of July 2006 include:[540]

- Condensation of Mixed Working Fluids.
- Heat Exchanger Linings.
- Air-cooled Condensers.
- Alternative Non-Condensable Gas Removal Methods.
- Geothermal Facility Siting Issues.
- International Market Assessment.

One major obstacle for the future of geothermal R&D is the uncertainty (or lack of) federal funding. The Energy Policy Act of 2005 included a significant increase in funding for DOE's geothermal energy research program, as well as private loan guarantees and tax credits for geothermal development.[541] However, in its 2007 budget request, the DOE proposed to terminate the program and requested no funding for it.[542] The reasoning behind DOE's request to terminate funding is that "the 2005 EPAct should spur commercial development of geothermal resources without the need for subsidized Federal research to further reduce costs." As might be expected, the Geothermal Energy Association (GEA) is opposed to terminating the program, claiming, "There are substantial needs for improvements in technology, information, and efficiencies for which federal research is vital."[541]

537 Kagel et al., 2005.
538 Ibid.
539 Ibid.
540 National Renewable Energy Laboratory, 2006d.
541 Fleischmann, 2006.
542 Office of Energy Efficiency and Renewable Energy, 2006b.

In response to the DOE's proposed budget cuts, the GEA proposed a budged of $32.5 million for fiscal year 2007 for the geothermal research program. Table 2-40 displays the DOE geothermal research budget for the years 1998 through 2006.

Table 2-40: Geothermal technologies annual research budget ($millions)[543]

Fiscal Year	Budget Request	Appropriation
1998	$26,518	$22,651
1999	$29,500	$21,730
2000	$29,500	$23,621
2001	$27,000	$26,911
2002	$13,900	$27,299
2003	$26,500	$29,390
2004	$26,000	$25,508
2005	$25,800	$25,800
2006	$23,100	$23,100
2007	$0 (Proposed)	?

RESOURCE CAPACITY

Only four states now produce electric power from geothermal resources: California, Hawaii, Nevada and Utah (Table 2-41). These states had a total installed capacity of 2828.25 MW in 2005 (Table 2-41 represents 2003 data) and generated a total of 14,355.8 GWh in 2004, accounting for 0.35 percent of U.S. annual production.[544] Although geothermal resources supply a small fraction of the nation's power, they are quite important in states with geothermal plants: 6 percent of total electric production in California comes from geothermal resources, 10 percent in Nevada and 25 percent in Hawaii.[545]

Table 2-41: Geothermal power plants in the United States[546]

State	Number of plants	Gross capacity	Net operating capacity
		MWe	MWe
California	48	1,759	1,659
Nevada	13	200	189
Utah	4	31	27
Hawaii	1	30	27
Total	66	2,020	1,902

RESOURCE AVAILABILITY

Currently, there are 1,454.9 MW of new geothermal plants under development in the United States, with 157 MW in the construction phase. These new facilities will be built in the four states listed in Table 2-41, as well as in Alaska, Arizona, Idaho, New Mexico and Oregon.[547] Although geothermal development has been limited to the western United States so far, Figure 2-9 shows that there are sufficient geothermal resources in other parts of the country (any area warmer than 150 degrees C is a potential geothermal resource, depending on the reservoir properties).

Projects under development will, if completed, nearly double U.S. geothermal generating capacity (Table 2-42). Continued development of geothermal resources depends on technological advances in identifying potential

543 Fleischmann, 2006.
544 Ibid.
545 Office of Energy Efficiency and Renewable Energy, 2003.
546 Lund, 2003.
547 Fleischmann, 2006.

geothermal reservoirs, drilling test wells and using enhanced geothermal systems to create reservoirs of geothermal fluids within previously dry bedrock.[548] Expediting the political process by working through the Bureau of Land Management's lease application backlog and establishing transmission rights of way can also lead to more rapid development of geothermal resources.[549]

Figure 2-9: U.S. geothermal resource map[550]

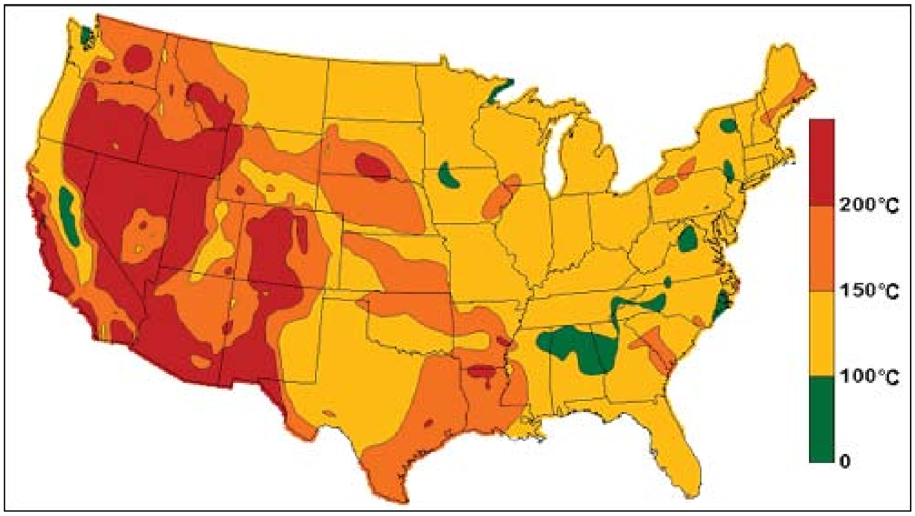


Table 2-42: Planned geothermal development[551]

State	Unconfirmed	PHASE 1 (Identifying site, secured rights to resource, initial exploration drilling)	PHASE 2 (Drilling and confirming)	PHASE 3 (Securing PPA and final permits)	PHASE 4 (Under Const.)	TOTAL* (PHASE 1 to PHASE 4)
	Number of sites and MW-range "# of sites / #MW"					
AK	1 / 10 -100 MW**		1 / 20 MW			1 / 20 MW
AZ		1 / 2 – 20MW				1 / 2 – 20 MW
CA		3 / 109.9 – 119.9 MW	4 / 220 - 270 MW	3 / 345 MW	1 / 18 MW	11 / 692.9 - 752.9 MW
HI		1 / 30 MW		1 / 8 MW		2 / 38 MW
ID	2 / 200 MW			1 / 20 MW	1 / 10 MW	2 / 30 MW***
NM			1 / 20 MW			1 / 20 MW
NV	6 / up to 200 MW	4 / 104 - 173 MW	2 / 50 – 60 MW	4 / 67 – 72 MW	3 / 60 MW	13 / 281 – 365 MW
OR		1 / 20 MW		1 / 120 MW		2 / 140 MW
UT	1 / 75 – 100 MW				1 / 69 MW	1 / 69 MW
Total	10 / 485 – 600 MW	10 / 265.9 – 362.9 MW	8 / 310 – 370 MW	10 / 560 – 565 MW	6 / 157 MW	34 / 1292.9 – 1454.9 MW

* Unconfirmed projects are not counted in the state or final total.
** Potential for more than 100 MW at Makushin Volcano – but this is unconfirmed
*** 2 sites are actually the same plant – Raft River.

Direct-use and Geothermal Heat Pumps

In addition to its use as a source for electricity generation, geothermal energy can be used directly as thermal energy to provide a wide variety of energy services. Direct-use geothermal energy can be used to provide district heating and hot water, as well as for greenhouse and aquaculture applications and in livestock waste

548 Bloomfield & Laney, 2005.
549 Farhar & Heimiller, 2003.
550 Office of Energy Efficiency and Renewable Energy, 2006f.
551 Fleischmann, 2006.

management.[552] On a smaller scale, individual facilities (residential, commercial or industrial) can employ geothermal heat pumps (GHPs) that use the constant heat of the earth as both a heat source and heat sink.[553] All together, "geothermal energy provides over 600 thermal megawatts of heating capacity for schools, homes, and businesses in the western U.S."[554]

The advantage of using geothermal resources directly is that low-temperature resources not sufficient for electricity generation can provide energy services that offset the need for direct fossil fuel combustion or traditional electricity generation and associated carbon dioxide emissions. According to the National Renewable Energy Laboratory:

> Nearly 40% of all U.S. emissions of carbon dioxide are the result of using energy to heat, cool, and provide hot water for buildings…Over an average 20-year lifespan, every 100,000 units of nominally sized residential GHPs will save more than 24 trillion BTUs of electrical energy, and save consumers approximately $500 million in heating and cooling costs at current prices [2003]. And over the same period, these 100,000 units reduce greenhouse gas emissions by almost 1.1 million metric tons of carbon equivalents.[555]

To date, almost 500,000 geothermal heat pumps have been installed, reducing U.S. greenhouse gas emissions by more than 1 million metric tons of carbon per year.[556] The growth potential for direct-use applications of GHPs is huge: "there are 2,500 potentially productive geothermal wells located within five miles of towns and medium-sized cities throughout 16 western states. If these 'collocated' resources were used only to heat buildings, the cities have the potential to displace 18 million barrels of oil per year."[557] The combination of resource availability and the economic benefits of direct-use geothermal energy (energy savings can be as much as 80 percent over fossil fuels)[558] make it a viable technology option to produce thermal energy and reduce greenhouse gas emissions.

ECONOMICS OF GEOTHERMAL ELECTRICITY PRODUCTION

Barriers for Geothermal Expansion

Developing a geothermal power plant involves three initial phases—exploration, confirmation and site development—and each phase carries a degree of uncertainty that affects the total cost of the project.[559] The lack of cost certainty makes financing geothermal projects more expensive and thus increases the wholesale cost of the resulting power output.

The uncertainty of exploration costs can have a significant effect on the cost of financing a geothermal project. Wells drilled in the exploration phase typically have a success rate of 20 percent to 25 percent at new sites. The cost of drilling is also uncertain and fluctuates considerably from year to year. At the early stages of development (exploration and confirmation), private companies must finance geothermal projects through equity investment, requiring an annual rate of return of about 17 percent.[560] This factor creates a strong incentive to avoid project

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552 National Renewable Energy Laboratory, 2004b.
553 National Renewable Energy Laboratory, 1998.
554 Office of Energy Efficiency and Renewable Energy, 2003.
555 National Renewable Energy Laboratory, 1998.
556 Ibid.
557 National Renewable Energy Laboratory, 2004c.
558 Ibid.
559 Hance, 2005.
560 Ibid.

delays associated with permitting or community resistance. Lease and permit application backlogs can delay exploration projects by up to 20 years.[561]

Considering all of the factors that contribute to the cost of exploration, estimates of exploration cost values come in at just over $100 per kW (Table 2-43).

Table 2-43: Exploration cost values in the literature[562]

Authors	Exploration cost values
Nielson (1989)	107.2 $/kW
EPRI (1996)	125.9 $/kW
EPRI (1997)	101.1–130.8 $/kW
GeothermEx (2004)	88.5–142 $/kW*

* Average projected exploration costs where little information is currently available (D-projects: downhole temperature > 212°F is not proven).

Confirming a site as a productive geothermal resource involves drilling production wells to establish that there is a sufficient flow rate for power production. Before independent power producers can pursue low-interest financing from lending institutions, they must demonstrate 25 percent of the total production capacity for the project. Drilling makes up 80 percent of the total costs in the confirmation phase of geothermal development, which is about 5 percent of the total cost of the project.[563514]

PURPA creates an additional incentive for IPPs to undertake geothermal development, since utilities are required to connect them to the grid and purchase their power at their avoided cost of baseline capacity construction.[564] However, the cost of money for IPPs is nearly 90 percent higher for IPPs than for municipal utilities (Table 2-44).

The exploration and confirmation phases can take between three and five years to complete, if there are no permitting delays. The entire process from initial exploration to power generation can take a decade. The lengthy amount of time necessary to complete a geothermal electric generation facility makes it difficult for the industry to grow, since federal production incentives are typically not extended that far in advance. For example, the production tax credits in the 2005 EPAct expire at the end of 2007, giving developers less than two years from the time the bill was passed until the incentive expires.[565] Reducing permitting delays, increasing the length of federal incentive programs and reducing the cost of financing can help make geothermal resources more economically competitive with traditional resources.

561 Farhar & Heimiller, 2003.
562 Hance, 2005.
563 Ibid.
564 McLarty & Reed, 1992.
565 NC Solar Center, 2006.

Table 2-44: Typical financing opportunities for power developers[566]

Financing Type	Capital Structure	Average Interest Rate	Debt Period
Municipal Utility	100% debt at 5.5%	5.5%	30 years
Regulated Investor-Owned Utility	47% debt at 7.5 %	9.6%	30 years
	6% preferred stock at 7.2%		
	47% common stock at 12%		
Generating Company	35% debt at 7.5%	11.1%	30 years
	65% equity at 13%		
Independent Power Producer	70% debt at 8%	10.7%	30 years
	30% equity at 17%		

Economic Potential for Geothermal Power Production

Currently, the levelized cost of geothermal electricity varies (Table 2-45), depending on the initial capital investment as well as the cost of financing the project. Geothermal projects can benefit greatly by economies of scale, allowing larger facilities to produce electricity at lower prices than smaller plants (Table 2-46). Economies of scale arise from a reduced average cost ($/kWh) of drilling and plant construction. Considering the information presented in Table 2-45 and Table 2-46, it can be inferred that geothermal facilities with more generation capacity become less expensive per kW, reducing the total cost of electricity. By fostering improvements in technology and resource knowledge, the DOE's geothermal technologies program [567] aims to reduce the cost of geothermal power production to 3 to 5 cents per kWh, making it competitive with traditional technologies.[568]

Table 2-45: Levelized cost of capital electricity (cost of power: cents/kWh)[569]

Initial Capital Investment	Municipal Utility	Regulated IOU	Generating Company	Independent Power Producer
$2400 per KW	3.99	4.85	5.20	5.76
$2900 per KW	4.40	5.44	5.89	6.54
$3400 per KW	4.81	6.06	6.54	7.33

Table 2-46: Economies of scale[570]

Capacity (MW)	Capital Cost
5	2500
20	2411
34	2325
49	2242
63	2163
78	2086
92	2011
107	1940
121	1871
136	1804
150	1740

566 Hance, 2005.
567 NOTE: Contingent on continued funding for the Geothermal Technologies Program in FY 2007.
568 Lund, 2003.
569 Hance, 2005.
570 Ibid.

With estimated capacity factors for geothermal power plants reaching 96 percent, geothermal resources are far more reliable than competing renewables such as wind and solar.[571] Although there are concerns regarding the long-term sustainability of reservoir production, enhanced geothermal systems technologies are being put into use that can extend the life of reservoirs beyond the expected life of the power plants. At present, it seems that sufficient financial support will ensure that geothermal resources continue to be commercially viable sources of electricity production.

571 Lund, 2003.

Renewable Energy: Ocean Thermal

Ocean thermal energy conversion (OTEC) uses heat energy from the sun stored within the ocean to produce electricity and, in some cases, desalinated water. While OTEC is not a viable generation option for the mainland United States, Hawaii and many U.S. island territories can use it to help meet public demand for both electricity and fresh water. Once a commercial-scale demonstration OTEC plant is built and long-term power purchase agreements (PPAs) are acquired, OTEC can be an economically competitive technology in equatorial islands that are more susceptible to oil supply shocks than mainland nations. A 1 MW demonstration plant will likely take up to 10 years to build, but can be upgraded to a 50 MW facility following the demonstration phase.[572]

TECHNICAL OVERVIEW

OTEC power plants use the large temperature gradients between warm (24 to 30 degree C) shallow water and cold (4 to 8 degree C) deep water mostly found in equatorial ocean regions.[573] Generally, the preferred depth of the cold water is between 800 meters and 1,000 meters.[574] A heat engine uses the energy of the warm water to create steam that is run through a turbine to produce electricity. The cold water, brought to the surface through a long pipe in a process known as upwelling[575], is used to condense the steam that has passed through the turbine.[576] This process is not unlike the conventional Rankine cycle, where the maximum efficiency is governed by the temperature difference between the heat source and the heat sink.[577] This is also known as the "Carnot cycle efficiency." The maximum efficiency that an OTEC cycle can achieve is 7.4 percent, meaning that 7.4 percent of the energy contained in the ocean can be converted to work (electricity). However, the efficiency of an OTEC power plant typically falls in the range of 2.5 percent to 3.4 percent.[578]

There are three different types of OTEC cycles that may be sited on or near the shore, or offshore: closed-cycle, open-cycle or a hybrid system.[579] A closed-cycle system uses the warm water to vaporize ammonia, which passes through a low-pressure turbine before it is condensed by the cold water and cycled back through the system.[580] In an open-cycle system, warm surface seawater is flash-evaporated in a vacuum chamber. The resulting steam is passed through a low-pressure turbine and condensed by the cold water. Since the flash-evaporation process removes all of the minerals from the seawater, the condensed steam from an open-cycle facility is usable fresh water.[581] As is suggested by the name, a hybrid OTEC system uses features of closed-cycle and open-cycle systems to generate electricity. Specifically, the warm seawater is flash-evaporated in a vacuum chamber and the resulting steam is used to vaporize a low-boiling-point fluid, such as ammonia, in a closed-cycle loop. Thus, a hybrid system also allows the facility to produce desalinated water as a byproduct of electricity generation.

There are benefits and drawbacks to each OTEC siting option. Land and near-shore facilities benefit from being closer to the electric grid that they serve, reducing transmission costs and associated efficiency losses. They also are relatively cheaper to maintain, due to costs related to maintenance of an open-ocean facility. Additionally, cold water brought up from deep waters can be used for air conditioning and mariculture applications in coastal

572 L. Vega, personal communication with B. Strode, 2006.
573 National Renewable Energy Laboratory, 2006i.
574 Vega, 2002.
575 Ibid.
576 Pelc & Fijita, 2002.
577 Vega, 2002.
578 Sea Solar Power Inc, n.d.
579 Office of Energy Efficiency and Renewable Energy, 2005b.
580 Vega, n.d.
581 Ibid.

communities surrounding the facility. However, the drawbacks of siting an OTEC facility on or near the shore include wear of the intake pipes and other structures from being in the surf zone, increased cost of materials for pipes that must extend away from the shore far enough to reach cold water reserves, and the requirement that discharge pipes must extend far enough away from land to avoid discharging the cold seawater into warmer surface zones.[582] Also, since the cold water must travel farther to reach near-shore facilities, more heat from the warm surface water is imparted on the cold water, reducing the facility's potential power output.[583]

Offshore floating OTEC facilities are generally moored in waters with depths reaching 2,000 meters, allowing for shorter cold water pipes than land-based plants. However, the additional efficiency and power generating capacity obtained by using shorter cold water pipes is offset somewhat by the need to transmit the energy to shore.[584] The energy may be delivered to the utility grid by a submersed transmission cable, or it may be stored by manufacturing methanol, hydrogen or ammonia.[585] As might be expected, the farther the OTEC facility is moored from the shore, the more expensive it will be to produce electricity. Table 2-47 shows the cost estimates for a 100 MW OTEC plantship to range from 0.07 to 0.22 $/kWh, depending on the facility's distance to the shore.[586] With regards to the possibility of storing the energy through the production of hydrogen or methanol, such efforts have been found to be far less favorable than submersed power cables.[587] Even at an optimum temperature difference for the production of hydrogen at an OTEC facility, it has been found that the "actual power input is far greater than the actual power output due to losses posed in the thermal conversion process."[588] Offshore OTEC facilities could reach 100 MW in net power output. However, in order to realize possible economic gains from desalinated water production, a hybrid cycle would need to be implemented and the water would somehow have to be transported to shore.[589]

Table 2-47: Cost estimates for 100 MW closed-cycle OTEC plantship[590]

Offshore Distance, km	Capital Cost, $/kW	Cost of Electricity, $/kWh
10	4,200	0.07
50	5,000	0.08
100	6,000	0.10
200	8,100	0.13
300	10,200	0.17
400	12,300	0.22

ADVANCED OTEC TECHNOLOGY

Ocean thermal research waned in the United States in the early 1990s as energy prices dropped and the federal government redirected research funds for renewable energy toward technologies that have broader geographic availability, such as biomass.[591] Also, fuel prices were then low enough to make capital-intensive technologies such as OTEC economically obsolete. However, private interests have continued OTEC research both in the United States and abroad, and such efforts have increased the thermal conversion efficiency of OTEC systems.

582 National Renewable Energy Laboratory, 2006e.
583 World Energy Council, 2005.
584 Ibid.
585 National Renewable Energy Laboratory, 2006c.
586 Vega, 2002.
587 Vega, 1992.
588 Kazim, 2005.
589 L. Vega, personal communication, with B. Strode, 2006.
590 Vega, 2002.
591 L. Vega, personal communication, with B. Strode, 2006.

A Baltimore, Md.-based company, Sea Solar Power Inc. (SSP), has designed a 100 MW closed-cycle OTEC facility that is far superior to the system designed by government and private researchers in the 1970s and 1980s. SSP's system achieves an efficiency of 3.4 percent, as opposed to 2.5 percent for the government-corporate baseline design. SSP's design also reduces the mass of the facility from 200,000 tons to 25,000 tons, uses pipes with smaller diameters and needs a smaller volume of seawater to produce the same amount of electricity. Additionally, SSP's design uses propylene instead of ammonia as its working fluid. Ammonia mixes with water vapor and must be replaced more often to maintain optimal heat transfer. The use of propylene also allows for use of a more efficient propylene vapor turbine. Ultimately, the entire cycle is more efficient with the use of propylene.[592]

Xenesys Inc., a Japanese company, developed a new OTEC cycle in 1994, known as the Uehara cycle. This cycle uses about half as much water as the Rankine cycle and achieves efficiencies that are 1.5 to 2 times greater. The Uehara cycle's net energy output[593] is 80 percent to 85 percent, compared with 55 percent for the Rankine cycle.[594]

MARKETS FOR OTEC TECHNOLOGY

Over the past century, many experimental OTEC facilities have been built throughout the tropics; the first was a 22 kW open cycle system built in Cuba in 1930, while the latest (and largest) is a 50 net kW open-cycle plant built at Keahole Point, Hawaii.[595] There are two key markets that can benefit from the renewable baseload generation that OTEC offers, as well as from the potential for desalinated water: "(i) industrialized nations and islands; and, (ii) smaller or less industrialized islands with modest needs for power and desalinated water."[596] Table 2-48 outlines the economic scenarios where OTEC becomes cost-competitive with fossil fuel generation. Under such economic conditions, a small OTEC plant could deliver enough power and desalinated water to meet the needs of up to 100,000 people in a developing island nation or territory.[597]

Another market that may arise for OTEC in equatorial regions arises from the technology's ability to offset carbon dioxide emissions. It is expected that a 100 MW OTEC system could reduce as much as 140,000 tons of carbon per year, compared with a 100 MW pulverized coal facility.[598] Additionally, "the synergistic CO_2 uptake effect by the compulsory circulation of the ocean was calculated to be 7,800 t-C/year for a 100 MW OTEC system on the basis of the difference between the present and pre-industrial CO_2 concentrations in the atmosphere."[599] As a result of OTEC's potential to reduce CO_2 emissions, it may be possible for industrialized countries to invest in OTEC systems in developing tropical island nations and receive "clean development mechanism" credits to use toward CO_2 reduction targets set out in the Kyoto Protocol.

592 Sea Solar Power Inc., n.d.
593 Net output means the usable power after deducting power needed for pumps for seawater and working fluid.
594 Xenesys Inc., n.d.
595 National Renewable Energy Laboratory, 2006a.
596 Vega, 2002.
597 Vega, 1992.
598 Tahara et al., 1995.
599 Ibid.

Table 2-48: OTEC potential sites as a function of fuel and water costs[600]

Nominal Size, MW	Type	Scenario	Potential Sites
1	Land-Based OC-OTEC with 2nd Stage for Additional Water Production	Diesel: $45/barrel Water: $1.6/m^3	Present Situation in Some Small Island States
10	Same as Above	Fuel Oil: $30/barrel Water: $0.9/m^3	U.S. Pacific Insular Areas and other Island Nations.
50	Land-based Hybrid CC-OTEC with 2nd Stage	$50/barrel $0.4/m^3 or $30/barrel $0.8/m^3	Hawaii, Puerto Rico if fuel or water cost doubles.
50	Land-Based CC-OTEC	$40/barrel	Same as above.
100	CC-OTEC Plantship	$20/barrel	Numerous sites.

COMMERCIAL DEVELOPMENT AND ECONOMIC BARRIERS

Currently, there are no commercial OTEC facilities in operation, nor are there any firm plans to build such a facility. In order for an interested party to obtain funding for a 100 MW OTEC power plant, it will be necessary to build a 5 MW demonstration plant that can be scaled up to 50 or 100 MW.[601] Funding for such a facility is dependent on long-term power purchasing agreements and "patient" financing that does not expect an immediate return on investment (i.e., government subsidized financing).[602] An immediate return on investment is difficult to realize, based on the assumption that it could take up to five years to put a demonstration plant into service from the time that financing is secured.[603] These barriers, however, are not insurmountable in the face of volatile fossil fuel markets. Island nations and territories, which are especially susceptible to fluxes in energy prices, represent a significant market opportunity for OTEC technology. Although funding is not yet secure, Sea Solar Power Inc. plans to build a $20 million test project within the next four years, followed by a 10 MW pilot project in Guam and a 100 MW floating plant in South India.[604]

600 Vega, n.d.
601 Vega, 2002.
602 L. Vega, personal communication, with B. Strode, 2006.
603 Vega, n.d.
604 Pelc & Fijita, 2002; Sea Solar Power Inc, n.d.

Renewable Energy: Waves

Ocean waves are generated by the action of the wind on the ocean surface; waves can travel thousands of miles until that energy is finally dissipated on a shoreline. Attempts to harness wave-generated electric power are rapidly moving beyond research and into development; commercial status in 2006 is comparable to wind-generated power in the mid-1990s. Various ocean wave technologies under development harness power both at the shoreline and offshore.

In January 2005, an offshore wave power feasibility report was published by groups sponsored or cosponsored by the Electric Power Research Institute. These groups included the Electricity Innovation Institute, Global Energy Partners LLC, Virginia Polytechnic Institute and State University, and the DOE National Renewable Energy Laboratory. The study found "…a compelling case for investing in wave energy related research, development and demonstration…"[605] Specific conclusions of the report were:

- With proper siting, wave energy may be one of the most environmentally benign ways to generate electricity.
- Offshore wave energy minimizes Not-in-My-Backyard issues that plague other energy projects, from nuclear to wind.
- Wave energy is more predictable than solar and wind energy and therefore offers a better possibility than either for being dispatchable and earning a capacity payment.
- Due to its high power density, wave energy may be one of the lowest cost renewable energy sources.
- Ocean energy "has substantial promise and is a large and as yet untapped energy resource that is too important to overlook."[606]

TECHNICAL OVERVIEW AND RESEARCH & DEVELOPMENT

Technology for wave power is new and rapidly evolving. As of July 2006, wave-generated electric power was moving into small-scale commercial and pilot stage testing. Table 2-49 summarizes the 10 wave energy conversion devices in various stages of development in the United States, Europe and Australia.

605 Bedard et al., 2005.
606 Ibid.

Table 2-49: Wave energy conversion projects

Unit	Company	Location
Limpet	Wavegen	Inverness, Scotland
Pelamis	Ocean Power Delivery LTD	Edinburgh, Scotland
OWC	Energetech	Australia, Connecticut
Wave Dragon		Denmark
Wave Swing	TeamWorks	Netherlands
AquaBuoy	AquaEnergy	Washington, U.S.A.
Sea Dog	Indep. Natural Res. Inc.	Minnesota, U.S.A.
MRC 1000	Orecon	UK
Wave Bob		UK
Floating Buoy	Ocean Power Technologies	New Jersey, U.S.A.

Two examples of wave technology are presented here: the Limpet and the Pelamis, which representing the most commercially advanced shoreline based- and offshore power generation systems, respectively.

Shoreline Wave Power

The Limpet (Land-Installed Marine-Powered Energy Transformer) was developed by Voith Siemens Hydro Power Generation, a joint venture of Voith and Siemens in the field of hydroelectric equipment. Wavegen, Voith Siemens Hydro's research, development and operating unit in Inverness, Scotland, focuses on converting wave energy by means of an oscillating water column.

In this process, the waves create oscillations on the water surface in a hollow chamber. These oscillations continuously compress and decompress an air column above the chamber. This difference in pressure compared to the environment powers a Wells turbine to generate electricity.[607]

The turbine is subjected to a bidirectional flow of waves, but never changes its direction of rotation. In 2000, a 500 kW pilot plant on Scotland's west coast was commissioned, the electricity output of which is fed into the public grid. The Limpet unit on Islay has an inclined oscillating water column (OWC) that couples with the surge-dominated wave field adjacent to the shore. The water depth at the entrance to the OWC is typically seven meters. The design of the air chamber is important to maximize the capture of wave energy and its conversion to pneumatic power. The turbines are carefully matched to the air chamber to maximize power output. The performance has been optimized for annual average wave intensities of between 15 and 25 kW/m. The water column feeds a pair of counter-rotating turbines, each of which drives a 250 kW generator, giving a nameplate rating of 500 kW. The Limpet's low profile design reduces impacts on coastal landscapes and views.[608]

Wavegen also has taken another approach to the shoreline capture of wave energy. The company has built a unit on the Faroes Islands of Scotland, in collaboration with the Faroese electric company, SEV. They are jointly developing a wave-power station based on a series of Wavegen's air turbine power generation modules. The Faroese power station is also based on OWC technology developed by Wavegen at its Islay plant, using tunnels cut into the cliffs on the shoreline to form the chamber that captures the energy. The new design offers an approach to shoreline devices that is well-protected and unobtrusive.

607 Ibid.
608 Ibid.

In addition, Wavegen has developed small power take-off modules for incorporating into breakwaters, coastal defenses, land reclamation projects and harbor walls. The 18.5 kW power modules consist of a Wells turbine, a valve and a noise attenuator. The complete modules weigh less than a ton; installation or removal uses a small mobile crane. The modules are very simple and rugged: the blades are fixed onto the rotor, have no pitching mechanism or gearbox and have no contact with seawater. Wavegen is currently in discussion with a number of European port authorities interested in installing this technology into existing structures such as seawalls.

Offshore Wave Power

The Pelamis, developed by Ocean Power Delivery Ltd., is a semi-submerged, articulated structure composed of cylindrical sections linked by hinged joints. The wave-induced motion of these joints is resisted by hydraulic rams (water-powered cyclic pumps) that pump high-pressure oil through hydraulic motors. The hydraulic motors drive electrical generators to produce electricity. Power from all of the joints is fed down a single umbilical cable to a junction on the seabed. Several devices can be connected together and linked to shore through a single seabed cable.

A novel joint configuration is used to increase power capture in small seas. Control of the restraint applied to the joints allows them to be "turned up" in small seas where capture efficiency must be maximized or "turned down" to limit loads and motions in survival conditions. The machine is held in position by a mooring system (for which a patent has been applied) comprising of a combination of floats and weights that prevent the mooring cables becoming taut.

The mooring system maintains enough restraint to keep the Pelamis positioned but allows the machine to swing head on to oncoming waves. Reference is achieved by spanning successive wave crests. The 750 kw full-scale prototype is 120 meters long and 3.5 meters in diameter. It will contain three power conversion modules, each rated at 250 kW. Each module contains a complete electro-hydraulic power generation system.

Ocean Power Delivery believes its Pelamis system will ultimately produce electricity at a cost of less than $0.10/kWh (in U.S. dollars).[609] The units are manufactured in Scotland. The company has secured its first order for a wave farm, from a Portuguese consortium led by Enersis SA. In May 2006, the first of three 750 kW Pelamis machines were shipped to Portugal. The 2.25 MW project will be installed off the country's northern coast as the first stage of a 24 MW plant. Ocean Power Delivery has secured a Letter of Intent for a further 28 machines to complete the plant once the first phase has been installed and commissioned. On June 27, 2006, the company announced that it had raised over £13 million (approximately $24 million) of new investment from a consortium of new and existing investors for the project.

Future wave farm projects would consist of an arrangement of interlinked machines connected to shore by a single subsea cable. A 30 MW plant would consist of a total of 45 individual units clustered in rows, which could generate 300,000 MWH/year. The total ocean surface area required for such a plant would be 16 square kilometers.

Areas for Future Development

Areas for future development include optimization of configuration, reduction of capital costs, development of structures and systems suitable for volume production, and improved control systems to maximize energy capture.

609 See *http://www.oceanpd.com/default.html* for more information.

COST OF ENERGY

Although a number of wave energy technologies are under development, including some that may be at or near the precommercial stage, publicly available data on resource quantity, quality and distribution and on technology cost and performance are inadequate to describe the details of the technologies.[610] Data is available for specific projects, however. For example, the Electric Power Research Institute's Wave Energy feasibility report provided an evaluation and cost-estimates for a 300,000 MWH/year commercial wave plant (Table 2-50).[611]

Table 2-50: Commercial cost of energy after tax incentives: 300,000 MWH/yr

Location/Technology	Oregon Pelamis	CA Pelamis	CA Energetech	Mass Pelamis	Maine Pelamis
Total Plant Investment ($M)	235	279	238	273	735
No. of units req. for 300K MWh/yr	235	279	238	273	735
Annual O&M ($M)	11	13	11	12	33
COE (cents/kWH) real	9.7	11.2	9.2	11.1	32.2

The study also reported the breakdown of costs as a percentage of the total plant investment:

- Annual operation and maintenance: 40 percent
- Power conversion modules: 28 percent
- Concrete structural sections: 11 percent
- Mooring: 5 percent
- 10-year refit: 4 percent
- Facilities: 3 percent
- Installation: 3 percent
- Loan: 3 percent
- Management: 2 percent
- Cables: 1 percent
- Transmission and grid connection: 0 percent

RESOURCE AVAILABILITY

A number of site attributes are important for wave potential, including depth of seafloor, seafloor surface geology, coastal utility grid and competing use of sea space. Potential wave energy is measured in terms of native energy and energy spectra potential, which determines energy as a function of wave height and wave period or frequency. EPRI's reports measured total U.S. available incident wave energy flux as approximately 2,300 terawatt-hours per year; 24 percent of this available base, at 50 percent conversion efficiency, is equivalent to 10 times the hydroelectric capacity of the United States in 2004.[612]

Wave energy is concentrated near the water surface with little action below 50 meters in depth.[613] This makes wave power a highly concentrated energy source with much smaller hourly and day-to-day variations than other renewable resources, such as wind or solar.

Since 2001, there has been a resurgence of research activity in wave energy, as technology has developed that enables capture of the resource potential. A number of developers in different countries have either installed or

610 Energy Information Administration, 2006a.

611 Bedard et al., 2005.

612 See *http://www.epri.com/oceanenergy/waveenergy.html#briefings* for more information.

613 Ocean Power Delivery Ltd., 2006.

are about to install full-scale prototypes, with public and private funds in excess of 70 million Euros committed to these projects.

There are many promising sites around the world. Sites with an average wave power level greater than 15 kW/m have the potential to generate wave energy at competitive prices.[614]

The western seaboard of Europe offers an enormous number of potential sites. The most promising sites are off the United Kingdom, Ireland, France, Spain, Portugal and Norway. The economically recoverable resource for the United Kingdom has been estimated to be 87 TWh per year, or approximately 25 percent of current U.K. demand.[615]

CHALLENGES

When evaluating a site for a possible "wave farm" development, the following are key issues for consideration:

Wave Resource

Wave levels will naturally dictate the possible electrical output; it is therefore desirable to select a site that has high annual levels of wave energy. Wave energy is generally measured in kW per meter wave face; in energetic areas of the world, the annual average energy level can exceed 50 kW/m.

Bathymetry (Ocean Floor Topography)

The Pelamis is designed to be moored in water depths of about 50 meters; Energetech's unit is designed to sit on the ocean bed at similar depths. Seabed obstacles that reduce wave energy or prove hazardous to installation and operation must be identified and properly mitigated.

Electrical Grid Connection and Cable Routing

The proximity of any site to an electricity grid with suitable capacity available is an important factor in determining required cable lengths for connection between the site and the onshore grid. This will contribute to both project costs and transmission losses.

Onshore Facilities

A dock facility capable of accommodating a Pelamis, which is approximately 150 meters in length, is required for maintenance.

Barriers to Wave Technology Development

Economic and Social Barriers

Land-based wave projects (such as Limpet in Islay, Scotland) bear smaller construction-related start-up costs due to easily accessible turbines and shorter transmission distances. Land-based units often face hurdles due to public visibility along valued coastline real estate. Barriers affecting sea-based units include the concern of additional navigation hazards, interrupted marine mammal migration, competing usage for the area (specifically

614 See *http://www.epri.com/oceanenergy/waveenergy.html#briefings* for more information
615 Ocean Power Delivery Ltd., 2006.

fishing grounds) and reduced wave energy negatively impacting coastal ecosystems and sediment transport. Sea-based units require greater initial investment for installation and transmission infrastructure, but are visually benign from shore. A significant barrier to development is the complex arrangement of federal and state agencies responsible for permitting both wave and tidal energy projects.

Shoreline-based wave-power would minimally impact the surrounding coastline on human time scales. Extracting this energy could slow the rate of cliff erosion, tending to reduce sediment availability for nearby beaches, but on a rocky shoreline these effects will be relatively minor and spread over a long period.

Offshore wave-energy extraction, however, could have significant effects if practiced along a sandy shoreline (e.g., the southeastern and Gulf Coasts of the United States). Substantially reducing the local wave energy reaching shore could have an effect on the shoreline adjacent to the installation that is analogous to building a breakwater; sediment transport will be reduced in this area, causing the shoreline to accrete seaward. This local effect could be beneficial if the installation is positioned offshore of an isolated coastal community. However, it could tend to cause erosion on downstream shoreline segments. The tendency for enhanced erosion will spread farther down the shoreline the longer the energy-extraction facility is operated. The input and consideration of communities potentially impacted should be carefully considered during project development and regulatory approvals.[616]

Policy Barriers

Permitting for an ocean-based power plant involves coordinating numerous agencies at all levels of government. In the United States, efforts are still under way to determine agency jurisdictions and designate a lead agency to oversee the process, even though the first permits were granted in 2002. Without a clear understanding of each agency's role and responsibilities, approvals may be delayed and complicated, increasing the initial costs of these technologies and widening the gap of economic feasibility. Parallels for this process can be drawn to offshore wind farm permitting, oil and gas exploration, and coastal water treatment plants. Agencies involved in the comprehensive permitting process currently include the Federal Energy Regulatory Commission, the National Oceanic and Atmospheric Administration, the Minerals Management Service and the Army Corps of Engineers, along with various state coastal management agencies and local governments. Completing the permitting process for a commercial scale pilot site could take several years.[617]

Economic Barriers

Ocean-based energy production has not yet been issued a tax credit or benefit from the federal government. Government policies require a cost-benefit analysis prior to implementation, and analysis of the economics of commercial-scale wave energy still has many unknowns. Economic uncertainties can best be resolved through demonstration projects funded by private investment.

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616 Brad Murray, Duke University; personal communication with R. Lotstein, October, 2006.
617 Ram et al., 2004.

Renewable Energy: Tidal

The nonpolluting nature, constancy and predictability of ocean tidal movements make them an appealing source of renewable energy.[618] Tidal kinetic energy results from the moving mass of water caused by gravitational forces of the sun and moon in combination with the earth's rotation. The rotational period of the moon is approximately four weeks, while one rotation of the earth takes 24 hours; this results in a tidal cycle of roughly 12.5 hours. If tidal movements could be harnessed in a cost-effective and environmentally sensitive manner, they would represent an extremely predictable source of renewable energy, on the scale of centuries.

Tidal currents are often generated in coastal waters (sometimes in areas removed from environmentally sensitive bays and estuaries). In many areas, the shape of the seabed forces water to flow through narrow channels or around headlands (similar to wind channeled through narrow valleys and around hills). Sea water is 832 times denser than air, which means that a fast-moving 8 knot tidal current, common in areas such as Deception Pass in the Pacific Northwest, is the equivalent of a 390 km/hr wind.[619] Unlike wind, tidally generated coastal currents are completely predictable. The predictable tidal cycle produces currents that reach peak velocity four times every day.

The two primary approaches to harnessing electricity from the ocean tides are tidal barrages and tidal streams. For each of these approaches, a number of options for turbine technology and configuration are available.

TECHNOLOGY OVERVIEW AND RESEARCH & DEVELOPMENT

Tidal Barrages

Tidal barrages, also known as tidal fences, capture the energy from high current velocities as large volumes of water pass through narrow channels. Blocking estuaries with a barrage and forcing water through turbines is considered a potentially effective way to generate electricity, if certain environmental impacts can be effectively managed (see Barriers to Tidal Technology Development, below). Tidal barrages are conceptually incorporated into other essential infrastructure, such as roadways that transverse channels.

In concept, tidal barrages function similarly to conventional hydroelectric power, except that instead of a traditional impoundment structure (i.e., a dam), a barrage or fence is built across a channel, such as a river estuary. Water flows through the barrage into the basin as the tide comes in. The barrage contains gates that allow the water to pass through. The gates close when the tide has stopped, trapping the water within the basin and creating a hydrostatic head. As the tide recedes, the gates reopen; the hydrostatic head causes the water to flow through these gates, driving the turbines and generating power. Power can be generated in both directions through the barrage.

The advantage of a tidal barrage is that all of the electrical equipment (e.g., generators and transformers) can be kept high above the water. Also, by decreasing the cross-section of the channel, current velocity through the turbines is significantly increased.

Different types of turbines are available for use in tidal barrages.[620] In a bulb turbine, water flows around the turbine. The major disadvantage of this configuration is that water flow must be stopped for turbine and generator maintenance.[621]

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618 See *http://www.darvill.clara.net/altenerg/tidal.htm* for more information.
619 Fujita Research, 1998.
620 Boyle, 1996.
621 Ibid.

In a rim turbine, the generator is mounted at right angles to the turbine blades, providing easier access for maintenance. This turbine's major disadvantage is the inability to adjust turbine output.[622]

Tubular turbines have been proposed for the United Kingdom's most promising site, the Severn Estuary. The blades of this type of turbine are connected to a long shaft and are orientated at an angle so that the generator is sitting on top of the barrage.

The turbines in the barrage can be used to pump extra water into the basin at periods of low demand, usually coinciding with off-peak electricity prices at night when demand is low. The company therefore buys the electricity to pump the extra water in and then generates power at times of high demand when prices are high. This concept is the same as with conventional pumped storage hydropower.

There are few operational commercial tidal plants in the world; one of these is La Rance barrage in northern France, the largest such station in the world (and the only one in Europe), installed in 1966.[623]

The construction of this barrage began in 1960. The system consists of a dam 330 meters long and a 22-square-kilometer basin with a tidal range of 8 meters; it incorporates a lock to allow passage for small craft. The plant became operational in 1967 when 24 bulb turbines, each 5.4 meters in diameter and rated at 10 MW, were connected to the 225 kV French electricity transmission network. The turbines, which were developed by Electricite de France, allow power generation on both ebbs of the tide. These axial-flow turbines are also designed to pump water into the basin for the purposes described earlier, making it easier to meet energy demand. This type of turbine has been used for conventional hydropower on mainland Europe in dams on the Rhine and Rhone rivers. La Rance satisfies 90 percent of Brittany's electric power demand, and a major refurbishment program (due for completion in 2007) will ensure operation over the coming decades.

Proponents of this approach in the United Kingdom periodically propose a tidal barrage project in Wales, called Severn Barrage. The project would incorporate over 200 large turbines to produce 8,000 megawatts of power, or 7 percent of the United Kingdom's electricity demand.[624] Other possible benefits of the project include protecting a large stretch of coastline against damage from high storm tides. However, the project has not progressed, due to concerns over potential environmental impacts (see Barriers to Tidal Technology Development, below).

A large commercial tidal barrage project was planned in Southeast Asia, to cross the Dalupiri Passage between the islands of Dalupiri and Samar in the Philippines. The Philippine government reached an agreement to build the barrage with Blue Energy Engineering Company of Vancouver, Canada, in late 1997. However, a change in Philippine government resulted in cancellation of the project, illustrating how large, visionary, expensive projects can be vulnerable to political shifts.

Still, the project proposal reflects the scope of ocean energy potential. The site originally proposed, located on the south side of the San Bernardino Strait, is approximately 41 meters deep (with a relatively flat bottom) and four kilometers in length, and has a peak tidal current of about 8 knots. The estimated cost for phase 1 of the project was $2.79 billion (in U.S. dollars), with all four phases costing an estimated $38 billion. Phase 1 was estimated to offset an estimated 6.5 million tons of carbon dioxide emissions per year and provide additional revenue through sales in the newly emerging emission offsets markets. Prior to its cancellation, phase I was

622 Ibid.
623 Electricité de France, n.d.
624 Darvill, 2006.

scheduled to install 274 ocean-class Davis turbines, each generating from 7 MW to 14 MW, for a total estimated capacity of 2,200 MW of power at peak tidal flow (1,100 MW base average).[625]

This project was to have used a unique vertical axis turbine system design—a "highly efficient underwater vertical-axis windmill" marketed by Blue Energy that contains four fixed hydrofoil blades connected to a rotor that drives an integrated gearbox and electrical generator assembly. [626] The turbine is mounted in a durable concrete marine caisson that anchors the unit to the ocean floor and directs flow through the turbine, further concentrating the resource and supporting the coupler, gearbox and generator above it. These components sit above the surface of the water and are readily accessible for maintenance and repair. The hydrofoil blades employ a hydrodynamic lift principal that causes the turbine foils to move proportionately faster than the speed of the surrounding water. The unit's computer-optimized cross-flow design ensures that the rotation of the turbine is unidirectional on both the ebb and the flow of the tide.

Blue Energy claimed that its design requires no new construction methodology. The transmission and electrical systems are similar to thousands of existing hydroelectric installations.[627] Power transmission is by submersible cabling buried safely in the ocean sediments, with power drop points for coastal cities and connections to the continental power grid. The company also said the system's standardized mass-production design would have made it "economic to build, install and maintain" for the project in the Philippines. The system was designed to withstand typhoon winds of 150 mph and tsunami waves of seven meters. The project designed allowed for power to be generated in the fourth year of the project with installation of the first module in the chain, and additional modules would be added to bring the system to full capacity by year six.

Completing the following three phases between Luzon and Samar were projected to add an additional 25,000 MW; this was expected to serve as a "backbone" for an Asian Grid and enable the Philippines to become a net exporter of electrical power. All four phases were estimated to cost $38 billion (in U.S. dollars), with $30 billion for expenses related to power production side and the remainder to expenses related to transmission.[628] Perhaps future changes in government in the region will lead to resumption the project.

Tidal Streams

Tidal streams are fast flowing volumes of ocean water with immense amounts of kinetic energy. These usually occur in shallow seas where a natural constriction forces the water to accelerate. Free-standing tidal turbines are an alternative approach to tidal fences. They resemble an underwater wind turbine and offer a number of advantages over tidal fences; they are less environmentally disruptive, allow small boats to continue to use the area and have much lower material requirements than the fences.

The technology for energy capture is very similar to wind energy, with some key differences. Water is more than 800 times denser than air, and this density results in greater energy capture from turbines with smaller diameters. Other key differences are in the slower flow rate of ocean tides and their predictability. Technology development and deployment is still in relative infancy compared to other forms of renewable energy. As a result, no specific technology has yet become the "gold standard" and several technologies are in varying stages of development. In fact, there is still disagreement about nomenclature to reference the technology. Hence, technology to generate electricity from kinetic energy in flowing water is variously referred to as:

625 Blue Energy, 2006a.
626 Blue Energy, 2006b.
627 Blue Energy, 2006a.
628 Blue Energy, 2006c.

- Instream energy generation technology (IEGT).
- Free-flow hydropower technology.
- Kinetic hydro energy or power systems.
- Tidal in-stream energy conversion (TISEC)

Regardless of terms, the systems all have a number of common traits:

- They share operational ability in rivers, manmade channels, tidal waters or ocean currents.

- They use the water stream's natural pathway.

- They do not rely on the potential energy of artificial water-head, created, for example, by dams or other impoundments.

- They do not require the diversion of water through manmade channels, riverbeds or pipes, although they might have applications in such conduits.

- They do not require large civil works.

- They can be placed in existing tailraces and channels.[629]

Several designs will be briefly summarized here. The main differences between developer companies' systems are center on drive train and generator styles, mounting/anchoring arrangements and geometries of the turbine or kinetic energy conversion device. These designs include:

- Vertical-Flow Axis Turbines. Blue Energy's vertical axis turbine was described above for tidal barrages. This same design is considered viable for tidal stream energy capture.

- Axial-Flow Rotor Turbines: These turbines consist of a concentric hub with radial blades, and they most closely resemble conventional windmill designs. Mechanical power is applied directly through a speed increaser to an internal electric generator, or through a hydraulic pump that, in turn, drives an onshore electric generator.

Major concerns over tidal turbines and generators include the cost and practicality of maintenance, due to the constant exposure of the components to the sea environment. An alternative Swan Turbine design attempts to address this concern with a direct drive, where the blades are connected to the electrical generator without a gearbox in-between.[630] The Swan Turbine also may use a "gravity base," a large concrete block that anchors the unit to the seabed, rather than drilling into the seabed. To further increase reliability and decrease maintenance, the blades are fixed pitch rather than actively controlled.

An alternative configuration developed by Marine Current Turbines, a company based in the United Kingdom, allows turbine blades to be raised above the water surface for maintenance. The company has used a 300 kW prototype in the United Kingdom for more than three years. Testing on a 1 MW commercial version was scheduled in 2006.

629 Verdant Power, 2003.
630 Swanturbines, 2005.

- Open Center Fan Turbines. A flotation chamber and frame holding two donut-shaped turbine blades rotate in opposite directions in the current. Rotation of the blades drives hydraulic pumps along the edge, and the pumps, in turn, drive a conventional AC generator that produces electricity.

- Helical Turbines. These turbines are low head, reaction cross-flow hydraulic turbines. The blades have hydrofoil sections that provide tangential pulling forces in the cross water flow. These forces rotate the turbine in the direction of the leading edge of the blades. Thus, the direction of turbine rotation depends only on orientation of blades and not on direction of fluid flow.

- Cycloidal Turbines. This design consists of a paddle wheel with articulating blades. The turbine works by placing a blade broadside to the flow while the opposing blade is feathered to the local flow. Thus, it allows the blades' individual lift and drag to be optimized, giving the system the best overall performance.

- Lift or Flutter Vane Turbines. Resembling a Venetian blind, the generator is powered by a flutter or lift-vane type of turbine that consists of a parallel linkage holding a number of large hydroplanes. The generator produces electricity using the linkage oscillatory movement of hydroplanes driven by flowing water.

- Hydraulic Tapped Ducted Turbines. The Rochester Venturi (RV), developed by HydroVenturi, is a pressure amplifier governed by Bernoulli's Theorem. It uses shapers placed into a primary (tidal or river) flow to accelerate the flow and generate a reduction in pressure at the point where the flow is most constricted.[631] The reduction in pressure can then be used to pull water or air from another location into the primary flow. It is this secondary flow that allows generation of electrical power.

  To avoid the need for water turbines, HydroVenturi has developed air-injection technology that uses air as the secondary flow medium. This design has many advantages. Among them, moving or electrical parts can be removed underwater; power is transferred from the primary water circuit to the turbine by air, thus minimizing energy losses and allowing a power match to the turbine's technology; multiplexing is possible among many RVs or other turbines; and it can utilize flow rates that are too low for conventional water-driven turbines.

COST OF ELECTRICITY

Only a limited number of tidal power stations worldwide now operate on a commercial basis, and the technology seems unlikely to achieve substantial market penetration unless lower-quality resources can be harnessed economically. As with wave energy technologies, while some of these technologies appear to be in fairly advanced precommercial development, available information is insufficient to support reasonable market assessment.[632] Some of the projected figures are speculative and based on company marketing information. Some data are available as a result of EPRI feasibility studies at a limited number of sites chosen due to specific characteristics.[633]

631 HydroVenturi Ltd, 2006.

632 Energy Information Administration, 2006a.

633 See *http://www.epri.com/oceanenergy/streamenergy.html* for more information.

Verdant Power's Roosevelt Island Tidal Energy (RITE) project is the first tidal energy project in the United States to be granted a license by the Federal Energy Regulatory Commission. The project is licensed under the authority granted through the preliminary permit that was issued by FERC in September 2002. Once constructed, the project will consist of approximately 390 turbines (approximately 3.4 kW each) located in the East Channel of the East River, adjacent to the east shore of Roosevelt Island. The project will generate up to 10 MW of distributed electricity that will be available to residents and businesses of Roosevelt Island, as well as to customers throughout New York City.[634] Among its specifications, the project's installation costs are $4,300/kW, its operating costs are 7 to 9 cents per kWh free flow, and the dates for market penetration are 2010 to 2012.

Estimated costs of central power generation using in-stream tidal power, as determined by EPRI's North American Tidal In-Stream Energy Conversion Technology Feasibility Study, are shown in Table 2-51:[635]

Table 2-51: In-stream tidal power costs

Tidal In-Stream Power Density (kW/m²)	Capacity Factor (%)	Capital Cost (2005 $/KW)	COE (Cents/KWh)	CO_2 (lbs/MWh)
>3.0	29-46	1700-2000	4-7	0
1.5-3.0	29-46	2100-2400	4-11	0
<1.5	29-46	3300-4000	6-12	0

RESOURCE AVAILABILITY

Coastal tidal currents are strongest at the margins of the world's larger oceans. A review of likely tidal power sites in the late 1980s estimated the energy resource in excess of 330,000 MW.[636] Southeast Asia is one area where it is likely such currents could be exploited for energy. In particular, the Chinese and Japanese coasts, and the large number of straits between the islands of the Philippines, are suitable for development of power generation from coastal currents.

Tidal turbines function well where coastal currents run at 2 to 2.5 m/s (slower currents tend to be uneconomic, while larger ones place high stress levels on the equipment). Such currents provide an energy density four times greater than air; an ocean tide turbine 15 meters in diameter will generate as much energy as a wind turbine that is 60 meters in diameter. In addition, tidal currents are predictable, a feature that gives them an advantage over both wind and solar systems. The majority of the assembly is hidden below the waterline, and all cabling is along the seabed. The tidal turbine also offers significant environmental advantages over a tidal barrage, as it does not impede the flow of water by blocking an estuary.

There are many sites around the world where tidal turbines could be effectively installed. The ideal site is close to shore (within 1 kilometer) and in water depths of about 20 to 30 meters. As of mid-2006, approximately 20 permit applications were submitted to U.S. federal and state agencies for pilot demonstration projects.[637]

The U.K.-based Marine Current Turbines maintains that the best sites could generate more than 10 megawatts of energy per square kilometer.[638] The European Union identified 106 sites that would be suitable for the turbines, 42 of them around the United Kingdom. Underwater turbine projects are under consideration by the governments of the Philippines, Indonesia, China and Japan.

634 Devine Tarbell & Associates Inc., 2006.
635 Bedard et al., 2006.
636 Comments from Verdant Power, Renewable Energy Modeling Workshop on Hydroelectric Power, May 10, 2005
637 Roger Bedard, EPRI; personal communication with R. Lotstein, September 14, 2006.
638 Argyll and the Islands Enterprise, 2006.

Verdant Power has mapped more than 120 potential tidal power locations in North America, each with multiple sites averaging 5 MW capacity. Other independent studies estimate available U.S. tidal power to range from 12,500 MW to 170,000 MW.[639] Independent analysis of the Gulf Stream estimates 685,000 MW of capacity.

CHALLENGES

Tidal Barrages

Concerns over the potential environmental and ecological effects of tidal barrages have inhibited their progress. Similar to large conventional hydroelectric projects, capital and environmental costs for tidal barrages are very high. Environmental impacts can extend for several miles upstream and downstream from the actual structure, affecting habitat of diverse species of animals and plants. Barrages present a barrier to navigation by boats and fish alike; reduced tidal range (difference between high and low water levels) can destroy much of the intertidal habitat used by wading birds; and sediment trapped behind the barrage can reduce the volume of the estuary over time. Few sites worldwide are deemed suitable for tidal barrages.

In-Stream

The environmental impacts of tidal power in tidal streams are considered less severe than for a tidal barrage. Submerged tidal turbines, mooring and grid connections may affect the seabed where they are positioned, potentially affecting aquatic life in the area. These considerations are site-specific and best addressed by rigorous environmental impact assessments in conjunction with appropriate regulatory oversight. Early environmental assessments supporting approval will likely be very cautious; processes for licensing could be a substantial barrier due to the wide variety of regulations and oversight agencies. In the United States, the Federal Energy Regulatory Commission will likely play a lead role in evaluating applications and coordinating decisions among the several federal, state and local agencies involved. Harnessing the immense capacity of the Gulf Stream would entail working with international regulatory bodies, making the possibility and feasibility much lower than implementing development within U.S. coastal borders. Most experts in the growing field have dismissed any realistic possibility of tidal energy capture from the Gulf Stream.

Economic challenges include cost of technology and deployment, mooring, operations and maintenance. Transmission and linkage to the broader grid also are issues.

Barriers to Tidal Technology Development

Environmental and Social Barriers

Development of a barrage project today would face many regulatory hurdles and would likely draw intense criticism over environmental impact. The "fence" would disrupt boat traffic, alter the flow of sediment to the shore and inhibit the free movement of fish and other marine animals in the surrounding region. Building a fence that disrupts flow across an entire estuary or tidal inlet creates an "all or nothing" approach that, once pursued, cannot be easily undone.

In-stream tidal energy avoids the larger initial investment of barrages and localizes the environmental impact while allowing the uninterrupted portions of the tidal region to operate uninhibited for marine life, sediment transport and boat traffic. Disadvantages include moderate operation and maintenance costs due to fully sub

639 Comments from Verdant Power, Renewable Energy Modeling Workshop on Hydroelectric Power, May 10, 2005

merged turbines, inability to control or readily store the production of energy for use during peak hours and the cost of transmission lines needed to bring the power to areas of electricity demand.

Extracting tidal energy could reduce the tidal range in the basin. This reduction may affect intertidal environments. The severity of these effects would depend on what percent of the tidal energy was extracted and how rapidly the installation came on line; slow addition of turbines to gradually approach the final electrical energy production would increase the chances that tidal marshes could adapt with minimal disruption.[640]

Predicting the tidal-range reduction based on the tidal power extracted would be relatively straightforward, although hydrodynamic modeling would be required to address possible changes in the resonance of the tidal basin that creates the high tidal ranges required to make these technologies feasible. Predicting the changes to intertidal environments would be challenging at the present time and would require numerical modeling, including modeling the influences of physical and biological (especially marsh vegetation) processes.[641]

POLICY BARRIERS

Permitting for an ocean-based power plant involves coordinating numerous agencies at all levels of government. Without a clear understanding of each agency's role and responsibilities, approvals may be delayed and complicated, increasing the initial costs of these technologies and widening the gap of economic feasibility. Parallels for this process can be drawn to offshore wind farm permitting, oil and gas exploration and coastal water-treatment plants. Agencies involved in the comprehensive permitting process currently include the Federal Energy Regulatory Commission, the National Oceanic and Atmospheric Administration, the Minerals Management Service and the Army Corps of Engineers, along with various state coastal management agencies and local governments. Completing the permitting process for a commercial scale pilot site could take several years.[642]

640 Brad Murray, Duke University; personal communication with R. Lotstein, October, 2006.
641 Ibid.
642 Ram et al., 2004.

Renewable Energy: Biomass

Biomass includes all plant and plant-derived matter, and is generally classified into forest residue, mill residue, agricultural residue, urban wood waste and dedicated energy crops.[643] Biomass can be converted to energy or to alternative fuels through a variety of processes, including direct combustion, gasification, pyrolysis, anaerobic digestion, ethanol production, biodiesel production and methanol production.[644] Biomass can be combusted alone or co-fired with another fuel, such as coal or natural gas, for the production of electricity alone or electricity and heat in combined heat and power applications. The chemical and manufacturing industries, which currently consume each year one-eighth of the petroleum used in the United States, can also substitute biomass to produce industrial oil and organic chemicals.[645]

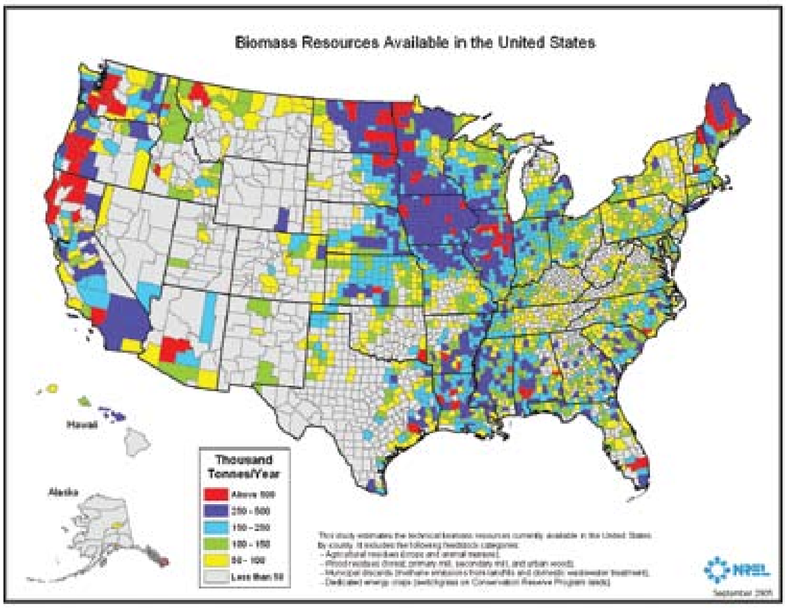
Biopower is driven by economic and environmental concerns. Under some circumstances, biopower can be less expensive to produce than traditional fossil fuels and can contribute to rural economic growth. Biopower can also help reduce overall CO_2 and SOx emissions when used in place of or co-fired with traditional fossil fuels. Closed-loop biomass systems are assumed to have no net carbon emissions, as burning merely releases previously sequestered atmospheric carbon.

Estimates of total U.S. biopower capacity vary by source and depend on how co-fired, industrial use, combined heat and power, and municipal solid waste applications are classified. The Energy Information Agency estimated biopower generation from the electric-power sector to be approximately 152,690 GWh in 2003.[646] When combined with residential, commercial and industrial production, total U.S. biopower generation in 2003 was approximately 739,000 GWh.[647] Biomass stocks vary across the United States, with higher concentrations in the Midwest and along the Mississippi and the coasts (Figure 2-10). The Southeast is also particularly high in biomass resources, with an estimated 10.4 Tg of available wood fuel in North Carolina alone.[648] Current total U.S. biomass production is estimated at 190 million dry tons per year, but significant increases in biomass production are expected over the next 50 years.[649]

Assuming continuing increases in crop yields, increases in efficiency of residue harvesting and increases in perennial energy crop acreage, total U.S. biomass production potential is estimated to be 1.3 billion dry tons per year, an amount sufficient to offset one-third of current U.S. petroleum consumption.[650] But while a number of biomass technologies are in various stages of development, the simple co-firing of biomass with traditional fossil fuels such as coal has the greatest potential for near-term use of biomass.[651] Co-firing is explored further under "Existing Fleet" above.

643 See, e.g. Bain et al., 2003; Perlack et al., 2005; Walsh et al., 2000.
644 See, e.g. Oregon Department of Energy, 2006.
645 U.S. Department of Energy, 2005a.
646 Energy Information Agency, 2005c.
647 Ibid.
648 U.S. Department of Energy, 1997.
649 Perlack et al., 2005.
650 Ibid. Estimate of petroleum offset is based on biomass utilization in electrical generation, transportation, and manufacturing sectors.
651 Bain et al., 2003.

Figure 2-10: Biomass resources available in the United States[652]



While each of the above applications of biomass technology is the subject of on-going demonstration, research and development, the following synthesis will focus primarily on biomass for electricity generation, referred to here as biopower. Furthermore, while municipal solid waste, landfill gas (LFG) and manure are sometimes included under the category of biomass energy sources, they are not included in this section unless explicitly noted. Landfill gas is discussed separately later in this chapter.

SOURCES OF BIOMASS

As mentioned above, biomass is generally classified into forest residue, mill residue, agricultural residue, urban wood waste and dedicated energy crop categories. A description of each is included below.

Forest, mill and agricultural residues form one class of biomass feedstock. The first subset, forest residues, is generated as a byproduct of harvest and fuel management operations; such residues may include small-diameter trees, leaves, trimmings and brush.[653] Although larger-diameter trees are often reserved for production into saw-logs, finished forest products, and pulp and paper products, depressed regional market conditions may result in the availability of these trees for biomass as well.[654] Research also has been conducted on techniques to use entire trees without the need for trimming or chipping.[655]

The second subset, mill residues, includes bark, trimmings and other byproducts from mill operations. These residues are often uniform and have a low moisture content, and these factors contribute to their cost-effectiveness as a fuel for direct combustion; approximately 97 percent to 98 percent of all primary mill residues are already being utilized.[656]

652 Milbrandt, 2005, p. 44.

653 Government Accountability Office, 2005.

654 Ibid.

655 An example of this technology is Whole Tree Energy, which involves cutting the tree at the base, transporting it whole to a generation facility and drying it on-site with heat from the plant's operation. See, e.g. Perlack et al., 1996., Husain et al., 1997. For hybrid polar in Minnesota, Husain et al., 1997 estimates a per acre savings of 40 percent using Whole Tree Energyover conventional harvesting techniques.

656 Perlack et al., 2005.

The third subset, agricultural residues, includes stover and straw left over following seed or grain harvest. Although agricultural residues comprise 58 percent of an estimated 194 million dry tons of annually available agriculture biomass, the low efficiency of postharvest collection of residues remains a challenge.[657] Current agricultural residue collection efficiency is generally limited to a 30 percent to 40 percent recovery rate, but can achieve a rate as high as 60 percent to 70 percent under some conditions.[658],[659]

Urban wood wastes are another class of biomass feedstock. Urban wood wastes are generated from tree trimmings, packaging, and construction and demolition debris. Contamination and current allocations to recycling and composting limit the potential annual availability of urban wood wastes for biopower to approximately 36 million dry tons per year.[660]

Dedicated energy crops comprise a third class of biomass feedstock. These crops include switchgrass and fast-growing woody species such as hybrid willow and hybrid poplar. Production of these crops is not yet on a large scale, though the U.S. potential capacity is 377 million dry tons of energy crop biomass per year.[661]

BIOPOWER APPLICATIONS AND TECHNOLOGY

Direct combustion is the dominant technology for biopower generation in the United States; however, gasification and pyrolysis anaerobic digestion, as well as ethanol, biodiesel and methanol production processes, also can be used for biopower or to convert biomass into alternative fuels.[662] In the near term, co-firing of biomass with traditional fossil fuels such as coal has the potential to be a cost-effective mechanism to cut carbon emissions.

The simplest form of biopower generation is direct combustion or direct-firing. In direct combustion or direct-fired systems, biomass is burned to produce steam that, in turn, drives a turbine. Most direct-fired systems employ a Rakine steam cycle, and they average approximately 20 MW in capacity.[663] While simple direct-fire systems have an efficiency of approximately 20 percent, total system efficiency can be increased to 70 percent to 90 percent through CHP applications.[664],[665]

Under the heading of direct combustion, there are three basic types of biomass firing: pile, suspension and fluidized bed combustion (FBC).[666] Pile combustion systems consist of heaping feedstocks onto a grate and then passing the pile into a combustion chamber with the assistance of feed-stokers or augers. Pile systems are relatively simple to design and operate, and they accommodate a wide variety of particle sizes and moisture contents. Combustion in these systems, however, can be difficult to control, given the large volume of fuel involved. Alternatively, suspension systems require low fuel moisture content (less than 15 percent) and uniform particle size (less than 6 millimeters), and work by combusting particles suspended in turbulent air streams.[667] The small amount of fuels being fired at any given time means that combustion in suspension systems is relatively easy to control. Fluidized bed combustion involves suspending fuels on a bed of inert material (such as sand) and exposing all surfaces of the fuel particles to combustion air. The resulting combustion is highly efficient, responsive

657 Compiled from Ibid.
658 Bain et al., 2003.
659 Perlack et al., 2005.
660 Ibid.
661 Ibid.
662 U.S. Department of Energy, 1997.
663 U.S. Climate Change Technology Program, 2003.
664 U.S. Department of Energy, 2001.
665 U.S. Climate Change Technology Program, 2003.
666 Badger, 2002.
667 Ibid.

and easy to maintain. However, initial costs for FBC systems may be higher than traditional pile systems, and fuel particles must be properly sized to ensure correct suspension in the bed.[668]

Another technique for biopower generation is gasification. Gasification uses high temperatures in an oxygen-limited environment to convert biomass into a combustible gas that, in turn, can be fired to generate electricity. The gas produced through biomass gasification, called syngas, mixes well with oxygen and chemical catalysts, making it more efficient for both combustion and conversion to other fuels or materials; gasifiers have an estimated electrical conversion efficiency of 30 percent to 40 percent.[669] Gasifiers can be operated as either fluidized or up- or down-draft fixed beds. Of these two general types, fluidized bed systems are capable of accepting a wider variety of particle sizes, a wider variety of fuel types and a greater range of moisture contents.[670] In addition to generating syngas for combustion, gasification can be used to supply producer gas for fuel cell applications,[671] and the process is being explored as an alternative utilization technology for "black liquor," a byproduct of the pulp and paper manufacturing process.[672] While black liquor is already used in industrial applications for power and heat generation, gasification has the potential to increase the efficiency of aging traditional boiler/recovery systems.[673]

Flash pyrolysis is similar to gasification in that it uses rapid heating in an oxygen-limited environment to convert biomass into a fuel oil. By controlling the temperatures, heating rate and residence time, the process can be controlled to yield a predominantly liquid or slurry output. This pyrolysis fuel oil, or bio-oil, has the added benefit of being easier to transport, store and use in a wide variety of chemical or energy production applications.[674] Although bio-oil is corrosive by nature, its production through flash pyrolysis has received renewed attention recently.[675] Flash pyrolysis systems can be in the form of fluidized beds, circulating beds or ablative reactors. In the latter, fuel is mechanically pressed against a heat source, reducing the need for uniform fuel particle size and the presence and processing of inert gasses.

Biomass can also be converted into methane, a combustible gas, through a process known as anaerobic digestion. Animal manures and municipal solid waste are two primary waste streams for anaerobic digestion. The capture and use of methane gas from municipal solid waste is a proven technology, and is discussed in greater detail in the "Landfill Gas" section later in this chapter. With regard to manure waste streams, the capture and processing of methane from animal manures at approximately 50 farm-level CHP operations generates a combined 30 GWh of electricity annually.[676] While large (20 MW) centralized, county-level manure biopower generation facilities are technically feasible, locally centralized facilities are more prevalent.[677] A facility in Tillamook, Oregon, for example, has been on-line since 2003 and uses collected manure from 4,000 dairy cows to power two 200 kW generators.[678]

Finally, biomass can be used to create ethanol, biodiesel and methanol. While the feedstocks and processes used to create each fuel differ somewhat (ethanol-grain and lignocellulosic feedstock; biodiesel-oilseed crops; methanol-wood/agriculture residues), each fuel is used primarily in transportation applications. However, ethanol and methanol have been identified as possible hydrogen sources for fuel cells.[679],[680]

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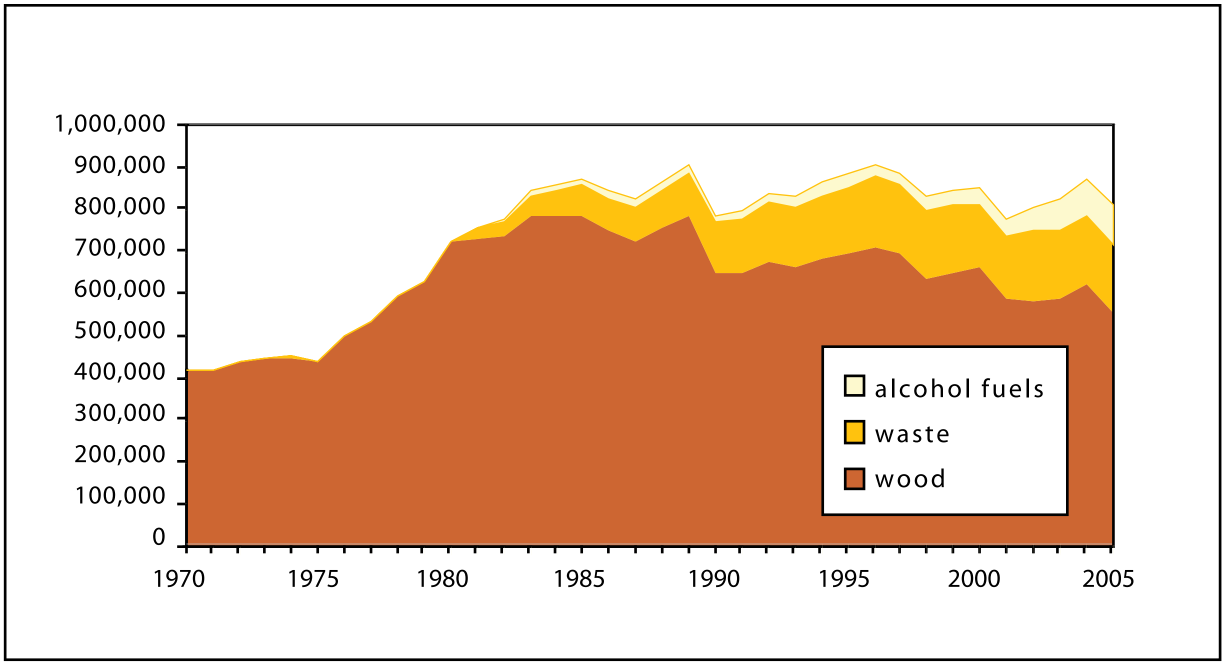
668 Ibid.
669 Scahill, 2003.
670 Badger, 2002.
671 See, e.g. Brown et al., 1998.
672 See, e.g. U.S. Department of Energy, 2005a.
673 Ibid.
674 Food and Agriculture Organization, 1994.
675 Zerbe, 2006.
676 U.S. Climate Change Technology Program, 2003.
677 Ibid.
678 See *http://www.potb.org/methane-energy.htm* for more information on the Tillamook project.
679 Demirbaş & Arin, 2002.
680 U.S. Climate Change Technology Program, 2003.

HISTORIC IMPROVEMENTS AND KEY DRIVERS

The Public Utilities Regulatory Policy Act of 1978 helped to encourage the expansion of biopower in the United States (Figure 2-11).[681],[682] Between 1980 and 1990, total grid-connected biopower generation capacity tripled, but growth stagnated in the 1990s due to unfavorable market conditions and increased feedstock prices.[683]

Figure 2-11: U.S. biopower consumption, by fuel type[684]



While PURPA encouraged biopower growth, it did not provide a strong incentive for energy efficiency. Consequently, most U.S. biopower facilities opted for conventional combustion and steam driven technologies. The sector continues to be dominated by direct combustion/steam turbine platforms, with an average plant efficiency of approximately 20 percent.[685]

Biomass feedstock costs have varied widely over time,[686] but the COE of biopower generation has decreased, and is projected to continue to do so. [687] The decline in biomass LCOE is attributed to improvements in technology, design optimization, and fuel feedstock handling and processing.[688] While increases in efficiencies are forecasted for both direct-fired and gasification systems, gasification in particular is expected to decline on a $/kW basis, primarily as a result of continued demonstration and maturation in technology.[689]

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681 U.S. Department of Energy, 1997.
682 Bain & Overend, 2002.
683 Ibid.
684 Compiled from Energy Information Agency, 2006.
685 Bain & Overend, 2002.
686 For example, Bain et al. (2003) cites an increase of approximately 140 percent in California biomass fuel costs between the late 1980s and early 1990s.
687 Energy Analysis Office, 2002. (in 2000 dollars)
688 Ibid.
689 U.S. Department of Energy, 1997.

EXISTING INNOVATION AND CAPACITY

The cost and performance of biopower generation depends heavily on the feedstock and technology, and can vary widely from site to site (Table 2-52).[690]

Table 2-52: Performance characteristics for biomass direct-fire and gasification

	Direct Fire (1997)[A]	Direct Fire (2001)[B]	Gasification (2003)[C]
Total Plant Cost, $/kW	1,884	1,505-2,282	1,192-1,467
Total Capital Requirement, $/kW	1,965	1,605-2,426	1,312-1,626
Fixed O&M, $/MWh		8.9-10.4	4.64-6.2
Variable O&M, $/MWh		5.4	4.0-4.2
Levelized Cost of Energy (COE) $/kWh		0.08-0.12[D]	0.06-0.08[D]
Net Thermal Efficiency, % (HHV)	23	24-30	36
Net Heat Rate, Btu/kWh	15,280	11,373-14,234	9,483
Average Heat Content, MBtu/ton[E]	16.99	17	17
Capacity Factor	80	80-90	80-90
CO Emissions, lbs/MWh*		3.556[F]	0.001[G]
CO_2 Emissions, lbs/MWh*		3,407[F]	1,962[G]
SO_2 Emissions, lbs/MWh		0.4[F]	0.58[G]
NOx Emissions, lbs/MWh		1.5[F]	1.08[G]
Particulate Matter Emissions, lbs/MWh		1.5[F]	0.05[G]

* CO and CO_2 data is reported as gross smokestack emissions. For closed loop biomass systems, net carbon emissions are assumed to be zero.

The Energy Information Agency reported electricity generation from biomass in 2003 to be approximately 10,550 GWh for utilities and 142,140 GWh for independent suppliers, for a total of 152,690 GWh.[691] For the same year, the EIA reported that approximately 586,142 GWh of biopower was produced in the residential, commercial and industrial sectors, bringing 2003 total biopower generation to approximately 739,000 GWh. In 1989, 67,700 GWh of biopower was generated by the electrical power sector (utilities, 5,861 GWh; independent suppliers, 61,838 GWh).[692] Also in 1989, the residential, commercial and industrial sector biopower production was 808,876 GWh, bringing total biopower generation that year to approximately 876,576 GWh. The decline in total biopower production over the past 15 years is largely attributable to declines in residential and industrial generation. Still, the EIA estimates a gradual expansion of biopower over the next 25 years, with the electrical power sector's net summer capacity expanding by 3.3 percent over 2004 levels.[693] Commercial and industrial sectors are also predicted to expand somewhat over the same time frame, with net summer capacity expanding by 2 percent over 2004 levels.[694]

690 The data in Table 2-52 are intended to provide a representative example of costs and performance. Caveats to estimates are noted when appropriate.

A U.S. Department of Energy, 1997. 1997 data. Assumes a 50 MW direct-fired plant.

B Bain et al., 2003. Estimates based on stoker-grate technology at 25 to 100 MW capacity (in 2001 dollars).

C Ibid. Estimates based on 75 MW and 150 MW high-pressure direct gasification systems.

D Scahill, 2003. Cites year 2000 data.

E Average heat content varies with fuel type. Curtis et al. (2003) use an average of 13 MBtu/ton, while Energy Information Agency, 2005a. estimates a range of 3.8 MBtu/ton to 25.83 MBtu/ton for a variety of potential feedstocks.

F Xenergy, 2003. 2001 data. Assumes stoker-grate, wood-fired plant.

G Ibid. 1997 data. Assumes combined cycle biomass gasification plant.

691 Energy Information Agency, 2005c. EIA's definition of electrical power sector includes "electricity-only and combined-heat-power (CHP) plants within North American Classification System (NAICS) 22 category whose primary business is to sell electricity, or electricity and heat, to the public." Total biopower estimates include both wood and other waste (comprised of MSW, LFG, agricultural residues, etc.).

692 Energy Information Agency, 2005b.

693 Energy Information Agency, 2005c.

694 Ibid.

The United States currently produces 190 million dry tons of biomass per year, but significant increases in biomass production are expected over the next 50 years.[695] Perlack et al. estimate that with continued crop yield improvements, increased efficiency of residue harvesting and increased production of perennial energy crops, total U.S. biomass production potential is 1.3 billion dry tons per year.[696] However, when factoring in the cost and regional availability of various biomass feedstocks, economically viable feedstock production may be significantly lower. For example, Bain et al. estimate that 24 million dry tons of biomass is available at a delivered price of $25/dry ton or less.[697] At a delivered price of $55/dry ton, total biomass availability increases to 510 million dry tons.[698] Within this aggregate estimate, state-by-state availability at a given price point varies widely. California, Florida, South Carolina, Texas and New York dominate national supply at lower price points, while Illinois, Iowa, Kansas, Minnesota, Nebraska and North Dakota dominate national supply at higher price points.[699]

Beyond the costs of plant construction, operation and maintenance, the costs of fuel acquisition and transport factor heavily into the economic feasibility of biopower.[700] High transportation costs remain a key impediment to expanding the use of biomass, and any facility greater than 100 to 200 miles from a feedstock source is generally considered cost-prohibitive.[701] Even when located within 50 miles or less, transportation costs are $5 to $10 per dry ton for bailed switchgrass[702] and as high as $10 to $30 per dry ton for forest biomass.[703] As a result of the this high cost of transportation, distributed generation applications located near fuel sources are considered as being more cost-effective alternatives than a large-scale, centralized power plant.[704]

High collection costs also remain an impediment to the use of biomass. Bain et al. estimate collection costs at $20 to $25 per dry ton for agriculture residues and $10 to $30 per dry ton for forest residues.[705] When production costs, collection costs and transportation costs are combined, the total delivery price for biomass ranges from $25 to $75 per dry ton, depending on feedstock.[706] Mill residues and urban wood waste are at the lower end of this range, while dedicated energy crops are at the higher ranges.

RESEARCH & DEVELOPMENT

Approximately $1.4 billion to $1.5 billion has been spent on biomass research and development since the 1970s.[707] Research continues into improving the efficiency of direct-fired biopower generation. For example, steam cycle improvement and the addition of dryers have the potential to increase the efficiency of direct-fired combustion systems by 10 percent while reducing per kW capital investment costs by over 36 percent.[708]

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695 Perlack et al., 2005.
696 Ibid.
697 Bain et al., 2003.
698 Ibid.
699 Ibid.
700 California Biomass Collaborative, 2005. estimates an approximate $0.001 per kWh increase in COE for every $1 per bone dry ton increase in fuel costs.
701 See, e.g. Bain et al., 2003; Government Accountability Office, 2005; Society of American Foresters, 2005.
702 Bain et al., 2003. Figures are in $1995.
703 Calculated from Perlack et al., 2005. Figures are based on an estimated cost of $0.20 to $0.60 per dry ton-mile and assuming a 50-mile haul.
704 Government Accountability Office, 2005.
705 Bain et al., 2003.
706 Ibid.
707 U.S. Department of Energy, 2005a.
708 Bain et al., 2003.

Research efforts are also under way to increase the efficiency of biomass gasification systems. Combined cycle gasifiers have the potential to nearly double efficiency for biomass applications, and they have the added benefit of leveraging existing funding and research for advanced turbine design.[709],[710],[711]

Improving harvest and transportation efficiency is another area of continued research and development. The Department of Energy has set a target of a 50 percent reduction in agriculture residue harvest, transportation and storage costs, while striving to achieve a $35 per dry ton delivery price.[712] Research is under way to develop whole-crop harvest systems to increase efficiency and decrease costs.[713] The achievement of fully integrated harvest, storage and transportation systems has also been identified as a long-term goal.[714] Research continues into increasing the yield of energy crops over the long term, as well as determining the optimal rate of residual removal to avoid compromising soil nutrient levels and site productivity.[715]

Demonstrating new techniques for biomass utilization is a third area of continuing research and development. Research surrounding syngas clean-up, hydrogen production and the demonstration of integrated biorefineries are areas of particular interest in the near term.[716] Syngas clean-up and hydrogen production are important concerns in the operation of fuel cells, while biorefineries can be used to produce biofuels or other chemicals.

The demonstration and validation of new biopower technologies is a fourth area of continued research and development. The Department of Energy reports that approximately 600 10 kW or greater stationary fuel cells are currently in operation, but most are fueled by natural gas.[717] The use of biomass-derived gas in fuel cell applications has the benefit of being a net zero carbon fuel with low sulfur and high volatility and reactivity.[718] As a result, biomass-fed fuel cells face lower risks of contamination or fouling, and they can be run at lower temperatures and pressures.[719],[720] However, demonstration and validation of biomass-fed fuel cells is still needed in order to encourage further R&D and eventual commercial application of the technology.[721]

BARRIERS TO BIOMASS UTILIZATION AND SELECT TECHNOLOGIES

The high capital cost of emerging, more efficient biopower technologies, compounded by high feedstock costs, remains an impediment to biomass utilization. The lack of adequate infrastructure for biomass processing and refining likewise remains a continued barrier to biopower generation in the United States.

The cost of biopower generation on a per-kWh basis is greater than that of traditional fossil fuel technologies, and even greater than the cost of some renewable resources, such as wind and geothermal.[722] While total capital requirement for coal-fired facilities range from $1,430 to $1,610 per kW, with a LCOE of 4.65 cents to

709 Ibid.
710 U.S. Climate Change Technology Program, 2003.
711 Bergman & Zerbe, 2004.
712 U.S. Department of Energy, 2005a.
713 U.S. Climate Change Technology Program, 2003.
714 Ibid.
715 Ibid.
716 Ibid.
717 U.S. Department of Energy, 2006h.
718 Bergman & Zerbe, 2004.
719 Bain et al., 2003.
720 Bergman & Zerbe, 2004.
721 Bain et al., 2003.
722 California Biomass Collaborative, 2005.

4.99 cents per kWh,[723] total capital requirement for biopower facilities can range from $1,312 to $2,426 per kW, with a LCOE of approximately 6 cents to 12 cents per kWh.[724],[725],[726] Beyond these costs of facility construction, the costs of operation and maintenance, as well as the previously identified costs of harvest and collection, grid exit and standby fees, have been cited as barriers to expanded use of biomass.[727]

Uncertain fuel supplies and an inability to make cost-effective use of fuels impede utilization and investment in woody biomass.[728] Unreliable supplies of woody biomass have been attributed to an absence of long-term stewardship contracts, project opposition and litigation, and federal agency staff shortages.[729],[730] Natural disturbances such as fire, drought or insect infestations also can affect the availability of biomass feedstocks. Agriculture residues and energy crops face supply concerns as a result of a currently undeveloped market.[731] Without a developed biorefinery infrastructure, demand for these products is unlikely to be strong and consistent, discouraging the further establishment of infrastructure and compounding the problem.

As noted above, transportation is a key driver in the cost of biomass. For this reason, facilities must be cited in close proximity (50 miles or less) to their fuel source in order to be cost-effective. Distributed generation technology, defined as "small, modular electricity generators sited close to the customer load,"[732] may be key in harnessing biomass to its full potential by providing biopower capability at or near feedstock sources.

Biopower is also impeded by a number of institutional barriers. The downturn in federal timber contracts in the 1990s led to a contraction in timber industry that may now impede the production of woody biomass through a shortage of personnel and mills.[733],[734] This shortage in infrastructure is likely to translate into fewer processing options and longer transportation distances, decreasing utilization efficiency and increasing costs.[735] A shortage of infrastructure also holds true for energy crops and agriculture residues, and the shortages are emerging as a key impediment to cost-effective production of fuels and/or chemicals from lignocellulosic biomass.[736] This shortage of infrastructure is directly linked to the lack of an established market, cited above.

Another institutional concern is public acceptance of biomass harvest and collection operations, as well as public adoption of biomass-fed applications. Increasing the rate and extent of forest thinning and agriculture residual removal may be seen as undesirable unless the public is fully educated on the benefit of biomass utilization and the sustainable nature of operations.[737] Furthermore, complete market acceptance hinges on biomass costing the same or less than comparably performing traditional fuels.[738]

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723 Dalton, 2004. Estimates are in 2003 dollars, and based on estimates for Pittsburgh # 8 bituminous pulverized coal (pc) subcritical, pc supercritical, and integrated gasification combined cycle 500 MW plants.

724 Antares Group, 2003.

725 Bain et al., 2003.

726 California Biomass Collaborative, 2005.

727 Government Accountability Office, 2005.

728 Ibid.

729 Ibid.

730 Society of American Foresters, 2005.

731 U.S. Department of Energy, 2005a.

732 U.S. Department of Energy, 2006c.

733 Government Accountability Office, 2005.

734 Society of American Foresters, 2005.

735 Ibid.

736 U.S. Department of Energy, 2005a.

737 U.S. Climate Change Technology Program, 2003.

738 U.S. Department of Energy, 2005a.

Finally, the increased use of biomass has several environmental impacts, potentially positive and negative. While closed-loop biomass systems have no net carbon emissions, widespread harvesting of biomass feedstocks has the potential to impact water quality, soil erosion, slope stability, mass and energy exchange with the atmosphere (with impacts on local temperature), and biodiversity.[739] However, the perennial nature of many energy crops can actually reduce soil erosion as compared to other crops or land uses.[740] Similarly, localized thinning operations can help to reduce the risk of catastrophic wildfire or insect infestations.[741]

CONCLUSION

Biomass can be converted to energy or to alternative fuels through a variety of processes, and can be combusted alone or co-fired with traditional fossil fuels. Under some circumstances, biopower can be less expensive to produce than traditional fossil fuels and can contribute to rural economic growth. Biopower can also help reduce overall CO_2 and SOx emissions when used in place of or co-fired with traditional fossil fuels. Closed-loop biomass systems are assumed to have no net carbon emissions, as burning merely releases previously sequestered atmospheric carbon.

Current total U.S. biomass production is estimated at 190 million dry tons per year, but significant increases in production are expected over the next 50 years. Assuming continuing increases in crop yields, increased efficiency of residue harvesting and an increase in perennial energy crop acreage, total U.S. biomass production potential is estimated to be 1.3 billion dry tons per year. But while a number of biomass technologies are in various stages of development, the simple co-firing of biomass with traditional fossil fuels such as coal has the greatest potential for near-term use. The high capital cost of many emerging, more efficient biopower technologies, compounded by high feedstock harvesting and transportation costs, remains an impediment to biomass utilization. The lack of adequate infrastructure for biomass processing and refining, as well as uncertainties surrounding feedstock supply, likewise remain barriers to biopower generation in the United States.

739 See, e.g. Skog & Rosen, 1997.

740 Bain et al., 2003.

741 Society of American Foresters, 2005.

Renewable Energy: Landfill Gas

Landfill gas is a byproduct of the metabolic breakdown of municipal solid waste. Varying somewhat in chemical composition, LFG is generally assumed comprise approximately 50 percent methane (CH_4), approximately 50 percent carbon dioxide (CO_2) and less than 1 percent of non-methane organic compounds.[742] Landfill gas is considered a medium-Btu fuel, having a heating value of 400 to 550 Btu per cubic foot, roughly half that of natural gas.[743] By capturing LFG, either through active or passive measures, the gas can be used for electricity generation, for direct use or for combined heat and power. High-Btu LFG may be piped off-site for commercial applications or fed directly into an existing natural gas distribution system. Finally, LFG can be used in various transportation applications through the production of methanol or conversion into compressed landfill gas (CLG). While each of these applications is the subject of on-going demonstration, research and development, the following synthesis will focus primarily on LFG to energy (LFGTE) applications.

Regardless of the end-use application, the collection and use of LFG has the benefit of capturing significant amounts of methane and potentially toxic organic compounds that would otherwise escape into the atmosphere. As roughly 25 percent of methane released in the United States is generated by municipal landfills, a net emission of roughly 140.9 million metric tons of CO_2 equivalents,[744] the collection and utilization of LFG can dramatically reduce emissions of this powerful greenhouse gas, as well as displace fossil fuel combustion that would have been needed to generate the electricity produced by LFG.

LFG APPLICATIONS AND TECHNOLOGY

Electrical generation from LFG follows three general stages: collection or capture, processing and treatment, and electrical production.

The cost of an LFG collection system will vary depending on its size, the number of horizontal wells and the depth of vertical wells. Costs of the system may or may not be directly attributable to LFGTE operations, as a collection system may be required for gas flaring. Collection systems for LFGTE applications may be more elaborate or efficient than simple flaring systems, however.[745] Table 2-53 identifies costs for collection systems and generalized gas and power output for 1, 5 and 10 metric ton landfills.

Table 2-53: LFG collection system construction, operation and maintenance costs[746]

Landfill size	Estimated Gas Flow (mcf/day)	Estimated Output (kW)*	Collection System Construction Costs ($1994)	Collection System Operation and Maintenance Costs ($1994)
1 million metric tons	642	963-984	628,000	89,000
5 million metric tons	2988	4,727-4,934	2,100,000	152,000
10 million metric tons	5266	8,344-8,709	3,600,000	218,000

* Estimated output range based on combustion turbine and IC engine technologies.

There are two basic strategies for capturing LFG: passive and active. In passive collection systems, collection wells, constructed of slotted or perforated plastic, extend down to 50 percent to 90 percent of the landfill's waste depth. They can be installed either during or after landfill construction. The efficiency of passive collection systems can be affected by a number of design and ambient environmental factors, including landfill design and

742 U.S. Environmental Protection Agency, 2006f.
743 California Energy Commission, 2002.
744 U.S. Environmental Protection Agency, 2006c.
745 U.S. Environmental Protection Agency, 1996b.
746 Ibid.

barometric pressure.[747] Active collection systems also use a set of collection wells, but add vacuums or pumps to help draw LFG out of the landfill. The addition of valves and sampling ports also enables site managers to monitor gas pressure and composition, and to adjust flow to achieve maximum efficiency.

Following collection, LFG must undergo processing and treatment. LFG that is greater than 20 percent methane can be directly combusted. LFG with less than 20 percent methane must be mixed with other fuels such as natural gas in order to burn efficiently.[748] Regardless of methane content, however, LFG must undergo a primary pretreatment in order to remove water and particulates. A secondary pretreatment can be used to remove other chemical substances, including hydrogen sulfide (H_2S) and halogenated solvents.[749]

Once captured, processed and treated, LFG can be used for electrical generation through a number of different technologies, including organic Rankine cycle engines, fuel cells, Stirling cycle engines, combined cycle, cogeneration, steam turbines, microturbines, gas turbines and reciprocating engines. The vast majority of operational and planned LFG electricity projects, however, use reciprocating engines (Table 2-54).

Table 2-54: Number of operational LFG electricity projects by technology type[750]

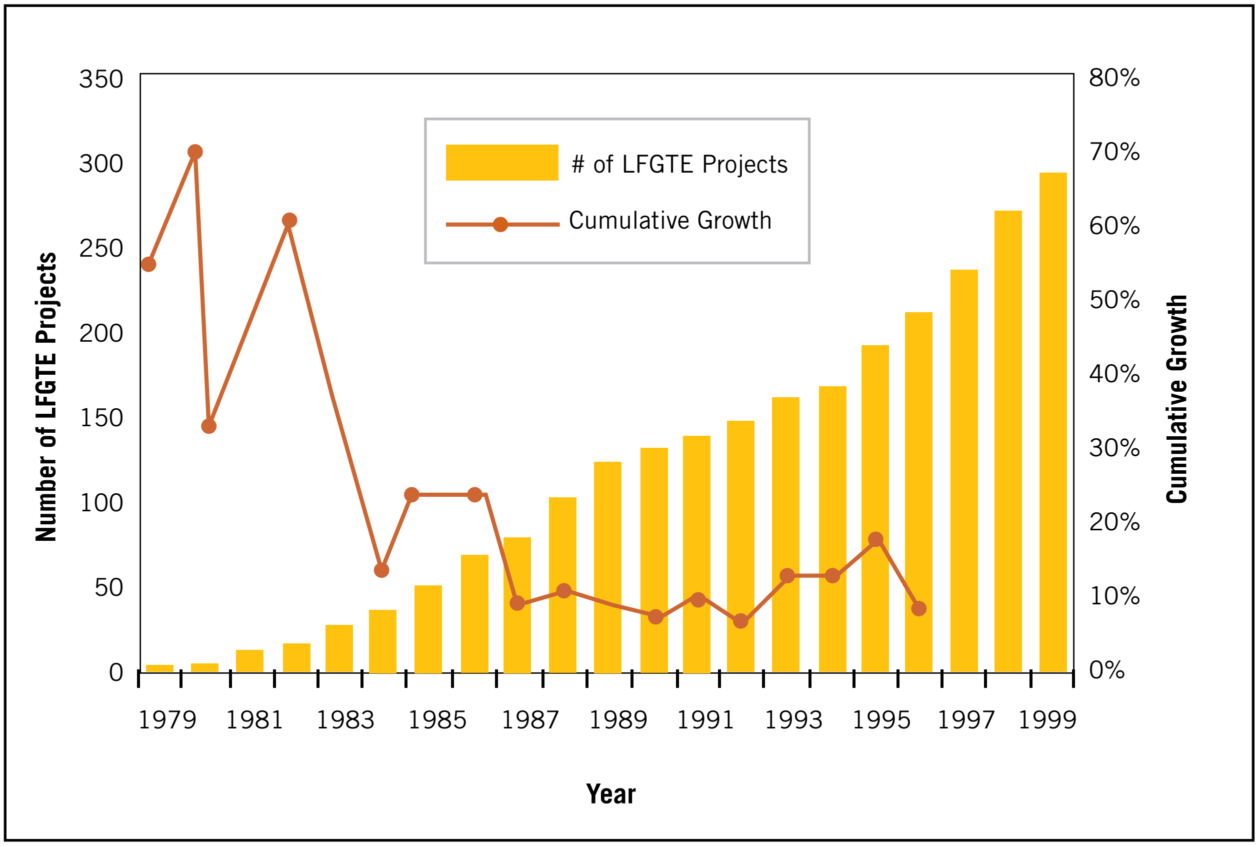
Project Type	Number of Operational Electricity Projects	%
Reciprocating Engine	251	76.3
Gas Turbine	30	9.1
Steam Turbine	20	6.1
Microturbine	17	5.2
Combined Cycle	7	2.1
Organic Rankine Cycle	2	0.6
Fuel Cell	1	0.3
Stirling Cycle Engine	1	0.3
Total	329	

HISTORIC IMPROVEMENTS AND KEY DRIVERS

As of August 2006, there were 329 LFGTE projects in operation nationwide.[751] The first projects began operating in the late 1970s and early 1980s. Over the past 25 years, growth of LFGTE projects has been rapid, achieving double-digit cumulative growth in 12 out of 18 years between 1981 and 1999 (Figure 2-12). Corresponding to the increase in number of LFGTE projects, overall landfill methane capture and combustion has increased in recent years. In 1990, roughly 930,000 metric tons of methane was recovered and combusted, increasing to roughly 5.34 million metric tons in 2004.[752] Overall U.S. landfill methane emissions have decreased by 18 percent during the same period.[753]

747 Agency for Toxic Substances and Disease Registry, 2001.
748 Ibid.
749 Environment Agency, 2004.
750 Data compiled from U.S. Environmental Protection Agency, 2006e.
751 Ibid.
752 U.S. Environmental Protection Agency, 2006c.
753 Ibid.

Figure 2-12: Number of U.S. LFGTE projects and year-over-year cumulative growth[754]



EXISTING INNOVATION AND CAPACITY

Available literature often fails to distinguish between LFG- and natural gas-fueled technology information. However, while there is some difference in thermal efficiency and net heating value between LFG and natural gas, a greater differential exists within the fuels themselves, based on the choice of vintage/technology and manufacturer. Consequently, factors generally are considered comparable among fuel sources (Table 2-55).[755]

754 Data compiled from Thorneloe et al., 2000.

755 R.Goldstein, U.S. EPA, personal communication, August 28, 2006

Table 2-55: Historic LFG operating costs

	1994 1A (1994$)	2003
Total Plant Cost, $/kW	1,035-1,360	1,044 2B
Total Capital Requirement, $/kW	1,263-1,628	1,268 3B
Fixed O&M, $/MWh	0.015-0.018	47 ($/kw/yr) 4B 0.016 5C
Variable O&M, $/MWh		119.05 ($/kw/yr) B
Levelized Fuel Cost, $/kWh	0.043-0.047	0.04567 B
Net Thermal Efficiency, % (HHV)		21.9-36.0 6D
Net Heat Rate, Btu/kWh		9,492-15,580 D
CO_2 Emission Rate, lbs/MWh		0.393 7E
SOx Emission Rate, lbs/MWh		0.17 8F
NOx Emission Rate, lbs/MWh		2.05 F
Hg Emission Rate, lbs/MWh		$3.4x10^{-6}$ F

The Environmental Protection Agency estimates current U.S. LFG generating capacity at 1,093.8 MW.[756] Based on an average plant capacity of 3 MW and the existence of an additional 600 feasible landfill sites nationwide, the DOE's Office of Scientific and Technical Information estimates an additional LFG technical capacity of 1,800 MW.[757]

The EPA estimates that for every 1 million tons of municipal solid waste, approximately 432,000 cubic feet of LFG is generated per day.[758] The rate and amount of LFG gas production at each particular landfill site depends on a number of factors, including pH, temperature refuge quality, refuse compaction, moisture content and air intrusion.[759]

Landfill gas production falls into five general categories or phases.[760],[761] Phases I and II can last as short as a few weeks or as long as a few years. Phases III and IV, characterized by the greatest rates of methane production and composition, can last for a few months to several years. Total LFG production can last 80 years or more.[762]

The economic feasibility of LFG recovery and generation operations depends on a wide variety of site-specific factors, including the choice of technology, the availability of government incentives and the current price of substitute fuels such as natural gas. Still, the following general guidelines have been put forward as a rough indication of the economic feasibility of recovery operations:

- Landfill waste is stable and greater than 30-35 feet deep.
- The landfill is greater than 35 acres in area.
- The landfill contains more than 1 million tons of waste.
- The landfill will be in operation for many more years, or, alternatively, a short time has elapsed since closure of landfill.

756 Data compiled from U.S. Environmental Protection Agency, 2006e.
757 Bailey & Worrell, 2005. estimate a technical capacity of 1800MW, but do not estimate existing capacity. It is assumed that their 1,800 MW technical capacity estimate is in addition to existing capacity.
758 U.S. Environmental Protection Agency, 2006f.
759 Illinois Environmental Protection Agency, 2005.
760 Johannessen, 1999.
761 Illinois Environmental Protection Agency, 2005.
762 Ibid.

- Climate is not too cold or dry.

- The landfill can produce LFG at a rate of 1 million cubic feet per day and with a methane content of at least 35 percent.

- End use for the LFG is either nearby or on-site.[763], [764]

Beyond the feasibility criteria identified above, the price of substitute fuels and the availability of incentives have strongly influenced the cost-effectiveness of LFGTE operations.[765] With specific regard to incentives, the Energy Policy Act of 2005 offers a $0.09/kWh income tax credit for LFGTE facilitates built between October 22, 2004, and January 1, 2008.[766] LFGTE projects are also eligible for Clean Renewable Energy Bonds and for production payments under the Renewable Energy Production Incentive program.[767] Beyond the federal level, LFTGE projects are also eligible for a variety of state incentive programs.[768]

RESEARCH & DEVELOPMENT

While there exist a number of technologies for LFGTE operations, most are currently restrained by cost. The following technologies in particular continue to be the focus of R&D efforts; all have been field-demonstrated, are currently undergoing field-demonstration or are planned for future demonstration. Combined heat and power operations and direct-use applications, although the focus of continued interest (especially in the manufacturing sector), are not explored here.

- Fuel Cells
- Phosphoric acid fuel cells (PAFCs) were commercially tested in LFG applications in the late 1990s.[769] Other fuel cell types, including molten carbonate, solid oxide, and solid polymer fuel cells, are in various stages of use or development.[770] Fuel cells are characterized by high rates of efficiency and low (if any) emissions.[771] Cost-effective purification of LFG for use in fuel cells remains a key impediment to expanded use of this technology.[772]

- Microturbines
- Microturbines spin at high rates, producing large amounts of energy relative to their size, and have been shown to have much lower NOx emissions than reciprocating engines.[773] Still, capital costs are much higher for microturbine operation (resulting in 0.07 to 0.14 $/kWh) than for a comparable reciprocating engine (resulting in 0.04 to 0.06 $/kWh).[774] Microturbines are also susceptible to fouling from impurities unfiltered from LFG fuel sources.

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763 Agency for Toxic Substances and Disease Registry, 2001.
764 U.S. Environmental Protection Agency, 2002.
765 See, e.g., Hickman, 2001.
766 U.S. Environmental Protection Agency, 2006a.
767 Ibid.
768 See, e.g. *http://www.epa.gov/landfill/res/primers.htm* for an overview of state specific incentives and requirements (accessed August 23, 2006).
769 Roe et al., 1998.
770 U.S. Climate Change Technology Program, 2005.
771 California Energy Commission, 2003.
772 Ibid.
773 U.S. Climate Change Technology Program, 2005.
774 Ibid.

- Organic Rankine and Stirling Cycle Engines
- Stirling cycle engines are low-emission, high-efficiency engines capable of running on LFG. Organic Rankine cycle engines use fluids in a closed cycle, resulting in virtually no emissions. The high cost of both engine types and the lack of commercial-sized units have impeded their adoption.[775]

- Operating Landfills as Aerobic/Anaerobic Bioreactors
- Bioreactor technology, the use of air and/or liquids to enhance chemical decomposition, can be used to either limit or enhance methane production.[776] Anaerobic bioreactors have been shown to increase the production of methane in the early years of landfill operation while simultaneously reducing emissions of other important pollutants. Alternatively, aerobic reactors use oxygen to inhibit methane production and may be useful in reducing greenhouse gas emissions from those landfill sites where LFG capture and use may not be practical or feasible. Research suggests that bioreactor landfill LFG recovery costs may be 25 percent to 50 percent below that of a conventional landfill; a program of market penetration is slated for 2007 to 2012.[777]

- Conversion of LFG to Vehicle Fuel
- LFG can be converted to compressed landfill gas, an equivalent of compressed natural gas.[778] LFG-derived fuels have the benefit of being cleaner-burning than diesel or gasoline, with lower NOx and particulate matter emissions.[779] But while several projects have demonstrated the potential of LFG to be converted and used as a vehicle fuel, issues of fuel distribution and storage, as well as the limited number of LFG-conversion equipment manufacturers, preclude widespread use of this technology.[780]

- Conversion of LFG to Methanol
- Since the 1980s, LFG has been successfully converted to methanol and ethanol for use as a chemical feedstock or fuel additive.[781] Still, limited end-use applications and the cost of conversion remain impediments to widespread use.[782]

- Conversion of LFG to Pipeline-Quality Fuel
- LFG can be split into its primary constituents, methane and CO_2, allowing methane to be sold as a pipeline-quality fuel and fed into existing natural gas distribution networks. The primary obstacle to this use is the high cost of processing and purifying captured LFG, making it cost-effective only at the largest of landfills.[783]

- Production of Commercial CO_2
- CO_2 derived from the processing of LFG into a pipeline-quality fuel can be

775 Ibid.
776 Ibid.
777 Ibid.
778 Roe et al., 1998.
779 U.S. Climate Change Technology Program, 2005.
780 Ibid.
781 See, e.g. Roe et al., 1998; U.S. Climate Change Technology Program, 2005.
782 U.S. Climate Change Technology Program, 2005.
783 Ibid.

commercially marketed. The use of triple-point crystallization to produce food-grade CO_2 has been demonstrated for several years,[784] and projects to demonstrate the use of cold liquid CO_2 are under development.[785] The cost of purifying processed CO_2, the cost of compressing and transporting processed CO_2, and the social stigma of using landfill-derived CO_2 for food applications have remained impediments to the commercial use of CO_2 for several years. The use of CO_2 to enhance plant growth in greenhouses and its use in coalbed, oil and gas recovery operations may represent viable alternatives.[786]

- Use of LFG to Evaporate Leachate
- As landfill leachate is a primary pollution concern, the use of LFG to evaporate and combust leachate waste can be an economical and efficient strategy to address numerous environmental objectives. To date, several test projects have been constructed and demonstrated with some success.[787]

BARRIERS TO SELECT ADVANCED TECHNOLOGIES

Economics remain the primary barrier to wider adoption of advanced LFG technologies. In particular, the high cost of fuel cells and microturbines currently preclude expanded use of these technologies, despite benefits in emissions and efficiency.

Uncertain Fuel Supply with High Transaction Costs

Where available, LFG represents a highly stable fuel source, achieving high capacity factors (85 percent to 93 percent).[788] Unfortunately, high transaction costs, such as grid connection fees, have proved to impediments to additional LFGTE projects.[789] Also, limited generation capacity will likely prevent LFG from becoming anything other than a minor contributor to total U.S. energy production.

Locating Near Fuel Supply and Electricity Demand

Most LFGTE projects are located on or nearby the associated landfill site.[790] In some cases, pipelines may be extended for short distances to deliver fuel directly to an off-site end user.

Institutional

For some uses, such as the production of commercial food-grade CO_2, social stigmas remain in place.

784 See, e.g. Roe et al., 1998; U.S. Climate Change Technology Program, 2005.
785 U.S. Climate Change Technology Program, 2005.
786 See, e.g. Roe et al., 1998; U.S. Climate Change Technology Program, 2005.
787 Roe et al., 1998.
788 U.S. Environmental Protection Agency, 2006d.
789 R. Goldstein, U.S. EPA, personal communication, August 22, 2006
790 U.S. Environmental Protection Agency, 2006d.

ELECTRICITY INFRASTRUCTURE

Much of the discussion about the future of energy revolves around generation—facilities, fuels and associated emissions. Researchers are devising new technologies to generate electricity from both alternative energy sources and existing conventional sources. But the discussion does not always continue beyond generation. Once electricity is generated, it must be transmitted and distributed to end users. Transmission is difficult to site, with regulatory approval required at the federal, state and local levels, and it is expensive to build, at several hundred thousand dollars per mile on the low end. But with the U.S. grid increasingly strained by continued demand growth, grid expansion projects are being planned and new transmission technologies are being developed. Improvements in distribution are focused on advanced technologies that can provide real-time demand data so utilities can adjust output accordingly and respond to growing interest in distributed generation technologies. Grid reliability is likewise an important concern in transmission and distribution research and development. Electricity storage is another aspect of electricity infrastructure discussed in this section. Although energy storage has great potential to smooth loads from renewable energy sources and distributed generation, storage currently represents a very small part of U.S. generating capacity. Addressing electricity infrastructure, including transmission, distribution and storage, will be crucial to any future transformation of the U.S. energy sector in response to federal carbon policy.

Transmission

Electricity transmission refers to the bulk transfer of electric power from one place to another. In the United States, more than 160,000 miles of transmission line carry electricity to consumers. As additional customers come online and demand more electricity, and as new power generation sources are built in new places, the existing transmission system is increasingly strained. Some improved line maintenance efforts and new, more efficient transmission technologies will increase transmission capacity and prevent line loss, but ultimately, the transmission grid will need to be expanded and potentially redesigned. Research, development and demonstration is focused on reducing line losses, increasing efficiency and the physical limits of the existing system, and improving grid materials and monitoring technologies.

Investment in new transmission had consistently declined over the past 20 years, even as electric generation facilities and power demand continued to expand. As a result, the reliability of the U.S. electric grid is increasingly being challenged, as evidenced by the blackout in the northeast United States in August 2003. Confusion over regulation, ownership and responsibility has been a primary factor preventing increased investment in transmission.

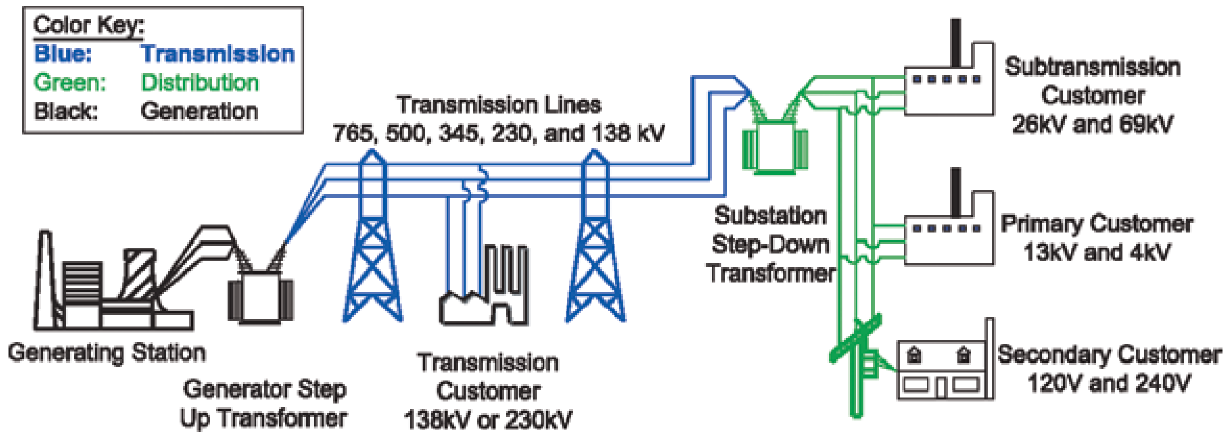
Before electricity industry deregulation, transmission was the purview of vertically integrated utility companies, which managed every step of the process from generation to distribution. As deregulation has changed the structure of the electricity market, and new types of generation and transmission companies enter, transmission has become a cloudy topic, with uncertain regulation, ownership and maintenance responsibilities. In the long term, reliable transmission will depend on the close coordination of generation and transmission planning and construction. Because of regulatory changes and new, different market participants, transmission planning must now be accomplished through different means than in the past and must involve coordination among many players.

TRANSMISSION BASICS

When electricity is generated at a power plant, it is produced at 10 to 25 kilovolts (kV). Transformers at power plants convert the electricity to between 138 and 765 kV, depending on the amount of electricity desired and the distance it must travel. Power then gets transmitted through lines from the power plant to substation transformers, which "step down" the power to between 69 kV and 120 volts (V). From there, the distribution network takes over and delivers electricity to consumers. [791] The interlocking system of transmission lines is commonly referred to as the grid. About 12 percent (160,000 miles) of all power lines are transmission lines carrying high voltage electricity (230 kilovolts and above). The remaining 88 percent are distribution lines carry electricity to the great variety of end users.[792] Figure 2-13 outlines the process.

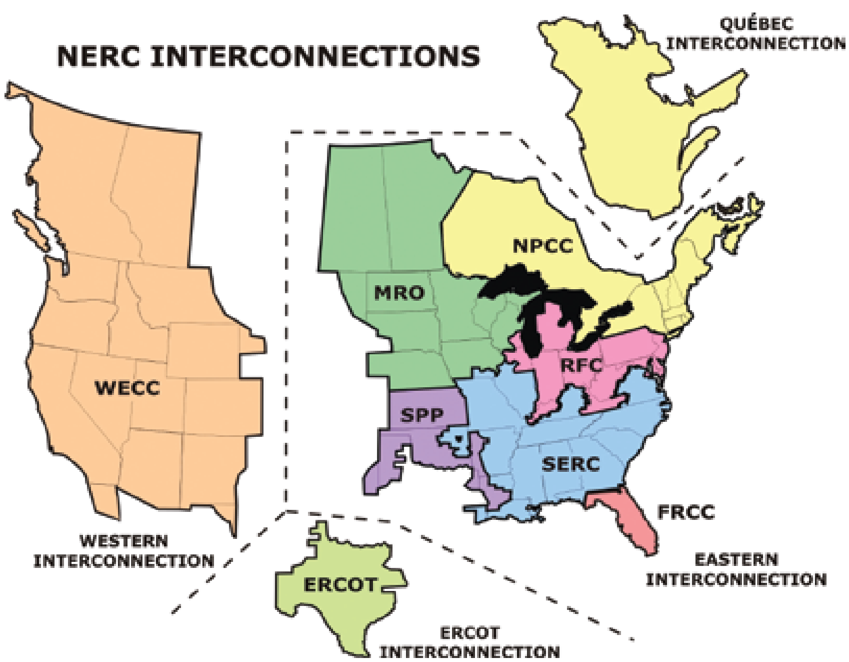
791 U.S.-Canada Power System Outage Task Force, 2004.
792 Edison Electric Institute, 2001.

Figure 2-13: Electricity transmission and distribution process[793]



The United States, Canada and parts of Mexico share transmission networks. In the United States, there are three regional transmission interconnections in the grid: the Eastern Connection, which connects the eastern half of the United States (north to south) and parts of the Midwest, and into Canada; the Western Connection, which also reaches into Canada; and the Electric Reliability Council of Texas (ERCOT), which covers most of the state of Texas. (Alaska and Hawaii maintain their own grids.) Utilities and other generators within each interconnection are able to share and trade power to meet changes in supply or demand. Many power trades are in response to economics. If a power company's peak generation facilities are expensive to run, the company may buy power from other companies during peak periods. Emergencies and unexpected plant maintenance are other reasons for power purchases.

Figure 2-14: North American Electric Reliability Council interconnections[794]



793 U.S.-Canada Power System Outage Task Force, 2004.
794 North American Electric Reliability Council, 2006b.

TRANSMISSION TECHNOLOGIES

Transporting Power

Most power plants generate electricity at voltages of approximately 20 kV, although it can range from 10 to 25 kV. Transformers operated near the generating facility increase or "step-up" the voltage to levels as high as 765 kV, to facilitate more efficient transmission over large distances. The power is transmitted to population and demand centers through the grid—the network of transmission lines. For distribution to end users, the transmission-level voltages are reduced in "step-down" transformers to primary distribution voltages connected to primary distribution lines. At areas where the power is finally used, the voltage is further stepped down to secondary distribution levels of about 240 to 2,400 volts for commercial and industrial users, and to about 120 to 240 volts for residential customers.

Almost all transmission networks use three-phase alternating current (AC); some transmission lines use high-voltage direct current (DC). High-voltage DC transmission systems have advantages over AC transmission in certain applications, such as undersea cables, and the number of DC systems is growing. Large-scale implementation of DC networks is limited by the risks involved in converting DC to AC and the costs for additional equipment, such as DC filters and converters. Most electrical equipment currently uses AC.

The difference between AC and DC has to do with the direction in which the electrons flow. In three-phase AC, the electrons switch back and forth, whereas in DC, the electrons flow in only one direction. In the United States, the AC back-and-forth motion occurs 60 times per second, creating a 60 Hertz (Hz) frequency. Worldwide, in more than 99 percent of the electrical industry, frequencies are either 50 or 60 Hz, depending on each country's electrical system.

The advantages of using 3-phase AC for transmission and distribution of electricity are:

- The physical amount of material (usually copper or aluminum) necessary for a given level of power is less than in a single-phase system.
- At a specified voltage, a three-phase system has less loss in transmission over the same distance compared to a single-phase system.
- Compared to DC systems, AC systems are more efficient in transforming voltages from higher to lower and vice-versa; hence, AC uses higher voltages for transmission and lower voltages for final distribution more easily and efficiently.

Transmission Line Control

An electric utility has to determine and monitor if it has enough generation and transmission capacity to meet customers' demand and to be able to avoid and respond to problems in the grid. Utilities use computer models to simulate demand loads or to simulate problems and their effects on the system. When problems arise, such as a lightning strike, they must be solved within seconds to avoid a major outage.

Further, computerized systems are used to monitor the transmission network and coordinate power transfers. Because transmission lines can carry a limited amount of electricity at any given time, electricity supply and demand must be balanced as closely as possible. Operators at control areas, in addition to balancing supply against demand, run tests to ensure the reliability of the system. They also maintain a "reserve margin" of generating capacity, above the system's expected peak demand, to enhance reliability when demand rises unexpectedly or when generating capacity is taken offline for maintenance or other purposes.

Understanding Losses

To understand power losses in transmission and distribution, it is first necessary to understand power. Power, the rate or flow of electric energy, measured in watts, accomplishes useful work over time, including heating, illumination and motion. Transmission and distribution losses in the United States average around 7 percent, with approximately 60 percent of the losses resulting from lines and 40 percent from transformers.[795],[796] Power loss in transmission lines is caused by line resistance, corona discharge, and inductance and capacitance. Loss in transformers is due to coil and core losses.

Power Loss in Transmission Lines

All transmission wires currently used have some resistance. Electrical resistance is a measure of the degree to which any material opposes the passage of current.

The power demanded from a substation is given by $P = I\,V$, where P=power, I=current and V=voltage.

This equation means that the higher the transmission voltage, the smaller the current.

Let the total resistance of the transmission line leading from a power station to the local substation be called 'R'.

Line loss is given by $P_{loss} = I^2 R$

Or $P_{loss} = P^2 R / V^2$

Since P is power required in a given area and is fixed according to demand, and R is as small as possible and constant, reduced line loss depends to a large extent on voltage.

Generating plants produce energy at relatively low voltages, and the energy is then stepped up to a higher voltage for transmission. The upward voltage transformation during transmission reduces the current in the lines, while maintaining the same level of power. Since the losses are proportional to the square of the current, halving the current results in a fourfold decrease in transmission losses.

Inductance is the property of a circuit element to oppose a change in the flow of current. Capacitance is the property of a circuit element to store electric charge. Energy that is absorbed by capacitance and inductance of circuit components is not transmitted to the load, resulting in extra losses in the transmission circuit. These effects can be reduced by using technologies such as phase shifting transformers, static VAr compensators and flexible AC transmission systems (FACTS).[797]

795 U.S. Climate Change Technology Program, 2005.
796 Energy Information Administration, 2006h.
797 See Transmission Technology Research and Development section for descriptions of advanced transmission technologies.

Power Loss in Transformers

According to the Environmental Protection Agency's ENERGY STAR program, most large facility distribution transformers convert at least 95 percent of input power into usable output power. Smaller units have efficiencies of 98 percent or less. Transformer losses in power distribution networks are estimated to total 140 billion kilowatt-hours (kWh) per year in the United States. The ENERGY STAR program estimates that converting these transformers to higher efficiency units would reduce wasted electricity by about 61 billion kWh each year.[798]

The material used in transformers and wires affects efficiency and loss. Loss in transformers occurs from the magnetizing and demagnetizing of the core during normal operation. Transformer cores are normally made of carbon steel, but amorphous iron and silicone steel are alternatives. Amorphous iron reduces core loss to less than 30 percent of standard steel cores, but is more expensive. Silicone steel, which is less expensive, results in fewer losses than standard steel cores, but has higher losses than amorphous iron.

For wires, copper, steel and aluminum are the choice elements. Copper is an excellent conductor of electricity and copper wires result in much lower resistance and loss compared to aluminum or steel. Using wires of larger diameters that allow current to flow with less resistance can also minimize transformer losses, although the magnetic steel structure that contains the wires will also need to be larger, increasing costs and other internal energy losses.

Matching the demand for electricity with the size of the distribution transformer can also greatly influence transformer efficiency. The transformer size must be large enough to meet demand and avoid outages, but small enough to avoid efficiency losses when the core is energized but not carrying electricity.

Technology Research & Development[799]

Given the time and cost involved in building new power generation plants and transmission, research is being focused on enhancing the reliability of current transmission lines and increasing existing capacity.

The next generation of transmission lines is high temperature super-conducting lines, which can carry larger amounts of current with almost no resistance. The materials used in these lines are still expensive and require a much higher initial investment than with current lines. These cables also require extreme cooling and low temperatures, which results in higher operating costs.

Another line technology is ultra-high voltage lines. The maximum voltage line currently used is 765 kV. Ultra-high voltage lines can carry power close to 1,000 kV. Transmitting power at higher voltages results in lower loss, but requires larger right-of-ways and creates some public health concerns from stronger electromagnetic fields.

Improved grid monitoring is another way to improve grid performance and increase the load that the current transmission system can handle. Utilities are increasingly using real-time control of the power system to measure operating conditions using direct system voltage sensors. This allows for enhanced system control. Flexible AC transmission systems are electronic-based systems that can provide control of AC transmission system parameters to increase controllability and power carrying capacity. FACTS are expensive to install, but many demonstration projects are under way, and advances in power electronics may result in lower costs. Computer-optimized designs of transmission line towers also allow for higher current carrying capacity in existing cables.

798 U.S. Environmental Protection Agency, 1996a.
799 Information in this section taken primarily from Hauer et al., 2002; U.S. Department of Energy, 2002.

Other advancements in R&D include conductors made of composite cores, instead of traditional steel cores, that have higher current-carrying capacity without the need for cooling. These materials are just entering commercial testing and presently are more viable than high temperature super conductors. Small, distributed generators located close to the load can reduce dependence on the transmission network and address local demand cost-effectively. Deployment of distributed generators continues to increase.[800] Energy storage devices, including batteries, flywheels and superconducting magnetic energy storage, permit the use of lower cost, off-peak power during periods of high demand. While several demonstrations are currently in progress, they have still not achieved the desired cost-benefit levels.[801]

ECONOMICS

Transmission Ownership

Deregulation of the electricity industry in parts of the United States has led to a separation of electricity generation from transmission and distribution. Today, five different kinds of companies and organizations own and maintain transmission lines[802]:

- Utilities: integrated, investor-owned; own plants, transmission systems and distribution systems.
- Regulated transmission owners: own and operate the distribution system (e.g., National Grid Company in New England).
- Regulated transmission owners: own transmission only, no distribution (e.g., Vermont Electric Power Company).
- Merchant companies: earn return on investment based on what market pays to use their transmission lines; regulated by the Federal Energy Regulatory Commission (e.g., American Transmission Company).
- Consumer- and publicly owned electric companies: usually not regulated by state and federal commissions (e.g., NY Power Authority, TVA).

In wholesale electricity trade, companies can use their own existing transmission lines or contract with other transmission line owners to send power through their lines. The Energy Policy Act 1992 established regulation that required transmission owners to give wholesale generators access to the grid. EPAct 2005 called for increased access to transmission, requiring transmission organizations to make long-term transmission agreements available to generation companies meeting certain guidelines.[803]

Costs

Transmission costs account for 5 percent to 11 percent of the total delivered retail cost of electricity.[804] Cost depends on the voltage of the line (higher voltage lines require larger tower constructions), the materials used

800 See "Clean Distributed Generation" section in Chapter 1 for more information.
801 See "Storage" section for more information.
802 Brown & Sedano, 2004, p. 50.
803 Federal Energy Regulatory Commission, 2006.
804 See Brown & Sedano, 2004, p. 11; Gee, 2001; Hirst, 2000; U.S. Department of Energy, 2002.

(e.g., lines, poles), the terrain over which the line is built, right-of-way and land acquisition, and any regulatory costs, including filing applications, conducting studies and coping with delays.

The tables below detail estimated costs for transmission lines, per mile, by voltage. As noted, underground transmission lines, although they can increase reliability and avoid weather-related outages, are anywhere from four to twenty times more expensive than above-ground lines, given physical and permitting costs associated with burying the lines. Table 2-56 is from the National Council on Electricity Policy,[805] and Table 2-57 is from CSA Energy Consultants.[806]

Table 2-56: Typical capital costs for electric transmission lines, by voltage

Transmission Facility	Typical Capital Cost
New 345 kilovolt (kV) single circuit line	$915,000 per mile
New 345 kV double circuit line	$1.71 million per mile
New 138 kV single circuit line	$390,000 per mile
New 138 kV double circuit line	$540,000 per mile
New 69 kV single circuit line	$285,000 per mile
New 69 kV double circuit line	$380,000 per mile
Single circuit underground lines	Approximately four times the cost of above-ground single circuit lines.
Rebuild/Upgrade 69 kV line to 138 kV line	$400,000 per mile
New 500-765kV line	At least $1 million per mile

Table 2-57: Typical costs and capacity of new transmission lines (1995 dollars)

Voltage	Normal Rating MW	Cost per Circuit per Mile[a]
	Above Ground	
60 kV	32	$120,000
60 kV	56	$125,000
60 kV	79	$130,000
115 kV	64	$130,000
115 kV	108	$135,000
115 kV	151	$140,000
115 kV	151	$250,000
115 kV	302	$400,000
115 kV	151	$160,000
115 kV	302	$250,000
230 kV	398	$360,000
230 kV	796	$530,000
230 kV	1,060	$840,000
230 kV	398	$230,000
230 kV	796	$350,000
230 kV	1,060	$550,000
	Underground	
115 kV	180	$3,300,000
230 kV	360	$3,700,000

[a] These costs do not include right-of-way costs.

Utilities can apply to the Federal Energy Regulatory Commission [807] to recover the costs of transmission through rate increases; FERC sets the rates utilities can charge. However, not all utilities fall under FERC regulation; public utilities, federal agencies, most of Texas, and all of Hawaii and Alaska are not part of FERC's jurisdiction.[808] In addition, some regulated utilities are under state-imposed rate caps. Utilities in those states may have a harder time recovering transmission costs and may be reluctant to invest in new transmission.[809] Utilities can also charge fees

805 Brown & Sedano, 2004, p. 15.
806 As cited in Energy Information Administration, 1996.
807 See "Regulatory Environment" for more information on FERC.
808 Brown & Sedano, 2004, pp. 24-26.
809 Ibid., p. 47.

to other utilities (e.g., telephone, cable) to use their pole infrastructure. More recently, private transmission companies have entered the market. They depend on power purchase agreements and sales of transmission rights for their revenue.

Other considerations in the economics of transmission lines are potentially avoided costs associated with line congestion and electricity generation. Expanding transmission may delay the need for construction of new power plants, if the transmission lines improve power flow to a region without sacrificing grid reliability in another region. The costs of line outages and congestion can also be avoided with appropriate transmission expansion and line maintenance. A 2001 FERC study estimated congestion costs for individual line constraints at $5 million to $50 million during the summer months of 2000 and 2001, depending on the region and conditions of the constraint (one constraint in New York in summer 2000 was estimated as costing more than $700 million).[810] Another study, which surveyed six independent system operators (ISOs) that control and monitor regional electric power systems,[811] found congestion costs of $1.8 billion in 2000 $1.3 billion in 2001.[812]

PLANNED IMPROVEMENTS AND EXPANSION

With electricity demand expected to increase 19 percent in the United States over the next 10 years, expansion in transmission will be key to maintaining grid reliability.[813] Transmission investment had declined over the past several decades, especially during the transition to deregulation in parts of the country. Deregulation created more competition among utilities, which resulted in precautionary spending being curtailed. In addition, utilities were unsure about regulation and ownership and responsibility for transmission. Around the turn of the century, however, transmission investment began to increase again, due in part to increasing line congestion and reliability problems. Edison Electric Institute estimates that investor-owned utilities are planning an estimated $24 billion in transmission infrastructure investment between 2005 and 2008.[814] According to the North American Electric Reliability Council (NERC),[815] investment will include more than 9,000 miles of new transmission lines (230 kV and above) planned in the United States through 2010—a 6.1 percent increase in total installed miles.[816] American Transmission Company (ATC), the first multistate, transmission-only utility in the United States, has invested $481 million to build 75 miles of new transmission lines and upgrade 565 miles in the upper Midwest since it began operation in 2001. ATC's current plans call for $3.4 billion in transmission system improvement costs through 2015.[817] Even with those levels of planned investment, transmission is only expected to increase 6 percent between 2002 and 2012, versus a 20 percent increase in electricity demand during the same period.[818] Table 2-58 details the NERC regions and their planned transmission additions through 2014.[819]

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810 U.S. Department of Energy, 2002.

811 See "Regulatory Environment" for more information on ISOs.

812 Dyer, 2003.

813 North American Electric Reliability Council, 2006a.

814 Edison Electric Institute, 2005.

815 See "Regulatory Environment" for more information on NERC.

816 North American Electric Reliability Council, 2006a.

817 American Transmission Company, 2005.

818 U.S. Department of Energy, 2002.

819 North American Electric Reliability Council, 2005.

Table 2-58: Planned transmission additions[820]

	Transmission Circuit Miles – 230kV and Above			
	2005 Existing	2006-2010 Additions	2011-2015 Additions	2015 Total Installed
United States				
ERCOT	8,311	648	-	8,959
FRCC	6,998	350	127	7,475
MRO	15,912	1,382	272	17,566
NPCC	6,426	364	16	6,806
RFC	26,258	592	-	26,850
SERC	31,179	1,292	947	33,418
SPP	9,955	14	21	9,990
WECC	58,751	3,063	1,821	63,635
Total U.S.	163,790	7,705	3,204	174,699
Total Canada	46,707	1,322	298	48,327
Total Mexico	638	152	192	982
Total NERC	211,135	9,179	3,694	224,008

REGULATORY ENVIRONMENT

Overview

Transmission of electricity not only requires complex networks of sophisticated equipment; it also requires equally elaborate networks of monitoring, coordination and regulation. The U.S.-Canada electricity grid is among the greatest engineering achievements of the 20th century because it harmonizes power generation resources controlled by thousands of different organizations.[821] When this harmonization fails, the consequences can be dramatic, as seen during the August 14, 2003, blackout. All efforts to significantly modify the U.S. electricity system must seriously consider their impacts on the grid and how the changes can most effectively be incorporated into the grid system—both technically and in terms of regulation. This section describes the organizations responsible for the efficient and reliable operation of the grid and explores the 2003 blackout.

Organizations Responsible for Grid Operation and Reliability

Among the many organizations that influence the use of the electric grid are government regulators, industry associations and private companies, acting together and independently. Frequently, these groups overlap and specific groups often fill several roles. For example, PJM is a regional transmission organization (RTO) that serves as a reliability coordinator and operates control areas for several utilities; PJM's nine control areas spread over three different regional reliability councils.[822]

Federal Energy Regulatory Commission

FERC is the primary U.S. government regulatory agency of the electric system. FERC's authority originates in the Commerce Clause of the Constitution; the clause establishes the federal government's responsibility for regulating interstate commerce.[823] FERC designates much responsibility for ensuring reliability to the Electric Reliability Organization (ERO), but retains the authority to audit the North American Electric Reliability Council in its new role as ERO.[824] The federal government, through FERC, generally regulates transmission lines, which cover

820 Data from Ibid.
821 U.S.-Canada Power System Outage Task Force, 2004.
822 Ibid.
823 Brown & Sedano, 2004.
824 Strangmeier, 2006.

greater distances at higher voltages. FERC oversees rates and terms for most transmission and determines how much transmission system owners can earn; publicly owned utilities, however, are exempt from FERC regulation.

North American Electric Reliability Council

NERC is the overarching trade group that has taken responsibility for ensuring reliability of the electric grid in the United States and Canada through self-regulation.[825] In July 2006, NERC was approved by FERC to be the Electric Reliability Organization for the United States under the Energy Policy Act of 2005, which gives NERC legal authority to enforce reliability standards.[826] Eight regional reliability councils form NERC's membership; these regional councils are composed of investor-owned utilities, federal power agencies, rural electric cooperatives, state and municipal utilities, wholesale power producers, power marketers and power customers.[827] NERC:

- Sets standards for operation and planning and monitors compliance with those standards.
- Accredits training programs and certifications for professionals and organizations and provides educational resources.
- Reports on adequacy and performance of bulk electric system and investigates disturbances.
- Coordinates standards, procedures, data and services among smaller organizations and facilitates information exchange among them.
- Serves as the central leader for protection of infrastructure.
- Administers conflict-resolution procedures. [828]

Reliability Coordinators

Eighteen reliability coordinators are designated by NERC to provide reliability oversight over wide regions, typically encompassing several control areas. These coordinators report on reliability and coordinate real-time emergency operations among their control areas. Reliability coordinators cannot participate in wholesale or retail market functions, but in many cases they do operate and facilitate these functions. Regional transmission organizations and independent system operators are commonly designated as reliability coordinators.[829]

Control Areas

Control areas, single entities that balance generation and loads instantaneously from dispatch centers, are traditionally the networks of vertically integrated utilities. North America's 140 control areas are linked to adjacent areas by transmission interconnection tie lines, and grid operators control their generation resources to meet contracted interchange schedules with other areas. Due to industry restructuring and unbundling of generation,

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825 See *www.nerc.com/about/* for more information.
826 Strangmeier, 2006.
827 US-Canada Power System Outage Task Force, 2004.
828 Ibid.
829 US-Canada Power System Outage Task Force, 2004.

transmission and marketing activities (under FERC Order No. 888/889), many control areas are not the domain of a single vertically integrated utility. Today, many control areas are RTOs or ISOs.[830]

RTOs and ISOs

Regional transmission operators and independent system operators control and monitor the operation of a region's electric power system; the only difference between the terms is that RTOs operate across state lines while ISOs operate in single states. This distinction can be confusing, as two of the four RTOs in the United States include the phrase "Independent System Operator" in their names.

RTOs and ISOs are generally nonprofit corporations set up according to governance models described by FERC Order No. 2000; they do not own transmission assets, but operate assets owned by members.[831] Order No. 2000 requires all public utilities that own or operate interstate transmission resources begin filing plans to form or participate in an RTO.[832] The purpose of RTOs and ISOs is to ensure open access to the transmission grid to all power suppliers, consistent with FERC Order No. 888/889. RTOs and ISOs comprise one or more control areas.

State Public Utility Commissions

In general, states regulate distribution lines, the lower voltage lines which feed to customers. Many State Public Utility Commissions site and grant permission to build new lines, both transmission and distribution. In addition, states approve utilities' plans and help determine retail electricity rates. Most states (more than 75 percent) have one agency or board that handles transmission projects and issues or denies permits, with Public Utility Commissions being the predominant agency.[833] Almost half of all states require review of transmission projects if the proposed line is rated at least 100 kV, with half of those states not requiring review unless the line is greater than 200 kV.[834]

Other Commissions and Agencies

Other agencies, at both the state and federal levels, can get involved in transmission siting and approval. Environmental and public health agencies can engage when proposed transmission lines cross environmentally sensitive areas, or in considering electromagnetic field impact on those who live near lines, and land managers can become involved when proposed lines pass through publicly owned land. In the case of federal lands, federal land managers can supersede state authorities in approving or denying transmission projects. In addition, the Department of Energy maintains some emergency transmission functions, such as during regional blackouts.[835]

Citizen Groups

The public is often opposed to new transmission lines, even if a new line is required for increased reliability. People in rural areas are concerned about environmental degradation if land is cleared for transmission tower construction. In urban areas, concerns are visual pollution, negative effects on property values and potential health impacts from living near electric and magnetic fields given off by lines.[836] Public witnesses can participate in state-level siting hearings or can organize with nonprofit groups or government representatives to support or oppose transmission projects.

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830 Ibid.
831 Ibid.
832 Federal Energy Regulatory Commission, 1999.
833 Resource Strategies, 2001.
834 Ibid.
835 See U.S.-Canada Power System Outage Task Force, 2004, for further information.
836 Hirst, 2000, p. 12.

Table 2-59 summarizes the various types of transmission regulations:

Table 2-59: Transmission regulation summary[837]

Federal review if a project:	State review regarding:	Local review:
• Crosses federal lands	• Need for project	• Depends on state
• Crosses navigable rivers	• Environmental impacts	
• Involves a federal power agency	• Land use impacts	
• Might interfere with aviation	• Depends on state	

Note regarding State review[838]

Any entity at any level of regulation (e.g., federal, state, local) can delay a transmission project at any stage in the process, creating timing problems in trying to coordinate generation expansion with transmission expansion.

Current levels of regulatory uncertainty result from myriad state and local regulations, even though electricity transmission is largely interstate and regional. Different utilities answer to different regulatory bodies, depending on the state in which the company operates, the state or states in which the transmission lines will run and the type of utility or corporation that is proposing the project (government- and consumer-owned utilities are not subject to FERC regulation). The following two case studies outline problems with transmission regulation that can affect grid performance, reliability and expansion.

CASE STUDY: AUGUST 14, 2003, BLACKOUT

The August 14, 2003, Blackout—the largest blackout ever in North America—has led to much scrutiny of the electric industry and several major changes. Although the blackout occurred at a peak period of power demand and summer thunderstorms damaged transmission infrastructure, it was not demand and weather alone that caused the outage, but several "long-standing institutional failures and weaknesses."[839] NERC has identified seven specific violations of its standards; five of the violations and several other conclusions are grouped into four primary causes by the U.S.-Canada Power System Outage Task Force:[840] These primary causes are:

- FirstEnergy (an Ohio control area including four utilities) and ECAR (the NERC region in which FirstEnergy operates) did not understand the weaknesses of FirstEnergy's system with respect to voltage instability or operate with appropriate voltage criteria and remedial measures.

- FirstEnergy exhibited inadequate situational awareness and thus failed to recognize system deterioration.

- FirstEnergy failed to adequately manage vegetation along its transmission rights-of-way.

- Grid reliability organizations failed to provide effective diagnostic support.

837 Compiled from Ibid.
838 Must file in every state that project will impact.
839 U.S.-Canada Power System Outage Task Force, 2004.
840 Ibid.

In addition to these causes, the task force found that FirstEnergy and others failed to arrest the spread of the blackout because of several reasons, including violations of NERC policies, lack of communication among control areas and failure to promptly take measures, such as load reduction, to alleviate dangerous grid conditions.

Relations Among Organizations and Institutional Issues

The blackout demonstrates several institutional issues within the electric grid. In this section, these issues are explained in the context of the organizations described above.

1. NERC provisions address many contributing factors to the blackout. However, these standards allow multiple interpretations by different reliability councils, control areas and reliability coordinators. NERC standards are intended to be minimums, but some regions, reliability coordinators and other groups have declined to select more stringent standards. Further, NERC previously had no regulatory authority to monitor or enforce compliance with these standards, and many standards even lack measurable compliance criteria.

2. The reliability community, including NERC, was aware of the vagueness of some standards and delegation of reliability coordinator functions to control areas, but moved slowly to correct the problems. Since NERC's authority relied on member consensus, NERC had limited ability to act decisively to specify the policy requirements in detail. Such consensus regulations often struggle to advance beyond the lowest common denominator.

3. Similarly, the NERC compliance and auditing program has been neither comprehensive nor aggressive enough to assess control area capability or direct operation of the bulk power system. Again, effectiveness of these programs varied among regional councils. The driving factors of this inadequacy are lack of regulatory authority and reliance on consensus decision making. NERC's recently adopted process for developing standards is lengthy and not well understood or applied by many grid participants.

4. NERC standards are frequently administrative and technical rather than results-oriented.

5. Some regional councils have developed procedures for tracking the implementation of recommendations from NERC reports by ISOs and control areas, but in general tracking and accountability are ineffective.

Overall, these institutional issues show that the reliability coordinators and control areas that operate the grid on a daily basis do so according to standards and guidelines established by NERC and the reliability community. However, these policies are weak, ambiguous and difficult to monitor. If the standards were clearer and enforceable, accountability and reliability would be higher.

CASE STUDY: AMERICAN ELECTRIC POWER'S WYOMING-JACKSONS FERRY TRANSMISSION LINE PROJECT[841]

"Electricity Transmission: A Primer," published by the National Council on Electricity Policy, outlines five basic steps in the transmission expansion process: planning, cost studying, study of possible routes for the line, obtaining state and federal agency approvals, and financing and construction.[842]

American Electric Power's (APC) Wyoming-Jacksons Ferry 765kV line project demonstrates the complexity of the regulatory process. AEP is one of the nation's largest electric utilities and electricity generators, and it owns the nation's largest transmission network, with almost 39,000 miles of transmission lines. The company serves almost 5 million customers in 11 states, mostly in the central part of the United States, stretching from Michigan to Kentucky to Louisiana and parts of Texas.

In March 1990, citing a more than 100 percent increase in electricity demand in southwest Virginia, AEP announced a proposed 765 kV transmission line project. With regard to the third planning step outlined above, study of possible routes for the line, AEP worked with teams from Virginia Tech and West Virginia University to determine an optimal path for the transmission corridor. The analysis focused on environmental impacts affecting "natural and cultural resources and…the visual landscape," among other considerations. The university teams did not consider construction costs in their assessment.

The next step, gaining state and federal agency permission to construct the line, took nearly 12 years to complete. The process began with applications to the U.S. Forest Service, the National Park Service and the Army Corps of Engineers for permission to build the line on federal lands (Jefferson National Forest in Virginia), citing the need to increase reliability and reduce the risk of an outage.[843] Over the next two years, the company filed applications with the utility commissions in the two states in which the transmission line would run: the West Virginia Public Service Commission and the Virginia State Corporation Commission.

Initially, the federal agencies denied the project because it would cross over sensitive federal lands. Shortly after those decisions, however, in the second half of 1996, electric reliability became a larger issue, and the line was reconsidered. The Department of Energy entered the mix and requested that three reliability councils (part of NERC) that would be affected by the transmission project study the project's implications for transmission reliability in the southern West Virginia-southwestern Virginia area. The study recommended that the project be approved. In fall 1997, AEP resubmitted applications to the West Virginia PSC and the Virginia SCC with a modified route for the line. Following hearings and other follow-up actions, the state and federal agencies approved the project by the end of 2002.

The final two steps in the transmission planning process, financing and construction, proceeded relatively quickly, compared with the permitting process. Construction of the transmission line began in spring 2004, and the 90-mile line project was finished in summer 2006, at a cost of $306 million.

AEP's construction timeline comports with Brown and Sedano's (2004) estimation of power line construction timing: "From the time permits are issued, it can take two years or more to build a power line. This includes time for the utility to secure contractors, to acquire land, to order parts, and to build the line."[844] But the nearly

841 American Electric Power, 2006a.
842 Brown & Sedano, 2004.
843 U.S. Department of Energy, 2002.
844 Brown & Sedano, 2004.

12 years and half-dozen agency approvals required before AEP could construct the line demonstrate the complexity of transmission regulation in the United States.

CONCLUSION

The electricity transmission system in the United States is increasingly strained with continued growth in demand. With the changing regulatory structure of the electric utility industry, confusion over transmission ownership and regulation prevented needed investments in transmission expansion over the past 20 years. With clarification of roles and responsibilities, and renewed fervor to improve grid reliability, transmission investments, technology developments and planned expansions are on the rise.

Distribution

Distribution follows transmission in electricity infrastructure. After electricity is generated and transmitted, the voltage must be brought down to a level that can be consumed, and then distributed locally and delivered to end-use customers. Advanced distribution management systems and technologies aim to more accurately simulate and report grid conditions to increase the performance, reliability and integration of the system. With increased interest in distributed generation, in which electricity is generated close to the point of consumption, advances and expansions in distribution will be necessary in the near future.

DISTRIBUTION BASICS

After electricity is generated at a power plant, the voltage is stepped up at a generator transformer, and the power is then transmitted over high voltage lines, to maximize efficiency and minimize loss (transmission). As electricity nears the point of consumption, it is stepped down so it can be delivered to end-use customers. Electricity distribution is the section of the grid between transmission and the user's electric meter. Distribution is generally considered to include medium-voltage power lines (less than 50 kV), low-voltage electrical step-down substations and pole-mounted transformers, and low-voltage distribution lines (less than 1 kV).

Electricity, which is transmitted at voltages over 100 kV, is stepped down at a substation transformer, and sometimes again at a pole-mounted transformer, and then distributed to customers at lower voltage, usually 120 V to 70 kV. Pole-mounted transformers, which change the current from three-phase to single-phase, are used for electricity delivery to homes. Figure 2-41 above shows the distribution process (outlined) and common voltages delivered to different customers.

In North America, some city and suburban distribution systems use a 2,400/4,160 volt three-phase alternating current system (AC; described in more detail under Transmission), but most have been converted to a 7,200/12,470 volt system for higher efficiency and lower loss (the two voltages given, e.g., 2,400/4,160, depend on whether the customer uses one or two phases; all three phases used together is for distribution only, not consumption). Those voltages are then stepped down to as low as 120 volts, which is the common voltage delivered to U.S. homes. In contrast, European systems have generally used higher voltages for distribution. Residential and other end-users get power from a 220/380 volt system. The voltage from substations, where transmission lines are stepped down, has increased from 6,600 volts (6.6 kV) to 11,000 volts (11 kV) over time.

North American and European electrical systems also differ with regard to the structure of the distribution system. In the United States, there are a greater number of low-voltage step-down transformers with smaller capacity located closer to end-use customers. For example, a pole-mounted transformer may supply only one or a few houses. In the United Kingdom, on the other hand, the higher distribution voltages can be transmitted over larger distances, so a typical substation might supply a whole neighborhood. One advantage of the North American system is that a smaller population or area is affected by failure to any single transformer. The advantage of the U.K. system, however, is that fewer, larger and more efficient transformers are used, and less spare capacity is needed.

Current research in electricity distribution is focused on increasing reliability and integration, particularly as more renewable energy generators come online and distributed generation, in which energy is generated close to the point of consumption, gains more attention. The distribution system can be made more efficient by using distribution management systems. These systems consist of electronic and computer-based tools that return real-time data from all sections of the distribution system and help in analysis, control and optimization of the network. Current research into distribution management systems is detailed below.

Because distribution is managed locally, it has not encountered the same regulatory hurdles that interstate transmission increasingly has.[845] But like transmission, distribution companies need to respond quickly to consistent growth in customers and energy demand.

TECHNICAL OVERVIEW AND RESEARCH & DEVELOPMENT

The Energy Policy Act of 2005 instructed the Department of Energy to develop a plan for modernizing electric infrastructure through a comprehensive research, development and demonstration program.[846] The Electric Distribution Program (which refers collectively to the Electric Distribution Program and the GridWise Initiative) is aimed at transforming the electric distribution infrastructure to increase affordability, reliability and security, through integration of advanced communications, information, sensors and controls, and distributed energy resources.[847]

Electric Distribution activities are structured under four major program areas:[848]

- Architecture and Communication Standards, focused on providing platforms to integrate electric delivery services with market operations.

- Monitoring and Load Management Technologies, which aim to allow the distribution system to detect and respond to problems quickly, including economic dispatch of all available assets, and transparency of market and pricing operations in electricity delivery. Technologies combine sensing, communications, information analysis, and control management for improved distribution networks and peak load reduction.

- Advanced Distribution Technologies, including advanced modular plug-and-play interconnection and control technologies. Technology goals are to improve smoothness of operations between distributed energy resources and the electric power system and local loads. Another focus is microgrids, electricity delivery systems that include distributed energy resources and operate in parallel with a larger power delivery system.

- Modeling and Simulation, aimed at developing simulation and analysis tools to model and predict complex interactions of resources, demand loads and relevant policies.

The Department of Energy's Office of Electricity Delivery and Energy Reliability is engaged in research in visualization and controls, high temperature superconductivity, distributed energy, energy storage and power electronics. Efforts include near-term development of visualization tools, real-time information systems, cyber security systems, distributed generation systems and regional demonstrations of intelligent distribution systems; mid-term development of "next generation" energy-storage devices, more affordable and durable power electronics devices, and commercial applications for high temperature superconducting materials, such as wires, cables, motors and transformers, that will reduce energy losses in electrical equipment; and long-term development of advanced materials and concepts for electricity delivery and storage to the U.S. electric grid.[849]

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845 See Transmission section for more information.
846 Office of Electricity Delivery and Energy Reliability, 2005.
847 Office of Electricity Delivery and Energy Reliability, 2006a.
848 Office of Electric Transmission and Distribution, 2004.
849 Office of Electricity Delivery and Energy Reliability, 2006b.

The DOE's Pacific Northwest National Laboratory[850] (PNNL) is developing several technologies, including the Grid Friendly Appliance controller, which senses grid conditions by monitoring the frequency of the system and provides automatic demand response in times of disruption. In the North American power grid, a disturbance of the 60 Hz frequency indicates an imbalance between supply and demand that can lead to a blackout. The controller computer chip can be installed in household appliances and is programmed to turn them off for a few seconds to a few minutes to allow the grid to stabilize. The controllers can react automatically in fractions of a second when a disturbance is detected, whereas power plants take minutes to come up to speed. The computer chips can even be programmed to delay restart, so that not all appliances come back on at once after a power outage. The Grid Friendly Appliance controller is ready for licensing and installation in the next generation of appliances.

PNNL is also developing the ability to simulate the electric system as a dynamic network of economic energy transactions simultaneously with the engineering aspects of power grid operations. The framework aims not only to share software among common users, but also to combine system components (transmission grid, distribution systems and customer systems, including equipment and appliances) to create a variety of electric system simulations.[851]

Some of the technical problems with the PNNL electric system simulation project are the vastness of the physical- and time scales and the difficulty of analyzing the interactions among engineering and market behaviors. The variation in time scales ranges from subsecond time frames for grid stability to years for building additional capacity. The physical scales are evident in the two levels of the simulation: the distribution-to-customer level and the generation/transmission-to-distribution bulk power level. At the bulk power level, only a few substation-level distribution systems will be simulated in detail; other substation loads will be modeled to capture their response to cost and control signals.[852]

REGULATION OF DISTRIBUTION

The electric industry has historically been dominated by vertically integrated utilities, which perform all the major operations of generation, transmission and distribution. However, the industry is being restructured as it moves toward competition and deregulation. Electricity deregulation, beginning in part with the Energy Policy Act of 1992, which allowed the Federal Energy Regulatory Commission to consider electric power generation separate from transmission and distribution, has proceeded at different speeds and degrees across the United States. Some previously vertically integrated utilities have sold off their generation facilities and are becoming distribution companies, focused on providing electricity and a few other basic functions, such as line maintenance and tree trimming.

Regulation of electric power distribution comes under the jurisdiction of state public utility commissions (PUCs). In traditional regulated markets, PUCs set retail rates for electricity based on the total cost of generation, which includes the cost of distribution. PUCs also have a say in siting distribution lines, substations and generators. As the industry restructures, PUCs will no longer regulate retail rates for generated power, but may continue to regulate local distribution of power to consumers.[853]

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850 Pacific Northwest National Laboratory, 2006.
851 Ibid.
852 Ibid.
853 Energy Information Administration, 2000.

Most utilities maintain their own distribution networks and rights of way. As described on Duke Energy's website:

> Distribution lines carry power from local substations to homes and businesses. A distribution right of way gives access to a strip of land so that utilities (electric, telephone, cable, water and/or gas) may build and maintain service lines. This corridor is a property right granted to a utility in perpetuity by a property owner and is required to provide safe, reliable delivery of the product. The right of way width required for overhead distribution power lines of any voltage is normally a 30-foot corridor (15 feet on each side).[854]

DISTRIBUTED GENERATION[855]

Distributed generation refers to electricity production that generally is at a smaller scale and takes place near the site of consumption. Examples of distributed generation include backup generators, solar photovoltaic systems on rooftops, small wind turbines, fuel cells, and combined heat and power systems in industrial plants. Residential solar photovoltaic systems and backup generators used by businesses and large commercial buildings can be several hundred kilowatts in size. Industrial combined heat and power systems can range in size from 40 kW to 40 MW.

In a 1995 survey, the Energy Information Administration determined that about 5 percent of commercial buildings in the United States had some capacity to generate electricity on-site, but less than 0.1 percent was used (to meet peak demand or avoid service interruption).[856] However, distributed generation is expected to continue expanding. The 2006 EIA Annual Energy Outlook reference case projects that close to 18 percent (more than 62,000 MW) of additions to electricity generating capacity between 2005 and 2030 will come from distributed generation, including renewable energy additions.[857] That capacity is in addition to 14,000 MW of existing commercial and industrial distributed generation capacity, excluding residential.[858] Distributed generation currently represents less than 1 percent of total U.S. generating capacity.

Distributed generation, in the context of electricity delivery, affords benefits of reduced line loss and displaced demand for large-scale investments in transmission and generation. As electricity travels through the transmission and distribution system, changes in voltage as the power approaches the point of consumption result in energy losses. The EIA estimates that transmission and distribution losses in the United States averaged about 9 percent of electricity generated in 2005.[859] Distributed generation, on the other hand, significantly reduces transmission and distribution and associated line losses because the power is generated on-site. Where there are increasing loads and/or congestion, distributed generation could supplant short-term generation and transmission investment, potentially delaying increases in retail energy prices.

With research focused on improving the integration of electricity distribution with distributed generation, as well as on increasing the security and reliability of the entire system, distribution is being updated and transformed along with the rest of the electricity industry.

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854 Duke Energy, 2006.

855 See *Clean Distributed Generation* in Chapter 1 for more information.

856 Boedecker et al., 2000.

857 Energy Information Administration, 2006a.

858 Energy Information Administration, 2006d.

859 Energy Information Administration, 2006b.

Storage

Storing electricity, through pumped water, compressed air, batteries, fuel cells and other means, offers significant potential for improving the electricity industry. Electricity is generally consumed as soon as it is produced; electricity is the only commodity that requires that supply and demand match instantaneously, not just on an average basis. Being able to store energy provides the potential to bypass this requirement. Energy storage creates more flexibility in generating capacity requirements, especially as generation from distributed generation technologies and intermittent renewable energy sources increases. Energy storage technology R&D is focused on improving existing technologies, reducing costs and developing new, more practical technologies.

Electricity storage has the potential to provide significant advantages to utilities and customers, including:

- Commodity storage. Electricity can be generated when it is cheapest and consumed when it is most efficient to do so. This capability can be viewed as a form of arbitrage by competitive players in the market, or it can be used by utilities as a means to lessen capacity requirements (they would only need to produce enough power to meet average demand; stored energy could be used to meet extra demand in peak periods). Of course, this capability implicitly improves the effective capacity factor of intermittent sources of electricity generation; intermittent sources, such as renewable energy sources, can contribute to meeting average demand while generating with an irregular time profile. Distributed storage capability, at the local level, would also mean that expanding transmission capacity in response to increasing demand could be avoided or delayed, since transmission would only need to meet average demand, and stored energy would provide peak power to the end user.

- Load Smoothing and bridging. In a distributed generation context, short-term load smoothing allows production to work on the smooth shape of aggregate loads rather than the erratic shape of disaggregated loads. Stored electricity also can provide the energy needed to ramp up new generation sources (e.g., diesel generators) when another generator (e.g., wind turbine) goes offline, while still meeting grid demand.

- Power quality. Storage can insulate consumers from short-term fluctuations in the grid, such as voltage decays, frequency variation and even blackouts.

Energy storage is currently not widely used; it represents about 2.5 percent of U.S. generating capacity, almost all of which is pumped hydro storage.[860],[861] Historically, storage facilities have not been economical in most locations. This situation may change as storage technologies become cheaper and benefits grow due to increased use of intermittent renewable sources and distributed generation, as well as to the high costs of increasing transmission and distribution networks.[862] Some projections suggest that over the next 15 years, storage could provide benefits to generation, transmission and distribution worth over $100 billion.[863]

860 van der Linden, 2006.
861 Moore & Douglas, 2006.
862 McDowall, 2001.
863 van der Linden, 2006.

ELECTRICITY STORAGE TECHNOLOGIES

Different storage technologies are best suited to different applications, locations and scales. Some of the important characteristics are:

- Power/energy ratio or discharge rate. This factor relates to how quickly the technology releases the energy it has stored; a high power/energy ratio is the same as a high discharge rate, which means the technology has a fast output. A higher ratio is better suited to short duration releases.

- Size and capacity of the technology and its applications.

- Space and location requirements.

- Capital and operating costs.

- Durability to cycling (e.g., as a battery loses strength each time it is recharged).

Pumped Hydro Storage

Pumped hydro storage currently represents the vast majority of U.S. electric storage capacity.[864] Pumped hydro requires two large water bodies separated by a significant elevation difference; it uses a pump/generator to store/release gravitational potential energy of water by moving the water between the bodies. As a well understood technology, pumped hydro is used for commodity storage in large-scale (5,000-20,000 MWh),[865] high-capital-cost operations. The efficiency of pumped hydro storage is 75 percent,[866] and marginal costs are fairly low.

Superconducting Magnetic Energy Storage

Superconducting magnetic energy storage (SMES) technology uses the electromagnetic phenomenon of inductance to store energy in a magnetic field (by running DC current through a coil of wires). The magnetic field creates resistance to changes in the current, thereby providing superb power quality protection.[867] SMES has a very high discharge rate, about 1kWh/s (for a typical 1 to 3 MW system),[868] and high capital costs, rendering this technology less practical for commodity storage applications. Although SMES technology provides a high efficiency of storage, it requires significant energy to cool the superconductors, leading to low total efficiency and high operating costs. Recent advances in high temperature superconductors may dramatically improve total efficiency and reduce lifecycle costs and environmental impacts.[869] Greater than 100 MW of SMES storage is already installed in the United States, with typical installations below 3 MW per unit. Where grid reliability is a concern, even with high capital costs, SMES is cost-competitive with transmission upgrades.[870]

864 Ibid.
865 U.S. Climate Change Technology Program, 2005.
866 Ibid.
867 De Steese et al., 1993.
868 Moore & Douglas, 2006.
869 Hartikainen et al., 2007.
870 van der Linden, 2006.

Ultracapacitors

Ultracapacitors are comparable to SMES except that they operate on a different principle (capacitance), storing energy in an electric field. Ultracapacitors can be used in similar applications to SMES, but they are much smaller in capacity (less than 1 kWh).

Flywheels

Flywheels are one of the simplest forms of energy storage, depending only on rapidly spinning wheels, low friction bearings and motors. Similar to SMES, flywheels have an almost instantaneous dispatch time, high power/energy ratio and high capital cost, making them better suited to power quality applications than to large-scale commodity storage. However, flywheels are also well adapted to load smoothing and bridging; containerized modules of flywheels sold by Beacon Power can provide megawatts of electricity for a few minutes per container at costs competitive to diesel generators.[871]

Fuel Cells

Fuel cells can serve as a type of storage technology by interconverting water and elemental hydrogen or by serving as generators that run on hydrogen, natural gas or liquefied petroleum gas. In the context of commodity storage, fuel cells can store energy as hydrogen when electricity is cheap, either by electrolysis of water or by diverting a stream of natural gas from electric generation and using it to create hydrogen through steam reforming. Their high capital costs, but low noise and emission levels, make fuel cells well suited to small-scale residential applications in the context of distributed generation. Refrigerator-sized fuel cells rated at 5 to 10 kW may be widespread in these applications in the future.[872]

Compressed Air Energy Storage

Compressed air energy storage (CAES) technology uses excess electricity to pump air into geologic caverns or artificial storage chambers, and the highly pressurized air is then released into a gas expansion turbine. CAES projects can generally operate as conventional combustion turbines or combined cycle plants, or they can burn gas or gasified coal at doubled efficiencies while using the pressurized air.[873] The large scale and capital cost of CAES, along with relatively slow start up time and power/energy ratio, make CAES best suited for large-scale commodity storage, particularly on a diurnal cycle. CAES equipment on a 500 MW clean coal plant could allow the plant to run 24 hours a day at 500 MW, but sell only 300 MW during the night, when demand is less, and the remainder during the day, when demand is higher. The only additional fuel requirements would be to power a 90 MW gas turbine running during the day. CAES technology, with about $550/kW capital costs, is competitive for storing bulk electricity at $6/mmBTU natural gas.[874] One major CAES plant is currently operating in the United States (the 110 MW McIntosh facility owned by Alabama Electric Cooperative, which has been operating for 11 years and can generate continuously for 26 hours), and several more have been proposed.[875]

871 Ibid.
872 McDowall, 2001.
873 Hartikainen et al., 2007.
874 van der Linden, 2006.
875 Ibid.

Batteries

There are many types of batteries; the most common now used for large-scale storage is the lead acid battery, but many alternative technologies exhibit great potential. Table 2-60 compares the characteristics desired in batteries for distributed generation support (e.g., load smoothing, bridging and power quality) versus commodity storage. In order to be cost effective, batteries must retain these characteristics over time and be robust to the types of cycling that are inherent in the application.

Table 2-60: Battery characteristics by application[876]

Characteristic	Distributed Generation	Commodity Storage
High discharge power	X	
Deep discharge cycling		X
Shallow discharge cycling	X	X
Operation at temperature extremes	X	
Compact size	X	
Transportability	X	

Batteries are diverse. For example, lead acid batteries are the conventional choice because they are inexpensive, but they have a low energy and power density and short cycling life, especially in high-temperature environments. High-power versions of lead acid batteries can be made (e.g., car batteries), but this further shortens the cycling life.[877]

Lithium ion batteries are rapidly becoming dominant in the consumer electronics market because of their portability, durability, long life (more than 10 million shallow cycles) and high voltage and energy. High-power versions can be made, increasing their applicability to distributed generation. These "smart" batteries require minimal maintenance and supervision.[878] Lithium ion batteries are expected to dominate future high-power storage applications, especially in settings where high power is needed for minutes at a time.[879]

Sodium-sulfur (NaS) batteries operate at high temperature (approximately 300 degrees C) and have been demonstrated at large scale, including in a 57.6 MWh system[880] and three 48 MWh systems, all in Tokyo. Currently, production has been heavily subsidized, but costs are expected to drop to levels equivalent to lead acid batteries for high-capacity installations.[881]

Flow batteries use an electrolyte pumped through a stack of electrodes between two storage tanks; the power is determined by the size of the electrode stack, and capacity is determined by the size of the storage tanks. Thus, flow batteries can be designed for either high-power or high-capacity, or for both, although high-power applications are not likely to be cost effective. There are several different types of flow batteries that rely on different electrochemistry, including batteries that use sodium bromide, sodium polysulfide, vanadium redox and zinc-bromide. Some types are unaffected by deep discharge cycling and are well suited to commodity storage applications, which look to be their most promising application.[882] There are several existing flow batteries now operating, including a 250 kW, 2 MWh vanadium redox system owned by PacifiCorp in Utah.[883]

876 Adapted from McDowall, 2001.
877 Ibid.
878 Ibid.
879 McDowall, 2005.
880 Ibid.
881 McDowall, 2001.
882 Ibid.
883 McDowall, 2005.

Although electricity storage has a long way to go before it is commercially viable on a wide scale, several technologies already exist to help integrate intermittent renewable resources and distributed generation into the generation mix. Electricity storage can also smooth the peaks of generation requirements; companies can maintain high levels of generation, even during periods of low demand, and store excess electricity to use during peak periods.

Electricity transmission, distribution and storage, all of which happen after electricity has been generated, have the potential to significantly influence future generation options. If renewable energy can be generated in remote areas, including desert solar and offshore wind applications, it will be largely ineffective unless the electricity can be transmitted and distributed to demand centers cost-effectively. Given that intermittency is one of the primary barriers to renewable energy, electricity storage presents great potential to remedy that concern. In developing new electricity generation sources and technologies, the infrastructure required to deliver the electricity must likewise be considered.

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CHAPTER 3 — SEQUESTRATION OF CARBON

Minimizing the impacts of climate change due to increased levels of greenhouse gas (GHG) requires an integrated approach involving complementary strategies. An important component of this approach is the capture and storage—sequestration—of carbon dioxide (CO_2). Broadly, both natural and engineered systems offer opportunities to mitigate atmospheric CO_2 through sequestration.

Biological systems absorb and trap CO_2 in plants on land and in phytoplankton in water through photosynthesis. A variety of policies, projects and programs can be considered that may enhance land-use options that increase the potential to sequester CO_2. Optimizing the true potential for biological carbon sequestration will require careful planning and management, along with strong policy direction. The potential for GHG mitigation through biological systems, however, is significant.

Engineered systems are available for capturing and storing GHG as part of new processes and new technologies. Advanced technologies for using coal, such as integrated gasification combined cycle (IGCC), enable pre-combustion capture of an almost pure stream of CO_2. In this concentrated form, the CO_2 may be transported via pipeline and injected directly into geologic reservoirs, where it can be stored indefinitely—or even used in operations to recover additional fossil fuels. Recently (November, 2006), the International Maritime Organization, based in London, announced its support for CO_2 storage in sub-seabed geological formations.

Alternatively, oceans, which now serve as earth's largest reservoirs of anthropogenic carbon, may in theory serve as sinks for captured CO_2 that is directly injected at appropriate sites. However, even though this option has been considered for decades, it remains controversial due to technical feasibility, cost issues and possible long-term environmental problems (e.g., acidification) that are difficult to anticipate and quantify on a large scale.

This chapter reviews and summarizes the various options being considered for carbon sequestration. The sections below will consider the technical and economic feasibility of approaches that may be of highest interest to the electric utility market sector.

Biological Sequestration

Through photosynthesis and carbon storage, terrestrial ecosystems play a vital role in regulating atmospheric concentrations of CO_2. Agriculture and forestry may contribute to GHG mitigation opportunities through sequestration of carbon in soil, plant biomass and wood products. Carbon pools can be net sinks or net sources of atmospheric CO_2. A carbon pool is a net sink if, over a given period, more carbon is flowing into the pool through photosynthesis and sequestration than flowing out through natural releases via respiration, biomass removals and other disturbances. Likewise, a carbon pool is a net source of CO_2 emissions if more carbon is flowing out of the system than in.[1] Forestry and agriculture can act as either sources or sinks of CO_2 emissions, depending on the specific activities and time frames of measurements or observations.

Land use significantly impacts levels of atmospheric CO_2. Tropical deforestation, for example, accounts for approximately 20 percent of the world's anthropogenic CO_2 emissions each year.[2] Yet a greater amount of atmospheric CO_2 is currently removed by forests than is emitted by land-use changes. With a total land area of nearly 700 million hectares, U.S. forest and agricultural lands comprise a net carbon sink of almost 830 teragrams (Tg) of CO_2 equivalent (CO_2 Eq.)—or nearly 225 Tg of carbon equivalent—per year.[3] Major U.S. land uses in 2002 were forests, 263 million hectares (28.8 percent); grassland pasture and range land, 234 million hectares (25.9 percent); cropland, 179 million hectares (19.5 percent); and special uses, such as parks and wildlife areas, 120 million hectares (13.1 percent).[4] In 2005, the U.S. biological carbon sink—over 90 percent of which occurs on forest lands—offset 12 percent of U.S. GHG emissions from all sectors of the economy.[5]

Biological carbon sequestration raises unique issues when evaluating GHG mitigation potential, all of which are critical for technical analyses, policy formation and resource management.[6] These issues include tracking carbon storage and saturation over time, reversibility (i.e., release) of carbon back into the environment, fate of downstream products that store carbon (e.g., paper and wood) and shifting of activities from one region to another (i.e., "leakage"). The uncertainty surrounding these issues highlights their importance when considering biologically sequestered carbon as a practical and realistic strategy to mitigate CO_2 emissions. These issues are discussed in more detail later in this chapter.

BIOLOGICAL SEQUESTRATION OPTIONS IN U.S. FORESTRY AND AGRICULTURE

Forestry-Afforestation

Converting cropland to forest has the highest potential in the United States for increasing biological carbon sequestration over current (base-line) projections of storage. Carbon accumulates in forest soils and biomass, both below ground in roots and above ground in stems, branches and leaves. Forests therefore have higher carbon sequestration potential than agricultural lands, where the primary sink is soil. Approximately 44 million hectares, or one-third of all current U.S. cropland, would require conversion to forests to offset 10 percent of 2002 CO_2 emissions over the current base-line level.[7] This gross biophysical potential is likely much higher than the actual net storage capacity, when carbon losses from forest disturbance and post-harvest timber use are taken into account. Moreover, not all of this conversion is economically feasible unless moderate to high prices are paid for

1 Intergovernmental Panel on Climate Change, 2000.
2 Ibid.
3 U.S. Environmental Protection Agency, 2005.
4 Lubowski et al., 2006.
5 U.S. Environmental Protection Agency, 2005.
6 Jackson & Schlesinger, 2004.
7 Ibid.

GHG reductions or sequestration.[8] Assessment of a realistic potential for forest carbon sequestration should consider regional planting and harvesting cycles. Developing a national policy to foster the use of forests as biological sinks for CO_2 will requires assessment of the amount of carbon stored on a regional basis, potential economic incentives, programmatic challenges and limitations, and broader environmental co-benefits and costs, such as changes in water quality, water yield and water runoff.[9]

Afforestation enhances the removal of atmospheric CO_2 through biological sequestration of carbon in forests newly established on lands that were without trees for some period, generally defined as 50 years under the Kyoto Protocol. The Intergovernmental Panel on Climate Change (IPCC) defines afforestation as "the planting of new forests on lands that, historically, have not contained forests."[10] Afforestation enhances carbon sequestration over base-line levels as land is allocated away from uses with relatively low carbon-storage potential (e.g., conventional crop agriculture) to forest cover with higher carbon-storage potential. The rate of carbon accumulation for afforestation varies and depends on the newly planted tree species, climate, soil type, management and other site-specific characteristics (e.g., 2.2 to 9.5 tons of CO_2 per acre per year[11]). Shifting land use from agriculture to forestry also generally leads to a reduction in the various GHG emissions from agriculture, as well as to other environmental co-benefits, such as improvements in water quality. Most recent afforestation in the United States occurred on pasture lands; between 1982 and 1997, more than 5.7 million hectares of pasture lands were converted to forest cover.[12]

The Kyoto Protocol allows for developed ("Annex I") countries to offset part of their CO_2 emissions by establishing new forests under "joint implementation" with other Annex I countries or under the Clean Development Mechanism with non-Annex I countries. New policy and market incentives to sequester carbon in biological systems will likely accelerate the conversion of natural grasslands to forest plantations, just as recent years already have seen such a shift over extensive areas of the southern hemisphere.[13] However, past global initiatives to sequester carbon in new forests have not consistently included careful analysis of environmental co-effects, both positive and negative. Positive co-effects can include improvements in water quality, biodiversity, flood control and salinization reversal. These benefits are especially evident when afforestation is applied to areas where former forests were replaced by crops.[14] Negative co-effects can include reduced stream flow, decreased groundwater recharge, soil acidification and increased salinization.[15] Biodiversity also can be negatively affected if the new plantations are monocultural and nonnative species begin to take over species-diverse native habitats. Research indicates that co-effects of afforestation depend on a broad range of factors, including historical plant habitat (e.g., shrubs versus grassland), chosen plantation species, climate, topography and socio-economic land use. Differences and interactions among these various factors have important implications for decisions about where plantations should be established and which tree species should be used.[16] Environmental tradeoffs should be recognized and analyzed prior to land conversion; the ability to predict and quantify the possible effects of afforestation in specific locations may be one of the largest challenges to zoning and planning such projects in the future.[17]

While afforestation has the greatest potential for establishment of carbon sinks on former agricultural land,

8 U.S. Environmental Protection Agency, 2005.
9 Jackson & Schlesinger, 2004.
10 Intergovernmental Panel on Climate Change, 2000.
11 Birdsey, 1996.
12 U.S. Department of Agriculture, 2000.
13 Farley et al., 2005.
14 Ibid.
15 Jackson et al., 2005.
16 Farley et al., 2005.
17 Ibid.

other options also are under consideration due to the various environmental co-benefits they may provide. It should be noted, however, that the total biological sequestration potential for these other options appears to be relatively small. One example involves former mine lands. More than 1.8 million hectares of land were under active coal mining permits in the United States during 2001, and more than 600,000 hectares of this land currently is considered "disturbed."[18] Many studies have determined that reclamation of mine lands can lead to a quick formation of soil horizons[19] which support vegetation that supports wildlife habitat, decreases water runoff and establishes aesthetic landscapes.[20] Initial studies indicate that the conversion of abandoned mine land to productive forest has the potential to sequester 369 million tons of $CO_{2,}$ with a rate of 920 to 1,070 tons of CO_2/ hectare over 70 years.[21]

Another area of growing interest for afforestation concerns the planting of trees in highly urbanized areas. Although the total potential for urban forest carbon sinks is relatively small, the potential co-benefits may argue for full consideration of project support. Urban areas cover about 4.4 percent of the continental United States and contain approximately 3 percent of its total tree cover.[22] Urban forests sequestered an average 72.1 Tg of CO_2Eq. per year between 1990 and 2004.[23] Urban forest sequestration potential, like other forest carbon sequestration, depends heavily on the ages and types of trees present.[24] For any project, it is important to plant tree species that will adapt well to the surrounding environment in order to maximize carbon sequestration.[25] Moreover, urban afforestation can reduce carbon emissions in ways that do not involve sequestration, by providing shade that cools buildings and reduces the need for energy-hungry air conditioning.[26] Simulations from 12 cities found that one well-placed 25-foot-tall deciduous tree produced energy savings from cooling ranging from 100 to 400 kWh and produced peak demand savings ranging from 0.3 to 0.6 kW.[27]

Forestry-Forest Management

Forest management mitigates CO_2 emissions by preserving existing sinks of carbon sequestered in tree biomass and soils. Traditional forest management focuses on maximizing the value of harvested commercial timber over time. Yet silviculture and conservation approaches can be adapted to enhance carbon sequestration in forests.[28] The mix of tree species can be designed to ensure the fastest and most efficient biomass growth and the highest sequestration potential. Forest managers may plant trees that grow moderately fast in order to accumulate harvestable timber faster, or they may fertilize and thin forest stands to increase productivity.

Forest timber rotations may also have an important role in carbon sequestration programs. Managed forests pass through multiple phases, ranging from stand establishment to harvest. Tree harvest rotation lengths vary by region and species type. According to a 2005 EPA report, "the non-industrial private forests of the southern United States are commonly managed with softwood or mixed species on a rotation of approximately 25 to 35 years or more." Under future U.S. carbon-control policies, carbon may be assigned a value and considered a forest output. Under this scenario, the value of delaying a forest harvest rotation will be higher because carbon

18 National Energy Technology Laboratory, 2006b.
19 Akala & Lal, 2001.
20 Burger et al., 2005.
21 National Energy Technology Laboratory, 2006b.
22 U.S. Environmental Protection Agency, 1995.
23 Ibid.
24 McPherson & Simpson, 1999.
25 Ibid.
26 Nowak & McPherson, 1993.
27 McPherson & Simpson, 1999.
28 U.S. Environmental Protection Agency, 2005.

accumulates in soil and wood as trees mature. By considering carbon as a valued output, forest managers can thereby actively enhance sequestration and the value of their stand by extending the harvest age of timber.

Actual carbon sequestration rates due to forest management practices will vary depending on the tree species, climate, topography, soil type and practices. The energy inputs for these practices also must be factored into the true cost and benefits of the total sequestration program. Although common forest management practices use equipment to establish, cultivate and harvest stands of trees, forestry is less energy-intensive than agriculture; in forestry, a relatively small number of activities can be spread over 20 to 50 years, while in agriculture, producers typically manage fields on time scales of perhaps 120 days, which is a growing season for a row crop such as corn.

Another forest management option, forest protection, preserves existing carbon pools and avoids CO_2 emissions resulting from timber harvest and wood processing.[29] Once harvested and replanted, a forest can take over 200 years to attain the equivalent carbon-storage capacity of a mature forest, due to significant on-site declines in carbon postharvest.[30] Deforestation will similarly release a substantial amount of carbon into the atmosphere at the time of harvest, and will do so rapidly. The benefits of reducing or avoiding deforestation are similar to those of increasing afforestation and improving forest management. Yet the timing of GHG effects can vary widely among practices. It may require decades for carbon to accumulate in forest soils and biomass after afforestation, but there is a net addition to the total biological carbon pool over that period. Deforestation transfers some carbon off-site in the form of harvested wood products; yet 150 to 800 Tg CO_2/acre is released immediately through harvesting and manufacturing and is unlikely to be replaced as the land is developed for other use.[31]

Agricultural Soil Carbon Sequestration

Adopting new practices and technology, changing overall land and crop management, modifying cropping intensity and retiring marginal lands from crop production can enhance biological carbon sequestration in agricultural soils or reduce CO_2 emissions associated with agriculture. Agricultural soils thus may have the potential to become a net sink for carbon and contribute to atmospheric reductions of CO_2.

Cropland management practices impact the amount of carbon stored in soils. Depending on the practice, soil carbon may increase as a result of biomass input or as a result of reductions in the rate at which organic matter is lost. Precision agriculture already is broadly adopted by crop producers in the United States; such agriculture uses a portfolio of practices that minimize crop inputs (e.g., fertilizers and pesticides) and negative environmental impacts (e.g., topsoil degradation) while maximizing yield. Private- and public-sector organizations actively promote these approaches to crop production due to their potential environmental benefits, such as topsoil preservation. Management practices that optimize crop production for yield and other environmental benefits may also optimize carbon sequestration. Most of these approaches could be adapted and refined to customize a carbon-sequestration management plan to maximize the total potential of agricultural sinks.

A primary example of new crop management approaches that can yield environmental co-benefits centers on soil tillage, turning soils over with a moldboard plow and mixing soils with a disc plow prior to replanting crops such as corn and soybeans. These practices not only prepare soil for replanting but also inhibit weed and insect infestations during the following growing season. However, soils containing organic material that would otherwise be protected by vegetative cover are exposed through conventional tillage and become susceptible to decomposition. Frequent or intense tillage breaks down soil macroaggregates, thereby enhancing the exposure of carbon to microbial activity. This added soil exposure also enhances decomposition by raising the soil temper-

29 Ibid.
30 Harmon et al., 1990.
31 Skog & Nicholson, 2000.

ature. As a result, croplands often emit CO_2 directly to the atmosphere. In addition, these techniques also involve intensive use of fossil fuels in the operation of farm equipment, adding to the overall GHG emissions of agriculture.

Conservation tillage is different. This approach includes no-till, ridge-till and minimum-till techniques, and can maintain at least 30 percent of crop residue on the soil surface as protection against erosion. As a result, the soil carbon pool is maintained and enhanced. In addition, adoption of no-till reduces use of fossil fuel required for plowing fields, thereby potentially reducing production costs. To address the challenges of crop pests normally managed through conventional tillage, growers will often adopt new pesticide application practices. Some large agribusiness companies market a portfolio of products, such as herbicides designed to be used in combination with herbicide-tolerant transgenic crops, on the basis of conserving soil, improving profitability and reducing GHG emissions.[32] While the environmental benefits of adopting new crop-production technologies and practices are potentially broad, caution must be used to avoid overestimating their impact on GHG emissions. Following adoption of conservation tillage, soil carbon typically accumulates for 15 to 20 years and then returns to a steady state, with few additional sequestration gains.[33] The theoretical upper limit of carbon sequestration on all agricultural lands in the United States is roughly 0.059 Pg (1 petagram=10^{12} Kg) of carbon per year; reaching this upper limit would require 100 percent conversion (from approximately 30 percent in 2005) of U.S. farmland to no-till agriculture or related approaches and would offset 3 percent to 4 percent of total U.S. fossil fuel emissions.[34]

Other opportunities in agriculture may also be considered as components to a broader biological sequestration program. Grassland conversion refers to converting existing cropland to grasslands or pasture. Because grassland has a continuous vegetative cover, the retention of soil carbon is higher than for conventionally tilled cropland. Depending on the new land cover of these retired lands, they can become a carbon sink. Lands are already retired through federal programs such as the U.S. Department of Agriculture's Conservation Reserve Program , which typically pays growers to plant grasses and other perennial plants instead of row crops.[35] Depending on a variety of environmental factors, grassland conversion may be preferable to afforestation. While expanding grassland area can enhance carbon storage, further sequestration may be possible from improving the way grasslands are used for livestock grazing. Sequestration can be enhanced by increasing the quantity and quality of forages on pastures and native rangelands and by reducing carbon losses through the degradation process, thereby retaining higher soil carbon stocks.[36] The range of mitigation estimates for grazing practices is wide, and the applicability of these numbers to the United States is a topic of ongoing research. Grazing management practices can have multiple GHG co-benefit effects. For instance, the quality of forage can affect livestock digestion processes and the amount of the greenhouse gas methane that livestock emit through enteric fermentation.

Riparian Buffers and Wetlands Management

Riparian buffers are coarse vegetative land cover (e.g., trees, brush, grasses, or some mixture) on land near rivers, streams and other water bodies. Riparian buffers can be an example of afforestation, forest management or grassland conversion, and therefore they fall under both forestry and agriculture. As in previous examples of afforestation, the overall potential for mitigating GHG emissions through riparian buffers is low, relative to other biological sequestration options. However, like mine lands and urban afforestation, environmental co-benefits may be considerable. The EPA reported in 2005 that "water quality co-benefits make protecting or establishing new riparian buffers an appealing option when considering biological sequestration options."[37] Riparian buffers

32 Monsanto Company, 2006.
33 U.S. Environmental Protection Agency, 2005.
34 Jackson & Schlesinger, 2004.
35 Ibid.
36 Intergovernmental Panel on Climate Change, 2000.
37 U.S. Environmental Protection Agency, 2005.

also filter the runoff of sediment, nutrients, chemicals and other compounds associated with development or cultivation that adversely affect water quality. Existing riparian buffers may be left intact during timber harvests as a matter of federal, state or local regulation. Riparian buffers sequester CO_2 in the soil as a result of organic material accumulation and in vegetative biomass. Establishment of a new riparian buffers can also reduces base-line GHG emissions from agriculture if the total cultivated area declines. In 1997, a total of 81,000 hectares of field borders and filter strips were in place on cropland, along with a total of 650,000 hectares of grassed waterways.[38]

Wetlands (including bogs and peat lands) cover about 2.8 billion hectares (7 percent) of the world's land surface, and approximately 43.6 million hectares (5.5 percent) of the continental United States is wetlands.[39], [40] Although wetland soil carbon dynamics are not well characterized, recent studies have shown that globally, wetland soils contain approximately 498 Pg of carbon, or about one-third of the total carbon present in soil.[41] The global rate of carbon sequestration has been estimated to be 210 ± 20 g C/m^2/year.[42] Wetlands store carbon in their standing vegetation, debris, peats and other soils, and they can act as a carbon sink for much longer periods than can non-wetland soils.[43] Long-term carbon storage is restricted in terrestrial soil due to quick decomposition and rerelease of carbon into the atmosphere, whereas the reversibility of carbon in wetlands is much slower due to their highly saturated nature.[44]

Studies have shown that variation exists in the carbon uptake, storage and release in various types of wetlands worldwide. Lagoons sequester the most carbon, followed by intertidal environments, salt marshes, freshwater marshes and aeolian environments.[45] Variability in carbon storage has been found within a single wetland as well. Scientists studying a coastal wetland in north Florida reported finding short-term carbon accumulation rates of 42 to 193 g C/m^2/year in low marsh areas, 18 to 184 g C/m^2/year in middle marsh areas and -50 to 181 g C/m^2/year in high marsh areas.[46] This study also showed that long-term carbon sequestration varies over time, from approximately 130 ± 9 g C/m^2/year during the past century to approximately 13 ± 2 g C/m^2/year during the past millennium.[47] Another study, of a southern California coastal lagoon-wetland complex, found a mean rate of carbon accumulation of 33 ± 2.9 g C/m^2/year over 5,000 years.[48]

Coastal wetlands have been shown to have a higher net sequestration of greenhouse gases when compared to freshwater wetlands, which release larger amounts of methane and nitrogen dioxide.[49], [50] Because 95 percent of U.S. wetlands are freshwater, additional studies are needed to determine potential for carbon sequestration and its effects on additional GHG concentrations in the atmosphere.[51] As with riparian buffers, establishment and protection of wetlands offers significant potential for other environmental co-benefits aside from carbon sequestration.

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38 Uri, 1997.
39 U.S. Climate Change Technology Program, 2005.
40 Dahl, 2006.
41 Choi & Wang, 2004.
42 Chmura et al., 2003.
43 Kusler, 1999.
44 Ibid.
45 Brevik & Homburg, 2004.
46 Choi & Wang, 2004.
47 Ibid.
48 Brevik & Homburg, 2004.
49 Choi & Wang, 2004.
50 Brevik & Homburg, 2004.
51 Dahl, 2006.

EPA REPORT 430-R-05-006: *GREENHOUSE GAS MITIGATION POTENTIAL IN U.S. FORESTRY AND AGRICULTURE,* NOVEMBER, 2005

In 2005, the EPA reported the potential for additional carbon sequestration and GHG reductions in U.S. forestry and agriculture over the next several decades.[52] The agency evaluated considerations that are unique to biological sequestration and the impact of GHG price incentives; it also modeled and reported possible atmospheric GHG reductions as changes from base-line trends, starting in 2010 and projected out 100 years. The report employed the Forest and Agriculture Sector Optimization Model with Greenhouse Gases.[53] Some of the report's key observations and conclusions are summarized in the sections below. Readers are encouraged to review the report itself for more information.

Unique Considerations for Biological Sequestration

Biological carbon sequestration raises unique issues that are critical for technical analyses, policy formation and resource management when evaluating GHG mitigation potential.[54] The degree of uncertainty surrounding these issues underscores the importance of the report's consideration of biologically sequestered carbon as a practical strategy for mitigating CO_2 emissions.

Time Dynamics

Comprehensive GHG accounting of biological sequestration requires the inclusion of both sequestration and release of CO_2. This tracking needs to occur over long time frames and to cover both normal land-use and management practices and mitigation activities. Three fundamental factors need to be considered: "the slowdown or saturation (or approach to equilibrium) of sequestration rates, the potential for reversal of carbon benefits if sequestered carbon is re-released into the atmosphere at some future point in time, and the fate of carbon in long-lived products after the time of harvest."[55] These issues are addressed briefly below.

Saturation

Sequestration projects result in a net accumulation of carbon once the rate of the ecosystem's carbon inputs exceeds the rate of its outputs. Over time, carbon reaches saturation levels in vegetative biomass and soils. This impacts biological sequestration potential, as carbon recycles back to the atmosphere and new equilibriums are achieved as a result of saturation. Biophysical factors constrain the amount of carbon that can be sequestered in agricultural soils and forest ecosystems. However, biophysical processes evolve over time until the rate of carbon output equals the rate of carbon input. The time frame over which this occurs varies among practices, from 15 years with reduced tillage on croplands to over 120 years for afforestation and reforestation.[56] Mechanisms that control ecosystem carbon balance are the subjects of ongoing research; the long-term ability of a plant ecosystem to store carbon may be constrained by other factors, such as soil nitrogen availability and microbial activity.[57] Because saturation rates vary across carbon pools, activities and land conditions, saturation has important implications for assessing biological sequestration projects. The maximum, cumulative carbon storage potential of land use alternatives is a critical factor for assessing climate change mitigation using terrestrial ecosystems.

Reversibility

Carbon stored in soils or wood may return to the atmosphere in a relatively short period as a result of human

52 U.S. Environmental Protection Agency, 2005.
53 Adams et al., 1996; Lee, 2002.
54 Jackson & Schlesinger, 2004.
55 U.S. Environmental Protection Agency, 2005. p2-9.
56 Ibid.
57 Gill et al., 2006.

and natural activities, such as harvesting, plowing, severe weather, fire or decomposition. Cultivation causes rapid decomposition of soil carbon with little benefit in net carbon sequestration.[58] The climate benefits of a carbon-sequestration program are therefore potentially reversible. This is sometimes referred to as the "permanence" or "duration" issue.

Fate

Carbon is immediately released to the atmosphere through such activities as forest logging or milling (about one-half to two-thirds is emitted at or near the time of harvest, depending on the product and region), but some carbon may be sequestered in wood products for years. The carbon that is removed from a terrestrial sink will appear in one of the following carbon pools at any time following the harvest:

- Products in use (short-lived for paper, long-lived for lumber).
- Landfill storage (often stored for extended periods).
- Atmospheric gases (released to the atmosphere through combustion, sometimes to produce energy, or through product decay).

Appropriate accounting for carbon after harvest is an important aspect of a viable biological sequestration strategy and policy.

Leakage

Some activities can shift to locations outside of a biological sequestration program that counteract its benefits. Direct GHG benefits of these efforts will be undercut by leakage of emissions outside the boundaries of the project.[59] Leakage is "the unanticipated decrease or increase in GHG benefits outside of the project's accounting boundary (the boundary defined for the purpose of estimating the project's net GHG impact) as a result of project activities."[60]

Leakage rates vary regionally and over time because of market responses and soil carbon dynamics. Most leakage due to targeted afforestation occurs within the first two decades. Leakage from individual activities in the agriculture sector appears to be small, from virtually none to perhaps 5 percent.[61]

ECONOMIC EVALUATION OF POTENTIAL OPTIONS

Federal policies that set "price signals" for GHGs can serve as a critical component of a successful mitigation strategy involving biological sinks. The EPA study evaluated various GHG price scenarios, both constant and increasing over time at different rates. The agency found, for example, that under a constant GHG price, national carbon mitigation rates rose substantially in the initial decades of a policy, but then declined over time, yet cumulative CO_2 mitigation steadily increased. The eventual declining rate of annual mitigation (i.e., occurring

58 Ibid.
59 U.S. Environmental Protection Agency, 2005.
60 Intergovernmental Panel on Climate Change, 2000.
61 U.S. Environmental Protection Agency, 2005.

in a given year) was the result of saturating carbon sequestration (to a new equilibrium) from the initial activity in forestry and agriculture and carbon losses after timber harvesting. Cumulative GHG mitigation (i.e., achieved in the years up to a given year) steadily increased. This cumulative amount reaches about 26,000 Tg CO_2 (7,080 Tg C) by 2055. On an annualized basis over 100 years, a relatively moderate carbon cost (\$15/t CO_2 Eq.) scenario generates 667 Tg CO_2/yr (182 Tg C) in GHG mitigation relative to business as usual, or almost 10 percent of current national GHG emissions levels. Modeling results also indicated that nearly 2,000 Tg CO_2 Eq. (or 2 billion tons) per year of mitigation potential exists at the highest-price scenario evaluated (\$50/ton CO_2 Eq.) if all private land, activities and GHGs are included. This would offset almost one-third of current U.S. GHG emissions.

The EPA study also found that under scenarios of rising GHG prices, forest and agriculture mitigation actions may be delayed. The primary reason for the effect was the "one-shot" nature of carbon sequestration activities. The economically optimal response under steadily rising carbon prices was to delay sequestration actions to take advantage of higher future prices.

The quantity and timing of targeted sequestration objectives may also be major factors to consider in determining selected activities. Modest mitigation quantities (less than 300 Tg CO_2 Eq. per year) may be achieved in the near term, with activities that primarily include agricultural soil carbon and forest management, at less than \$5/t CO_2 Eq. More ambitious levels require a different range of activities (e.g., afforestation) and require \$15 to \$30/t CO_2 Eq. and above. Long-term mitigation requires permanent reductions in CO_2 and non-CO_2 emissions from agricultural practices (achievable at a relatively low GHG price incentive).

Targeting a specific sequestration level over a short time frame may shift GHG emissions to periods before and after the period of interest. The EPA study tested scenarios in which an average annual mitigation quantity is set for 2025 (the midpoint of the decade 2020 to 2030), which is then either maintained, increased or dropped after that period.

An unintended consequence of a policy approach that sets a one-time target is that the absence of any fixed level for the first decade (2010 to 2020) means that GHG emissions could exceed base-line levels, as producers substitute current (unconstrained) emissions for future (constrained) emissions. This could be considered a form of temporal leakage. As the EPA report indicates, negative consequences such as leakage might be avoided if a cumulative mitigation quantity from a base year (e.g., 2010) onward is put in place instead of an annual quantity for the future period and if the target quantity is not dropped in the future.

The EPA report concluded that concerns with leakage in U.S.-based projects may be largely confined to the forest sector. If all GHG mitigation activities in forestry and agriculture are included in a comprehensive approach, leakage is projected as negligible in the United States, although some leakage is possible internationally (international leakage was not addressed in the EPA report). However, under some projected scenarios where some forest activities and regions are singled out as sequestration options, some of the benefits could be offset by emissions from other activities and regions. The primary driver of this leakage is the interaction between how much land is devoted to forests and the intensity with which forests are managed. The EPA report expressed both the concern and the solution: "If only afforestation is included as a mitigation activity, but not the management of existing forests, the latter could suffer at the expense of the former, leading to carbon losses from the decline in management. However, if both afforestation and forest management are given incentives, the results suggest that leakage practically disappears."[62]

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62 Ibid. p8-7, 8-8.

Agricultural activities do not appear to be as prone to leakage as forestry activities in the United States.[63] Leakage estimates for agricultural options were found to be less than 6 percent of the direct mitigation benefits. Leakage may be limited due to the fact that changes in agricultural practices do not have as profound an impact on agricultural commodity markets as forest activities do on timber markets.

The EPA study shows that raising GHG mitigation levels in forestry and agriculture can cause both positive and negative environmental co-effects. Major changes in land use and production can also have a substantial impact on non-GHG environmental outcomes in forestry and agriculture, primarily because of the role of agricultural soil carbon sequestration in the mitigation portfolio at a fairly low GHG price scenario. Even such a low GHG price can induce changes in tillage practices across a broad area of cropland. These practice changes also reduce erosion and nutrient runoff to waterways as a co-benefit but can lead to a modest increase in pesticide use as a negative effect.

Taking these environmental co-effects into consideration could affect the relative attractiveness of competing mitigation options. In general, a modest GHG mitigation action will probably have negligible effects on non-GHG outcomes within the sectors. However, the more aggressive the mitigation action, the more likely that co-effects may factor into the net benefits of GHG mitigation.

Payment methods could also determine efficiency of mitigation activities. The EPA study shows that paying on a per-ton CO_2 Eq. basis is more efficient than paying on a per-acre basis to generate additional GHG mitigation. Compared to the scenario paying for afforestation only (at \$15/t CO_2 Eq.), paying for afforestation on a uniform \$100-per-acre basis generates only 30 percent as much additional carbon but requires 60 percent as much in payments. Per-acre payments do not directly vary with the biophysical potential of the site. The inefficiency could be remedied somewhat by adjusting per-acre payments based on land productivity.

The EPA report suggests that if outreach is needed to deliver GHG mitigation, these efforts might best focus in regions with the largest mitigation potential. The study shows that regional distribution of mitigation opportunities may be skewed toward the eastern United States. Federal and other public lands were not included in the analysis, however, "thereby ignoring mitigation potential on those lands."[64] The report suggests that public lands management, if included, would elevate the role of the western United States in a national strategy. The report also states that on the remaining private lands, the regional distribution varies with the level of mitigation sought. According to the report: "At low levels of mitigation and prices, the two South regions (South-Central and Southeast), via forest management, and two Midwest regions (Corn Belt and Lake States), via agricultural soil carbon sequestration, are the focal regions and activities. As prices rise and mitigation levels expand, farmers in the South and Midwest may participate by planting trees on agricultural land. If GHG incentives are strong enough to induce biofuel production, owner participation could expand beyond the Midwest and South to include the Northeast region."[65] Overall, the report concludes that carbon policies and prices are projected to reduce net emissions from the forest and agriculture sectors below baseline levels.

CONCLUSIONS

Terrestrial biological sequestration of carbon will likely play a role as one aspect of a multifaceted strategy to reduce net carbon emissions. Socolow and Pacala estimate that if phased in globally over the next 50 years, expanding conservation tillage to 100 percent of all cropland and stopping deforestation would prevent the

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63 Ibid.

64 Ibid. p8-9.

65 Ibid. p8-9.

release of 50 billion tons of carbon to the atmosphere.[66] Their study, however, does not assess whether this is an economically realistic outcome.

Increased carbon storage rates are typically maintained in agricultural soils for only 10 to 20 years after a tillage intervention, so such benefits could be short-lived. Moreover, some observers maintain that impractically large land areas will be required to have a significant and sustained effect. Converting large areas of cropland to forests or biofuel production—or retiring them completely—could decrease food production and agricultural exports and increase food prices. Possible co-benefits of carbon sequestration as a mitigation strategy include reduced soil erosion and agricultural fertilizer runoff and increased biodiversity. However, some mitigation options may carry environmental costs as well, including negative effects on water availability and quality and increased pesticide loading. Evaluating and quantifying both positive and negative environmental co-effects is essential to formalizing sound policies and programs to encourage biological sequestration of CO_2.

Establishing an incentive program based on appropriate GHG pricing will also be key to a successful biological sequestration program. A recent EPA economic study concluded that GHG reduction incentives can generate substantial mitigation from U.S. forestry and agriculture in the first few decades after policy implementation. It demonstrated that with rising GHG prices, mitigation starts low and increases over time.

An important conclusion of the 2005 EPA report summarized here was that the magnitude, timing and scope of biological sequestration programs will impact benefits and costs of an incentive program. As higher levels of mitigation are targeted, the portfolio of options expands, as does the cost of mitigation. The report further concludes that "sequestration can generate substantial mitigation in the near to middle term (1 to 3 decades) but can decline after that because of biophysical saturation and practice reversal."[67] The approaches that offer the largest potential for biological sequestration may be reduced via criteria that narrow the activities, GHGs and time frames considered. Selected projects could range from "all activities in forestry and agriculture that have some measurable GHG impact to a select few activities or GHGs that are targeted for their cost-effectiveness, desirable co-effects, or ease of monitoring."[68]

Appropriate structure of a biological sequestration project is essential to achieve objectives of any sequestration program. Critical issues for further analysis and consideration include the basis for carbon payments—that is, whether payments are based on a per-ton of CO_2 equivalent or on per-acre basis. The EPA report states that although the latter is less costly to measure, monitor and verify, the former tends to be more efficient. The report further states that project quantification should reflect net mitigation over time and that "adjustments may be necessary to capture base-line emission or sequestration levels that would have occurred without the project, GHG effects induced outside the project boundaries (leakage), and future carbon reversal likely to occur after a project ends." As well, mitigation actions may produce environmental co-effects that could influence the desirability of GHG mitigation strategies. Whenever possible, these environmental co-effects should be quantified and evaluated to determine their impact on the attractiveness of certain mitigation options.

Finally, the EPA and many other stakeholders believe that standardized and widely available measurement, monitoring and verification guidelines and methods may help landowners overcome implementation barriers and facilitate participation in biological sequestration programs. Private firms are undertaking new commercial opportunities to aggregate GHG credits as a financial service for the agriculture and forestry sectors, and in doing so they may help to establish the infrastructure necessary for successful implementation of biological carbon sequestration programs.

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66 Socolow & Pacala, 2006.

67 U.S. Environmental Protection Agency, 2005. p8-1.

68 Ibid.

Geologic Carbon Sequestration

CO_2 can be captured from fossil fuel combustion at point sources and stored in underground geologic reservoirs, resulting in direct reduction in release to the atmosphere. Successful sequestration of CO_2 in geologic reservoirs requires several key process steps in order to be technically feasible and cost-effective: CO_2 capture, concentration, transportation, injection and storage.

CO_2 CAPTURE AND CONCENTRATION

Coal combustion results in effluent flue gas released at atmospheric pressure containing 10 percent to 15 percent CO_2 by volume.[69] In order for CO_2 to be stored in geologic formations, it must be separated from the other flue gas constituents, purified to remove trace contaminants and compressed from atmospheric pressure to pipeline pressure (100 atmospheres). This energy-intensive process requires the installation of new technologically advanced scrubbers, membranes and compressors.[70]

Integrated gasification combined cycle offers the most optimal coal-based process for capturing and concentrating CO_2 for geological sequestration (see Chapter 2: Electricity Supply). The CO_2 from the syngas produced during IGCC can be separated using absorption or membrane methods, at an efficiency of 95 percent.[71] The hydrogen produced through the precombustion capture method is then burned in a combustion turbine to produce steam, resulting in additional electrical power generation.[72] Carbon capture technology for conventional pulverized coal facilities—oxyfuel and postcombustion—is being developed, though it is expected to be more expensive than capture from IGCC facilities.[73]

The installation and operation of carbon-capture systems could comprise as much as 75 percent of the total cost of carbon capture, compression, transportation and injection in geologic sinks (depending on distance between source and sink, as well as other factors). Because carbon capture requires power drawn directly from the electricity generator, capturing CO_2 from a flue gas stream also imposes an energy penalty of approximately 14 percent of total plant energy consumption in an IGCC plant. A plant with carbon capture is effectively derated in capacity, producing less generation. While a plant outfitted with carbon capture produces more CO_2 than a plant without carbon capture, it releases far less CO_2 to the atmosphere when the CO_2 is properly stored in a geologic reservoir.

CO_2 STORAGE IN GEOLOGIC RESERVOIRS

The identification of potential geologic carbon storage locations necessitates an in-depth analysis of regional characteristics. Extensive geophysical exploration is necessary to determine the approximate volume of a sink, as well as any potential weaknesses in the structural integrity of the formation. Prior to full-scale injection of CO_2 into a reservoir, a test well is drilled and pilot testing performed, during which CO_2 is injected and tracked as it moves throughout the subsurface.[74]

Suitable rock formations for geological sequestration are typically hundreds of meters below the land surface, a factor that requires CO_2 to be at or above pipeline pressure during injection. The specific injection pressure required is a function of depth to the target formation, the quantity of CO_2 to be stored and the volume and physi-

69 C. Angelelli, personal communication, 2006, with T. Beard, K Carey, N Greenglass, K Herrmann, J Sabrusala, M Semcer.
70 Dalton, 2004; Gibbins & Crane, 2004; Heddle et al., 2003; Herzog, 1999.
71 Newell & Anderson, 2004.
72 W. Rosenberg, personal communication, 2006, with R. Lotstein.
73 Herzog, 1999; Newell & Anderson, 2004; Sekar, 2005; U.S. Department of Energy, 2006.
74 Intergovernmental Panel on Climate Change, 2005; Smith et al., 2002.

cal properties of the geologic sink.[75] Additional compressors and pumps are required at the site if the injection pressure must be greater than 100 atmospheres.

There are currently three viable targets for CO_2 storage in geologic formations: depleted or diminishing oil and gas reservoirs, unmineable coal seams and saline aquifers.

Depleted or Diminishing Oil and Gas Reservoirs

The extraction of oil and natural gas from reservoir rocks leaves empty pore space in the reservoir formation; injected supercritical CO_2 fills the space and remains sequestered within the reservoir rock.[76] In a partially depleted reservoir, some of the original fossil fuel resources remain in the rock, inaccessible by standard extraction techniques. CO_2 injected into these pore spaces increases pressure and reduces viscosity of the fossil fuels, forcing the remaining oil (or gas) out and to the surface.[77] CO_2 in the pore spaces of the reservoir rock remains sequestered as long as its pressure does not exceed that of the original formation and its contents. The pressure required to maintain CO_2 in its stable supercritical phase necessitates use of storage reservoirs at least 800 meters below the surface injection point.[78] Carbon dioxide stored in this manner potentially remains sequestered from the atmosphere for thousands of years. However, concerns exist regarding possible leakage of CO_2 from capped wells due to well failures or undetected fractures.[79]

Unmineable Coal Seams

Unmineable coal seams in the United States may also provide geologic reservoirs for CO_2 and provide opportunity for cost-effective recovery of coal-bed methane. According to the U.S. Geological Survey, the majority of coal seams nationwide are unmineable; seams deeper than 800 meters cannot be reached with current mining techniques.[80]

Normally, methane gas is adsorbed onto coal. Under the pressure and temperature conditions present at 800 meters or below, injected CO_2 will readily adsorb onto the surface of coal molecules, displacing the methane gas and forcing it toward the surface. Methane may then be captured and collected at the surface. Since this is a relatively new technology, further work is needed to determine the physical and geochemical reactions that lead to the sequestration of CO_2 and what factors may result in leakage. Given the high global warming potential of methane, benefits of CO_2 storage may be quickly outweighed by the risks associated with methane leakage into the atmosphere.

Saline Aquifers

Supercritical carbon dioxide can be sequestered in deep saline aquifers at least 800 meters below the land surface via three physical and chemical reactions between the CO_2 and formation waters: displacement of formation waters, molecular and convective diffusion, and chemical reactions between CO_2, formation waters and the host rock mineralogy.[81]

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75 Smith et al., 2002; Stevens et al., 2001.
76 Hovorka et al., 2006.
77 Newell & Anderson, 2004; Stevens et al., 2001.
78 Brennan & Burruss, 2003; Intergovernmental Panel on Climate Change, 2005.
79 Newell & Anderson, 2004; Nordbotten et al., 2005.
80 Friedmann, 2003; Intergovernmental Panel on Climate Change, 2005.
81 Kaszuba et al., 2003.

On injection, supercritical CO_2 displaces formation waters. Almost immediately, a very small fraction of the CO_2 dissolves into the surrounding brine, resulting in solubility trapping of CO_2 within the aquifer. Diffusion of CO_2 through the formation water proceeds on a molecular level in a process that can take thousands to tens of thousands of years to completely distribute CO_2 throughout an aquifer.

Mixing occurs due to the density difference between aquifer waters containing dissolved CO_2 and waters not containing CO_2. This mixing occurs orders of magnitude faster than pure molecular diffusion of CO_2 and continues until the dissolved CO_2 reaches equilibrium with respect to formation waters. Once dissolved in brine, CO_2 may remain sequestered in a deep aquifer for thousands of years under constant temperature and pressure conditions.[82]

In addition, mineral reactions between dissolved CO_2 and the formation waters or the host rock mineralogy also sequester carbon within saline aquifers in processes known collectively as mineral trapping. The reaction of CO_2 with dissolved constituents within saline water may result in the precipitation of carbonate minerals stable on geologic time scales.[83]

GEOLOGIC SEQUESTRATION POTENTIAL IN THE UNITED STATES

The United States contains abundant resources for geologic sequestration of CO_2. Proximity of these storage sites relative to existing and proposed coals plants is a key consideration for technical and economic feasibility; many existing and proposed coal plants are located near appropriate geologic reservoirs.

The Appalachian Basin and Gulf Coast regions contain robust geologic reservoirs capable of storing CO_2. The Gulf Coast region is an attractive site for sequestration because of the magnitude of potential geologic storage capacity, the existing knowledge of regional geology and the technological infrastructure already in place from the petroleum and natural gas industries. Numerous depleted oil and gas reservoirs provide a known storage capacity for 2,500 MMT of CO_2. Enhanced oil recovery in some areas is expected to add another 15 percent in storage capacity and can provide oil revenue to offset some costs associated with capture and storage. Further, deep saline aquifers in the Gulf Coast region can provide additional, even larger geologic storage.[84]

The Midwest Regional Carbon Sequestration Partnership is preparing detailed estimates for storage capacity in the Appalachian Basin. Unmineable coal beds and depleted oil and gas reservoirs in this region are estimated to contain 25,000 MMT of CO_2 and 2,000 MMT of CO_2 storage capacity, respectively.[85] Extensive deep saline aquifers in this region may contain up to 500,000 MMT of CO_2 storage capacity.[86] However, concerns remain regarding groundwater contamination by CO_2.[87]

The western United States also has abundant yet unmeasured capacity for sequestering CO_2 in coal basins, saline aquifers and oil and natural gas fields. A report by the Advanced Coal Task Force of the Western Governors' Association identified the location of emission point sources relative to potential sequestration sites as a critical success factor, due to the high cost of transportation ($25,000 to $30,000/inch of pipe diameter per mile).[88] The report's recommendations call for new generation plants to be sited as close as possible to potential sinks. Many potential sinks have been identified throughout the region, but pilot-scale tests of geologic sequestra-

82 Ennis-King & Paterson, 2003; Xu et al., 2006.
83 Brennan & Burruss, 2003; Xu et al., 2006.
84 Ambrose et al., 2005.
85 Midwest Regional Carbon Sequestration Partnership, 2005.
86 Ibid.
87 Beecy & Kuuskraa, 2001.
88 Western Governor's Association, 2005.

tion and dedicated assessments of statewide storage capacity are still needed. Pilot-scale sequestration tests are proposed that would range between 1,000 tons and 500,000 tons of CO_2 per year. Projects above 500,000 tons would be considered industrial scale. State-centered surveys of the CO_2 storage potential are still needed to assess total capacity for CO_2 injection, delineate areas of low and high risk and provide inputs into economic characterizations of storage.[89]

Detailed regional analysis of potential geological sinks is vital for developing a cost-effective strategy. As an example, Duke University evaluated the potential for geologic storage in North Carolina to assess the viability of capturing and sequestering carbon from new coal generation in the state. The study concluded that North Carolina's geology is poorly suited for geologic carbon storage. Its eastern geomorphic province, the Coastal Plain, holds the only true potential. In this region, only one saline aquifer, located in the Lower Potomac area, was deemed appropriate for geologic carbon storage based on minimum acceptable depth of the aquifer.[90]

This geologic sink contains 29.91 MMT of CO_2 storage capacity, enough for three years of captured CO_2 emissions from a hypothetical 1,600 MW IGCC plant. Transportation of CO_2 to a viable geologic sink in North Carolina would be a sizeable investment, ranging from \$0.5 to more than \$1.0 billion (see "CO_2 Transportation and Cost," below). Infrastructure to transport and sequester CO_2 from one generating facility for three years would clearly not be a sound investment for either the private or public sectors.

CO_2 TRANSPORTATION AND COST

Carbon dioxide captured in its gaseous form at ambient pressure must be compressed to pipeline pressure (100 atmospheres) before transportation and storage.[91] At pressures above 73 atmospheres and temperatures above 31.1 degrees C, CO_2 exceeds its critical point and enters the supercritical phase, a homogenous state that has properties midway between those of a gas and liquid.[92] These physical properties enable CO_2 shipment by rail, ship or truck, but the lowest-cost option is transport by pipeline; 3,000 miles of commercial CO_2 pipeline for enhanced oil recovery operate in the United States today.[93]

Unique engineering and safety considerations for CO_2 piping projects include:

- CO_2 must be completely dehydrated to prevent carbonic acid formation and degradation of the pipeline.
- Supercritical CO_2 physical and chemical properties necessitate the use of specific materials and sealants.
- Since CO_2 is denser than air, a large accidental release may become trapped at ground level, presenting a suffocation hazard to humans and other animals.

Despite these challenges, industrial system failures and resulting adverse environmental or health effects are reportedly rare. Cost-effective system management and risk mitigation measures are therefore possible not only for existing U.S. CO_2 pipelines, but for new infrastructure as well.[94]

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89 Ibid.
90 Hovorka et al., 2006.
91 Newell & Anderson, 2004.
92 Bachu, 2000; Kaszuba et al., 2003.
93 Dooley et al., 2006.
94 Kinder Morgan, 2006; Newell & Anderson, 2004.

The cost of constructing a dedicated CO_2 pipeline depends on the pipeline's length and diameter, the cost of obtaining the right of way on which it is constructed and the type of terrain through which it travels.[95] The diameter of pipeline required is proportional to the maximum flow rate of CO_2 emitted at the source. Diameter is a major determinant of pipeline cost and is determined by the flow rate required to transport the gas over a given distance at a minimum required pressure (Figure 3-3). Adequate pressure maintained along the pipeline ensures delivery of the gas at a pressure suitable for injection.[96] Base-case assumptions for cost per mile based on pipeline diameter are illustrated in Table 3-1.[97]

Figure 3-3: Relationship between CO_2 and flow rate and pipeline diameter[98]

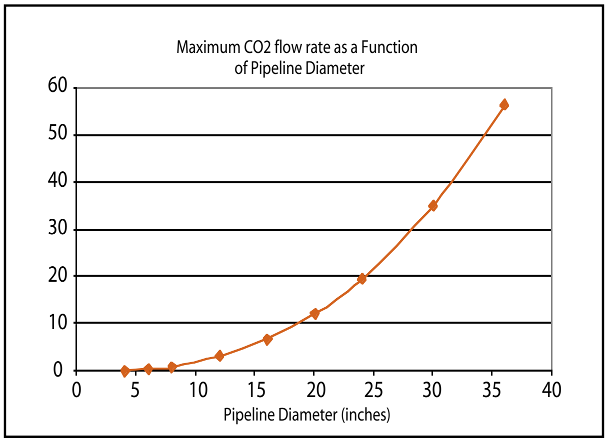

Table 3-1: Base-case pipeline costs

Table 2: Pipeline Costs per Mile	
Pipeline Diameter (in)	Cost ($/mile)
16	704,000
20	910,000
24	1,104,000
30	1,305,000
36	1,584,000

Capital costs associated with pipeline construction would be unique to each scenario, based on the least-cost path determined by a geographical information systems (GIS) analysis. Cost multipliers for various geographic features can be used in GIS analysis to determine the least-cost route, as illustrated in Table 3-2.

Table 3-2: Example pipeline cost multipliers[99]

Pipeline Crossings	
Construction Condition	Cost Factor
Base Case	1
Populated Area	15
Wetland	15
Waterway Crossing	10
Railroad Crossing	3
Highway Crossing	3

Generally, of the total upfront costs, right-of-way costs comprise approximately 5 percent to 10 percent, miscellaneous costs account for 20 percent, labor expenses account for 45 percent to 50 percent and materials comprise approximately 25 percent.[100] In addition to estimating pipeline costs, CO_2 storage costs can also be estimated.[101] Key factors for consideration include the number of tons of CO_2 to be sequestered per day, the

95 R. W. Beck Inc, 2003.
96 Bock et al., 2003 ; Smith et al., 2002.
97 Greenglass, 2006.
98 Ibid.
99 Ibid.
100 R. W. Beck Inc, 2003.
101 Bock et al., 2003

type of reservoir (e.g., saline aquifer, depleted oil well) and the number of wells required. The number of wells determines the cost of injection equipment, well drilling, and operations and maintenance. Well drilling and subsurface maintenance costs are a function of well depth. Site evaluation also adds additional cost, but at a small percentage relative to total project cost.

The case study of North Carolina described above illustrates how these factors can be used to determine whether a project is economically feasible or unrealistic. Given the potential carbon-storage capacity in other regions, such as the Appalachian Basin and the Gulf Basin, a viable strategy for North Carolina may involve constructing a dedicated pipeline for transporting CO_2 captured from multisite electricity generation to viable geologic sinks. This approach takes advantage of cost reductions by pooling transportation and storage from a greater number of generation facilities, as well as production of offsetting revenues from enhanced recovery of oil or coal-bed methane.

Electricity-generating utilities sharing a common pipeline for CO_2 transport could divide cost among participants. A national pipeline to viable geologic sinks could be linked with regional power generation in North Carolina, as well as other states in the region, along the Texas Eastern and East Tennessee pipelines.[102] The Texas Eastern pipeline runs 9,040 miles from the Appalachian Basin to the Western Gulf Coast Basin. The Texas Eastern pipeline intersects the East Tennessee pipeline in Tennessee. A second CO_2 pipeline could be constructed along the East Tennessee right of way in order to connect North Carolina's utilities to the Texas Eastern pipeline, which would allow CO_2 to be piped to either of the targeted sequestration regions. A 1,730 mile segment of the Texas Eastern right of way would be sufficient for CO_2 transport to both the Appalachian Basin and the West Gulf Coast region, while a 523 mile length of the East Tennessee right of way could be built to connect the North Carolina pipelines to the Texas Eastern. The Duke University analysis suggests that the cost of constructing and operating these pipelines would be a small part of the entire cost of an IGCC equipped with a carbon capture and storage system.

STATUS OF WORLDWIDE GEOLOGIC SEQUESTRATION PROJECTS

Table 3-3, from the 2005 IPCC Special Report on Carbon Dioxide Capture and Storage, outlines existing and planned worldwide projects in geologic storage of CO_2.[103] Highlights include:

- Since 1996, the Sleipner project in Norway has successfully injected 7 million tons of CO_2 1,000 meters deep into the Utsira formation, a saline aquifer beneath the North Sea.[104] The CO_2 comes directly from the Norwegian oil and gas company Statoil's Sleipner West natural gas production facility. About 1 million tons of CO_2 are injected annually into the aquifer, which has an estimated capacity of more than 600 billion tons of CO_2.[105]

- Initiated in 2001, the Weyburn enhanced oil recovery project in Saskatchewan, Canada, is the longest running program in North America. The project has successfully sequestered 5 million tons of CO_2, with a projected maximum capacity of up to 30 million tons of CO_2.[106] As of fall 2005, there had been no indication of CO_2 leakage to the surface and near-surface environment.[107]

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102 Ibid.
103 Intergovernmental Panel on Climate Change, 2005.
104 Ibid.
105 Bartlett, 2003.
106 U.S. Department of Energy, 2005b.
107 White, 2005; Strutt et al., 2003, as referenced in Intergovernmental Panel on Climate Change, 2005.

- The In Salah project in Algeria has been injecting up to 1.2 million tons of CO_2 per year since 2004. The CO_2 is stored in a sandstone reservoir 1,800 meters deep. Over the life of the project, up to 17 million tons of CO_2 could be stored in the reservoir.[108]

Table 3-3: Selected current and planned geological storage projects[109]

Project	Country	Scale of Project	Lead Organizations	Injection start date	Approximate average daily injection rate	Total storage	Storage type	Geological storage formation	Age of formation	Lithology	Monitoring
Sleipner	Norway	Commercial	Statoil, IEA	1996	3000 t day^{-1}	20 Mt planned	Aquifer	Utsira Formation	Tertiary	Sandstone	4D seismic plus gravity
Weyburn	Canada	Commercial	EnCana, IEA	May 2000	3-5000 t day^{-1}	20 Mt planned	CO_2-EOR	Midale Formation	Mississippian	Carbonate	Comprehensive
Minami-Nagoaka	Japan	Demo	Research Institute of Innovative Technology for the Earth	2002	Max 40 t day^{-1}	10,000 t planned	Aquifer (Sth. Nagoaka Gas Field)	Haizume Formation	Pleistocene	Sandstone	Crosswell seismic + well monitoring
Yubari	Japan	Demo	Japanese Ministry of Economy, Trade and Industry	2004	10 t day^{-1}	200 t Planned	CO_2-ECBM	Yubari Formation (Ishikari Coal Basin)	Tertiary	Coal	Comprehensive
In Salah	Algeria	Commercial	Sonatrach, BP, Statoil	2004	3-4000 t day^{-1}	17 Mt planned	Depleted hydrocarbon reservoirs	Krechba Formation	Carboniferous	Sandstone	Planned comprehensive
Frio	USA	Pilot	Bureau of Economic Geology of the University of Texas	4-13 Oct. 2004	Approx. 177 t day^{-1} for 9 days	1600t	Saline formation	Frio Formation	Tertiary	Brine-bearing sandstone-shale	Comprehensive
K12B	Netherlands	Demo	Gaz de France	2004	100-1000 t day^{-1} (2006+)	Approx. 8 Mt	EGR	Rotleigendes	Permian	Sandstone	Comprehensive
Fenn Big Valley	Canada	Pilot	Alberta Research Council	1998	50 t day^{-1}	200 t	CO_2-ECBM	Mannville Group	Cretaceous	Coal	P, T, flow
Recopol	Poland	Pilot	TNO-NITG (Netherlands)	2003	1 t day^{-1}	10 t	CO_2-ECBM	Silesian Basin	Carboniferous	Coal	
Qinshui Basin	China	Pilot	Alberta Research Council	2003	30 t day^{-1}	150 t	CO_2-ECBM	Shanxi Formation	Carboniferous-Permian	Coal	P, T, flow
Salt Creek	USA	Commercial	Anadarko	2004	5-6000 t day^{-1}	27 Mt	CO_2-EOR	Frontier	Cretaceous	Sandstone	Under development
Planned Projects (2005 onwards)											
Snøhvit	Norway	Decided Commercial	Statoil	2006	2000 t day^{-1}		Saline formation	Tubaen Formation	Lower Jurassic	Sandstone	Under development
Gorgon	Australia	Planned Commercial	Chevron	Planned 2009	Approx. 10,000 t day^{-1}		Saline formation	Dupuy Formation	Late Jurassic	Massive sandstone with shale seal	Under development
Ketzin	Germany	Demo	GFZ Potsdam	2006	100 t day^{-1}	60 kt	Saline formation	Stuttgart Formation	Triassic	Sandstone	Comprehensive
Otway	Australia	Pilot	CO2CRC	Planned late 2005	160 t day^{-1} for 2 years	0.1 Mt	Saline fm and depleted gas field	Waarre Formation	Cretaceous	Sandstone	Comprehensive
Teapot Dome	USA	Proposed Demo	RMOTC	Proposed 2006	170 t day^{-1} for 3 months	10 kt	Saline fm and CO_2-EOR	Tensleep and Red Peak Fm	Permian	Sandstone	Comprehensive

108 Intergovernmental Panel on Climate Change, 2005; National Energy Technology Laboratory, 2006a.
109 Intergovernmental Panel on Climate Change, 2005.

CONCLUSIONS

Future developments in power generation technology and carbon policy will likely lead to economic and technical viability of CO_2 capture, transport and storage in geological reservoirs. Technology, capacity, economics and infrastructure will likely evolve quickly once a regulatory framework and a price signal for carbon are firmly established.

In this light, carbon capture, transportation and storage in geologic reservoirs may become more economically cost-effective, especially when incorporated into strategies that involve new generation capacity using clean-coal technologies, such as IGCC. A viable immediate-term approach may be to use technology such as IGCC in the development of new generation capacity, and later add carbon capture with geologic storage when it becomes technologically and economically feasible.

Coupling new clean-coal technology with carbon capture and storage can substantially reduce CO_2 emissions from coal-powered generation, but at a higher cost. In a carbon constrained environment, this cost will be at least partly defrayed and possibly entirely offset depending on the level of a carbon price. As well, establishing a national infrastructure that allows utilities to pool resources will enhance the economic feasibility.

Using existing rights of way along natural gas pipelines makes this a particularly compelling option. Public utilities have vital experience in constructing and operating natural gas pipelines in the United States; this positions them to be technological leaders in the development of a pipeline infrastructure for geologic storage of CO_2.

Oceanic Carbon Sequestration

Oceans are the single largest reservoir of CO_2 on earth, and they provide long-term storage for more than 90 percent of all anthropogenic CO_2.[110] Current estimates for the uptake of CO_2 at the ocean's surface are 25 million tons per day.[111] Surface mixing and photosynthetic plankton in the near-surface waters are the primary agents of ocean-based carbon sequestration. One study estimates that 10,000 Gt of CO_2 could be stored for millions of years within the 200-mile economic zone of the U.S. coast.[112]

Accelerating ocean carbon sequestration processes to mitigate atmospheric CO_2 concentrations has been investigated for over 20 years.[113] The two most commonly studied methods are enhanced phytoplankton productivity achieved through ocean fertilization and direct injection of CO_2 liquid into the ocean. Proposals to use ocean sequestration for GHG mitigation have met strong opposition due to uncertainty surrounding possible environmental impacts (e.g., acidification), technical feasibility and economic factors.[114] However, direct CO_2 injection beneath the ocean floor is a strategy that may provide an almost unlimited storage potential while minimizing environmental risks to the ocean ecosystems. In November 2006, the International Maritime Organization announced support and approval for CO_2 to be buried under the sea floor in geologic reservoirs, with appropriate site assessments and regulatory oversight mechanisms.

PHYTOPLANKTON FERTILIZATION

Phytoplankton comprise less than 1 percent of biomass on earth but are responsible for almost 50 percent of all carbon sequestration.[115] Productive phytoplankton communities require sunlight and the proper balance of available nutrients. The need for sunlight limits them to the photic zone, within 100 meters of ocean's surface. Atmospheric CO_2 mixes into surface waters and is fixed during the photosynthetic process, effectively reducing the atmospheric CO_2 concentration. The "residence time" of CO_2 in the ocean varies from 200 to 2,000 years depending on how deeply the CO_2 is transported.[116] Millennia-scale CO_2 storage requires carbon to be transported below depths of 1,000 meters. The natural process of carbon transport to deep-ocean storage occurs through large-scale mixing and sinking fecal material and detritus. In the deep ocean, CO_2 will either be deposited as sediment or dissolved into the water where it will reside for centuries to millennia.[117]

Phytoplankton fertilization, also referred to as iron fertilization, supplies additional iron to high nutrient-low chlorophyll regions of the world's oceans. Excess nitrogen and phosphorous are found in the subarctic northeast Pacific, the equatorial Pacific and the Southern Oceans. In small-scale (roughly 100 square kilometer) experiments, researchers demonstrated that adding iron to these waters allowed phytoplankton to use the nitrogen and phosphorus present in the water, which increased phytoplankton primary productivity and biomass.[118] Models from similar studies predict that if all available nitrogen and phosphorus were incorporated with CO_2 from the atmosphere into organic compounds, the anthropogenic carbon present in the atmosphere could bedecreased by 15 percent[119] (98

110 Dewey & Stegen, 2001.
111 Brewer et al., 1999.
112 House et al., 2006.
113 Dewey & Stegen, 2001.
114 Chisholm et al., 2001.
115 Ibid.
116 R. T. Barber, personal communication, 2006, with R. Lotstein
117 Dewey & Stegen, 2001.
118 Martin et al., 1994.
119 Chisholm et al., 2001.

to 181 Gt C) in the first 100 years.[120] Despite these promising results and encouraging model predictions, experiments did not document any net transfer of atmospheric CO_2 to the deep ocean.[121]

Carbon sequestration through phytoplankton fertilization is therefore deemed to be only a concept at the present time. Many aspects of iron fertilization still need to be studied in oceans (based on effects of nutrient enrichment in freshwater bodies). Such studies would include modeling leftover nitrogen and phosphorus, the changes that would occur in the phytoplankton population and the effects on the ocean's food web. Some models indicate that industrial-scale ocean fertilization could lead to deep ocean hypoxia or anoxia[122] producing greenhouse gases methane and nitrous oxide, both of which hold higher warming potentials than CO_2.[123]

The U.S. Climate Change Technology Program has been collecting data from the Southern Ocean Iron Fertilization Experiment (SOFEX), in an effort to determine whether or not iron fertilization results in a vertical flux of carbon, assess possible environmental effects and address other research questions.[124] The Department of Energy states that the magnitude and vertical depth of carbon sequestration caused by adding iron to high nutrient-low chlorophyll ocean waters is unknown. More research is planned to determine possible amounts of carbon that could be sequestered as well as potential ecosystem impacts such as eutrophication and toxic blooms.[125]

DIRECT OCEAN INJECTION

Naturally occurring long-term carbon storage requires carbon transport to the deep ocean. Global ocean convection moves surface waters and their associated carbon to the deep ocean, preventing gas exchange with the atmosphere for thousands of years. Researchers propose to accelerate this process by directly injecting CO_2 into the deep ocean.

Deep ocean environments, with temperatures as low as 4 degrees C and pressures greater than 100 atmospheres, are well suited for storing large volumes of CO_2. Carbon dioxide captured at an anthropogenic source can be transported on ships or piped directly to deep water regions. Below the water's surface there are proposed locations for final deposition: shallow water (800 to 1,500 meters), deep water (more than 3,000 meters) and below the seafloor. Shallow water distribution allows the liquid CO_2 to dissolve into the seawater at relatively low cost.[126] Deep-water injection distributes the liquid CO_2 at colder temperatures and greater pressures. Under these conditions, CO_2 forms a negatively buoyant liquid that will gather on the ocean floor. Using Ocean Global Circulation Models, deep-water sites have been found to be more efficient in long-term storage by avoiding upwelling and convection more commonly found in shallow waters.[127]

Initial studies of direct-injection carbon sequestration yielded positive results that will lead to another generation of studies from researchers from universities; oceanographic centers, such as the Scripps Institute of Oceanography; and the Department of Energy. Developing this technology will require specific studies focusing on the impact of CO_2 on marine life and water chemistry.

120 Sarmiento & Orr, 1991.
121 Chisholm et al., 2001.
122 Sarmiento & Orr, 1991.
123 Fuhrman & Capone, 1991.
124 Chisholm et al., 2001.
125 U.S. Department of Energy, 2005a.
126 West et al., 2003.
127 Dewey & Stegen, 2001.

SUB-OCEANIC CARBON SEQUESTRATION

A relatively new method for trapping large amounts of CO_2 in reservoirs involves pumping a pure stream of the gas into geologic sinks below the ocean floor. In August 2006, researchers proposed a strategy whereby CO_2 is pumped into porous sediment a few hundred meters below the seabed in deep parts of the ocean (at depths greater than 3,000 meters)—a plan that some of the participants called "a fairly simple, permanent solution."[128]

The researchers proposed that injections into the sea floor could take advantage of the pressure and temperature of the ocean, while avoiding the negative side effects of direct ocean injection. CO_2 could be brought to the sequestration site by ship or pipeline and piped into the seabed in liquid form with equipment similar to that used by the oil industry for drilling deep-sea wells. Once injected, CO_2 would "interact with the surrounding fluids and produce hydrate ice crystals, which would plug the rock pores, serving as a secondary cap on the carbon dioxide. Over hundreds of years, the carbon dioxide would dissolve in the surrounding water, and then would only have the potential of leaking out by diffusion, a slow process that would take millions of years."[129]

128 House, et. al., 2006
129 Ibid

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Introduction

Many climate change policy experts agree that a carbon price signal from a cap-and-trade system or tax is necessary to reach climate stabilization. Because emission sources are so widely dispersed and numerous, and emission levels depend on millions of individuals making everyday decisions, the only way to ensure a socially optimal mix of investments and behavior is to provide a price signal that reflects the societal cost of emissions (or at least a signal strong enough to change behavior in a way that leads to stabilization).

Because price signal alone may not be sufficient for reaching climate stabilization, focused effort on technology development and innovation is also necessary. Climate change is such a long-term problem that any initial politically viable carbon-price signal will almost certainly cover a much shorter time frame than what is needed to reach stabilization. Without the certainty of a price signal over the next 50 to 100 years, the market will most likely invest less in long-term technology innovation than is socially optimal. A complementary mix of price signals and technology policy is needed.

But there also are barriers to the development and adoption of new technologies that need to be addressed in the context of climate change and technology policy. A carbon price[1] would need to be high to achieve the desired result if imposed on an economic structure with rigidities or barriers that inhibit the ability to respond to the price signal. While one option may be to impose a strong price signal that overwhelms any existing barriers, a less costly option would be to minimize or remove those barriers in combination with a more moderate price signal. Barriers and challenges to advanced supply- and demand-side technologies involve such issues as information availability, institutional structures, regulatory matters, financing, cost, split incentives, NIMBYism, safety, security, and environmental concerns. These barriers are discussed in the next section. For a full discussion of barriers to specific technologies, refer to Volume I.

The next section also provides an overview of federal climate policy, outlining the elements needed for a cap-and-trade system and a carbon tax. Cap-and-trade and carbon tax policies are then compared, followed by an assessment of the political environment for federal climate policy and a catalog of federal climate proposals. Next, policies aimed at developing new technologies and overcoming or removing barriers are discussed. Many of these policies have been introduced at the state level and could be adapted and expanded at the federal level. Supply-side policies include public-benefit funds (renewables), renewable portfolio standards, feed-in tariffs, reverse auctions, subsidies and incentives, and research and development policy. Demand-side policies include demand-side management, energy efficiency utilities, public-benefit funds (energy efficiency), revenue decoupling, building codes and standards, appliance standards, rebates and tax incentives, and loan-assistance programs.

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1 The term "carbon price" is used generically to refer to a price of CO_2 or GHG allowances in a cap-and-trade system or a CO_2/GHG tax.

Chapter 1 – Barriers and Challenges

There are a number of barriers and challenges to implementing climate-mitigating technologies and behavior. Addressing these barriers through complementary policies will lower the cost of compliance and improve the effectiveness of an overarching cap-and-trade system or a carbon tax. These barriers and challenges include:

INFORMATION

One of the most basic barriers for advanced technologies is lack of information. Any person or company planning a technology purchase, whether it be a light bulb or an electricity-generating plant, must be aware of all alternatives in order to make a rational decision. Even if potential purchasers are aware of the options, they may have imperfect or incorrect information about them. Federal and state government education and outreach programs have been implemented to help overcome the information barrier; these programs include the federal ENERGY STAR labeling program and outreach activities by the North Carolina State Energy Office and the New York State Energy Research and Development Authority.

INSTITUTIONAL

Institutional barriers are pervasive and often difficult to overcome through policy. An example of an institutional barrier might be a utility with an established operational structure geared toward conventional electricity generation. Utility engineers, operations and maintenance staff, planners and other involved individuals may have been initially hired for their expertise in building or operating conventional generation. Not surprisingly, the internal momentum and incentives to maintain the status quo within a company tend to favor familiar technologies over alternative technologies. Combined with utilities' legally obligated responsibility in most states to maintain system reliability, the overall institutional inertia within utilities to use proven technology is considerable and can be a real barrier to the adoption of new technologies.

Purchasing and accounting practices also pose institutional barriers in many companies and organizations. Often, the responsibility to purchase appliances or machines falls to a purchasing department, whose charge is to get the lowest purchase price, not necessarily the lowest lifetime cost. Higher efficiency options are typically not selected because another department is responsible for providing or purchasing electricity or direct fuels, and those costs (or savings) are often not factored into the purchase decision. Accounting practices may exacerbate this problem by weighing upfront costs more than lifecycle costs.

NETWORK EXTERNALITIES OF CONVENTIONAL SOURCES

A network externality is the advantage a given technology has based on its number of users and corresponding support network. The classic example of a network externality is the telephone. The usefulness of a telephone is in direct proportion to the number of people who have adopted the technology. Electricity transmission networks that are designed for conventional generation make additional conventional generation more attractive. Conversely, the existing network of transmission serves as a barrier to wind and other renewables that have concentrated resources in different areas than fossil fuel resources, where many large power plants are and, consequently, where transmission is.

Similarly, any technology that is commonly used will have a support network that has built up around it. For example, because of the number of coal-fired power plants and the long time that they have been operating, a robust network of expert plant operators, engineers, technology suppliers and other involved individuals is available. Any company planning to purchase a new generating plant will weigh the availability of such a support network in its investment decision. New technologies not only must compete with conventional technologies in terms of cost and performance, but also in terms of support networks, which are limited with new technologies.

REGULATORY

A number of regulatory barriers stand in the way of alternative technologies. These barriers include outdated building codes or appliance standards, siting/permitting for electricity generation, lack of interconnection standards for renewables and distributed generation, and least-cost generation requirements for new generation.

Outdated Building Codes. Outdated building codes and standards miss important opportunities to lock in lower energy consumption for new buildings, which may be used for a century or more. Codes can also act as a direct barrier. For example, some local jurisdictions have aesthetic codes that prohibit residential solar thermal or photovoltaic systems. In other cases, zoning ordinances may not allow distributed generation within residential areas by default, in which case small distributed-generation projects must go through a formal review process that deters homeowners from pursuing the option.

Siting and Permitting. The siting and permitting process can act as a barrier for new technologies that do not fit easily within the framework established for conventional technologies. For example, tidal power projects fall under the jurisdiction of the Federal Energy Regulatory Commission, the National Oceanic and Atmospheric Administration, the Minerals Management Service and the Army Corps of Engineers, as well as many state coastal-management agencies and local governments. Completing the permitting process for a commercial-scale pilot site could take several years.[1] Another example of siting as a barrier is the North Carolina Ridge Law, which was passed to prevent a high-rise building in the mountains of the western part of the state. Although the law specifically exempts "windmills," the attorney general of North Carolina has interpreted it to apply to wind turbines. As a result, wind development in that area, despite good wind resources, has been stalled.

Lack of Interconnection Standards. A lack of interconnection standards has limited the adoption of distributed generation and combined heat and power (CHP) systems. CHP systems can achieve efficiencies in the 70 percent to 80 percent range, compared with the 30 percent to 40 percent efficiencies of large central-station fossil fuel plants. Since CHP systems generate power and heat where consumed, they do not suffer line losses of 9 percent to 10 percent, as central power stations do. From a carbon mitigation perspective, CHP is very promising and important. Yet many utilities have interconnection standards designed for large central-station plants that are unnecessarily burdensome for small CHP systems and can, in many cases, turn an economically attractive CHP project into an uneconomic one if it must comply with arcane interconnection rules. Some states have enacted streamlined interconnection standards for small distributed-generation and CHP systems to lower the cost of integrating these systems into the electric grid.

Least-Cost Generation Requirements. Most states have an agency, often a Public Utilities Commission (PUC), which oversees the electric industry. PUCs invariably have a legal obligation to ensure that utilities acquire electricity generation and capacity at the lowest cost. Most states do not clarify which kinds of costs should or

1 United Nations Framework Convention on Climate Change, 2004.

should not be included. As a result, PUCs typically seek the lowest direct cost possible given current applicable policies. Even though many utilities and analysts assume that federal climate policy will be in place for a significant period over the life of new generating capacity, some PUCs prevent the inclusion of a cost of carbon emissions in the determination of least-cost. As a result, the lowest-cost plants now may be high-cost in the near future under a federal climate policy; conversely, higher-cost plants now may be low-cost in the future. Some states have implemented an integrated resource planning (IRP) process that is meant to account for environmental and social costs that are not captured under a conventional definition of least-cost. States with a full IRP process also have incorporated an explicit carbon price signal and require an equal assessment of demand-side reductions as an alternative to new supply.

Least-cost requirements pose a barrier only to actions taken before implementation of a national carbon policy; however, once a national carbon policy is in place, least-cost requirements should then work in favor of low-carbon technologies, since the price of carbon will be part of the existing policy framework.

FINANCING

Any new technology is perceived as risky simply because it is new and has not been proven. Financiers expect a higher return for this risk. Also, the intermittent nature of some renewable technologies precludes owners from offering firm long-term contracts. The owners cannot guarantee delivery of power and must settle for less valuable nonfirm contracts and spot markets, which make it more difficult to finance. Similarly, any fuel-based generating technology must demonstrate a guaranteed supply of fuel in order to obtain financing. Agriculture feedstock biomass projects may have dozens or even hundreds of suppliers who may change from season to season. Demonstrating guaranteed fuel supply is difficult and is a barrier to financing for agriculture-based biomass.

Some mature technologies that have demonstrated their risk from past experience may also have difficulty obtaining financing. For example, nuclear power in the 1950s and 1960s was going to be "too cheap to meter." Massive investments were made in the 1960s and 1970s to build many new nuclear plants, but a myriad of circumstances came together—safety concerns leading to design changes midway through construction that increased construction costs and led to big delays, double-digit inflation combined with construction delays that drove up the cost of financing, and public opposition—that brought investments to a stop. Many utilities with nuclear plants were left with enormous costs on their books, some of which were not recoverable through their ratebase. The utilities' credit rating suffered as a consequence, and for nearly 30 years financing of new nuclear plants was considered impossible.[2]

Adoption of energy-efficient products and practices faces financing barriers within companies. Many corporations, for example, have a limited pool of capital for internal investment. Potential projects are put forward and evaluated for their rate of return and their relevance to the company's core business function. While many energy-efficiency investments have a positive rate of return, they may not have a sufficiently high rate of return compared to other internal investment opportunities; with limited capital, energy-efficiency investments are often not selected. For most companies, investing in efficiency also does not further their core business strategy and may be discounted as a result.

2 Circumstances have changed today with federal climate policy on the horizon and new plant designs that promise to lower costs and improve safety, though financing may still prove to be a challenge.

EXPERIENCE NEEDED TO BRING COST DOWN

New technologies invariably have higher costs, at least initially, than conventional generating technologies. Higher costs result from a lack of experience designing and manufacturing the technology—the cost saving steps and processes have not been found yet—and from a small production base that cannot take advantage of economies of scale. The rationale of many environmental policies, including direct incentives/subsidies and mandates such as renewable portfolio standards, is encouraging the purchase and operation of these technologies helps manufacturers gain valuable "learning by doing" experience that lowers the cost of technology.

SPLIT INCENTIVES

Split incentives are encountered when decisions over the installation or use of particular products are made by someone other than the individuals who stand to benefit from energy savings. An example of a split incentive is a landlord who pays none of the energy bills associated with an appliance or HVAC unit. Under perfect information conditions, potential tenants could take this into consideration as they compare the full cost of occupancy across alternatives, but there are many impediments to this information flow. Split incentives are specifically cited as an impediment to increased use of a wide variety of energy-efficient products and practices, including but not limited to commercial HVAC, appliances and building practices.[3]

NIMBYism

Almost all electricity-generating technologies have some negative co-effects. Some are worse than others; some are real and some perceived. Negative co-effects can include aesthetic concerns, as with wind turbines in natural surroundings; real health concerns, as with particulate pollution from nearby coal and biomass plants; and safety concerns, as with nuclear plants located close to residential areas. Many communities want electricity generation but prefer that plants be located "somewhere else" in order to avoid negative co-effects as much as possible. This phenomena is known as Not In My Back Yard, or NIMBY. Typically, more affluent communities, which can afford to forego the jobs and economic development offered by a new generating plant and can muster the resources to fight a proposed plant, will succeed in shifting the plant to a poorer community willing to trade those risks for economic development. For some kinds of plants, such as those using certain renewable energy sources, the plants must be sited where the resources are and cannot be moved to a different community more willing to accept the investment.

SAFETY

Safety is a challenge and potentially a barrier for certain technologies, such as nuclear plants and geological sequestration of carbon. A nuclear incident could result in a release of radiation that could kill thousands of people and render a large surrounding area uninhabitable. A sudden release of carbon dioxide from an underground storage reservoir could kill anyone in the area. Although the likelihood of these events is quite small, there remains a tangible risk. Given the power of NIMBYism, many communities prefer not to take any risk at all.

SECURITY

Directly related to safety concerns is the risk that terrorists would attempt to cause a nuclear incident or other disaster using energy infrastructure. The threat of such terrorist acts may increase the likelihood of disaster—and also increase the resistance within communities that might be home to a new nuclear plant or other potentially dangerous facility, such as a liquefied natural gas terminal.

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3 *See*, e.g. Prindle et al., 2003.

ENVIRONMENTAL

Environmental barriers include any negative environmental co-effect resulting from energy technologies. For example, biomass for electricity generation and for biofuels entails the possibility of massive land-use change to intensive fuel crops that bring with them a host of environmental concerns. Biomass also poses an environmental challenge through the emission of particulate matter and other types of air pollution. Poorly sited wind turbines can cause bird mortality. Conventional hydroelectric dams can destroy entire valleys where the water behind the dam is stored, as well as disrupt fish and wildlife along the river downstream from the dam.

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Chapter 2 – Federal Climate Policy Options

Two policy structures aimed at reducing U.S. emissions of greenhouse gases have gained substantial consideration among policymakers. These approaches include creating a greenhouse gas cap-and-trade system or, alternatively, enacting a carbon tax. Both of these are economic-incentive mechanisms—that is, they rely on the power of the market to achieve regulatory goals. Yet, substantial differences remain between the policy structures.

Under a cap-and-trade system, an upper limit—the cap—is placed on global (or federal, regional or whatever the jurisdiction of the policy) levels of greenhouse gas emissions, and regulated entities must either reduce emissions to the required limit or buy emissions allowances in order to meet the cap. These purchases must come from other parties who have more emissions allowances than they need, so that trading does not cause a violation of the cap.

In contrast, a carbon tax places a tax burden on each unit of greenhouse gas emissions and requires regulated entities to pay for their level of emissions. The price signal is anticipated to provide parties emitting gases with a motivation to improve energy efficiency, switch to less-carbon-intensive fuels and/or use less energy.

This section describes in more detail the structure of the alternative policy mechanisms, compares the structures and outlines questions for further research that will aid decision makers in their consideration of enacting either of these policies. This section is intended to provide a foundational "lay of the land" of market mechanisms that might be used to regulate greenhouse gases. In addition to providing an overview of each policy option, this section also considers how these policy options square with a variety of criteria that might be used to set policy, including environmental reliability, economic efficiency, equity, political feasibility and regulatory feasibility.

INTRODUCTION

Policy makers in the United States increasingly view cap-and-trade programs as an attractive tool for reducing or phasing out various pollutants. Such programs are often touted not only for their political feasibility and administrative viability, but also for their ability to obtain measurable environmental results. Regulated entities often favor cap-and-trade programs to regulatory alternatives because such programs involve the creation of a flexible market system that allows regulated entities to determine the most efficient way to meet reductions.

Cap-and-trade regulatory schemes attempt to combine traditional regulatory tools with the power of market incentives. Like many regulatory programs that aim to limit pollution, cap-and-trade programs set a target level for pollution, commonly referred to as a cap. Typically, the cap is broken down further by creating allowances that permit the holder to emit a specified amount of pollution.[1] Firms must hold allowances at least equal to the amount of emissions they produce. Once the cap is set and allowances are created and allocated, the flexibility of the regulatory mechanisms comes into play. Cap-and-trade programs allow regulated parties to buy and sell allocated allowances as they see fit.[2] In this way, a market for the allowances emerges. Firms choose the method by which they will achieve abatement results and the extent to which they purchase allowances. Variation in emission levels and reduction strategies among firms creates economic efficiency gains because the exchange of allowances is advantageous for both potential buyers and sellers and compliance is generally achieved at a lower cost than without trading.

ILLUSTRATIVE EXAMPLES OF CAP-AND-TRADE PROGRAMS

Cap-and-trade programs have become increasingly prominent as an environmental policy solution. Perhaps the most touted examples of the promise of cap-and-trade mechanisms are found in the regulatory approach used in the United States to successfully remove lead from gasoline and drastically reduce sulfur dioxide (SO_2)-induced acid rain.[3] Through the Kyoto Protocol, many countries are relying on cap-and-trade to reduce greenhouse gas emissions and attempt to mitigate climate change. Because of the prominence of the United States' experience in SO_2 trading and the relevance of the Kyoto Protocol's greenhouse gas trading system, each will be discussed briefly below.

The U.S. Acid Rain Program

Title IV of the 1990 Clean Air Act Amendments mandates the regulation of sulfur dioxide produced by electricity-generating facilities. This regulation is achieved through a cap-and-trade program. By 2010, the Clean Air Act aims to reduce annual SO_2 emissions to one-half of the level emitted in the United States during 1980.[4]

The cap-and-trade program is split into two phases. Phase I, which began in 1995, limited SO_2 emissions from the largest, highest-emitting electric-generating facilities (263 in total) in the United States.[5] Phase II, which began in 2000, set restrictions on almost all remaining fossil fuel electric power plants. Each year, electric power

1 Kuik & Mulder, 2004.
2 Ibid.
3 Ellerman et al., 2003; Environmental Defense, 2000.
4 U.S. Environmental Protection Agency, 2004.
5 Cramton, 2000.

facilities receive a specific number of allowances based on historical heat input; each allowance authorizes one ton of SO_2 emissions. Any unused allowances can be sold, traded or banked for future use.

The cap-and-trade mechanism provides utilities with the flexibility to select their own methods of compliance. Methods of compliance include installing pollution control equipment, switching from high-sulfur to low-sulfur coal, employing energy-efficiency measures and/or renewable generation, buying excess allowances from other sources or using a combination of these options.[6] A continuous emissions monitoring system (CEMS)—certified by the U.S. Environmental Protection Agency (EPA)— records and measures emissions of SO_2 to account for every ton of sulfur dioxide emitted. Plants that do not have enough allowances to cover their annual emissions automatically face a steep fine, must surrender future year allowances to cover any shortfall and may face civil or criminal penalties.[7]

In 2004, 10 years after the EPA's Acid Rain Program began, the agency released the program's progress report. The report found that SO_2 emissions had been reduced by over 5 million tons from 1990 levels, or about 34 percent of total emissions from the electric-utility sector.[8] Such drastic reductions have resulted in greater than expected environmental and human health benefits. The success of the SO_2 cap-and-trade program has fundamentally altered the nature of U.S. environmental policy, thus making emissions trading schemes a prominent option in several recent policy proposals.

The European Union Emissions Trading Scheme

In January 2005, the European Union's Emissions Trading Scheme (EU ETS), the world's first large-scale greenhouse gas cap-and-trade program, began to operate. Currently, the trading program encompasses about 12,000 installations in six major industrial sectors located in 25 countries.[9] The regulated sources account for roughly 50 percent of total CO_2 emissions that come from within these countries. The EU ETS consists of two distinct phases: Phase I, also known as the "warm up phase," will run from 2005 through 2007 and the more stringent Phase II will run from 2008 through 2012, which coincides with the Kyoto Protocol compliance period.[10] The founders of the EU ETS chose this time frame to enable the European Union to track and meet its Kyoto Protocol emissions target.

The overall ceiling of the EU ETS is based on each member state's national cap of CO_2 emissions as stated in the country's National Allocation Plan. However, prior to the start of the second phase, each member state must submit a new National Allocation Plan to account for the more rigorous emissions cap that must be in effect for the European Union to meet its Kyoto target. The total number of allowances each country receives every year is based on its National Allocation Plan. Each installation's emissions are primarily estimated using production data or emission factors coupled with data on fuel use.[11]

In Phase I, the vast majority of allowances will be given out for free. The European Union will allow individual member states, at their discretion, to auction off up to 5 percent of their allowances. During Phase II, the European Union will double the number of allowances that can be auctioned.

The EU ETS takes great measures to track the emissions and credits covered by its regulatory regime. The program verifies trades of emissions allowances with three electronic data systems, one managed by the European

6 U.S. Environmental Protection Agency, 2002.
7 Ibid., p. 4.
8 U.S. Environmental Protection Agency, 2004.
9 Pew Center on Global Climate Change, 2005.
10 Ibid.
11 Ibid.

Union and one managed by each of the home countries of the trading parties. The program permits regulated parties to bank unused allowances to offset future emissions. Additionally, installations involved in the EU ETS can acquire credits by engaging in specific reduction efforts in other parts of the world. [12] Firms are also responsible for making up missed emission reductions the following year.

In addition, the European Union designed the program so that it could potentially be linked to other emissions trading schemes. However, at this point there is no linking policy, although Norway recently requested a link between its scheme and the EU ETS. Additionally, Britain's prime minister, Tony Blair, and California's governor, Arnold Schwarzenegger, recently announced an agreement to explore the future linking of emissions trading systems in the United Kingdom and California, in light of California's new landmark legislation to limit greenhouse gases and the United Kingdom's participation in the EU ETS.[13]

During the first half of 2005, the emissions-trading market saw transactions of more than 90 million EU allowances, resulting in an estimated financial volume of €1.37 billion.[14] By the first half of 2006, traded volumes had grown to 440 metric tons (MT) and were valued at €9.9 billion.[15] Despite this dramatic increase in trade volume and value, and despite relative liquidity of the trading market, high fuel costs have limited conversion to alternate fuels; abatements have been largely the product of improvements in efficiency.[16]

Recent analysis of the EU ETS has identified four primary lessons from Phase I thus far. First, it is essential to correctly estimate the emissions base-line. The EU ETS failed to do this, which has lead to the creation of a "long market" (i.e., actual emissions are less than the established cap).[17] This situation fails to provide a strong incentive to reduce emissions and will likely cause the current carbon price of €16 per ton to fall considerably. Second, it is crucial to build long-term predictability into the trading scheme.[18] By establishing processes by which amendments to the trading mechanism can be made, and by planning for long-term (20-40 year) horizons, the scheme can enable participants to make informed and confident investment decisions. Third, effort must be made to incorporate risk-adverse entities into the trading scheme in order to create an efficient market.[19] Fourth, attention must be paid to the way credits are allocated; free allocation can create windfall profits for industries (e.g., utilities) that can pass through the carbon prices to customers.[20] Despite these shortcomings, the EU ETS is considered by some observers to be a success, especially with regard to the creation of an effective market mechanism, the growth of the allowance market and the change in corporate culture.[21]

DESIGN PRINCIPLES

Introduced below are some of the major decision points that policymakers face when considering a cap-and-trade program. This section does not prescribe an optimal approach, but rather illustrates the options available to policymakers. First, issues pertaining to the reach of a program are addressed, followed by implementation issues. Finally, specific proposed design options for building a cap-and-trade program are discussed.

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12 Ibid.
13 Http://gov.ca.gov/index.php/press-release/2770/
14 Pew Center on Global Climate Change, 2005.
15 Point Carbon, 2006.
16 Ibid.
17 Ibid.
18 Ibid.
19 Ibid.
20 Ibid.
21 International Emissions Trading Association, 2006.

Scope of Program

The reach of a program stems is determined by a number of factors. A program may regulate some pollutants and not others, include or exclude various geographic regions, and target some polluters and not others. These decisions constrain or extend the reach of a program. The factors that contribute to the decisions are discussed below, followed by consideration of how the decisions help determine the appropriate cap.

Pollutants

In establishing a cap, policymakers must determine what is being capped. In other words, what pollutants are "in" and what pollutants are "out." The few existing climate change policies typically target gases with the most global warming potential, which is largely a function of their prevalence and radiative forcing potency. The Kyoto Protocol, for example, covers six gases: carbon dioxide, methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulphur hexafluoride (SF_6). Other greenhouse gases include chlorofluorocarbons (CFCs), carbon tetrafluoride (CF_4), perfluoroethane (C_2F_6) sulfate (SO_4) and black carbon (soot).

In addition to being emitted in different quantities by various human activities, these gases also have specific global-warming potentials (GWPs), meaning that some pollutants are more potent than others. The GWP of each gas is based on its ability to trap heat as well as the length of its decay rate. The potentials are indexed in relation to CO_2. Gases with higher global warming potentials trap more heat and take a longer time to decay in the atmosphere. CO_2 acts as a base-line with a GWP of 1, with most other greenhouse gases having higher GWPs, such as methane (23), nitrous oxide (296), SF_6 (22,200), CF_4 (5,700), C_2F_6 (11,900) and HFCs (12-12,000).[22] Therefore, even though the most emitted greenhouse gas by volume is CO_2,[23] other greenhouse gases could have a large effect on global warming due to their high relative global warming potential.

In addition to having varying global warming potential, the emission of each greenhouse gas also has different environmental, social and health consequences that accompany it. Therefore, establishing a common currency, though difficult, is important when attempting to trade among gases.[24] Policymakers need to think carefully about the consequence of establishing the currency of the trading system because it may lead to unintended consequences, some of which may be undesirable. For example, other non-greenhouse gas pollutants may be automatically reduced when company A reduces its emission of a certain greenhouse gas in order to comply with a cap. On the other hand, company B may change its processes to reduce greenhouse gas emissions, but in doing so may increase emissions of or begin emitting other gases not covered by the trading system. In creating a currency, those covered by the cap-and-trade program respond to price signals. Policymakers must take care that the price signal the policy sends does not lead to unintended negative consequences that undermine the direct climate benefits.

Geographic Coverage

Policymakers must also determine the geographic coverage of a cap-and-trade program. For a wide range of geographic, scientific, political and economic reasons, some environmental programs are local; others are

22 Intergovernmental Panel on Climate Change, 2001.
23 U.S. Environmental Protection Agency, 2002.
24 Salzman & Ruhl, 2000.

regional, such as the Regional Greenhouse Gas Initiative (RGGI); and still others, such as the EPA's Acid Rain Program, are national in scope.[25]

Greenhouse gases are in some ways unique pollutants. For one thing, many of them can take decades and often centuries to decay in the atmosphere. Furthermore, atmospheric currents ensure rapid and uniform dispersion of CO_2 and other greenhouse gases across the globe. Thus, the effects of greenhouse gases are cumulative and global.[26] Releases of greenhouse gases in Durham, England, have the same impact on the atmosphere as those in Durham, North Carolina.

Because of the characteristics of these gases, the possibility of national or even international regulation becomes increasingly feasible and desirable from the perspective of economic efficiency.[27] The flexibility inherent to a large and robust cap-and-trade market is widely suggested by economists as a central component to reducing the burden of regulating greenhouse gases.[28]

From the perspective of political feasibility, policymakers may face some limits on how large they realistically can make cap-and-trade markets. Thus far, the United States has refused to participate in the international greenhouse gas regime established under the Kyoto Protocol. Given the difficulties of international coordination, some analysts have advocated intranational approaches that would allow individual countries to adopt their own CO_2 cap-and-trade programs and perhaps tie these programs together with an international market.[29] If the optimal geographic market extends beyond the United States, this may prove an important consideration for policymakers. If the federal government does not preempt the various state programs looming on the horizon, perhaps a mechanism that ties separate statewide and regional programs into a national market may also prove worthy of consideration.

Other factors, including administrative ease, may also be important in determining the geographic scope of a market. For example, the market may be constrained by the extent to which accurate monitoring devices are in place or the extent to which government oversight is robust and reliable. Another issue that may prove important is that of fairness. The Kyoto Protocol does not extend to developing countries because of the countries' desire to address poverty issues ahead of climate-change issues. This provision has been a sticking point for U.S. adoption of the Kyoto Protocol or any international agreement, since some of the designated countries are evolving beyond "developing" status and are major emitters.

Choosing Sectors

A key determination for policymakers is what parties will be regulated under a cap-and-trade program. Generally speaking, even if policymakers determine they want to regulate particular items, they still have to confront the decision about who should bear the direct burden of such regulations.[30] The decisions about the point in the economy to regulate and the sectors to regulate are highly correlated.

With energy, for example, on one hand, policymakers may chose to focus on energy producers, because energy accounts for the vast majority of the greenhouse gas emissions in the United States. On the other hand, policymakers may instead choose to focus downstream in the economy and target energy end-users: industrial,

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25 Burtraw et al., 2005.
26 Ellerman et al., 2003.
27 Ibid.
28 Stavins, 1998.
29 See Kuik & Mulder, 2004.
30 Companies that bear the direct burden can shift much of the burden to their customers.

commercial, residential and transportation sectors (EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2004 at 2-5, 2006). Policymakers will generally have a range of potential regulatory targets for each item that they intend to regulate with a cap-and-trade program. In making such decisions, policymakers will want to consider a host of factors, including the importance of particular targets in the program; the economic efficiency of regulating different points in the economy; what construct will result in a broader range of options to reduce emissions; and what policy design is politically tolerable, fair and less burdensome to administer. Most likely, these factors will point in different directions, and depending on how policymakers value different factors, different proposed solutions will emerge.

Depending on where policymakers place the regulatory burden, the sectors of concern will ebb and flow. In general, the further up the chain of production (e.g., toward the sources of fossil fuel extraction), the fewer entities will be regulated. In focusing on energy producers, for example, the complications and subtleties of the sectors in large part begin to diminish. On the other end of the spectrum, regulating downstream energy users and consumers of products multiplies the number of targets but also allows for much more precision in shaping the regulatory program. Policymakers may also choose to focus "mid-stream" on distributors and wholesalers in some instances. The decisions of where to place the burden, and the feasibility of different options, will likely vary across the economy.[31]

Policymakers also may find that it is cost prohibitive or unfeasible to regulate certain parts of the economy. In such instances, policy provisions for voluntary participation in the market, known as opt-ins, may be the only option to include such sources, at least initially. This economic and political reality may remain despite the fact that voluntary programs may prove inadequate to address the full impact of some emitters.[32]

The complexity involved in deciding which emissions to regulate and what point of the economy to regulate is reflected in the diversity of recent policies drafted in the United States. For example, a proposal by the National Committee on Energy Policy suggests placing a cap on upstream sources; however, the Regional Greenhouse Gas Initiative places the burden of regulation on downstream point sources, such as electric utilities.[33] The proposed McCain-Lieberman Climate Stewardship Act would place a cap on large downstream emitters and on transportation fuels upstream.

Setting the Emissions Cap

Once policymakers have determined which gases to regulate, the geographic region and the actual parties to regulate, the next task is to set an emissions cap. The cap will determine the environmental impact of the reductions and constrain the supply of allowances, and therefore it will have a real economic impact. The Kyoto Protocol and California's Climate Change Act do this by setting base-lines based on past emission levels. In large part, such an approach assures that the trend of emissions is declining. However, such a cap is not linked specifically to scientific assessment of needed emission reductions to avoid harmful climate change. Policymakers may consider the possibility of consulting with the scientific community to determine the extent to which reductions will result in environmental benefits and set the cap accordingly. At the end of the day, however, setting a hard cap likely boils down to a political decision where policymakers decide how much of a reduction they can afford given all issues on the table.

31 Wing, 2006.
32 Ellerman et al., 2003.
33 Burtraw et al., 2005; Smith et al., 2003.

The proposal put forward by the National Commission on Energy Policy does not set a hard cap, but rather focuses on ratios; for example, CO_2 emitted per unit of output is set as the cap.[34] This approach may have appeal due to political feasibility, because the initial distribution of allocations among firms is less complicated if there is already agreement between energy-intensive firms and the government on energy-efficiency standards.[35] It may also allow producers to easily estimate their reduction obligations and eliminate some uncertainty. On the other hand, this sort of approach may not achieve the intended environmental objectives and atmospheric stability because of the lack of an absolute emissions cap.

IMPLEMENTATION ISSUES

Initial Allowance Allocation

The degree to which a cap-and-trade program places a substantial burden on particular regulated parties stems in large part from how initial allocations are distributed. The overall economic efficiency, in theory, does not depend on how allowances are allocated, because the opportunity cost of emission reductions remains the same under any allocation scheme, which suggests that rational firms will make the same economic choice to reduce or not reduce their emissions regardless of their initial allotment of allowances. The number of allowances first allocated to a party and the cost of those allowances is crucial from the perspective of a regulated entity. Much of the political maneuverings of regulated parties and the most contentious decisions could grow out of decisions surrounding allowance allocations.

Although policymakers have a range of options for allocating allowances, two of the methods of allocation used most often are discussed here. Many of the programs give away allowances, and do so mainly to those entities that have polluted in the past. This method, known as grandfathering, is understandably politically popular among regulated entities. A second allocation method is to auction the allowances to the highest bidders. Although auctions have had only had a limited role in actual programs, they often are highly touted in critiques of cap-and-trade policy designs. While there are other alternatives not explored here, for the most part, policy allocation alternatives can be explained as a hybrid of these two types of allocation.

Free Allocation or Grandfathering

Strictly speaking, any allocation of allowances that can result in the free trade of those allowances is considered economically efficient. But how allowances are allocated can greatly affect the distributional equity of a cap-and-trade system. Allowances can be allocated to those who bear the ultimate cost of climate policy in order to soften the impact, but determining who should receive them and how many they should receive may prove difficult.

Grandfathering has garnered considerable support among regulated entities. This approach provides parties that have polluted in the past first right to allowances under a new policy regime. The most apparent advantage of grandfathering is that it can create political support, or at least reduce resistance, from those regulated.[36] In fact, grandfathering is largely credited with mustering political support for the 1990 Clean Air Act amendments that created a cap-and-trade system for sulfur emissions released by coal-burning power plants.[37]

34 National Commission on Energy Policy, 2004.
35 Kuik & Mulder, 2004.
36 Stigler, 1971.
37 Ellerman et al., 2003; Kruger, 2005.

While grandfathering may prove a popular proposal for the regulated community, this method of allocation may suffer from several imperfections. First, the base-period emissions level is not always a good indicator of a polluter's ability to abate emissions. Second, allocation based on past emissions can commit regulated entities to the processes that created pollution in the past. Third, because the allowances are given away, grandfathering foregoes a convenient way to raise funds for technology development, which would be easy with an auction allocation, discussed below.[38]

Permit Auctions

Given that auctioning allocations can raise revenue that can be specifically targeted for solving and adapting to the problem and do not reward entities for past pollution, auctions may prove to be an attractive alternative to grandfathering or some other system that gives away allowances.[39] The revenue generated from auctions can be used to fund initiatives, including technology research and development, or to cover administrative costs.

Despite such advantages, however, auctioning may prove politically difficult, because it turns the largest recipients of allowances under grandfathering into the larger buyers of allowances under auctions.[40] Higher-emitting regulated entities bear an increased financial burden in an auction system and do not have an institutionalized advantage over potential competitors who will need to obtain scarce allowances to enter the market.

Maintenance of the Allowance Market

Once a cap is in place and initial allowances are allocated, the market forces that sustain the cap-and-trade program should work without much prodding from government. However, government needs to take measures to provide a system that can validate who has the right to the allowances on the market and who is in compliance with the policy's emissions limits. Parties need this assurance to facilitate trades among each other. In setting up the system, the government should strive to make transfer of allowances as easy as possible. The European Union countries that participate in a cap-and-trade program for greenhouse gas emission allowances rely on a registry that essentially shows who holds title to a particular allowance at a given time. Once policymakers have created a cap-and-trade program, a simple registry or similar methodology to track allowances should prove adequate. Parties involved in the market can be expected to work toward an efficient way of facilitating allowance trading, given that government provides a simple method to verify ownership.

Monitoring and Enforcement

The purpose of monitoring (observing actual emissions at facilities in a trading system) and enforcement (assessing penalties to companies that emit greenhouse gases without associated allowances) is to increase the reliability of the program in capturing the sought-after environmental benefit. Monitoring and enforcement do this by altering the incentives of the regulated entities to comply with the program, rather than to ignore or violate the program's standards. To assure the integrity of the program, monitoring and enforcement need to be reliable. Even for regulated entities that are not disposed to emit more than allowed under the program, monitoring and enforcement mechanisms provide some certainty that other regulated entities will not secure a competitive advantage by cheating the system.

38 Hahn, 1998.

39 Cramton & Kerr, 2002.

40 Fischer et al., 1998.

The difficulty of providing monitoring and enforcement hinges, in large part, on the reach of the program: the gases, regions and industries regulated. For some entities, monitoring is quite simple, because monitoring mechanisms already in place for other air-pollution regulations can also monitor greenhouse gases. For other entities, monitoring mechanisms may not be in place. Monitoring also can be simple in cases where the regulated entities produce emissions by burning fuels to create energy, as the emissions caused by different fuels are well known and well documented. For other entities that generate emissions through industrial processes, it may be difficult to track emissions precisely. For these emitters, policymakers will need to decide whether approximate data will suffice, whether precise tracking will be required or whether the burden of monitoring and enforcement outweigh the benefits of including such emissions in the cap-and-trade program.

Policymakers also need to decide who should bear the burden of providing monitoring. Policymakers may opt to have the agency administering the program monitor for violators. Such a system would put the administering agency in a position similar to that of police officers patrolling their beat or the Internal Revenue Service determining who should be audited. Oversight obligations place a large burden on the agency, especially under a system that would cover many entities across multiple sectors of the economy. The more comprehensive the cap-and-trade program, the more difficult monitoring and enforcement become.

In an effort to lighten the expected burden on cap-and-trade administrators, policymakers could require that each regulated entity pay for and undergo an annual on-site independent audit conducted by a licensed third party to verify compliance. Policymakers may also consider the simpler approach taken by many U.S. environmental laws, namely, requiring regulated entities to keep records of their emissions, report particular types of emissions and audit paper records periodically. Such a system places the burden of monitoring on the regulated party and reduces the administrative burden of the program, but may increase the level of political opposition from regulated entities because they would bear an additional cost, as well as from parties that are suspicious of this form of self-regulation.

SPECIFIC DESIGN ISSUES

Some of the more important policy-design decisions that policymakers face in creating a cap-and-trade program are highlighted below. While this section does not cover every issue facing policymakers, the issues below are often the most important and contentious.

Credit Banking/Borrowing

Banking allows a firm to earn credits from pollution abatement in a given year by emitting less than the amount allowed and then apply those credits sometime in the future when they may need to emit more. This provides firms flexibility and incentive for early action. Banking is often held as a way to smooth the transition to a lower level of emissions, because technological improvements usually come in steps, and these steps may or may not fit well within the annual cap-and-trade framework. Many supporters feel banking is an integral component of any greenhouse gas cap-and-trade program. Banking also offers flexibility to deal with uncertainties (e.g., production levels, compliance costs, demand variability). The unique cumulative, long-term and uniform characteristics of CO_2 in the atmosphere mean that the timing of emission reductions within a fairly narrow window of time is of little relative importance.[41] Many observers cite banking as an essential component in the success of many cap-and-trade programs, including the Lead Trading Program and the Acid Rain Program, and

41 Ellerman et al., 2003.

omission of banking is often considered to be a weakness in California's major local cap-and-trade program, called RECLAIM.[42]

Borrowing allows firms to emit more greenhouse gases than they hold allowances for and to borrow from future years' allowances. Borrowing is much more controversial than banking because, unlike banking, there is no guarantee that emissions reductions will occur. Borrowing also provides an incentive for entities to postpone facility improvements. From a political perspective, a program may be more palatable if borrowing is allowed. Borrowing also allows the agency overseeing the program to offer companies a carrot—higher emissions now—for commitments to even lower future emissions. Borrowing, of course, also brings with it the possibility that this discretion will be abused by not enforcing future emission reductions.

Offsets

The inclusion of carbon-offset credits in a climate change policy enables participants subject to the cap to obtain credit for net carbon reductions by parties not subject to the cap. This provides regulated entities with flexibility as to how and where reductions occur. An example of this approach is the Clean Development Mechanism (CDM), discussed below in the section "Linking U.S. Trading System to Kyoto and the Clean Development Mechanism." Biological carbon-sequestration projects represent another example. Offsets often allow policymakers to reduce the total amount of greenhouse gases in the atmosphere while allowing sectors and countries that might not otherwise participate in greenhouse gas reductions to do so on a voluntary basis and with compensation. Such approaches often have political appeal to the groups eligible to provide offsets (e.g., farmers). Under revisions of the Kyoto Protocol agreement in Böhn and Marrakech, countries receive credit for terrestrial "carbon sinks" within their borders that may provide an overall net reduction in carbon emissions. Carbon sinks include things such as increasing and protecting forest area and changing tillage practices in agriculture, activities that sequester carbon in plants and soil. Additionally, the Clean Development Mechanism provides participants an opportunity to undertake emission-reducing projects in developing countries, provided that the reduction would not have happened without such investment. This mechanism provides an opportunity for relatively inexpensive reductions in the overall level of greenhouses gases while at the same time providing useful opportunities to contribute to sustainable development. Ideally, these mechanisms provide flexibility for those who choose to take advantage of them by creating another option for least-cost abatement.

While offsets may increase a program's political palatability, they may also increase the uncertainty of the program's effectiveness in reducing levels of greenhouse gases. For example, there are criticisms of using carbon sinks as offset credits without better knowledge of biologic carbon sequestration capability and capacity.[43] Moreover, carbon offset projects can also raise concerns about their permanence, leakage (diversion of emissions to areas outside the project boundaries) and additionality (extent to which reductions would not have occurred without the project.[44]

Safety Valves

A safety value provides a market price ceiling for an emission allowance and may also generate additional allowances beyond the cap once the price hits the ceiling. Depending on how low the price ceiling is set, a safety

42 Ibid.

43 Bohringer, 2002.

44 Murray, B.C., B.L. Sohngen, and M.T. Ross. 2007. "Economic Consequences of Consideration of Permanence, Leakage and Additionality for Soil Carbon Sequestration Projects." Climatic Change. (vol. and no. forthcoming)

valve can be viewed as a hybrid between a cap-and-trade and a tax. Under this hybrid approach, once the price of allowances hits the ceiling, the government sells additional allowances to maintain—or reduce—the market price of allowances. If the price ceiling is set at the uppermost range of expected carbon prices, the safety valve functions less like a tax and more as a buffer for volatile price spikes, allowing the market to function and equilibrate prices (except in the event of some unforeseen circumstance that drives the price beyond what policymakers thought likely). Either way, a safety valve gives regulated entities a form of price protection. However, if the safety valve is triggered, it will also work to reduce the overall environmental benefits of the program. A safety valve might be seen as a compromise between policymakers who want to enact a cap-and-trade program and business interests regulated by the program.[45] If policymakers decide to include a safety valve, they must also consider whether the ceiling should be adjustable. By setting a nonadjustable price ceiling, policymakers risk that the ceiling will be too low (undermining the environmental goals of the policy) or too high (undermining the concept of cost-certainty). An adjustable ceiling, on the other hand, can protect against unforeseen changes or shocks. But an adjustable ceiling also introduces a risk that at some point in the future the ceiling will be adjusted in a way that undermines the environmental benefits of the program.

Early Action

Some cap-and-trade programs provide incentives for early action by regulated entities in two forms. First, a program might honor emission reductions prior to the enactment of the program, which gives credit to firms that acted before the program began. Second, a program might provide extra credit for those who decide to act early (before the cap goes into effect), which would provide an incentive to take action sooner rather than later.

Early action incentives encourage firms to make real reductions rather than relying on purchasing allowances. Early action also mitigates against "gaming" free allocation by artificially increasing emissions prior to the start of the program to get a larger allocation. A downside of these incentives is that they begin to erode some of the environmental benefits of the program; in many cases, firms make decisions for economic reasons that also happen to reduce emissions, so giving them additional credit for an already cost-effective decision may not be necessary or prudent policy.

Leakage

Concern about leakage centers on the possibility that implementing a cap-and-trade program will provide an incentive for firms to simply relocate emissions to areas not subject to emissions regulation rather than reduce them. For example, a cap-and-trade program may give firms an incentive to move outside the current regulated market to an unregulated market or at least to reallocate production efforts. Or the market itself may simply move demand to producers that gain cost advantages by not having to reduce their emissions. To the extent that leakage is reallocating emissions rather than reducing them, it undermines the environmental benefits of the program. Leakage can also erode political support for the program because it often ends up providing firms outside the program a competitive advantage.

Policymakers must carefully consider measures to reduce leakage. Depending on the size of the market, leakage avoidance measures might raise difficult political and legal issues. For example, statewide greenhouse gas regulations promulgated in lieu of a federal policy might raise dormant federal commerce issues if measures to address cross-state leakage are seen to impede interstate trade. In the international arena, measures to avoid leakage might raise the possibility of violating agreements under the World Trade Organization.

45 McKibbin & Wilcoxen, 2002; Pizer, 2002.

Carbon Tax

Carbon taxes levy pollution charges on greenhouse gas emissions. While the name suggests an exclusive focus on CO_2, carbon taxes may also cover the emissions of other greenhouse gases such as CH_4, HCF-23 and N_2O. Carbon taxes may be seen as a way to make the emitter of greenhouse gases internalize the externalities inherent in pollution-causing activities.

As an excise tax, carbon taxes generally charge a specific dollar amount per ton of carbon released into the atmosphere. Taxes vary by fuel type to correspond to each fuel's carbon content. Policymakers considering a carbon tax have many issues to consider. Policymakers may choose to levy taxes annually, as with income taxes, or on an ongoing basis, as with sales taxes. Furthermore, policymakers must decide ahead of time what to do with the tax revenues collected by the jurisdictional governments.

The options before policymakers are many. Policymakers may decide to use tax revenues to offset other taxes. For example, a carbon tax to curb greenhouse gas emissions could be used to cut taxes to promote other goals, such as increasing incentives for socially desirable behaviors (e.g., employment) by reducing existing taxes (e.g., income taxes). Carbon-tax revenues may fund other government programs, including those related to reducing the risk and impact of climate change and other priorities.

This section will begin by providing an example of a national carbon tax and then review potential variations on carbon-tax design.

NORWEGIAN EXAMPLE

In 1991, Norway instituted a carbon tax as a means of stabilizing its CO_2 emissions. The tax, set at the equivalent of $55/ton of CO_2, initially covered only combustion-based point-source emitters. Given that 99 percent of Norway's domestically produced electricity comes from hydropower plants, the tax did not initially cover many entities. Soon after, however, Norway expanded the tax base to cover emissions from industry as well, including offshore oil and gas production. This expansion was met with predicted resistance, causing policymakers to include notable exemptions to industries facing international competition, such as international air and shipping transport and fishing. In addition, reduced tax rates were granted to energy-intensive industries, including pulp and paper, fish meal, national transport and continental shelf operations. A full schedule of 1999 rates in Norwegian currency for various industries is found in Table 2-1.

Table 2-1: CO_2 tax rates in Norway[46] (in Norwegian krones, as of January 1999)

	Taxes per metric ton CO_2
Gasoline	397
Petroleum products	
Light oil	174
Heavy oil	148
North Sea supply fleet	100
Coastal goods transport	100
Pulp and paper industry	87/74
Fish meal industry	87/74
Coal	189
Coke	144
Oil burned on continental shelf	336
Gas burned on continental shelf	381

46 Norwegian Ministry of Finance and Customs, as cited in Hoerner & Bosquet, 2001.

As part of its environmental tax reform, Norway has chosen to use part of the revenues to offset citizens' income taxes. In 1999, the tax revenue reduced personal income taxes by an average of 790 Norwegian krones ($117) per person. Other portions of the tax revenues have been spent on research and development of renewable energy and energy efficiency technologies.

Since the carbon tax was instituted, Norway's carbon emissions per unit of gross domestic product have decreased notably. However, research suggests that changes in Norway's energy mix, not the tax, were the primary driver for this reduction.[47] The relatively modest size of the carbon tax's behavior-changing effects may be attributed to its extensive exemptions and/or inelastic demand for fuel in covered sectors.[48]

Norway's carbon tax has been criticized for its high variability of tax rates and excessive exemptions.[49] Discussions are now under way to replace the carbon tax with a tradable allowance system that would provide an easier transition into the Kyoto Protocol framework that Norway has agreed to follow.

DESIGN PRINCIPLES

Scope of Program

Pollutants

One of the most critical questions in designing a greenhouse gas tax system is simply: what emissions should be taxed? Dividing emissions into two categories, CO_2 and all other greenhouse gases, is a logical partition. While there may be opportunities for low-cost emissions reductions of non-CO_2 gases, CO_2 represents 80 percent of U.S. greenhouse gas emissions by global warming potential[50] and could therefore make a substantive target for a carbon-tax regime. While other gases could also be addressed, taxing more greenhouse gases may bring additional complexity and administrative difficulty to the tax regime.

According to an analysis by the Organization for Economic Co-operation and Development (OECD) of non-CO_2 greenhouse gas taxes, a program that taxes all greenhouse gas emissions would be unfeasible. However, the analysis also concluded that some non-CO_2 gases would make good candidates for inclusion under a carbon tax system. Using criterion including quantity of emissions, importance of greenhouse gas, ease of monitoring and emissions projections, the OECD recommends a tax program targeting CO_2 along with the non-CO_2 greenhouse gases summarized in Table 2-2.

47 Bruvoll & Larsen, 2004.
48 Ibid.
49 Organisation for Economic Co-operation and Development, 2004.
50 U.S. Environmental Protection Agency, 2005.

Table 2-2: Greenhouse gas sources that are amenable to taxation[51]

Activity	Quantity of taxable entities	Importance	Ease of measurement/ monitoring	Emissions projection from 1995 to 2000 (percent)
CH_4 from oil and natural gas production	Few (producers)	High	Reasonable	+3
CH_4 from modern landfills	Many	High	Good	-8
CH_4 from underground coal mines	Medium	High	Good (for underground mining)	-9
N_2O from fertilisers	Many (purchasers)	High	Poor	+3
HFCs and PFCs used as ODS substitutes	Many (producers or purchas-ers)	Low, but increasingly rapidly	Good (complex to get complete accuracy)	+132
HFCs, PFCs, SF_4 emissions during production of these chemicals	Few	High	Good	
SF_4 used in magnesium processes	Few to medium	Low	Good	+19
HFC-23	Few	Medium (being phased out)	Good	-5
N_2O from adipic acid	Few	High (but reducing)	Good	-58
N_2O from nitric acid	Few	High	Good (but site specific)	-58
PFCS from aluminum production	Low	Medium	Good (but site specific)	13

Geographic Coverage

Geographic coverage of the tax system (e.g., national, regional, local) is another decision point for policymakers developing carbon policy. All tax-program designs discussed in this section are assumed to have a national scope. Including all covered sectors in the United States, as opposed to only certain regions of the country, addresses equity concerns and minimizes intranational leakage.

Upstream versus Downstream Spectrum

The U.S. Congressional Budget Office, in analyzing the period 2006-2015, recommended a carbon tax levied as far upstream in the energy value chain as possible, where combustion fuel is produced or imported.[52] The advantages of collecting a carbon tax upstream include:

- Minimizing market distortions by applying the tax throughout the market, not significantly altering consumer behavior by unevenly affecting only certain sectors.
- Providing for increased equity among energy consuming sectors by basing the tax on the amount and type of fuel used and avoiding a concentrated financial impact on certain sectors.
- Minimizing leakage because all fuel-using sectors are covered, leaving no room for cross-sector or geographical leakage.
- Reducing administrative complexity because taxing fewer parties entails less monitoring and enforcement.
- Rendering controversies surrounding "bubbling"53 policies unnecessary because bubbling would not be an option for compliance.

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51 Organisation for Economic Co-operation and Development, 2000, p. 6.

52 U.S. Congressional Budget Office, 2005.

53 Bubbling refers to the practice of classifying a group of emitting sources as one source for monitoring and compliance purposes. Bubbling is often used in cap-and-trade programs where covered entities can average out the emissions of a group of sources to meet compliance.

Fossil fuel producers and importers constitute a much smaller pool of entities than the large number of fossil fuel end-users. Accordingly, other analysts argue for levying the tax at the first point of agglomeration in order to minimize the number of taxed parties and facilitate monitoring and enforcement. This approach would entail levying the tax at the mouth of major natural gas pipelines, oil refineries and coal mines, or at customs for all imported fuels. Analysts have found that 82 percent of U.S. greenhouse gas emissions may be covered by taxing only 2,000 upstream entities.[54]

The point of tax collection may also affect the tax's perceived impacts and, by extension, its acceptability. Psychological studies indicate that policies having the most "visible" costs are least accepted by households.[55] In this light, carbon taxes applied at the firm level are less visible to individual households and may create the illusion that they will not cost household-level consumers.[56] Policies involving less visible costs may be more politically feasible; however, less visible costs may not induce behavior changes as significantly as intended.

The elasticity of demand for a product, or the degree to which demand changes in response to price, is determined, in part, by the availability of substitutes.[57] Consumer response to energy price increases is generally inelastic (unresponsive), although long-term elasticity does show that consumers make changes in their daily consumption patterns in response to market signals. In order to motivate firm and household behavior toward more climate-friendly energy use, consumers must be made aware that the price increase is permanent, which may imply the need for a more visible tax.

One complication of levying an upstream tax involves the fact that some uses of fossil fuels do not directly lead to greenhouse gas emissions; for example, the chemical industry uses natural gas as a feedstock for some processes, such as fertilizer production. Because these uses do not directly contribute to global warming, they should not be subject to the tax. Some form of tax credit could be created for noncombustion purchases of taxed fuels. Capturing and storing CO_2 postcombustion is another example of a process that may warrant credits under an upstream tax scheme. Giving credits would require the creation of a detailed fuel-use monitoring or auditing system for parties that wish to claim the tax credit, thus increasing the administrative complexity of such a tax scheme.

Sectors

Methods of selecting which sectors to cover under a tax program depend largely on where in the upstream/downstream spectrum the tax would be applied. In the case of a tax applied far upstream at the fuels' point of origin, the sector question becomes less critical, because all fuel-using sectors will encounter the tax at some point. In the case of a downstream tax where the tax is levied at the end-use of the fuel, there is opportunity to individually select which sectors are covered. All things considered, sector coverage concerns are not as significant with carbon taxes because almost all programs involve upstream collections.

Level of Tax

Choosing a tax rate has obvious implications on the cost, environmental effectiveness, revenue generation and political feasibility of a carbon tax. While there is a wide range of tax rates represented in proposals, most rates fall within the range of \$5 to \$40 per metric ton of CO_2. In theory, the level of tax should be set so that the price

54 Hargrave, 1998.

55 Lewis, as cited in Baranzini et al., 2000.

56 Thalmann, as cited in Ibid.

57 Elasticity of demand measures how much the quantity demanded of a good is affected when the price of that good changes. If a good has a relatively inelastic demand, the percentage decrease in the quantity demanded of the good is less than the percentage increase in the good's price.

of carbon emitted is equal to its real societal cost, which includes environmental damages. In reality, however, environmental costs are difficult if not impossible to pinpoint and, even if they could be accurately ascertained, the costs may be too high to garner enough political support.

Another aspect to be considered is how the tax rate will adjust along with inflation or other economic indicators in the national economy. All of the Nordic countries employing environmental taxes include index mechanisms that link the tax rate to inflation to keep the price signal constant in real terms.[58] Such mechanisms are helpful to maintain environmental benefits and avoid possibly heated debates over increasing the tax as inflation increases.

A carbon tax would raise the price of energy from various fossil fuels differentially, depending on their respective carbon contents. The tax per unit of energy output would thus increase from natural gas to petroleum to coal. As a result, energy- and carbon-intensive industries would ultimately pay higher taxes than less energy-intensive industries.

Whatever policymakers determine to be the optimal tax rate, a carbon tax that starts small and has a long-term (e.g., 50-year) scheduled rate of increase may assimilate most fluidly into the economy. Most company investment cycles are on the order of a decade or more, and long-term regulatory certainty helps companies make informed investment decisions to maximize economic gains. An incrementally increasing tax rate is also likely to be the most environmentally effective. If companies are given a chance to gradually adjust to higher energy prices and include them in their investment decisions, there may be a higher rate of compliance.

IMPLEMENTATION ISSUES

Monitoring and Enforcement

Monitoring compliance with a carbon tax would be essentially the same as done under a cap-and-trade program, assuming both schemes are compared at the same point in the upstream/downstream spectrum. As mentioned earlier, the fewer entities covered under the tax scheme, the less resource-intensive the monitoring process.

Enforcement is simply a matter of implementing a clear punishment sufficient to maintain compliance. Most carbon-tax programs specify a per metric ton of CO_2 penalty fee for noncompliance that is well above the specified tax rate. Programs that do not contain sufficiently high penalties for noncompliance may have trouble achieving their desired emissions reductions.

Revenue Use

Carbon tax revenue may be used to finance other greenhouse gas-reduction projects. These projects could include grants for research on new energy sources, energy-efficient technology or carbon sequestration. In addition, tax revenues may go toward emissions-offsetting projects or deployment of clean technology to developing nations. Depending on the market created by the carbon tax for this research, dedicated funding may or may not be necessary to initiate rapid research and development of new low-carbon technologies or sequestration techniques.

Another option would be to redistribute the funds through either a lump-sum payment or income tax (personal or corporate) replacement. Some programs call for redistributing government revenues by doling out equal

58 Baranzini et al., 2000, p. 406.

annual payments directly to each legal resident.[59] Other programs would decrease income tax rates and replace the government revenue loss with tax collections, as is done in Norway. Although the two policies would result in similar emissions reductions, they have differing effects on social welfare. Lowering personal income tax rates may provide a double dividend by lessening the distortionary effect of income taxes, thereby improving the efficiency of the economy.[60]

The decision of how to use carbon-tax revenues has obvious political ramifications. Potential recipients of the revenue, be it through research funding, tax cuts, or lump-sum payment, are more likely to support the carbon-tax proposal than nonrecipients. The revenue can therefore become an effective tool in garnering the political will needed to pass a carbon-tax law.

Revenue Neutrality

Policymakers may face less political opposition to a carbon tax and have less of an impact on the overall economy if the tax offsets other taxes rather than being used to primarily raise revenue. This approach is also referred to as revenue recycling. The overall effect of a revenue recycling program for a carbon reduction system, whether it comes from taxes or allowances, is dependent on market conditions and tax code provisions.

Some economists argue that taxing carbon and reducing taxes on labor and capital could greatly improve society while reducing the risks of climate change. They argue that society could capture a "double dividend" by protecting against climate change and lowering the burden of labor and capital taxes on society.[61] The extent to which offsetting other taxes will benefit the economy depends, in large part, on a host of technical factors, including the condition of the market and the ability of society to economically handle taxes. The prospect of a double dividend is very attractive; however, more studies need to be done to determine the magnitude of the effect and the net benefits to society.[62]

Distribution Effects

Lower-income populations spend a larger proportion of their annual income on energy than higher-income populations.[63] This disparity raises concern about the distributional effects of rising energy costs in the face of a carbon tax. While it is true that energy taxes, even when embedded in larger tax reform, tend to be regressive, with lower-income groups paying a larger percentage, there are numerous means of correcting this imbalance and even transforming such a regressive tax into a progressive system.[64]

While recycling tax revenues by lowering personal income taxes may be more economically efficient, it is not necessarily a more equitable use of revenue. A policy that includes replacing personal income taxes does not directly benefit energy consumers who do not pay income tax. If a goal of the revenue redistribution program is to reduce the effects on low-income households, policymakers should consider redistribution policies that target those groups, such as pensioners, the unemployed and other low-income households.[65]

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59 The SkyTrust scheme calls for 75 percent of the revenue generated from the government's carbon allowance auction to be distributed back to U.S. residents in this way.

60 Bovenberg & Goulder, 1996.

61 Schöb, 2003.

62 Intergovernmental Panel on Climate Change, 2001.

63 Walls & Hanson, 1996.

64 Metcalf, 1999.

65 Baranzini et al., 2000, p. 405.

In response to concerns that a carbon tax will disproportionately affect low-income households, the Dutch energy tax system introduced an income floor and progressive tax above the floor.[66] Certain customers who use small amounts of energy are exempt (i.e., they receive a tax-free allowance of energy); above the designated amount, energy use is progressively taxed.

Credits/Exemptions/Subsidies

Most of the countries that have already introduced a carbon tax grant energy-intensive industries a lower tax rate.[67] However, these varied rate structures decrease the economic efficiency of the tax and require an increase in other sectors' tax rates in order to achieve a given emissions reduction.[68] Although removing exemptions can be costly for those sectors, efficiency losses associated with exemptions can be substantial, even when the share of exempted sectors in overall economic activity and carbon emissions is small.[69]

Subsidies, the "carrots" of public policy, can be viewed as the inverse of taxes, the "sticks" of public policy. Some carbon-tax proposals have coupled the reduction or elimination of certain subsidies that contribute to greenhouse gas emissions (e.g., subsidies for oil and gas exploration). By reducing subsidies that distort market forces, the tax interaction effect of a carbon tax could be reduced, thus decreasing the monetary welfare costs of a carbon tax.

Leakage

Minimizing leakage—the situation in which emissions in nonregulated areas increase in response to regulation in other areas—is an important objective of most mandatory greenhouse gas emissions policies. If the net emissions of an area increase as a result of leakage, then the policy would be generally ineffective if not harmful. In this light, policies should consider measures to reduce the incentive for energy-intensive industries to relocate to jurisdictions without carbon regulations. Because this discussion is focused on national carbon-tax programs, there is less threat of leakage within the country. There may, however, be risks of leakage to other countries, essentially the same as those discussed in the previous cap-and-trade section.

66 Ibid.
67 Hoerner & Bosquet, 2001.
68 Bohringer & Rutherford, 1997.
69 Baranzini et al., 2000, p. 409.

Comparing Cap-and-Trade and Carbon Tax[70]

TARGETS

Central to the debate regarding the relative merits of a carbon-trading program and a carbon-tax program is the nature of the target the program is attempting to achieve. Policymakers must ask themselves what is more important: a fixed environmental outcome or a predetermined economic outcome. A cap-and-trade mechanism guarantees a fixed level of emissions by establishing a specific emissions limit; however, the cost of allowances is realized only when the program is implemented and trading has begun. The certainty of the environmental outcome is especially useful in international negotiations where a specific emissions target is often the motivating factor for multilateral cooperation. For these reasons, quantity mechanisms are generally preferred by the environmental community.

Conversely, tax mechanisms lock in a specific price for emissions allowances while leaving the quantity of emissions reductions for the market to determine. This strategy is preferable if the economic ramifications of regulating carbon are the chief concern and the price of carbon under a cap-and-trade system is uncertain. Because economic effects are often cited as the basis of opposition to carbon regulation, a price mechanism may help alleviate the fear that such regulation would be overly fiscally intrusive. Price certainty affords the business community more latitude in their planning. The downside of a tax program is that its very purpose—reducing greenhouse gas emissions—is not guaranteed.

Both quantity and tax mechanisms, if adjusted correctly, have the potential to reduce carbon emissions to a level that can achieve a stabilized concentration of greenhouse gas emissions of 550 parts per million (ppm), though the level of reduction needed for stabilization is uncertain, and no level of reduction can be guaranteed with pricing mechanisms.[71] Generally, a wider range of costs are associated with the cap-and-trade instrument than with a tax, which means the former system carries greater cost uncertainty. Alternatively, the range of resulting emissions is much smaller for the quantity target, and much larger for the price target, which results in greater emission uncertainty.

In discussions regarding climate change, fundamental questions are: what level of carbon emissions reduction is adequate and what amount of economic costs is manageable?

UNCERTAINTY

The relative merits of cap-and-trade and carbon-tax regulatory mechanisms become an issue of debate due to uncertainty. Four types of uncertainty are most pertinent to gauging the potential effectiveness of price and quantity instruments: cost, market elasticity, the marginal benefits of greenhouse gas emission reductions and the nature of climate-change threats.

There are three main sources of cost uncertainty: reduction costs, technological innovation and future emissions. Barely a year old, the European Union's Emissions Trading Scheme has demonstrated unpredictably high prices of emissions allowances, which have risen from an initial price of €8 in January 2005 to close to €30 a year later. In April 2006, the conclusion of the first annual compliance period, the price of allowances fell dramati-

70 For purposes of discussion, all references to quantity or trading mechanisms will denote a cap-and-trade program, while all references to price instruments will indicate a tax program. We will use the terms "permits" and "allowances" interchangeably as well. Further, the Intergovernmental Panel on Climate Change has identified as an objective the stabilization of the atmospheric carbon dioxide concentration at 550 ppm. This target will be referenced throughout the discussion.

71 Pizer, 1999.

cally as companies realized they had more allowances than they needed. Through the remainder of 2006, prices fluctuated some but stayed below the high levels found in early 2006.Apparently, smaller companies with little to no experience with a trading mechanism opted to retain their allowances until the end of compliance rather than trade them throughout the first year of trading. This artificial constraint in the supply of allowances was the driver in the initially high prices in the market.[72]

Optimistic projections of technological innovation favor quantity mechanisms because of their ability to provide incentives for behavior beyond compliance. The great successes of the U.S. sulfur dioxide cap-and-trade program can be partially attributed to organizational and technological innovation that evolved in the face of regulation.[73] Lastly, the Intergovernmental Panel on Climate Change has mapped six possible emissions scenarios for the future with varying predictions of environmental consequences. As to be expected, the scenarios represent a wide range of future emissions levels; these levels should be considered in the choice between price and quantity targets.

Uncertainty surrounding the elasticity of carbon-reduction demand introduces another dynamic in the debate. It is still fairly uncertain just how elastic demand is for carbon-intensive goods. The more inelastic the demand for carbon-intensive goods, the greater a carbon tax would have to be to achieve the desired emissions reduction. Although only imprecise predictions of how market demand would respond to regulation exist, experience from petroleum use reveals the market for energy to be very inelastic in the short run (around -0.3) and somewhat inelastic in the long run (around -0.7).[74] As such, a price tool may have to be set quite high in order to produce meaningful emissions reductions, making the accuracy of a quantity tool more attractive.

In the face of uncertainty, economists compare the relative steepness of marginal-cost and marginal-benefit curves to estimate potential welfare loss of price and quantity instruments. In theory, inaccurate estimates of abatement costs will result in more welfare loss when the cost of reducing one more unit of emissions is greater than the benefit of the reduction. This uncertainty is compounded by the unknowns surrounding the marginal benefits of emission reduction; at present, the benefits of greenhouse gas emission abatement are difficult to measure and graph. If the marginal-benefit curve of greenhouse gas abatement is less steep than the marginal-cost curve of abatement within the range of required abatement, price instruments would be preferable to quantity instruments.[75] The recently published Stern Review on the Economics of Climate Change is shedding some light on this issue; in an nutshell, the report finds that the total cost of not pursuing climate stabilization may result in a 5 percent to 20 percent loss in global GDP (seen another way, pursuing stabilization would result, in effect, in a 5 percent to 20 percent gain in global GDP relative to doing nothing), while the total cost of achieving stabilization is on the order of 1 percent of global GDP. While these costs are expressed as total costs, not marginal costs, logic dictates that, if the Stern Review is correct, the marginal cost of climate policy up to the point needed for stabilization is almost certainly not steeper than the marginal benefit, implying that quantity mechanisms may be the best choice.

Much of the literature surrounding the cap-and-trade versus tax debate was published during the period leading up to the 1997 Kyoto Protocol agreement. Since that time, climate science and modeling has progressed greatly, producing more accurate predictions of the state of climate change threats. If the possibility of abrupt and economically damaging climate change is significant, a quantity tool would be preferred because it provides more assurance that such events will be avoided.

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72 PointCarbon, "Carbon Trading in the US: The Hibernating Giant," Carbon Market Analyst, September 13, 2006

73 Burtraw, "Innovation Under the Tradable Sulfur Dioxide Emission Permits Program in the U.S. Electricity Sector," RFF Discussion Paper 00-38.

74 Graham & Glaister, 2002.

75 Weitzman, 1974.

FLEXIBILITY OF CAP-AND-TRADE VERSUS CARBON-TAX PROGRAMS

Characteristics inherent in a quantity or price instrument will determine how each type of program interacts with current and future technological developments, carbon-emission trends, and market forces to result in effective climate protection. In the context of carbon-mitigation policy, flexibility mechanisms include the ability of quantity- and price-based controls to adjust to sudden economic shifts, to incorporate the use of carbon-offset projects and allowance purchases, and to account for the six major greenhouse gases.

Response to Economic Trends

Shifts in both domestic and international economic environments have the potential to disrupt carbon pricing mechanisms associated with both cap-and-trade and carbon-tax programs. An important distinction between these two strategies is how they respond when costs associated with carbon mitigation change unexpectedly.[76] Under a quantity mechanism, the cost of a carbon allowance is determined by the market; the price is not fixed and is therefore able to adjust automatically for inflation and external price shocks. A carbon tax, on the other hand, has a fixed value and is not free to adjust to either transient or long-term fiscal trends without being indexed to an economic indicator. The valuation of the carbon tax would need to be regularly revisited, unless indexed, in order to maintain its effectiveness in influencing carbon emissions. This would undermine some of the cost certainty advantages of the tax, but would still avoid price volatility assuming the tax rate adjustments are planned and set at regular intervals.

Incorporation of Multiple Greenhouse Gases and Offsets

Although the majority of strategies currently under consideration focus on CO_2 emissions, there exists vast potential for reductions in the other major greenhouse gases—methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. A cap-and-trade system could address all of these gases by converting each to carbon equivalents based on their respective global-warming potentials (see Table 2-3). A price-based strategy focusing solely on CO_2 emissions fails to capture the potential for firms to undertake less costly projects involving one or another of the other greenhouse gases. A tax program could overcome this shortcoming by also instituting a tax for the emission of the non-CO_2 greenhouse gases. To accomplish this, it would first be necessary to determine at what point in each emissions stream the tax should be applied.

Additional flexibility under a cap-and-trade scheme can be achieved through the use of offset projects that reduce greenhouse gas emissions. Offsets allow firms to undertake projects that enhance existing greenhouse gas sinks or create new sinks as an alternative to reducing emissions at their sources. This flexibility may be achieved under a price-based program by providing tax exemptions based on the quantity of greenhouse gas sequestered by offset projects. However, like the incorporation of non-CO_2 greenhouse gases, the use of offsets within a tax program would add to the administrative cost and reduce the tax alternative's assumed advantage of simplicity and ease of implementation.

76 Pizer, 1999.

Table 2-3: 100-year global-warming potentials[77]

Gas	GWP
Carbon Dioxide	1
Methane	23
Nitrous Oxide	296
HFC-23	12,000
Perfluoromethane	5,700
Sulfur Hexafluoride	22,200

SCOPE, DISTRIBUTION AND EQUITY

The costs and benefits associated with both quantity- and price-based strategies depend on the extent of implementation across the economy. A carbon tax would likely apply across all economic sectors, while a cap-and-trade program would likely target the largest emitters of greenhouse gases or a combination of large downstream emitters and upstream or midstream transportation fuel providers. Quantity-based mechanisms incorporating multiple sectors of an economy, including power generation, industry, transportation and large commercial entities, have been proposed; however, their efficacy has yet to be demonstrated.

Under either carbon-mitigation option, the federal government must consider the regressive costs—those aspects of a strategy that have a proportionally greater effect on the poor than on the rich.[78] Possible revenue recycling and tax relief mechanisms to alleviate this regressive affect are addressed in "Revenue Generation" below.

The appeal of economywide responsibility for greenhouse gas emission reduction is the equitable distribution of the economic burden associated with achieving the reductions. However, to ensure the political feasibility of a price-based mechanism, it will be necessary for government to mitigate the impacts of a carbon tax on certain businesses and communities, including fast-growing areas in need of abundant, affordable energy and regions that currently depend on coal, the most carbon-intensive of the fossil fuels.

The allocation of allowances under a cap-and-trade strategy is critical to a quantity-based mechanism; this distribution determines the scope of the project, its associated costs and benefits, and its political feasibility. Entities regulated under a cap-and-trade mechanism bear the greatest direct cost burden. Decisions to target specific sectors of carbon emitters must be considered carefully within the context of continued competitiveness within both the domestic and international economies. Additional equity concerns surrounding a quantity-based strategy arise due to potential barriers against market entry for new firms.

COMPLEXITY OF IMPLEMENTATION

The complexity of either a cap-and-trade or carbon-tax strategy depends primarily on the scope of the mechanism and the point of regulation. As the scope expands, the potential for leakages decreases while simultaneously increasing the complexity and administrative costs associated with implementation. Conceptually, a tax based on the carbon content of a fuel would be simpler to implement than a cap-and-trade system, although it is unclear whether this would actually be the case. The simplicity of a price-based mechanism also depends on whether the tax is levied on the upstream, midstream or downstream segment of the fossil fuel value chain. Additional complexity may be introduced into a tax strategy if the greenhouse gases beyond carbon dioxide, as well as nonfuel

77 Intergovernmental Panel on Climate Change, 2001.
78 Parker, 2001.

uses of fossil resources, are included. Both of these tax options have the potential to increase the effectiveness of a price-based carbon policy mechanism. However, both options also increase the complexity of the mechanism.

The numerous options available to policymakers under quantity-based carbon mitigation strategies cover the comprehensive array of activities and transactions that result in greenhouse gas emissions and reductions in the United States. However, the complexity and costs associated with maintaining a viable cap-and-trade program rise rapidly as its scope expands. The administrative costs of measuring, monitoring and verifying emissions from each of the regulated sources and sinks of greenhouse gases in the United States are significant enough to warrant attention. Allocation of allowances could be a cumbersome and litigious process that has to be closely monitored and regularly revisited to maintain the effectiveness of the carbon-mitigation strategy.

REVENUE GENERATION

Both auctioned allowances and taxes generate revenue;; however, grandfathered allowances, which are simply given to emitters based on their historical emissions, do not. Mechanisms that produce revenue may be generally preferable if they are used to offset other social costs. First, revenue raised can offset the costs of regulation, including transaction, monitoring and enforcement costs. Because taxes do not involve the brokerage and approval processes associated with tradable allowances, their regulation costs are lower and will presumably be covered by the revenue collected.

Second, revenue can help offset existing distortionary taxes through revenue recycling. For instance, the revenue generated from a carbon tax may be used to reduce previously imposed income taxes, which tax workers for labor and shift the market away from equilibrium. Under this strategy, the tax burden is shifted away from beneficial products, such as labor, and onto harmful products, such as pollution.

POLITICAL FEASIBILITY

As with most public policy, the political feasibility of either a quantity- or price-based carbon-mitigation strategy is directly related to the economic, political and social costs associated with its implementation. Concerns regarding equity, costs to taxpayers, regressivity and competitiveness, as well as environmental and intergenerational concerns stemming from probable climate change, will affect the decisions of policymakers and voters alike. All other things being equal, the political feasibility of either mechanism depends on the perception of how a carbon tax or a cap-and-trade strategy would affect the members of a politician's constituency.

However, policies involving the introduction or reorganization of new taxes face strong political opposition in the current federal climate, as evidenced by the rejection of the recent bipartisan tax reform commission recommendations. It is therefore unlikely that a price-based carbon-mitigation mechanism will succeed at the federal level in the near future. On the other hand, a quantity-based mechanism can harness the flexibility afforded through allocation and offset provisions to buy political capital, which makes it a more politically feasible carbon-abatement option.

Linking U.S. Trading System to the Kyoto Protocol and the Clean Development Mechanism

Economists generally agree that in order to be most efficient, a carbon market should have maximum scope, both geographically and in terms of sectors and gases included. For this reason, as well as to increase political palatability among parties subject to a cap-and-trade or carbon tax, any proposals for U.S. carbon-trading systems should consider linkages to other carbon markets.

In general terms, there are two approaches available to the United States to link to carbon market schemes elsewhere:[79]:

- "Project-based crediting" would be a means to sell credits from emissions reductions projects into an existing, external market. The Kyoto Protocol's Clean Development Mechanism and Joint Implementation (JI) mechanism are examples of project-based crediting. Generally, project-based credits could be created by any project that reduced aggregate emissions relative to some business-as-usual base-line.

- The United States could create a new, separate system that would administratively link to an existing system, such as the European Union's Emissions Trading Scheme, and credits could be sold back and forth between the two if the EU ETS acknowledged U.S. credits. Otherwise, a U.S. system could unilaterally accept EU ETS credits.

PROJECT-BASED CREDITING

The Kyoto Protocol allows two types of project-based credit mechanisms: CDM and JI. Both mechanisms provide a means to earn emission credits with mitigation projects at carbon sinks or sources that would otherwise be counted in their emissions. Nuclear power projects are not eligible to create credits under either mechanism. CDM and JI allow projects that sequester forest carbon through land-use change (afforestation and reforestation), but do not currently allow projects that conserve existing forest stocks or avoid deforestation.

Clean Development Mechanism

Based on Article 12 of the Kyoto Protocol, CDM allows Annex I Parties[80] to implement emissions reductions in non-Annex I Parties (i.e., developing countries) in exchange for certified emissions reductions (CERs); alternatively, developing-country parties can implement the reductions themselves and sell the resulting CERs to an Annex B party facing emission targets. CDM projects are intended to assist the host country in achieving sustainable development while reducing or avoiding greenhouse gas emissions and lowering the cost of compliance for countries with targets. CDM is also intended to provide technology transfer, starting developing countries on the path to emission reductions.

79 Nordhaus, 2005.

80 Includes developed countries, including Russia and the former Eastern Bloc, that have emission targets under the Kyoto Protocol

The CDM Market

In November 2004, the first CDM project was registered.[81] CDM credits could be counted beginning January 1, 2005, the day the Kyoto Protocol went into effect. Today, there are 620 projects in the CDM process pipeline, with a total of 800 million CERs (one CER equals one ton of CO_2) expected through 2012. In 2004, Natsource projected the demand for CDM and JI projects to be at 84 to 762 million tons of carbon dioxide equivalent in 2010, which would be 45 percent to 73 percent of all purchases in greenhouse gas markets.[82] The current market appears to be in alignment with this projection.

Expansion of CDM projects into sectors such as energy efficiency and transportation received significant attention at the 2005 UNFCCC COP-10 meeting in Montreal, Canada. Finally, the role of China is one of considerable interest to many parties involved with CDM. Currently, the CDM Executive Board has approved only 32 projects in China, though the Chinese government has given approval for 208 CDM projects that would result in 650 million CERs [83]. The CDM Executive Board must approve those projects for them to earn CDM credits; if the board does so, China will be a significant supplier of CERs. Given the opportunity for emission reductions in China, if China were to eventually join an emissions trading program, the price of permits would most likely drop significantly.

United States and CDM

As an Annex I country (under the UNFCCC, not the Kyoto Protocol), the United States is not eligible to host a CDM project. There are three potential ways that the CDM could be connected to a U.S. project:

- The CDM could be modified to allow CERs to be created by projects in the United States. These credits could be awarded to projects that reduce or sequester carbon relative to a business-as-usual base-line. This modification appears unlikely as it would entail serious competitiveness concerns for firms in the European Union and would reopen CDM discussions.

- The United States could create an analogous process to the CDM that would allow U.S. firms to create credits similar to CERs with projects in developing countries. The parties to the Kyoto Protocol could decide to recognize these alternative CERs.84 It is unlikely that the parties would agree to recognize them unless the review process, accounting system, base-lines and monitoring were substantially similar to the bureaucratic CDM process.

- Any U.S. program could unilaterally allow CERs into the U.S. system, meaning that U.S. companies can purchase CERs and use them to meet their obligation.

JOINT IMPLEMENTATION

Based on Article 6 of the Kyoto Protocol, Joint Implementation allows Annex I Parties to implement emissions reductions projects in other Annex I Parties in exchange for emission reduction units (ERUs). JI includes two possible procedures, referred to as tracks one and two; track one requires that the host party meet all eligibility requirements, while track two allows projects to begin operation and issue ERUs after the requirements relating

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81 United Nations Framework Convention on Climate Change, 2004.

82 Michaelowa, 2004.

83 From *http:cdm.ccchina.gov.cn/english/NewsInfo.asp?NewsId=1425,* accessed 12/20/06.

84 Bodansky, 2002.

to its assigned amount (national allocation of credits under Kyoto) and registry have been met. Since the United States has not ratified the Kyoto Protocol, it is currently ineligible to host or invest in JI projects, but an amendment to the Protocol could allow JI projects in the United States.[85]

CREATING A NEW PROGRAM AND LINKING

With no modification to the Kyoto Protocol, the United States government or U.S. firms could purchase Kyoto allowances through brokers.[86] Kyoto allowances could be sold to U.S. entities by parties to the Protocol who would put the sold credits into their cancellation account. Since a modification of the Protocol would be required for non-Kyoto allowances to be recognized by the Protocol, an informal, brokered linkage would be possible only as long as the United States remained a net buyer for each vintage of allowances. An amendment to the Protocol allowing credits from an external program to be sold into Kyoto is politically unlikely unless the parties believed that the external program was generally compatible (comparably stringent and mandatory) with Kyoto.

85 Ibid.
86 Bodansky, 2002.

Political Considerations for Climate Policy

Any policy is only as effective as its ability to reach enactment. While a fair amount of economic analysis has examined the relative merits of market-based mechanisms for environmental regulation, namely taxes and tradable allowances, less analysis has focused on the ability of these mechanism to muster essential political support. This section describes political considerations of U.S. climate policy at the federal level. First, it addresses why market-based mechanisms, especially taxes, have traditionally been underused. Second, it examines the use of these mechanisms in environmental regulation in other countries. Next, it derives lessons from other policy formation-processes, such as the U.S. acid rain trading program and the international Kyoto treaty. Lastly, this section discusses the benefits of both tax and allowance programs to maximize government revenues and/or social welfare.

HISTORIC POLITICAL OPPOSITION TO MARKET-BASED MECHANISMS FOR ENVIRONMENTAL REGULATION

Although economists have long advocated for market-based mechanisms, traditional political reality has demonstrated a preference for command-and-control environmental regulation. A survey of congressional staff members conducted by Stephan Kelman (1981) reveals that preferences regarding market-based policy vehicles were based largely on ideological party grounds early on; Republicans wanted to harness the power of the free market while Democrats opposed the lack of government intervention. However, regardless of their position, neither party demonstrated sound understanding of the economic theory behind market-based policies.[87]

Further explanations of why U.S. environmental policy traditionally favored command-and-control approaches rather than market-based mechanisms can be analyzed from both demand- and supply-side perspectives.

From the demand side, command-and-control approaches were favored by the most salient interest groups exerting pressure on the environmental policy formation process. First, industry has harnessed its robust lobbying power to support policies favoring existing firms by raising barriers to entry. Command-and-control mandates often give existing firms a competitive advantage by placing tighter restrictions on new firms. However, this rationale does not explain why existing firms would not support a system of grandfathered allowances. Second, environmental advocacy groups traditionally opposed market-based mechanisms partly because they felt they granted firms an unethical "license to pollute."[88]. The straightforward message to stop pollution is much easier to deliver to the members of environmental advocacy groups than explaining a complex tax or trading system.[89] Additionally, these groups feared that once adopted, market-based mechanisms would be harder to intensify—either by recalling allowances or increasing taxes—than a command-and-control standard would be to toughen. Lastly, organized labor advocated for policies that would limit the flexibility of firms to substitute inputs or otherwise instigate shifts in the labor market. One such example is the United Mine Workers' opposition to the Clean Air Act's SO_2 trading system that allowed firms the flexibility to shift from high-sulfur coal in the unionized Appalachians to low-sulfur coal from the non-unionized West. Not surprisingly, this flexibility to find suitable substitutes is much of what made the SO_2 trading program so successful.

Politicians and bureaucrats on the supply side of policy formation customarily overlooked market-based mechanisms in favor of command-and-control policies. Legislators had a host of motivations to adopt command-and-

87 Kelman, 1981.

88 Stavins, 2001; Svendsen, 1999.

89 Seligman, 1994.

control approaches over market-based vehicles.[90] First, market policies make the cost of regulation more explicit than technological standards, creating more political liability for the supporter. Second, environmentally related standards lend themselves well to symbolic political victories to the public, whose members have relatively limited information, while leaving room for loopholes via exemptions and/or lax enforcement mechanisms. Third, specific standards leave less room for uncertainty, which is valued by risk-averse politicians. This effect is amplified by the narrow geographical focus of legislators who would, as a body, prefer less risky policies that may not result in the most efficient outcome at the national level but minimize risk in their constituent districts. Command-and-control approaches rely more heavily on the technical expertise of agency bureaucrats, who may fear that a shift away from these methods would result in scaling down their relevance in the policy process. As more and more environmental policy incorporates market frameworks, the bureaucratic resistance to them may subside.

Another option available to environmental regulation decision makers is voluntary agreements; these can be subdivided into three areas: unilateral, public voluntary and negotiated. Unilateral agreements are the result of firms making public pledges to improve their environmental performance. Public voluntary agreements exist when firms attempt to meet voluntary regulatory targets through good faith efforts. In negotiated agreements, both the affected firms and the regulatory agency participate in goal setting. Often, impending future regulation provides an impetus for industry to join voluntary agreements in hopes that its participation will render further regulation unnecessary or excessive.[91]

In the face of strong political pressures exerted by industry, voluntary agreements can be used by politicians as a regulatory tool. These agreements have overwhelmingly dominated federal climate policy even amidst the absence of a substantial regulatory threat. Studies suggest, however, that public voluntary agreements can actually reduce social welfare because they often result in fortifying industry opposition to socially beneficial tax proposals and reduce industry incentives to self-regulate.[92] Whereas mandated measures such as taxes and cap-and-trade programs may force inefficient firms out of the market, voluntary agreements allow firms to persist under less than optimal performance.

DOMINATION OF QUANTITY OVER PRICE INSTRUMENTS

In the 25 years since Kelman's study, market-based policies have become a more politically acceptable means of environmental regulation. Among the instances when these new environmental policy instruments are employed over command-and-control approaches, a distinct political proclivity toward quantity over price instruments has emerged. Although both price and quantity instruments can accomplish the same degree of economic efficiency, there are political reasons why the latter dominate contemporary federal environmental policy. Quantity instruments have nearly always been in the form of grandfathered cap-and-trade allowances given to covered entities initially free of charge.[93],[94],[95] Examining both the demand and supply sides of policy formation help explain this trend.

On the demand side of regulation, existing firms have an incentive to lobby for allowances freely allocated based on existing behavior, because they help erect barriers to entry for new firms.[96] Also, taxes, unlike allowances, represent a transfer of wealth from firms to the government that is, of course, undesirable to firms. Environmental groups are more successful in forwarding regulation when the costs are less obvious to the public,

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90 Stavins, 2001.
91 Segerson & Miceli, 1998.
92 Lyon & Maxwell, 2001.
93 Fullerton & Metcalf, 1997.
94 Goulder et al., 1997.
95 Stavins, 1995.
96 Svendsen, 1999.

as is the case with grandfathered tradable allowances. They also tend to favor quantity instruments because they guarantee a given level of abatement, as opposed to price instruments that leave the level up to the markets to decide. Additionally, environmental groups can directly affect policy outcomes in a regulatory framework involving emissions allowances by purchasing them from the market and then "retiring" the allowances. This strategy has been employed in the U.S. acid rain training program. The advocacy group Environmental Defense Fund (later renamed Environmental Defense), for example, had bought and retained 25,000 sulfur dioxide permits as of May 1996.[97]

On the supply side of regulation, legislators favor grandfathered allowances in part because the costs are less publicly visible and therefore a smaller political liability. Furthermore, allowance allocation affords legislators the flexibility to affect the distribution of winners and losers. This power can be wielded to buy both colleague and constituent votes. Lastly, taxes imply an expansion of the federal budget that is considered undesirable by the majority of Americans. However, a recent *New York Times*/CBS News poll found that most Americans would be willing to accept a tax on gasoline if it were framed in a way that helped reduce global warming.[98]

OTHER NATIONS' USE OF MARKET-BASED MECHANISMS FOR ENVIRONMENTAL REGULATION

Environmental taxes have been widely but unevenly used across European states since the 1970s.[99] Most of these taxes fall disproportionately on the energy sector. Nordic countries lead the number of ecologically based taxes, with Norway, Sweden and Finland levying 22, 20 and 19 different taxes, respectively.[100] A review of carbon-specific tax reforms in three Nordic countries (Norway, Finland and Demark)) suggests that they have demonstrated strong commitment to ambitious emission-reduction targets as well as considerable variation in the policy selection process. In addition, the countries have opted for carbon taxes over allowance-based instruments because of alleged economic efficiency arguments and double-dividend effects that reduce existing distortionary taxes. The exercise of environmental taxes in these countries is believed to have effectively pushed the business sector away from resource-intensive activities and toward labor-intensive production practices.[101]

Norway

Norway's seemingly paradoxical display of a strong willingness to control emissions under the context of a powerful industry lobby can shed some light on the potential for emission taxes in the probusiness United States. While a relatively hefty emissions tax is applied to the transportation sector, the energy-intensive industrial sector has managed to avoid these fees through important exemptions. Kasa explains that due to the political influence of industry, the evolution of climate policy remained largely limited to traditional industrial circles, while allowing little room for environmental interests to mobilize. Even though industry makes up 40 percent of the nation's emissions, industries remain outside the scope of regulation due to decision-making structures long in place.[102] These structures are based on the consistently powerful alliances between industrial organizations and the Ministries of Trade & Industry and Petroleum & Energy. While the Ministries of Finance and Environment both forwarded economic and environmental rationales for subjecting the industrial sector to the carbon tax, the historical alliance with industry and other influential agencies ultimately won out.[103] The result is a

97 Carman, 2002.
98 Friedman, 2006.
99 Jordan et al., 2001.
100 Ibid.
101 Kasa, 2005.
102 Ibid.
103 Reitan, 1998.

less-than-optimal tax that unequally burdens the transportation sector and neglects substantial opportunity to further reduce emissions in more politically connected sectors.

Finland

Industry enjoys significant exemptions in Finland, somewhat as a result of leakage concerns. The evolution of the carbon tax in Finland was first ramped up and then eventually weakened as business successfully lobbied for sizable exemptions. In 1989, when the climate-change issue first received significant attention from the Finnish government, the government implemented the world's first carbon tax, with reductions granted to energy-intensive industries. Over the next five years, the jurisdiction of the tax expanded to include inputs for energy production that abolished any exemptions the business community formerly enjoyed. This trend shifted in 1996, however, when the industry lobby effectively coalesced to reverse the energy production tax.[104] The pattern of strengthening and then relaxing the tax reflects the internal politics of the Finnish government that deliberately alienated the Environment Minister from decision making while the Trade and Finance Ministers dominated.[105]

Denmark

Denmark is the only nation currently imposing a carbon tax on its most energy-intensive branches of industry. Interestingly, the Danish government was successful in targeting the business sector for a CO_2 tax but failed at introducing NOx taxes to the agricultural sector. Early in the history of Danish environmental regulation, fiscal considerations were the primary motives for taxing consumers. Then, in 1988, when worries about climate change began to mount, the government introduced a modest carbon tax complete with exemptions for energy-intensive businesses. The tax signaled a shift in policy purpose from raising revenue to affecting behavior. In 1993, the carbon tax was expanded to include the business sector.

The use of environmental taxes in the three Nordic countries was, at some point, contingent on important business exemptions. More often than not, heavy resistance from industry resulted in a taxation system that deviated significantly from what was initially intended for the environmental regulation.[106] The Nordic experiences suggest that sizable business exemptions are needed to secure the political capital needed for passage of environmental taxes, and this situation tends to water down the effectiveness of the policy.

The United Kingdom

In the United Kingdom, energy taxes were originally proposed under a package that would provide relief for energy-intensive industries and signal long-term government support to help industries in transition. The tax revenue collected through the Climate Change Levy was to be fully recycled to industrial firms by offsetting their mandated employee insurance payments. The amount of the tax was to be based on the carbon content of the fuel source used. After eliciting consultation from energy providers and affected industries, the government made modifications to reduce tax rates and provide exceptions for renewable energy and energy efficiency technologies. However, the new proposal was again met with criticism, this time because the tax employed overall energy use as a tax base instead of the real culprit, emissions. Critics instead wanted the carbon emissions themselves to be taxed, allowing for more flexibility in how emissions reductions would be made, be it by cut-

104 (Sirinen, 2000)
105 Kasa, 2005.
106 Ibid.

ting energy use or shifting fuels. Finally, the tax program was abandoned in favor of the Marshall Report, which created the U.K. Emissions Trading Scheme. The fate of the U.K.'s experiment with a carbon tax is unsurprising considering the British tradition of actively engaging affected parties in policy formation while addressing practicality and cost concerns.[107]

Germany

Germany's first steps toward climate policy came in 1990 with the announcement of plans to cut 25 percent of greenhouse gas emissions. The initial call for a carbon tax was, of course, opposed by industry, which instead suggested a voluntary program. As the third UNFCCC Conference of the Parties approached, to be held in Berlin, the German government felt pressure to distinguish itself as a leader on the climate issue.[108] In order to have a program in place, the government dropped its tax proposal to instead secure a voluntary declaration from industry. This compromise allowed government to retain industry support for its emissions-reduction targets, set up a framework within which to reach its targets and appear as a leader on the issue to the international community.

In 1999, the Green-Red party was elected on a platform of ecological tax reform, using slogans such as "prices must tell the ecological truth."[109]. The new tax targeted transport, heating oil and natural gas, but strategically avoided the powerful coal lobby. The carbon-tax revenues were to be recycled back to industry to offset employer pension contributions; however, industry still opposed the tax. Although public protests over rising fuel prices led to the compensation of socially vulnerable groups, the tax remained.[110] The decision to adopt and maintain a carbon tax over a tradable allowance system reflects the German tradition of more stringent, less flexible regulation.[111]

While the United Kingdom has demonstrated a preference for tradable allowances, Germany has relied on environmental taxes. The variation in the use of market-based mechanisms is found to depend on national institutional traditions.[112]

LESSONS IN DISTRIBUTIVE POLITICS FROM THE ACID RAIN TRADING PROGRAM, DPARTP

The acid rain trading program adopted as part of the 1990 Clean Air Act amendments represents one of the largest emission allowance allocation schemes in U.S. policy history. Under the program, allowances for sulfur dioxide emissions from power plants were allocated in two phases. The first period, 1995 to 1999, covered only the 261 "dirtiest" plants; the second period covered all fossil fuel-fired power plants for the period 2000 and beyond. Analyzing the highly politicized context within which these allowances were distributed may provide insight into how to design politically feasible climate policy.

Joskow and Schmalensee use the final allocation to statistically examine the political factors that determined the distributional implication of phase II allocation by state.[113] The authors analyzed each state by special interest groups; leadership positions of the state's senators and congressmen; and the degree of competitiveness in

107 Bailey & Rupp, 2003.
108 Ibid.
109 Jordan et al., 2001.
110 Ibid.
111 Bailey & Rupp, 2003.
112 Ibid.
113 Joskow & Schmalensee, 1998.

senate, governor and president races. The acid rain program did not reflect a clear split between political parties; therefore, party affiliation was omitted from the analysis. Statistical analysis did not reveal any simple, structural theory of distributive politics present in phase II allocations.[114] Analysis did reveal that states considered "dirty" faired worse than average. Also, states with political clout (as indicated by being swing states in 1988 presidential elections, having competitive gubernatorial elections approaching, or having members in the House Energy and Commerce committee leadership) did comparatively well in phase II allocations.

One hypothesis supporting these results suggests that the Midwestern coalition that exerted early effort to thwart sulfur dioxide caps was too late coming to the allocation table once such legislation became inevitable. The states comprising this coalition failed to mobilize their powerful political capital to secure a larger share of allowances and instead ended up being some of the principal losers in the phase II allocation. While representatives from these states—namely Congressman Dingel from Michigan and Senator Byrd from West Virginia—were successful in delaying the passage of sulfur dioxide caps for nearly a decade, once this proposal became inevitable, their political influence within Congress was not harnessed in the allocation scheme.

LESSONS ON ATTRACTING POLITICAL CAPITAL FROM GLOBAL CLIMATE POLICY

Although Weiner's article, "Designing Global Climate Regulation," focuses on the complexities of climate policy formation at the global level, his discussion of participation efficiency sheds some light on the issues encountered with climate policy at the U.S. federal level. Taxes are widely recognized as a more efficient instrument than tradable allowances under an autocratic government, where a law is laid down by a singular rational actor.[115] However, neither the international nor the U.S. policymaking system is autocratic.

In policy at the international level, such as the Kyoto Protocol, participation must be attracted, not coerced, because sovereign states can be bound only to treaties they sign. Therefore, participation efficiency, defined as "the ability to attract participation at least cost," is critical to voluntary agreements.[116] Forms of international climate policy include direct subsidies for abatement in the form of cash subsidies, emission taxes or quantity-based instruments. A key component of each of these policy vehicles is their participation-efficiency potential. Similarly, at the federal level, a key component in the relative merits of various policy instruments is their ability to attract the support of at least 51 percent of the policymakers. Direct subsidies may create incentives for some parties to falsely pose as losers, which may erode cooperation and repel otherwise willing participants.[117] Emissions taxes impose the highest upfront costs on sources (assuming allowances are grandfathered) and therefore have the lowest participation efficiency. While the taxes may be coupled with positive side payments to engage participants, the side payments would have to be large enough to ensure positive net benefits to participation and would most likely negate emission reductions. Lastly, although quantity-based instruments repel would-be losers, fixed quantity targets coupled with direct payments may help attract the participation of cooperative losers, as was done to get Russia to sign on to the Kyoto Protocol.

Again, the international context of voluntary emissions treaties is very different from the U.S. majority-rules system in which parties may have to comply with a policy even if they fall in a minority that does not support it. Participation efficiency is not as critical at the federal level because a policy needs only 51 percent of the votes to be adopted. That said, the support needed to adopt federal climate policy depends, in part, on the policy instrument employed. Just as in the international context, quantity-based instruments in conjunction with allocation side payments may represent the most promising vehicle for U.S. federal climate policy.

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114 Ibid.
115 Wiener, 2002.
116 Ibid.
117 Ibid.

GOVERNMENT REVENUE VERSUS SOCIAL WELFARE CONSIDERATION IN POLICY CHOICE

Haucap and Kirsten[118] examine government incentives to choose either allowances or taxes to regulate pollution based on the government's relative interest in business concerns versus that of own revenue. Allowances are considered durable goods, whereas taxes are essentially a temporary lease on the right to pollute. Under either arrangement, governments are monopoly providers of the goods (e.g., allowance or tax lease). They theorize that governments, as profit-maximizing monopolists, have incentives to sell more allowances to the market each period until the additional revenue of the last allowance equals the marginal cost of provision. Because the buyers realize this incentive to sell more allowances in the next period, the government faces a credibility problem that will eventually erode its market power. Governments can avoid this credibility problem by leasing the right to pollute via a tax. Under taxing systems, the government can offer the profit-maximizing amount of leases in any given period. Tax systems simplify the firm's strategizing by removing the complexity surrounding banking allowances for future use.

However, governments do not operate solely as revenue-maximizing monopolists; they also have welfare concerns. The authors evaluate four different types of government along the revenue/welfare continuum: the benevolent dictator, the pure Leviathan, the green and the business-friendly. The later type most closely resembles the current U.S. system. The authors' analysis finds that although taxes maximize government revenue because they allow the government to be price setters every period, taxes perform worse in social-welfare terms. Allowances, on the other hand, force the government to deal with its credibility problem and lower the price of allowances to a price that equals marginal cost, the socially optimal level. For the U.S. government, which traditionally favors environmental regulation that imposes the least cost to business productivity and is not a source of government revenues, allowances represent the most socially efficient instrument to limit pollution.

118 Haucap & Kirstein, 2003.

Climate-Related Proposal Overviews

Given the political reality that a quantitative system, rather than a tax, is most likely to garner support, a number of climate policies based on cap-and-trade have been introduced at the national, regional and state levels. This section briefly describes the major proposals.

CONGRESSIONAL PROPOSALS

Climate Stewardship Act of 2003

Sponsored by Senators McCain (R-AZ) and Lieberman (D-CT), the Climate Stewardship Act of 2003 (CSA) failed by a vote of 43 to 55 on October 30, 2003.[119] The bill, S.139, proposed mandatory caps on greenhouse gas emissions for the electricity-generation, transportation, industrial and commercial economic sectors, which collectively accounted for approximately 85 percent of U.S. emissions in 2000. Agricultural, residential and any other sectors in which tracking emissions is infeasible were exempted from the mandatory cap.

The CSA assumed a cap-and-trade framework wherein covered entities would be allocated a certain number of emissions allowances according to a specified cap level, and the entities would be permitted to trade their allowances on the open market, allowing for least-cost compliance. The CSA would have capped emissions to 2000 levels by 2010. Covered emissions included CO_2, HFC, PFC and SF_6, all of which were converted to metric tons of carbon dioxide equivalents ($MTCO_2E$) for ease of comparison. Covered entities that did not submit to the Environmental Protection Agency, which would administer the program, one allowance for every $MTCO_2E$ they were associated with producing would be charged a penalty fee of three times the market value per ton of $MTCO_2E$.

Only entities in the covered sectors that dealt with more than 10,000 $MTCO_2E$ would be subject to CSA's requirements. Involvement could come in the form of owning a facility that emits greenhouse gases or producing or importing energy resources that emit greenhouses gases (e.g., petroleum, coal). The Secretary of Commerce would be responsible for determining the amount of allowances granted to existing entities and auctioned to entities who wanted to buy more on the open market. Proceeds from the auction were to reduce consumer energy costs and help workers disproportionately affected by the law.

One of the most notable features of the CSA was the flexibility granted for compliance. Not only were entities allowed to buy and trade their allotted allowances;; they also were permitted to meet 15 percent of their requirements through international allowances (e.g., through the European Trading Scheme), sequestration, registered reductions in noncovered entities, and/or borrowing allowances against future reductions. Covered entities that reduced emissions to 1990 levels were permitted to meet 20 percent of their requirements through the aforementioned methods.

The CSA also called for development of the National Greenhouse Gas Database, a centralized mechanism to report, inventory and register emissions reductions. Participation in the database would be mandatory for covered entities, and noncovered entities could voluntarily opt in, making them eligible to benefit from the 15 percent reduction measure. While the Commerce Department would be in charge of setting measurement and verification standards for the database, the EPA Administrator would be responsible for its implementation.

119 Michaelowa et al., 2003.

A companion bill to the CSA was introduced in the House by Representative Wayne Gilchrest (R-MD) in 2004 as H.R.4067. During the 109th Congress, Gilchrest reintroduced the same proposal as H.R.759. Although the bill has collected nearly 100 cosponsors, it has never officially been introduced on the House floor.

Clean Air Planning Act of 2003

Introduced by Senator Carper (D-DE), the Clean Air Planning Act (S.843) would require electric-power plants to reduce their emissions of SO_x, NO_x, mercury and CO_2 through a cap-and-trade system. The proposed CO_2 reduction schedule would reduce power-plant emissions to 2006 levels by 2009 and 2001 levels by 2013. Often referred to as a "4P Bill," the proposal would limit four pollutants as an alternative to President Bush's Clear Skies proposal, which would address only SO_x, NO_x and mercury.

An identical bill (H.R.3093) was proposed in the House by Representative Bass (R-NH) in 2003. Neither of the bills was ever brought to a floor vote.

Clean Power Act of 2003

The Clean Power Act of 2003 (S.366), proposed by Senator Jeffords (I-VT), would require electric-power plants to make reductions in SO_x, NO_x, mercury and CO_2—making it another "4P Bill." The caps would require CO_2 emissions to be gradually decreased, eventually reaching 1990 levels by 2009.

The Clean Smokestacks Act of 2003 (H.R.2042), proposed by Representative Waxman (D-CA), is identical to S.366. Neither of the bills was ever brought to a floor vote.

Climate Stewardship and Innovation Act of 2005

The Climate Stewardship and Innovation Act of 2005, sponsored by Senator McCain, was voted down as an amendment (S.1151) to the Energy Policy Act of 2005 by a vote of 38 to 60. The CSIA was almost identical to the Climate Stewardship Act of 2003 in that it proposed the same cap-and-trade system to limit greenhouse gas emissions to 2000 levels by 2010. The major difference was that the CSIA increased incentives for "climate-friendly technologies"; hence the addition of "Innovation" to the title. Under the bill, climate-friendly technologies included integrated gasification combined cycle with geological sequestration, large-scale cellulosic biofuel production, large-scale solar power facilities and advanced nuclear reactors. The inclusion of nuclear in the technology suite is believed to be responsible for the loss of votes as compared to the 2003 proposal.

Climate and Economy Insurance Act of 2005

The Climate and Economy Insurance Act (CEIA) of 2005 was a proposal drafted by Senator Bingaman (D-NM), ranking member of the Senate Energy Committee. The CEIA was based on the recommendations of a report published by the National Commission on Energy Policy titled *Ending the Energy Stalemate: A Bipartisan Strategy to Meet America's Energy Challenges*. Although the proposal stimulated a good deal of discussion upon its drafting in June 2005, it was never officially introduced on the Senate floor.

The CEIA would direct the Secretary of Energy to establish mandatory emissions targets based on emission-intensity measurements.[120] This approach is different from the absolute emissions targets of the CSA, because intensity targets are relative to economic activity. The proposal covers "upstream" fuel producers as well as manufacturers, importers and emitters of non-fuel greenhouse gases (e.g., HFC, PFC, SF_6 and N_20).

The CEIA also used a cap-and-trade framework; however, its cap levels were derived differently than in the CSA. Under Bingaman's proposal, the Department of Energy would calculate absolute emissions caps for years 2010-2019 by reducing the Energy Information Agency's projected emissions intensity by 2.4 percent each year and then multiplying that intensity measure by the forecasted GDP. For the next period, 2020-2024, the annual intensity reduction would be increased from 2.4 percent to 2.8 percent. Targets were to be established at least four years out (i.e., in 2006 for the first period and in 2016 for the second period) to give covered entities time to plan for compliance.

Once emissions targets were set, the Secretary of Energy would allot allowances equal to 91 percent of the target to regulated entities in a manner that offset losses expected from the proposal. The percentage of emission allowances allotted would gradually decrease until after 2019, when the allowance would stay at 87 percent. The balance of allowances would go toward auctions (5 percent in 2010; 10 percent after 2019), disproportionately affected workers (1 percent), international emissions offsets (3 percent) and early reductions (1 percent). In addition to allowances, credits would be granted to entities that geologically sequestered CO_2, exported fossil fuels or greenhouse gases [HOW WOULD YOU EXPORT A GREENHOUSE GAS?], or destroyed non-fuel greenhouse gases. These credits would reduce the number of allowances an entity was required to submit.

One of the most unusual features of the CEIA was its safety-valve mechanism whereby covered entities could pay a fee if they did not submit enough allowances to cover their year's emissions. The fee would begin at $7 per $MTCO_2E$ in 2010 and increase at an annual nominal rate of 5 percent. While this safety valve mechanism ensured that covered entities would not have to pay more than a certain price for compliance, it also introduced uncertainty as to the actual emission reduction outcomes. Covered entities that did not submit enough allowances or pay the safety-valve fee to meet their emission requirements would be fined three times the current safety-valve price.

The proposal also directs the president to establish an interagency group to examine climate policies in the member states of the Organization for Economic Co-operation and Development and in countries with emerging economies. Based on its research, the group was to make recommendations on potential modifications to the system, including adjustments to targets and safety-valve prices.

Sense of the Senate Resolution on Climate Change

This nonbinding resolution was introduced by Senator Bingaman as an amendment (S.Amdt.866) to the Energy Policy Act of 2005 and agreed to by a voice vote on June 22, 2005. The statement acknowledges the growing scientific consensus that human activity is causing an accumulation of greenhouse gases in the atmosphere. It also asserts that Congress should enact a mandatory national program that slows, stops and reverses the growth of greenhouse gas emissions using a market-based structure. It notes that such a program would not be likely to significantly harm the U.S. economy and should encourage major U.S. trading partners to adopt similar programs. While this amendment was nonbinding in the sense that no actual program was enacted, it did put the majority of the Senate on record as supporting its statements calling for a national mandatory program.

120 Emissions intensity is defined as the total amount of covered greenhouse gas emissions divided by the forecasted GDP.

New Apollo Energy Act

Introduced by Representative Inslee (D-WA) on June 9, 2005, the New Apollo Energy Act (NAEA) is much like the CSA, with a few modifications. The bill (H.R.2828) would impose a mandatory cap of greenhouse gas emissions at 2000 levels by 2015 (five years later than the CSA). The NAEA also asserted a strong commercial clean-coal component (various renewable forms of energy are also mentioned). It set escalating targets to sequester and recapture carbon equal to percentages of total U.S. greenhouse gas emissions: 20 percent by 2010, 40 percent by 2015 and 60 percent by 2020. To help in reaching these targets, the legislation would provide tax incentives for aggressive emission-control systems and up to $7 billion in loan guarantees for carbon-sequestering coal-fired power plants.

Keep America Competitive Global Warming Policy Act

Representative Udall (D-NM) introduced the bill (H.R.5049) on March 29, 2006.The bill establishes a cap-and-trade program beginning in 2009, along with a safety-valve provision set at $25 per ton. It also gives guidance for allocating allowances to compensate affected parties, provides transition and low-income assistance, funds research and development programs, and assists with emissions-reduction projects in developing countries. Up to 10 percent of allowances are to be given to the oil, natural gas and coal industries, which must submit allowances to cover the emissions embodied in the fuel they sell. The rest are allocated to states governments, the electric power industry, energy-intensive industries and the U.S. Departments of State, Energy and Treasury.

WHITE HOUSE PROPOSALS

Bush Climate Change Plan

In February 2002, President Bush introduced his proposed Climate Change Plan. The plan involved a voluntary greenhouse gas intensity target for the entire U.S. economy. The proposed target would aim to reduce the ratio of annual emissions to GDP by 18 percent by 2012. Analysis by the Pew Center on Global Climate Change suggests that such a target would allow actual emissions to increase by 12 percent over the period.[121]

STATE AND REGIONAL PROPOSALS

Regional Greenhouse Gas Initiative

The Regional Greenhouse Gas Initiative is an agreement between seven northeastern states (Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York and Vermont) to design and implement a mandatory greenhouse gas emissions-reduction program. Begun in April 2003, RGGI announced the final model rule specifying the details of the program on August 15, 2006.

RGGI uses a cap-and-trade framework for emissions reductions and covers electricity plants that have a capacity of more than 25 megawatts and burn at least 50 percent fossil fuels. Targets are designed to stabilize emissions between 2009 and 2015 and then gradually reduce emissions between 2015 and 2018, ultimately achieving a 10 percent reduction from current levels by 2019. Allowances will be collected every three years, a temporal flexibility

121 Pew Center on Global Climate Change, 2002.

measure that accounts for weather spikes that may affect emissions. The allowance period may be extended one year if the allowance price stays above $10 for a "sustained period."

Covered entities will have the option to fulfill part of their allowance requirements by supporting offset activities involving projects that reduce sulfur hexafluoride emissions, methane emissions from landfills and/or agricultural manure, or reduce CO_2 emissions through forest sequestration and/or end-use energy-efficiency projects. The percentage of emissions permitted through offsets is initially 3.3 percent; but this share may be increased if the price of carbon allowances on the open market reaches certain thresholds.

Participating states retain the right to distribute emission allowances as they see fit, so long at least 25 percent of the allocations are reserved for consumer benefit or strategic energy purposes. These reserves will be auctioned on the open market, and the proceeds are to go toward consumer rebates and/or energy-efficiency and renewable-energy projects.

California Global Warming Solutions Act of 2006

Signed into law on August 31, 2006, the California Global Warming Solutions Act of 2006 (A.B.32) requires the California State Air Resources Board to promulgate and implement a cap on greenhouse gas emissions from stationary sources, including electricity plants and facilities in the industrial and commercial sectors. As part of its mandate, the board must design a reduction schedule, develop enforcement mechanisms, and establish a program of mandatory reporting and tracking of emissions.

Under the law, emissions must be reduced to 1990 levels by 2020, a 25 percent reduction from current levels. The law pertains to all electricity consumed in the state, including that produced outside and then transported into the state. There are provisions within the law that account for early action so as to not penalize covered entities that voluntarily reduce their emissions prior to the law's implementation. The law specifically mentions "market-based compliance mechanism" as a means of compliance; most likely this will take the form of a cap-and-trade system. A.B.32 makes California the first state to pass a mandatory cap on all greenhouse gases emitted by major sources.

NONGOVERNMENTAL ORGANIZATION PROPOSALS

Sky Trust

Proposed by the Common Assets Defense Fund, a Washington, D.C.-based nongovernmental organization, the Sky Trust proposal would reduce U.S. carbon emissions to 1990 levels (1.3 billion metric tons) using a cap-and-trade system. All entities introducing fossil fuels into the economy (e.g., coal mines, petroleum importers, natural gas producers) would be required to submit an allowance for every ton of carbon they imported, giving the proposal an upstream concentration. As opposed to other systems that freely grant allowances to existing firms, all of the allowances would be auctioned by the federal government under Sky Trust. Seventy-five percent of the revenue generated from the auction would go into the Sky Trust, and the money would then be distributed directly to each legal U.S. resident in the form of equal annual payments. The remaining 25 percent of revenues would go to finance transition costs for disproportionately affected producers and consumers.

Table 2-4 summarizes major recent U.S. climate policy proposals.

Table 2--4: Summary statistics of climate-related proposals

Proposal Name	Bill #	Sponsor	Mandatory	GHG Targets	Status	Sectors Covered	Notes
Climate Stewardship Act of 2003	S.139	McCain	Yes	2000 levels by 2010	Vote failed (45-55)	Virtually all large emitters (downstream)	Covers CO_2, HFC, PFC, and SF_6
Clean Air Planning Act of 2003	S.843	Carper	Yes	2006 levels by 2009, 2001 levels by 2013	No vote	Electric power plants	Proposed substitute for Clear Skies
Clean Power Act of 2003	S.366	Jeffords	Yes	1990 levels by 2009	No vote	Electric power plants	Proposed substitute for Clear Skies
Climate Stewardship and Innovation Act of 2005	S.Amdt.826	McCain	Yes	2000 levels by 2010	Vote Failed (38-60)	Virtually all large emitters (downstream)	New nuclear provision lowered votes
Climate and Economy Insurance Act of 2005	None	Bingaman	Yes	Reduce GHG intensity 2.4% annually	Never introduced	Upstream producers & importers	Safety valve price beginning at $7/MTCO_2E$
Sense of Senate on Climate Change	S.Amdt.866	Bingaman	No	Slow, stop, reduce emissions growth	Passed by voice vote	Not mentioned	Mentions U.S. trading partners
New Apollo Energy Act	H.R.2828	Inslee	Yes	2000 levels by 2015	No vote	Virtually all large emitters	Aims to sequester carbon
Bush Climate Change Plan	None	President Bush	No	18% GHG intensity reduction (2002-2012)	Never Introduced	Net U.S. emissions	Allows for a GHG increase
Regional Greenhouse Gas Initiative	None	Northeastern States	Yes	10% below 2006 levels by 2019	Model Rule agreed to August 2006	Electric power plants over 25 MW	Allowances collected every 3 years
CA Global Warming Solutions Act of 2006	A.B.32 (CA Leg)		Yes	1990 levels by 2020	Signed into law August 2006	All large stationary sources	Early action provisions
Sky Trust	None	CADF (NGO)	Yes	1990 levels	Never introduced	Net U.S. emissions	No allowances grandfathered

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Chapter 3 – Technology Policies

Focused effort on technology development and innovation is necessary to reduce global greenhouse gas emissions. Because climate change is such a long-term problem, any initial, politically viable carbon policy framework will almost certainly cover a much shorter time frame than what is needed to reach stabilization. However, without the certainty of an emissions cap trajectory over the next 50 to 100 years, the market will most likely invest less in long-term technology innovation than is socially optimal. Technology policies can correct this market failure.

Various policies have been designed to overcome a number of barriers and challenges facing climate-friendly behavior as well as development and adoption of advanced climate change mitigating technologies. Supply-side policies include public benefit funds (renewables), renewable portfolio standards, feed-in tariffs, reverse auctions, subsidies and incentives, and research and development (R&D) funding. Demand-side policies include demand management, energy-efficiency utilities, public-benefit funds (energy efficiency), revenue decoupling, building codes and standards, appliance standards, rebates and tax incentives, and loan assistance programs. This chapter examines these two general categories of technology policies.

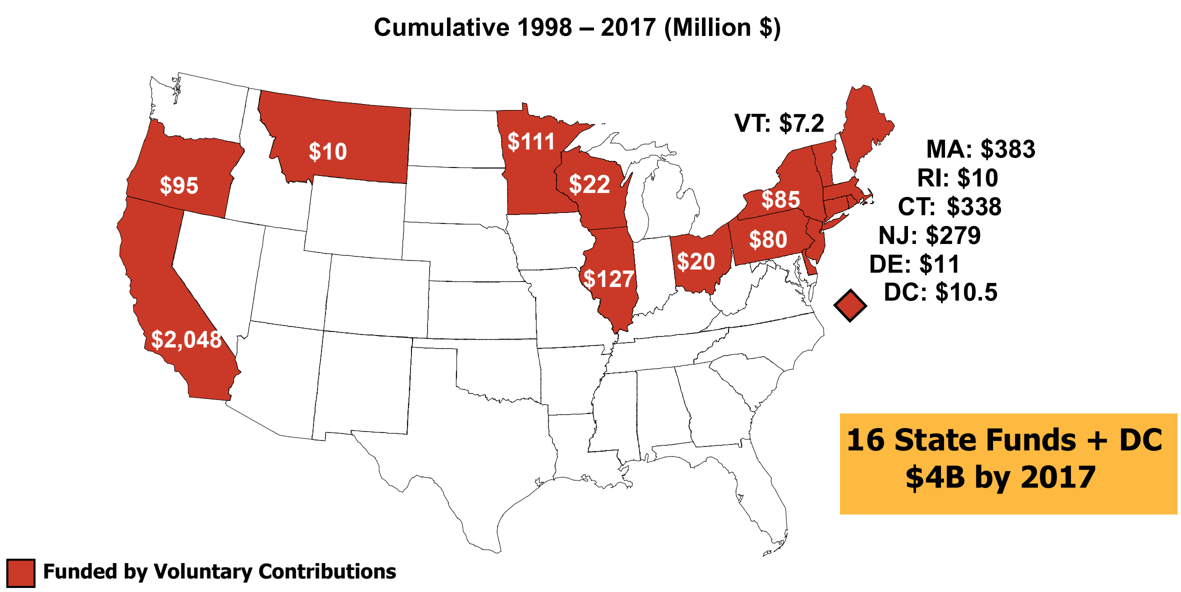
Supply-Side Technology Policies

Supply-side technology policies are designed to drive the creation or expansion of specific technologies. With respect to a national carbon policy framework, these technologies include renewable and/or low greenhouse gas emission applications. The choice of policy best suited to effect change is depends on a number of factors, including political, regulatory, economic, technological and social considerations. The suite of demand-side policy options include public-benefit funds (renewables), renewable portfolio standards, feed-in tariffs, reverse auctions, subsidies and incentives, and R&D funding. Each of these policy options has its own strengths and weaknesses and has experienced its own level of success. This section introduces each policy, describes key attributes, indicates where they have been implemented, and provides an overview of past impacts and future potential.

PUBLIC-BENEFIT FUNDS

A public-benefit fund (PBF) program consists of assessing a small charge—on the order of tenths of a cent per kilowatt hour (kWh)—on electricity and/or natural gas ratepayers and redistributing the money to promote growth of renewable energy and energy-efficiency programs.[1] PBFs provide funding for energy efficiency, low-income rate assistance and public education, as well as renewable energy research, development, installation and operation.[2] This section will focus on PBF funding for renewables; the role of PBFs in encouraging energy efficiency is discussed below in "Demand-Side Policies." About 16 states[3], plus the District of Columbia, have adopted PBF programs to complement renewable portfolio standards programs (Figure 3-1).[4] PBFs collect $500 million per year to support energy efficiency and renewable energy.[5]

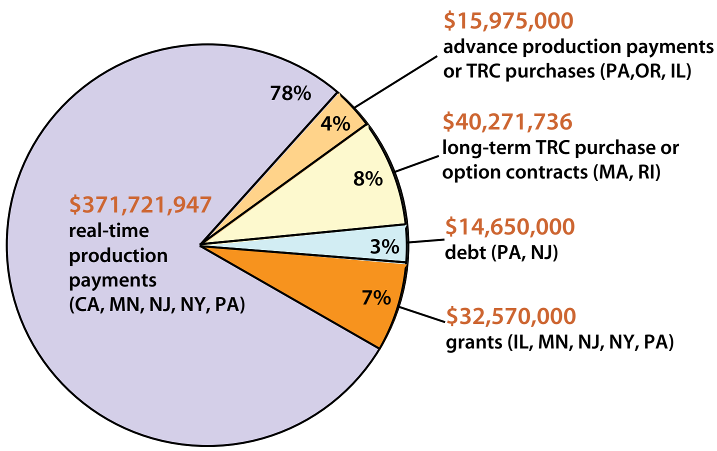
Figure 3-1. U.S. public-benefit fund programs for renewables[6]



1 CPAC, 2004.
2 Heiman & Solomon, 2004.
3 N.C. Solar Center, 2006. NOTE: The total number of states with PBC funds varies from resource to resource. The estimate of 16 states plus the District of Columbia is based on the database at *www.dsireusa.org*
4 NOTE: According to the database on *www.dsireusa.org,* the only state that employs PBCs to support energy efficiency and renewable energy that does not also have an RPS is Ohio.
5 Bolinger & Wiser, 2006.
6 N.C. Solar Center, 2006. NOTE: This map does not include Vermont, whose program began in 2005. Vermont's PBC program allows for expenditures of $6 million to $7.2 million per year until 2012.

PBF programs, which have provided over $400 million in obligated funding for renewable energy and energy efficiency, are credited for an early increase in new obligated renewable capacity.[7] However, poor availability of financing and power purchasing agreements (PPAs), in addition to lengthening development periods, has slowed the growth of new obligated capacity since 2003.[8] Contributing to the decline of capacity directly linked to PBF programs is the afflux of state RPS programs entering the implementation phase. With the results of traditional incentive structures, such as production incentives and grants, coming to a plateau, states have begun to extend new types of incentives to renewable energy project developers.[9] Newer incentive structures include advance production incentives, long-term renewable energy credit (REC) purchases and the provision of financing in the absence of a long-term PPA. At this time, however, real-time production payments remain the preferred form of financing (Figure 3-2).[10]

Figure 3-2. Percentage of obligated dollars awarded through various incentive types[11]



The disbursement of public-benefit funds differs on a state-by-state basis. Most states give PBFs a mandate to invest in renewable energy (often with an emphasis on small-scale distributed renewables), energy efficiency, public education and assistance to low-income households. Recipients of funds may be selected based on specific criteria, such as a project's potential to induce energy savings.[12] Another criterion may be to select the projects that need the least amount of funding on a per kWh basis, creating a type of "bidding war" among applicants (see "Reverse Auctions").[13] Funds are also divided among the development of noncommercial technologies, production and investment incentives for utility-scale renewable energy projects and maintenance of noncompetitive existing renewable supply.[14] With the addition of renewable portfolio standards programs in many states, some PBF investments have been diverted to offset above-market costs of RPS contracts. In New York, the addition of a renewable portfolio standards program required the cancellation of public-benefit funds for 267 megawatts (MW) of wind projects because participants in the state's RPS program are required to forfeit their PBF funding.[15]

Public-benefit funding for new programs has led to 1,115 MW of online renewable capacity in the United States, with 1,133 MW pending (Table 3-1).[16] In addition, 393 MW of renewable capacity have been cancelled.[17] The gap between obligated capacity and on-line capacity, represented by pending and cancelled capacity, has remained

7 Bolinger & Wiser, 2006.
8 Ibid.
9 Ibid.
10 Ibid
11 Ibid.
12 MacKie et al., 2004.
13 Bolinger & Wiser, 2006.
14 Heiman & Solomon, 2004.
15 Bolinger & Wiser, 2006.
16 This increase in renewable capacity is directly related to PBF funding and is independent of any capacity installed as a result of state RPS programs.
17 Bolinger & Wiser, 2006.

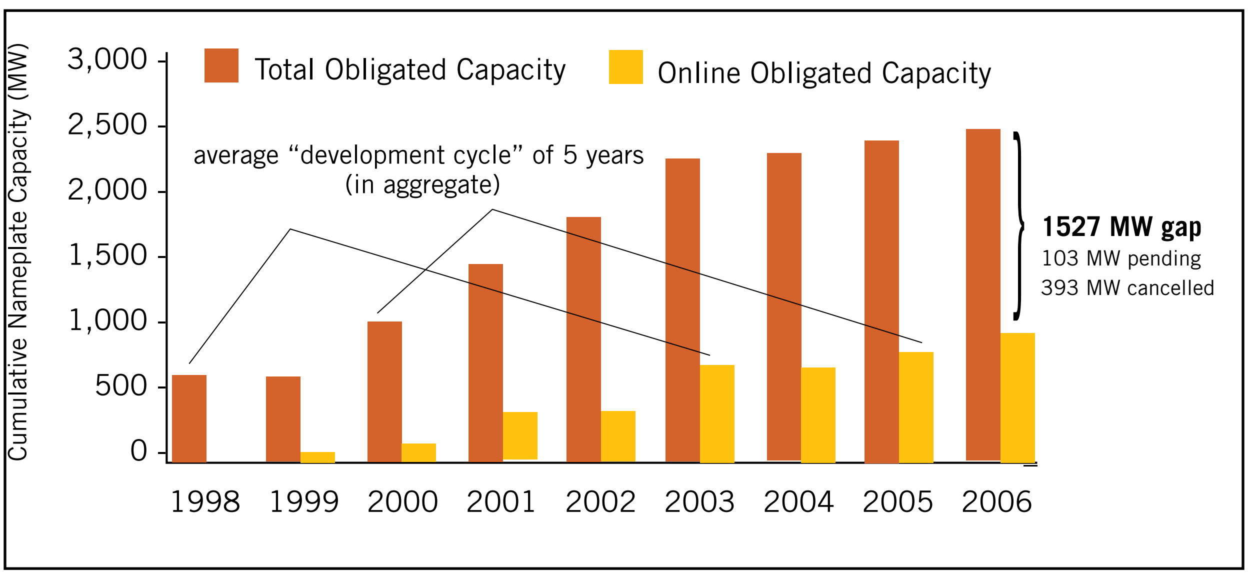
fairly constant over the past three years, due to difficulties in the development process.[18] Developers of renewable energy projects must overcome such obstacles as permitting challenges, lack of power purchasing agreements and unreliable extension of production tax credits by Congress.[19] These barriers to development have caused the length of development for new renewable energy projects to average about five years, as shown by Figure 3-3. This time lag between approval of funding and electricity production makes renewable energy projects less attractive for investors, as well as a potential quagmire for politicians who desire to display short-term positive results to their voters.

Table 3-1. Summary of state support for utility-scale renewable projects as of March, 31, 2006[20]

Project Location	# of Projects	Funding Originally Obligated ($)	Funding Currently Obligated ($)	Capacity Obligated (MW)	Capacity Cancelled (MW)	Capacity Pending (MW)	Capacity On-Line (MW)	Average Cost (Current Funding/ Capacity Pending plus Capacity On-Line) ($/MW)
CA	60	$243,573,376	$189,970,791	1,291.5	64.5	748.5	478.5	$154,828.70
IL	5	$8,425,000	$8,425,000	112.5	0.0	6.0	106.5	$ 74,888.89
MA*	5	$32,756,736	$32,756,736	52.3	0.0	49.0	3.3	$626,323.82
ME*	1	$5,600,000	$5,600,000	19.0	0.0	19.0	0.0	$294,736.84
MN	147	$107,679,545	$107,679,545	253.3	1.7	35.3	216.3	$427,911.08
NH*	1	$2,720,000	$2,720,000	50.0	0.0	50.0	0.0	$ 54,400.00
NJ	6	$17,782,026	$14,682,026	38.9	21.0	6.9	11.0	$820,683.38
NY	11	$25,560,000	$10,460,000	316.1	266.5	8.0	41.6	$211,099.90
OR	4	$3,800,000	$3,800,000	122.0	0.0	6.0	116.0	$ 31,147.54
PA	10	$27,292,000	$21,442,000	386.6	39.6	204.5	142.5	$ 61,792.51
Total	250	$475,188,683	$397,536,097	2,642.2	393.3	1,133.2	1,115.6	$176,772.75

*Maine and New Hampshire do not currently have clean energy funds. The projects located in these two states have received support from Massachusetts' clean energy fund. Similarly, one wind project located in Massachusetts has received financial support from Rhode Island's renewable energy fund.

Figure 3-3. Cumulative renewable capacity obligated and on-line over time[21]



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18 Obligate capacity is defined as capacity from projects that are in the development phase; on-line capacity is define as capacity that is currently providing electricity to the grid; and cancelled capacity represents all projects whose funding contracts have been cancelled.
19 Heiman & Solomon, 2004.
20 Clean Energy States Alliance, 2006.
21 Bolinger & Wiser, 2006.

Wind, by far, is the biggest recipient of PBF support, accounting for 87 percent of installed capacity, followed by geothermal at 5 percent (Table 3-2).

Table 3-2. Aggregate support for utility-scale renewable projects through PBFs, by resource type, as of March 31, 2006[22]

Resource Type	# of Projects	Funding Originally Obligated ($)	Funding Currently Obligated ($)	Capacity Obligated (MW)	Capacity Cancelled (MW)	Capacity Pending (MW)	Capacity On-Line (MW)
Biomass	9	$20,347,840	$16,407,902	98.7	9.5	77.9	11.3
Digester Gas	3	$4,108,210	$4,108,210	6.0	0.0	6.0	0.0
Geothermal	4	$80,331,618	$80,331,618	156.9	0.0	97.9	59.0
Hydro	8	$14,946,409	$13,757,139	50.8	0.0	18.5	32.3
Landfill Gas	30	$41,974,893	$33,689,649	91.7	23.7	24.6	43.4
Waste Tire	1	$7,232,413	$0	30.0	30.0	0.0	0.0
Wind	195	$306,247,300	$249,241,580	2,208.2	330.1	908.4	969.7
Total	**250**	**$475,188,683**	**$397,536,097**	**2,642.2**	**393.3**	**1,133.2**	**1,115.6**

Connecticut serves as an example of the potential impact of a PBF program. A $0.001 per kWh system charge would raise a total of $29 million annually until 2020. These funds would be used to purchase RECs, offsetting emissions from fossil fuel-powered generators. Under conservative estimates of high REC prices and an avoided emissions rate of 1,200 pounds per megawatt hour (MWh), the projected emissions reductions are 0.31 million metric tons (MMT) of carbon dioxide (CO_2) for 2010 and 0.41 MMT of CO_2 for 2020.[23]

Direct incentives—whatever form they may take—are easier to link to growth in renewable energy capacity than other forms of support, such as research and development and public education. Only 30 percent of public-benefit funds are designated for providing incentives for new supply.[24] Some opponents of PBF programs prefer renewable portfolio standards, green marketing and government financing, as they shift the burden of financial support toward private interests while letting the market pick the technologies.[25] A comparison between PBFs and portfolio standards is included in Table 3-3.

PBF programs are more flexible than alternate policies, as administrators are generally allowed to shift funding between emerging technologies that are competing for funding.[26] However, this flexibility may also prove to be detrimental to a PBF program's success. If not properly protected by the authorizing legislation, PBF programs may be susceptible to diversion to unrelated state government spending or to cover budget shortfalls. Public benefit funds also do not completely address one of the most significant barriers to renewable energy proliferation: resource intermittency. Operators of renewable facilities may be liable to pay penalties averaging 25 percent to 30 percent to transmission operators if the contracted output of energy is not met.[27] On the other hand, PBFs can be useful in providing crucial development funding for renewable energy and demonstration plants.[28]

22 Clean Energy States Alliance, 2006.
23 Connecticut Steering Committee on Climate Change, 2005.
24 Heiman & Solomon, 2004.
25 Switzer, 2002.
26 CPAC, 2004.
27 Heiman & Solomon, 2004.
28 Fitzgerald et al., 2004.

Table 3-3. Side-by-side comparison of portfolio standards and public benefits funds[29]

	Portfolio Standard	Public Benefit Charge
Key Attributes	- Mandated target approach using a flexible, market-based mechanism. - Goal-oriented: Delivers desired levels of efficiency or renewables, but with uncertain price impacts. (Can include price caps to address price uncertainties.) *Major uncertainty is cost.*	- Central fund approach allowing flexibility in future investment patterns. - Price-certain: Price impacts are defined by the level of charge (Xmills/kWh), but the amount of efficiency or renewables acquired is uncertain. (Charges can be altered, but not easily.) *Major uncertainty is level achieved.*
Design Questions	- Setting appropriate/ achievable goals - Determining qualifying resources (new vs. existing), etc.	- Setting appropriate/ acceptable charge levels - Allocating funds among target programs and technologies
Flexibility	- RPS: Tradable renewable energy credits. - EPS: Ability to gain credit by investing in regional activities (Northwest Energy Efficiency Alliance, BPA programs, etc.) or through combined heat and power.	- Can easily shift priorities among technologies and programs as conditions change.
Universality (small/large, IOU/COU)	No discernable differences?	
Administration & Implementation	- By UTC and municipalities - Implementation by Retail electricity providers (utilities)	- Administration and implementation by Central agency (i.e. OR Energy Trust) and/or utilities
Compliance & Verification	- RPS: Requires tracking system for generation attributes or certificates (can be modeled after other states) - EPS: Requires tracking system coupled with monitoring and verification. (No direct models available, could be adapted from demand-side management	- Oversight on proper use of funds by UTC or municipalities
Impact of Surplus Conditions (Note: meaning of “surplus” deserves further consideration)	- Financial loss or gain depending on whether surplus power is sold for more or less than cost. - Possible added risk and/or financing costs - Exemptions for surplus utilities are possible.	- Similar to portfolio standard, except funds can be banked or used for other purposes if cost impacts are unacceptable
Lowest cost vs. emerging technologies	- RPS: Typically focused on lowest cost commercial technologies (e.g. wind, geothermal, small hydro), but many jurisdictions include technology-specific targets. This can ensure resource diversity and help commercialize solar PV and other resources	- PBCs often support emerging, smaller-scale and non-electricity renewables applications. (e.g. solar PV, solar water heating, biogas, etc.)
Other Issues	- RPS: Renewable credit markets can create surplus for low-cost suppliers (adding to consumer costs), but competition can drive down costs.	- PBC funds can be diverted by state government to unrelated spending or budget shortfalls if not adequately protected.
Experience to Build Upon	- RPS: 15 states have one - EPS: WA would be the first	- Over 20 states have a PBC.
Potential for Complementarity (i.e. benefits of implementing both policies)	- Renewables: RPS and PBC can be implemented in tandem as is the case in several states (e.g. CA, NJ, MA). PBC funds often support smaller, emerging technologies, while, RPS policies promote larger and lower cost resources. PBC funds can also be used to help meet RPS goals (as CA is considering). - Efficiency: An EPS could conceivably provide efficiency targets, while an adjustable PBC could provide the means to achieve the targets.	

29 CPAC, 2004.

Renewable Portfolio Standards

BACKGROUND AND INTRODUCTION

Many U.S. states and several countries have implemented renewable portfolio standards (RPS) as a market pull on renewable energy technologies, both to facilitate adoption and lower costs through "learning by doing" and economies of scale. RPS programs require utilities to provide a minimum percentage of electricity from qualified renewable generation technologies (in some cases, programs require a minimum capacity of renewable resources in the system rather than minimum generation).[30] In the United States, Congress came close to passing federal RPS legislation when the Senate included in its version of the proposed Energy Policy Act of 2005 (EPAct 2005) an RPS of 10 percent.[31] Although the RPS legislation did not pass into law, 23 states and the District of Columbia have implemented either a mandated RPS program or minimum renewable electricity goals.[32]

The success of an RPS depends largely on providing the regulated entity with compliance flexibility. Many states have established tradable renewable energy credit (REC) markets that allow entities that cannot meet their renewable generation quotas to purchase RECs to apply toward their requirement. Some programs also allow utilities to receive credit for power purchased from other generators, provided that the power was generated from a renewable source.[33]

In the absence of a federal RPS policy in the United States, state RPS programs implemented in the past 10 years have produced a patchwork of heterogeneous policies. Each policy differs in the level of renewable generation that must be achieved, how regulated entities are allowed to meet the quota and which renewable sources are covered.[34] In most states, renewable generation now costs more than conventional generation; the likelihood of higher cost has somewhat limited RPS programs to states with good renewable energy potential and/or the political inclination to promote renewable energy. Proponents of RPS programs in states have typically cited economic development benefits of in-state renewable generation as a primary reason such policies; as a result, many RPS programs favor in-state renewables at the expense of out-of-state resources. Differences in resource availability, energy producers' political influence, utility deregulation status and public demand for renewable electric generation are factors that influence the heterogeneity among individual state RPS programs.

In the long term, market-pull policies such as renewable portfolio standards are intended to provide technology manufacturers with a sufficient demand to continually refine designs and manufacturing processes and to produce at greater economies of scale, advances that are expected to lead to reduced costs and better competition with conventional technologies. Since the implementation of RPS programs in the United States has only recently begun, a definitive evaluation of the effectiveness of RPS programs is not yet possible.

CURRENT APPLICATIONS OF RPS

Each state RPS program is different in many ways, including the percentage target, the generation sources allowed, the sectors of the economy regulated and availability of flexibility mechanisms such as REC trading. Table 3-4[35] and

30 Some RPS programs also include energy efficiency in the mix of technologies that can be used to satisfy the requirement.

31 However, RPS was removed in conference committee by request of the House of Representatives. The RPS was reported sacrificed in a trade for the demise of MTBE (a toxic gasoline additive) liability limitations. Inside Fuels and Vehicles (July 28, 2005). "Senate Trades Green Energy for MTBE in Final Deal on Energy Bill," Inside Washington Publishers. Vol. 4, No. 15.

32 Rabe, 2006.

33 Wiser et al., 2005.

34 Union of Concerned Scientists, 2006.

35 Rabe, 2006.

Figure 3-4 provide a summary of the specifics for each RPS program in the United States, including the final target for renewable generation capacity or percentage of total power generation. Table 3-5[36] displays the specific renewable sources that are eligible under each state's RPS program. An evaluation of the success or failure of some of these programs, based on the RPS program elements laid out in the previous section, is included below.

Table 3-4. State renewable portfolio standards; key design features[37]

State	Year Enacted	Date Revised	Governor Partisanship	Legislature Control	Preliminary Target	Final Target	Who's Covered	Credit Trading
Arizona	2001	2006	Rep	Split	0.2% by 2001	15% by 2025	Utility	No
California	2002	2005	Dem	Dem	13% by 2003	33% by 2020	Investor Owned Utility, Municipal Utility	Yes
Colorado	2004		Rep	Rep	3% by 2007	10% by 2015	Utility, Investor Owned Utility, Rural Electric Cooperative	Yes
Connecticut	1999	2003	Rep	Dem	4% by 2007	10% by 2010	Utility	Yes
Delaware	2005		Dem	Dem	1% by 2007	10% by 2019	Retail Electricity Supplier	Yes
District of Columbia	2005			Split	4% by 2007	11% by 2022	Utility	Yes
Hawaii	2004		Rep	Dem	7% by 2003	20% by 2020	Utility	No
Illinois	2005		Dem	Dem	2% by 2007	8% by 2013	Utility	No
Iowa	1991		Rep	Dem	none	105 MW	Utility	No
Maine	1999		Ind	Dem	none	30% by 2000	Utility	Yes
Maryland	2004		Rep	Dem	3.5% by 2006	7.5% by 2019	Electricity Supplier	Yes
Massachusetts	1997		Rep	Dem	1% new by 2003	4% new by 2009	Utility	Yes
Minnesota	1997		Rep	Dem	1,125 MW by 2010	1,250 MW by 2013	Xcel only	No
Montana	2005		Dem	Split	5% by 2008	15% by 2015	Utility	Yes
Nevada	1997	2005	Rep	Split	6% by 2005	20% by 2015	Investor Owned Utility	Yes
New Jersey	2001	2004	Rep	Rep	6.5% by 2008	20% by 2020	Utility	Yes
New Mexico	2002	2004	Rep	Dem	5% by 2006	10% by 2011	Investor Owned Utility	Yes
New York	2004		Rep	Split	none	25% by 2013	Investor Owned Utility	Yes
Pennsylvania	2004		Dem	Rep	1.5% by 2007	18% by 2020	Utility	Yes
Rhode Island	2004		Rep	Dem	3% by 2007	16% by 2020	Electric Retailers	Yes
Texas	1999	2005	Rep	Rep	2,280 MW by 2007	5,880 MW by 2015	Retail Supplier	Yes
Vermont	2005		Rep	Dem	none	load growth by 2012	Retail Electricity Supplier	Yes
Wisconsin	1999	2006	Rep	Rep	none	10% by 2015	Utility	Yes

36 Ibid.
37 Ibid.

Figure 3-4. Renewable portfolio standards by state[38][R4]

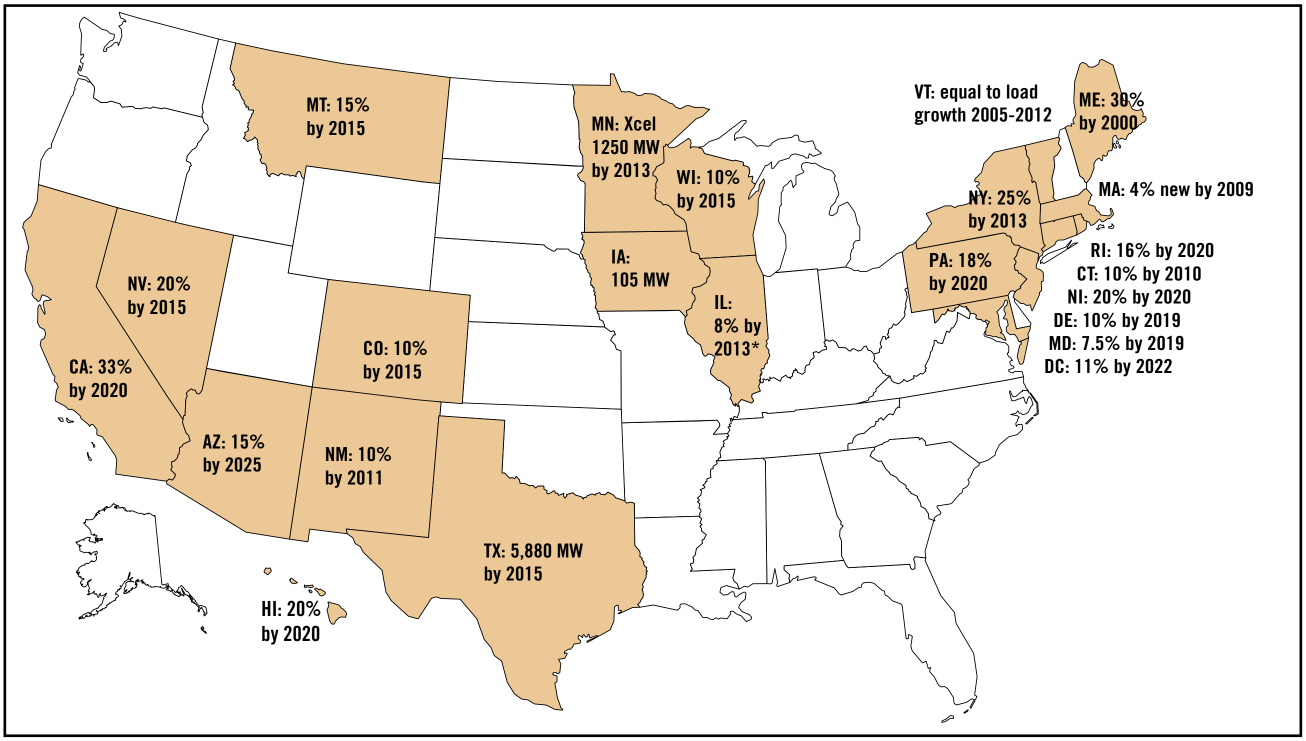


Table 3-5. Qualifying renewable electricity sources[39]

State	Wind	Photo-voltaics	Solar Thermal	Biomass	Geo-thermal	Small Hydro-electric	Fuel Cells	Landfill Gas	Tidal/ Ocean	Wave/ Thermal	Energy Efficiency
Arizona	√	√	√	√					√		
California	√	√	√	√	√		√	√	√	√	
Colorado	√	√		√	√	√		√	√		
Connecticut	√	√	√	√			√	√	√	√	
Delaware	√	√	√	√	√		√	√	√	√	
District of Columbia	√	√	√	√	√		√		√	√	
Hawaii	√	√	√	√	√		√	√	√	√	√
Illinois	√	√	√	√			√		√		
Iowa	√	√		√			√				
Maine	√	√	√	√			√	√	√	√	
Maryland	√	√	√	√	√		√	√	√	√	
Massachusetts	√	√	√	√				√	√	√	
Minnesota	√			√							
Montana	√	√	√	√	√		√	√	√		
Nevada	√	√	√	√	√		√		√		√
New Jersey	√	√		√	√		√	√	√	√	
New Mexico	√	√	√	√	√		√	√	√		
New York	√	√		√			√	√	√	√	

38 Ibid.
39 Ibid.

Pennsylvania	√	√	√	√	√		√	√	√		√
Rhode Island	√	√		√	√	√		√	√	√	
Texas	√	√	√	√	√		√		√	√	
Vermont	√	√	√	√			√	√	√		
Wisconsin	√	√	√	√	√		√	√	√	√	

Texas

Texas' RPS program is consistently viewed as one of the most successful RPS programs in the United States. In 1999, then Governor George W. Bush signed the Texas RPS into law and ignited what has come to be known as "The Great Wind Rush in West Texas," a phenomenon that helped Texas exceed its 2002 RPS obligation by twofold through 935 MW of wind power contracts established in 2001.[40] The original legislation mandated that 2,000 MW of renewable capacity be installed by 2009, in addition to the 880 MW of existing renewable capacity. Although the goal for 2009 amounts to only about 3 percent of the total electricity consumption in Texas, projected over-compliance prompted the legislature, in 2005, to extend the program to require 5,880 MW of renewable generation by 2015. In addition, the 2005 legislation set nonbinding targets of 500 MW of new renewable capacity derived from sources other than wind energy and 10,000 MW of renewable capacity by 2025.[41]

Texas has achieved a high level of RPS success due to its comprehensive implementation plan that includes specific, long-term goals and a tradable REC system that allows a great deal of flexibility in compliance.[42] First, the program applies to all investor-owned utilities, which comprise 80 percent of the total load in Texas. Each utility is required to meet an obligation proportionate to its annual electricity sales. Second, the long-term goals established by the RPS legislation have enabled renewable power generators to secure long-term purchase contracts, causing a rampant growth in wind-power investment. Third, the tradable REC system, which requires that each utility possess sufficient credits to meet its quota at the end of each year, allows utilities to bank credits for two years and/or borrow credits to meet up to 5 percent of their obligation during the first two years of compliance. The enforcement penalties are strict but serve as a reasonable price ceiling of $.05 per kWh or 200 percent of the mean REC trading value for those unable to meet their requirement.[43] The largest obstacle to further growth of the wind industry in Texas is the lack of transmission capability from large wind farms in West Texas to population centers in Dallas, San Antonio and Houston. However, the 2005 RPS extension legislation includes provisions that make the process for obtaining rights of way for transmission lines in Central Texas easier, which should allow for continued growth in the West Texas wind market.[44] Despite transmission issues, Texas investor-owned utilities have adopted wind power on a large scale, contracting for generation at prices under $0.03 per kWh with the help of the $0.019 per kWh federal tax credit.[45]

Massachusetts

The RPS experience in Massachusetts has been quite different from Texas. While in full compliance with the RPS (1 percent new renewable generation by 2003, 1.5 percent in 2004),[46] utilities have opted to purchase RECs from other New England states for more than half of their requirement. The boom of investment in renewable generation facilities seen in Texas has not materialized in Massachusetts. The largest proposed renewable generation project, a 420 MW offshore wind farm known as Cape Wind that would have 130 wind turbines, was successfully blocked by citizens on Cape Cod and Martha's Vineyard who did not want the view from their coastal properties

40 Mozumder & Marathe, 2004.
41 Rabe, 2006.
42 Langniss & Wiser, 2003.
43 Ibid.
44 Sloan, 2005.
45 Langniss & Wiser, 2003.
46 Union of Concerned Scientists, 2006.

impeded. The fallout from this fight has blocked siting of nearly all other large-scale wind projects in the western mountains of Massachusetts, as well as offshore. In the wake of the negative public response to wind energy, utilities in Massachusetts have selected biomass as the renewable generation source of choice, but power from biomass cannot easily be produced on the scale of projects such as Cape Wind.[47] The difficulty in siting new renewable generation has created a scarcity in long-term contracting for renewables in Massachusetts. Utilities have chosen to comply with the RPS via out-of-state REC purchases, boosting renewable energy investments in other states.

Pennsylvania

Pennsylvania embraces a two-tiered RPS approach that requires Tier 1 to make up 8 percent of its power generation by 2020 and Tier 2 to make up 10 percent by that date. Within Tier 1, 0.5 percent must come from solar photovoltaic (PV) power. Tier 1 technologies are typical renewable sources such as wind, solar, small hydro, geothermal and biomass. Tier 2 includes some nonrenewable technologies as well as some controversial renewable technologies, including waste coal, integrated gasification combined cycle (coal), large-scale hydropower, municipal solid waste and farm wastes. Due to the inclusion of these controversial technologies, some Pennsylvania environmental groups have dubbed this RPS program as the dirtiest in the country. [48]

The Pennsylvania RPS faces two other problems: the language is unclear regarding out-of-state REC purchases, and it does not require compliance from many electricity suppliers until 2011, which means it "has had no impact on renewable energy supply."[49] With regard to out-of-state purchases, the RPS policy makes conflicting statements, declaring that 1) "Eligible energy must be derived only from within the State of Pennsylvania" and 2) "within the service territory of any regional transmission organization that manages the transmission system in any part of this Commonwealth." The confusion is somewhat clarified by the assumption that renewable power purchases fall within the bounds of the Federal Inter-state Commerce Clause that requires Pennsylvania not to restrict the inter-state transmission of commerce.[50] The second problem has to do with the fact that the RPS applies only to independently owned utilities, and not all of those utilities are required to comply until 2011. Municipal utilities and rural co-ops are fully exempt from the RPS program, and electric distribution companies ("discos") are also exempt until they reach the end of their cost-recovery period.[51]

The requirement for regulated utilities is further complicated by the manner in which the renewable requirement is divided. Each regulated utility is required to deliver a minimum percentage of renewable energy to a certain percentage of its customers. For example, utility X could be required to provide 0.5 percent renewable power to 50 percent of its customers by year 2005 and to 80 percent of its customers by 2010.[52]

Pennsylvania's RPS experience appears to be a good basis for arguing in favor of a federal, unified approach to an RPS program that clearly establishes the definition of a renewable source, how much of an increase in production should be required, who should be under compliance and how stringent noncompliance penalties should be.

47 Rabe, 2006.
48 Union of Concerned Scientists, 2006.
49 Wiser et al., 2005.
50 Rabe, 2006.
51 Union of Concerned Scientists, 2006.
52 Berry & Jaccard, 2001.

Texas, Massachusetts and Pennsylvania represent a small sample of RPS programs within the United States. However, a brief review of each state's program demonstrates how heterogeneous the policies are. Standardizing and interconnecting the markets working within these dispersed systems can serve as a way to reduce costs for electric service providers and ratepayers by taking full advantage of renewable resources with the different regions of the country.

ECONOMIC COSTS ASSOCIATED WITH RPS

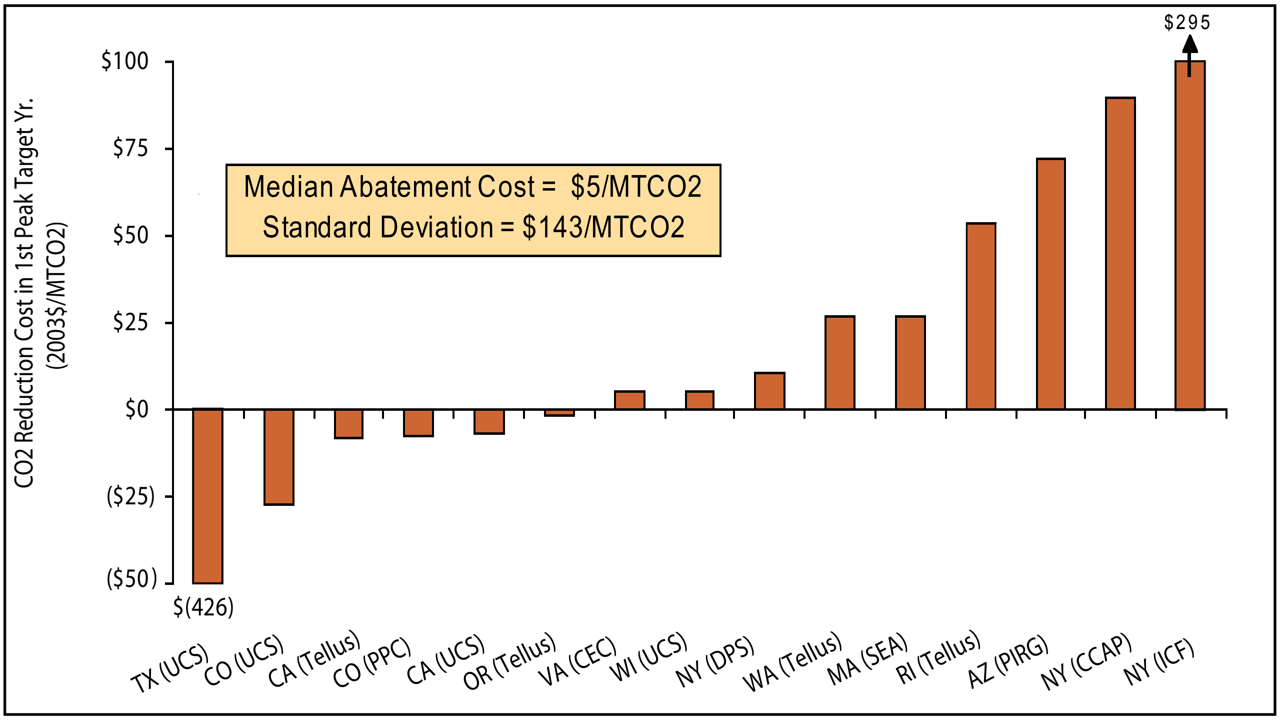
As mentioned in the previous section, some renewables can provide power to the market, especially with the help of federal tax credits, at a price that is competitive with traditional sources of generation (e.g., Texas wind is less than 3 cents per kWh).[53] A survey from the Lawrence Berkeley National Laboratory (LBNL) of multiple analyses of state RPS program costs shows that the impact on electric bills varies over a wide range. Renewable cost differentials range from a savings per household of $4 per month in Texas to an increase of $7.50 per household in New York and Arizona. The differences across states depend on many factors, including available renewable resources, RPS percentage requirements, timing, technologies allowed/required and flexibility mechanisms. The study's alternate scenarios show a wider range of potential additional costs than the base-case scenario for each state. Even with alternate scenarios, typical households in Texas, Hawaii, California and Oregon are likely to see lower electricity bills. Households in New Jersey, New York and Arizona are likely to see electricity bills increase by more than 5 percent, while households in the rest of the states are likely to see an increase of less than 5 percent.

RPS programs can provide an additional benefit by reducing pressure on natural gas markets, thereby lowering natural gas prices. Renewables tend to displace generation at low- to mid-range capacity factors, typically affecting natural gas-based generation more than others. For example, as a result of the RPS program, the price of natural gas was modeled to fall by just over $0.01 per million British Thermal Units (MMBTU) in Rhode Island, by nearly $0.03 per MMBTU in Texas and by $0.05 per MMBTU in Colorado.[54] While the results show a reduction in the cost of natural gas to residential customers, the magnitude of this reduction is quite small. Given the average residential natural gas price in 2003 of $9.63 per trillion cubic feet,[55] the actual reduction is no greater than 0.5 percent in the case of the Colorado (Union of Concerned Scientists) study.

Because RPS policies displace fossil generation from both existing and planned facilities, the effectiveness of RPS policies in reducing or avoiding CO_2 emissions can be evaluated. The analyses surveyed by the LBNL estimate that RPS policies result in implied CO_2 abatement costs (Figure 3-5) ranging from -$426 metric tons of carbon dioxide (MTCO2) in Texas to $295 per $MTCO_2$ in New York. 56 LBNL reports that 60 percent of these studies imply abatement costs of less than $10 per $MTCO_2$.

53 Langniss & Wiser, 2003.
54 Bolinger & Wiser, 2006
55 Unit conversions show this value to equal $9.63/MMBtu.
Data taken from http://tonto.eia.doe.gov/dnav/ng/hist/n3010us3a.htm on October 23, 2006.
56 Bolinger & Wiser, 2006.

Figure 3-5. CO_2 reduction costs in first target year of RPS[57]



ELEMENTS OF A SUCCESSFUL RPS PROGRAM

When designing an RPS, policymakers must first consider a few key elements. While most RPS programs are still new, experience thus far has shown that a well-designed RPS can lead to impressive increases in renewable power generation, while a poorly designed policy has little effect. One of the primary long-term goals of an RPS is to support renewables until they are commercially competitive with conventional generation. A successful RPS can create an economic environment for renewables to develop and mature.

First, both the level of the standard and the timing of incremental increases affect the ultimate outcome. Policymakers must set a realistic goal and clearly state well in advance future increases in the standard in order to achieve full, cost-effective compliance.[58] Firm, long-term goals allow for long-term purchase contracts of renewable energy, which in turn help developers obtain financing for new renewable facilities. Such contracts are instrumental in investors' decisions to invest the large amounts of money necessary to put capital-intensive renewable generation technology to work.

The standards' level and timing also affect the overall cost of the program. Providing sufficient phase-in time for the standard, as well as tailoring the size of standard to resource availability, can help to reduce the cost to utilities, which will pass on additional costs whenever possible to ratepayers.[59] Flexibility mechanisms, which are discussed below, can be used to minimize costs.

The second element that must be considered is the coverage of the program. Should municipal utilities or non-profit generators be exempt from the standard? May regulated entities apply for an exemption due to natural circumstances or financial hardship? Coverage will determine the total quantity of traditional generation offset

57 Ibid.
58 Wiser et al., 2005.
59 Berry & Jaccard, 2001.

or emissions abated. Wiser et al. advocate for the broadest possible applicability, which would encourage everyone who benefits from increased renewable generation to bear some burden of the cost.[60]

The third consideration is to decide which renewable sources qualify as meeting the target. How much, if any, existing renewable generation should count toward the quota? If policymakers deem some renewable sources as more desirable than others, they can put those renewable types into a different class or tier that either receives additional RECs per MWh or has a higher quota than other resources.[61] For example, some state RPS programs treat wind and solar differently than large hydropower and municipal solid waste.

Finally, policymakers need to determine which, if any, flexibility mechanisms will be part of the RPS program. The two primary RPS flexibility mechanisms are REC trading and credit for purchasing qualified power, either in- or out-of-state.[62] The greater the flexibility (e.g., out-of-state REC trading rather than in-state only), the more generators can be in compliance at a lower cost, while fully utilizing areas with particularly good renewable resources. Some generators will over-comply and be compensated by generators unable to meet their requirement internally. Provisions that mandate in-state compliance or discourage out-of-state compliance lead to higher compliance costs and, perhaps, to less in-state economic development benefit.

Some RPS programs, particularly in states with limited renewable resources, have cost control measures that limit the price of RECs rather than allow cheaper out-of-state RECs to meet requirements. Such a provision—commonly called a "safety valve"—would allow regulated entities to purchase RECs from the government at a predetermined price, should the cost of RECs rise above that price. If used, this provision would result in less generation from renewable resources than originally set in the standard.

To meet the ultimate goal of increasing the total percentage of power generation derived from renewable resources, there are a few key elements essential to program success:

- Set an aggressive, but realistic, standard for the increase in renewable power generation.
- Allow sufficient lead-in time for the regulated entities to install renewable capacity and establish purchase contracts for the power.
- Include as many power generators as possible in the program in order to increase total renewable power production, as well as gains from trade.
- Design the policy in a way that encourages growth for many renewable technologies, a measure that increases diversity in the energy portfolio. This may be done by counting more expensive renewable sources as part of a higher tier, allowing the power and credits from this resource to retain a higher value.
- Establish a market for renewable energy credits, allowing them to be traded on an open, inter-state (or international, where possible) market.
- Increase transmission capacity from areas that may have high renewable capacity but low population density.

60 Wiser et al., 2005.
61 Rabe, 2006.
62 Bolinger & Wiser, 2006.

Feed-in Tariffs

Feed-in tariffs are intended to guarantee a long-term power purchasing price to independent power producers using renewable-based generation.[63] This regulated minimum price per kWh generated is paid by the electric utility, which is required to allow the generator to connect to the grid.[64] The price of renewable-based electricity set by the regulator may be based on the cost of generating the electricity from a given renewable resource, the retail price of electricity or a static above-market price that provides an incentive to invest in renewable sources of electricity production.[65] Initial investment in capital-intensive, renewable-based electricity generation facilities can be difficult to procure without long-term power purchasing agreements. Feed-in tariff programs provide such long-term funding, removing a financial barrier to growth in renewable electric generation. In general, feed-in tariffs have been successful in enabling growth of wind power, which often is the least costly renewable generation source.[66] The use of feed-in tariffs, or a similar mechanism, has been used in the United States and, more extensively, in Europe.

Experience with renewable energy incentive mechanisms similar to a feed-in tariff model began in the United States with the adoption of the U.S. Public Utilities Regulatory Act (PURPA) in 1978. Under this legislation, utilities were mandated to connect all qualifying facilities (QFs) to the grid and buy the power produced by the renewable-power producers at each utility's avoided cost of generation.[67] "A power producer is a QF if it falls within one of two groups of non-utilities: (1) small power producers using renewable energy sources; and (2) cogenerators." A "small power producer" is considered to be any power producer with less than 80 MW capacity, 75 percent of which is fueled by renewable sources, and that has less than a 50 percent share of ownership by electric utilities.[68] California's implementation of PURPA required utilities to enter into fixed or increasing long-term power purchasing contracts with qualified renewable generators. Additional costs to the utilities associated with this program were passed down to the ratepayers, and although the PURPA mandate increased the cost of energy, the result may have been economically preferable to meeting the demand for electricity solely with nuclear generation.[69]

The most complete example of the use of feed-in tariffs to promote growth in renewable power generation is found in Europe. While many countries in the European Union (EU) have adopted some form of a feed-in tariff system, the most aggressive programs are in Germany, Denmark, Spain and Italy.[70] Through the use of feed-in models and other mechanisms, the EU has established aggressive targets for electricity produced using renewable energy sources (RES-E) generation by 2010. Table 3-6 shows that these RES-E targets range from 5.7 percent in Luxembourg to 78.1 percent in Austria.

63 Sawin, 2004.
64 Sijm, 2002.
65 Sawin, 2004.
66 Rosenquist et al., 2004.
67 Wiser & Pickle, 1997.
68 Louise, n.d.
69 Sawin, 2004.
70 Menanteau et al., 2003.

Table 3-6. EU member state targets of RES-E in relation to gross electricity consumption for the year 2010[71]

Country	RES-E (%)	RES-E (TWh)
Austria	78.1	55.3
Belgium	6.0	6.3
Denmark	29.0	12.9
Finland	35.5	33.7
France	21.0	112.9
Germany	12.5	76.4
Greece	20.1	14.5
Ireland	13.2	4.5
Italy	25.0	89.6
Luxembourg	5.7	0.5
Netherlands	9.0	15.9
Portugal	39.0	28.3
Spain	29.4	76.6
Sweden	60.0	97.5
UK	10.0	50.0
EU total	21.1	674.9

The targets in Table 3-6 may be misleading for two reasons: large hydropower is included as a RES-E, and each country's target is most likely a function of total availability of renewable energy resources. For example, the United Kingdom, as an island nation, has better wind resources than Germany, a nation with relatively little coastline. Therefore, a wind turbine in the United Kingdom is able to achieve at least 150 percent of the output from that same turbine in Germany (on average).[72] When the price paid for wind energy through the German tariff system is scaled according to the better U.K. wind resource, the relative price of wind in Germany is predicted to be lower than in the United Kingdom.[73]

As a means of achieving RES-E targets, policies in EU countries have required utilities to guarantee long-term power purchasing contracts, paying feed-in tariffs that vary between 7.7 and 9.3 eurocents (€ct) per kWh.[74] As Table 3-7 shows, the average feed-in prices paid per kWh in the key feed-in programs are greater than the average bidding prices paid to renewable generators via reverse auction programs.[75] Table 3-8 displays the effect of these two incentive schemes on installed wind-power capacity in the same countries.

Table 3-7. Comparison of wind-power prices in Europe in 1998 (in euros/kWh)[76]

	Country	Wind power price (euros/kWh)
Feed-in tariffs	Germany	0.086
	Denmark	0.079
	Spain	0.068
Average Bidding Prices	UK	0.041
	France	0.048

71 Rosenquist et al., 2004.
72 Butler & Neuhoff, 2004.
73 Ibid
74 Rosenquist et al., 2004.
75 [NOTE]: Reverse auctions will be discussed in more detail in a separate section. The purpose of this table is to display the relatively high price of electricity under feed-in systems.
76 Menanteau et al., 2003.. Note that reverse auctions are synonymous with bidding systems.

Table 3-8. Impact of incentive programs on the installed wind-power capacity in Europe[77]

Incentives	Country	Installed Capacity in MW (end 2000)	Installed Capacity in MW (end 2005)	Additional Capacity MW (in 2000)	Additional Capacity MW (in 2005)
Feed-in tariffs	Germany	6,113	18,428	1,668	1,808
	Spain	2,402	10,027	872	1,764
	Denmark	2,297	3,122	555	22
	Total	**10,812**	**31,577**	**3,095**	**3,594**
Bidding Systems	United Kingdom	409	1,353	53	446
	Ireland	118	495.5	45	157
	France	79	757	56	367
	Total	**606**	**2,605.5**	**154**	**970**

The information that these tables lack, however, is the total amount of money that is being given by the government or through mandatory power purchasing agreements. Even if the average per-kWh price is high, the total amount of contracts provided will also be a determinant of installed wind capacity. Also, it is not clear that 100 percent of the wind-power capacity reported in 2000 is the direct result of these incentive programs. These tables suggest that feed-in models tend to provide a higher price to wind operators than do reverse auctions and generally result in more installed wind capacity, although the relationship between the incentive structure and installed wind capacity is not absolute.

The original German feed-in model did not allow for the sharing of program costs among the utilities. Utilities that served areas with large wind resources paid a disproportionate fraction of their revenue to renewable energy contracts. As Germany entered the 21st century, it revised its feed-in law to address the unequal distribution of costs within the utility sector, promote renewable energy sources other than wind and decrease feed-in tariffs over time to take technological learning into account.[78] The Renewable Energy Law (REL), which came into force April 1, 2000, allows for the following provisions:[79]

- Feed-in tariffs are no longer linked to average consumer prices but based on generation costs of various renewable energy sources.
- Feed-in tariffs are differentiated by type of renewable energy technology (Table 3-9). These tariffs are paid for the first 20 years of operation of the facility.
- Feed-in tariffs for solar PV, biomass and wind energy decrease over time by a certain annual percentage (1.5 percent), starting for plants installed after January 1, 2002.
- The burden of feed-in payments is shared equally among all grid companies in the entire federal republic, corresponding to their amount of delivered electricity.

77 2000 data from Ibid.; 2005 data from European Wind Energy Association, 2006.. Note that all capacity is not directly attributable to the policies in question and that policies may have changed between 2000 and 2005.
78 Rosenquist et al., 2004., Sijm, 2002.
79 Sijm, 2002.

Table 3-9. Germany: feed-in tariffs under the Renewable Energy Law, 2000 [€ct/kWh][80]

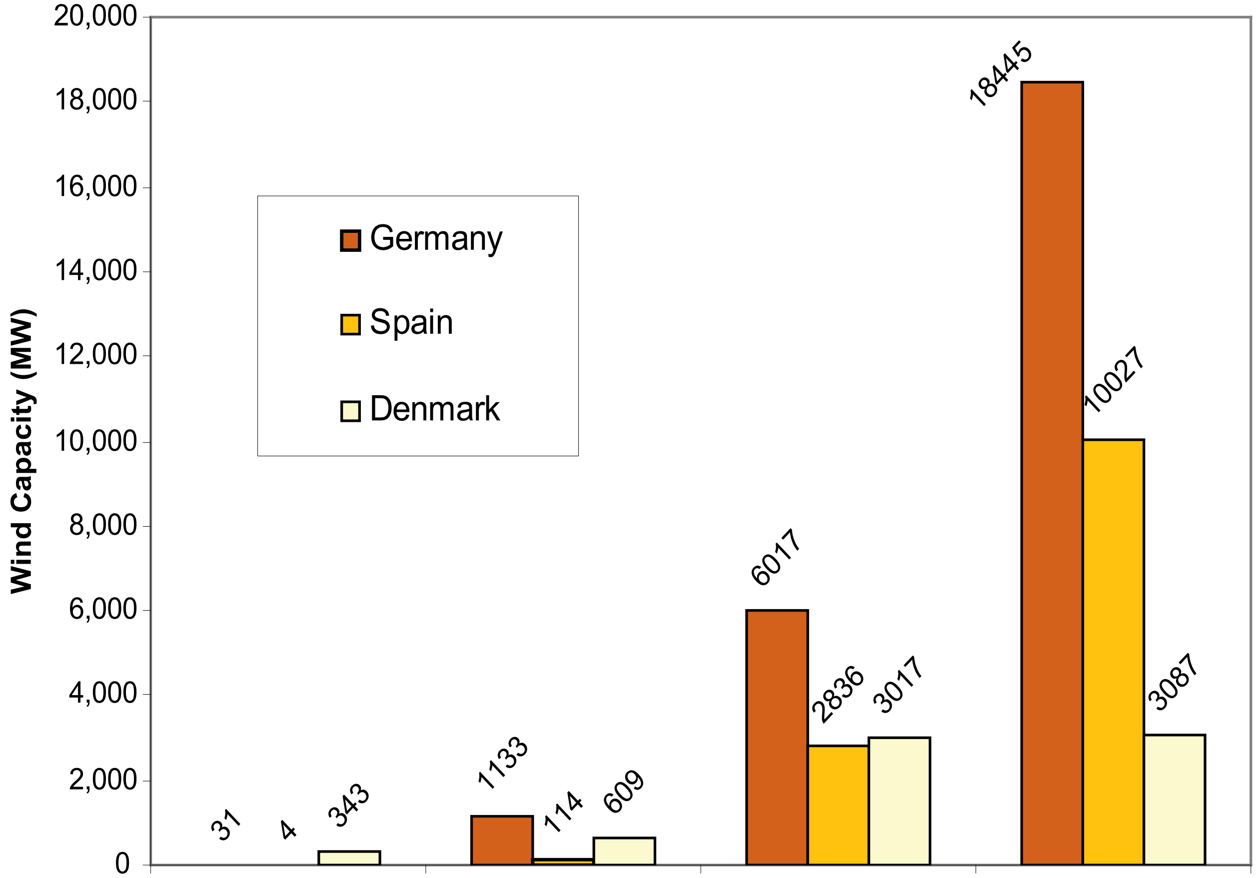
	0-0.5 MW	0.5-5 MW	5-20 MW	>20 MW	Annual Decrease beginning in 2002 (%)
Wind	6.2-9.1	6.2-9.1	6.2-9.1	6.2-9.1	1.5
Biomass	10.2	9.2	8.7		1
Photovoltaics	50.6	50.6	-	-	5
Geothermal	8.9	8.9	8.9	-	No
Hydro	7.7	6.6	-	-	No
Landfill gas	7.7	6.6	-	-	No
Mine gas	7.7	6.6	6.6	6.6	No
Sewage gas	7.7	6.6	-	-	No

As in Germany, Denmark amended its feed-in law at the turn of the millennium. Denmark faced the additional challenge, however, of liberalizing its electricity sector by 2003, changing its policy from its traditional nonprofit principle for power plants and utilities to one that treats them as "commercial enterprises."[81] The new Danish RES-E law combined its feed-in system with a tradable green certificate system as of 2005. The feed-in law was amended to allow existing wind turbines to receive a 4.4 €ct/kWh tariff until they are 10 years old; they then would receive 3.6 €ct/kWh for a limited amount of load hours. Additionally, starting in 2003, existing wind turbines more than 10 years old will get a green certificate for every kWh generated. New generation in place after 2003 will receive the market price for the energy, plus a green certificate for each kWh produced.[82] The new Danish policy indicates that the EU may be shifting away from feed-in tariffs in favor of tradable green certificates. The new system still bears similarities to feed-in tariffs because the utilities are obligated to buy the power, although at market price.

Feed-in tariff systems have been widely successful in Europe at promoting the development of wind energy, as evidenced by the increased share in European wind capacity for those countries with feed-in tariffs (Figure 3-6). During the 1990s, as some European countries experimented with feed-in tariffs as an incentive mechanism for renewable energy, economies of scale and technical progress helped increase the capacity from some renewable generation sources. However, the distribution of program costs and lack of market-based competition has led those countries to a transition away from feed-in tariffs to incentive programs based on market mechanisms . One explanation for the movement away from feed-in programs is that low-cost renewables, such as wind, are able to compete with traditional sources of energy, especially in the carbon-constrained European market. Because of the lower cost of renewable sources and the adoption of renewable energy credits (or green certificates in Europe's case), a guaranteed long-term premium price is no longer necessary to ensure that renewable energy is a growing part of the energy portfolio.

80 Ibid.
81 Rosenquist et al., 2004.
82 Sijm, 2002.

Figure 3-6. Total wind capacity of West European Countries from 1990 to 2005[83]



83 Ibid. for years 1990 and 1995. BP, 2006. for years 2000 and 2005.

Reverse Auctions

A reverse auction program requires operators of electricity generators powered by renewable energy sources to submit a tender (or bid) that states how much subsidy is needed to produce a given amount of electricity.[84] This program is a method of distributing RES-E incentives from a reserved market or fund in a competitive manner as a means of achieving an efficient allocation of financial resources. Typically, a program administrator announces a solicitation for bids that either sets the quantity of RES-E generation that is desired or the total financial incentives that are available for allocation. A RES-E operator will then submit a bid that proposes a price per kWh of renewable generation.[85] This bid will likely represent the difference between what it costs to generate electricity from renewable sources and the market price of the electricity. At the end of the solicitation, the administrating agency will award the winning bidders with contracts to pay them a fixed price per kWh for the length of the contract period.[86] Additionally, electric utilities will be obligated to purchase the electricity from the winning bidders at market price.[87] The reverse auction program encourages competition between RES-E generators by selecting the bids that will reach the program's goals in the most efficient manner.[88]

The two biggest efforts in the past 10 years to implement a reverse-auction bidding system to allocate RES-E incentives were in the United Kingdom and in California. RES-E supported by the U.K. program, discontinued in 2000, accounted for 85 percent of all renewable electricity generation in the United Kingdom.[89] The U.K. program, known as the non-fossil fuel obligation (NFFO), conducted five solicitations between 1990 and 1998. The prices paid to contracted RES-E projects in England and Wales decreased from €0.065 to €0.0271 per kWh over the period.[90] This reduction in contracted prices awarded trough the NFFO bidding system suggests that the competition among bidders provided an incentive to reduce the cost of renewable generation. During the same period, 880 contracts were awarded in England and Wales. However, as of March 2000, only 36 percent of those projects had entered primary development.[91] This low percentage suggests that bid prices were, at times, too low to support the financial needs of some projects.

California had more success with bringing contracted projects on-line in its competitive bidding system. Administered by the California Energy Commission (CEC), this reverse auction program has awarded $217 million to 69 projects over the course of three solicitations between 1998 and 2001.[92] As Table 3-10 shows, 94 percent of the expected 1,304 MW capacity of these projects had been brought on-line by 2006, or was expected to come on-line shortly thereafter. In addition to the completed projects, there are 22 projects that have not yet come on-line, accounting for an additional 777 MW of capacity, and 12 projects with a total of 38 MW capacity have been cancelled.[93] Table 3-10 also shows that although 75 percent of the total capacity contracted is from wind resources, the CEC has awarded contracts to many different types of projects, including biomass, digester gas, geothermal, landfill gas, small hydro and waste tire. Table 3-11 provides a breakdown of how much power is expected to be generated from each source and what percentage of the total funding is allocated to each source. Not surprisingly, while wind energy accounts for 75 percent of the total on-line capacity contracted by the three

84 Rosenquist et al., 2004.
85 Menanteau et al., 2003.
86 Rosenquist et al., 2004.
87 Menanteau et al., 2003.
88 Rosenquist et al., 2004. . [NOTE]: This does not mean that the lowest bids are always accepted. The program administrator may take into account the reliability of the applicant's project, the type of renewable source that is utilized (a program may be looking for diversity in generating sources), and/or the project's location and desirability.
89 [NOTE]: RES-E generation accounts for about 3 percent of the United Kingdom's total electricity supply.
90 Faber et al., 2000.. [NOTE]: These numbers are nominal prices. The median averaged exchange rate in 1998 was $1.10258/euro. (Source: xrates.com, http://*www.x-rates.com/d/USD/EUR/hist1998.html*. Accessed October 12, 2006.)
91 Ibid.
92 California Energy Commission, 2005., Bolinger & Wiser, 2006.
93 California Energy Commission, 2005.

CEC auctions, it receives only about 46 percent of the total funding. The only technology with a lower average bid price is small hydro. Although there have been some cancellations of contracts and 777 MW—or roughly 40 percent of the total contracted capacity—have yet to come on-line, it appears that the reverse auction program in California has provided a sufficient incentive to bring a large amount of diverse renewable capacity on-line.

While the merits of reverse auction allocation methods are both lauded[94] and criticized,[95] the case studies discussed here suggest that reverse auctions are no longer a favorable method of incentive allocation. In summer 2000, the United Kingdom passed the Utilities Act that replaced the NFFO reverse auction system with a Renewables Obligation (RO), a quota program similar to a renewables portfolio standard.[96] California also has changed the course of its renewables program. Although the CEC has not formally ended the reverse auction program, there have been no solicitations for bids since 2001, suggesting that California will allocate funds created by system benefits charges on a more subjective basis and rely on renewables portfolio standards to provide cost-reduction incentives to the state's renewable power producers.[97]

94 Faber et al., 2000., Menanteau et al., 2003.
95 Heiman & Solomon, 2004., Wiser & Pickle, 1997.
96 Rosenquist et al., 2004.
97 Bolinger & Wiser, 2006..

Table 3-10. New RES-E projects funded through CEC reverse-auction program[98]

Resource Type	Auction #1 Jun-98 Capacity (MW)	Auction #1 On-Line Capacity (%)	Auction #2 Nov-00 Capacity (MW)	Auction #2 On-Line Capacity (%)	Auction #3 Sep-01 Capacity (MW)	Auction #3 On-Line Capacity (%)	Total All Auctions Capacity (MW)	Total On-Line Capacity (%)
Biomass	11.6	32.76%	7.5	100%	-	-	19.1	59.16%
Digester Gas	2.05	100%	-	-	-	-	2.05	100%
Geothermal	156.9	100%	-	-	-	-	156.9	100%
Landfill Gas	70.125	60.04%	12.54	57.74%	-	-	82.665	59.69%
Small Hydro	1	100%	12.24	100%	21	95.24%	34.24	97.11%
Waste Tire	-	-	-	-	30	100%	30	100%
Wind	290.83	93.17%	439.05	99.97%	249.2	98.23%	979.08	97.51%
Total Installed Capacity	**532.505**	**89.54%**	**471.33**	**98.85%**	**300.2**	**98.20%**	**1,304.04**	**94.90%**

Table 3-11. Financial, generation and capacity statistics for new RES-E projects funded through CEC reverse-auction program[99]

Project Type (# of Projects)	Total Capacity On-Line (MW)	Average Bid Price ($/kWh)	Total Estimated Generation over 5 Years (kWh)	Total Conditional Funding Award	Share of Total Funding	Average Capacity Per Project (MW)	Average Generation per Project (kWh)
Biomass (2)	11.3	$ 0.01302	291,000,000	$ 3,787,902.00	1.75%	5.65	145,500,000
Digester Gas (1)	2.05	$ 0.01390	82,605,000	$ 1,148,209.50	0.53%	2.05	82,605,000
Geothermal (4)	156.9	$ 0.01282	6,263,800,000	$ 80,331,617.60	37.01%	39.23	1,565,950,000
Landfill Gas (17)	49.34	$ 0.01108	1,842,730,582	$ 20,410,021.53	9.40%	2.90	108,395,916.59
Small Hydro (5)	33.25	$ 0.00627	696,530,000	$ 4,366,785.00	2.01%	6.65	139,306,000
Waste Tire (1)	30	$ 0.00715	1,011,526,354	$ 7,232,413.43	3.33%	30.00	1,011,526,354
Wind (39)	954.68	$ 0.00669	14,917,319,281	$ 99,761,185.88	45.96%	24.48	382,495,366
Total (69)	**1237.52**	**$ 0.00865**	**25,105,511,217**	**$ 217,038,134.94**	**100%**	**17.94**	**363,847,989**

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98 California Energy Commison, 2005
99 Ibid.

Subsidies and Incentives for the Development of Renewable Electricity Generation

Government can play a variety of roles in expediting the switch to renewable energy sources; encouraging the use of clean energy-producing technologies, including clean coal and nuclear energy; and promoting energy efficiency and conservation. Among its efforts, government can provide direct subsidies, tax credits and other tax benefits. Additionally, government can provide funding for research and development of technologies that are not yet ready to compete on the open market.

SUBSIDIES

Although the most commonly considered subsidies are direct financial incentives or payments, indirect subsidies also exist. Indirect subsidies include price floors, price ceilings, import tariffs, and liability limitation. These subsidies can serve to alter the consumer price of a particular energy service or the profit margin of an energy service provider. Quantifying the value of indirect subsidies is difficult and beyond the scope of this report; the focus here is on direct subsidies.

A direct subsidy may take the form of an investment or production incentive. An investment incentive reduces the overall cost of the initial investment, while a production incentive provides a per-unit payment (e.g., per kWh).[100] A third type of direct subsidy provides financial support for R&D for new technologies. Table 3-12 indicates the average levelized subsidy (in $/MWh) for new renewables, clean coal and nuclear sectors, while Table 3-13 indicates the net present value (NPV) of both production and investment subsidies and R&D funding.

Table 3-12. Average levelized subsidy ($/MWh)[1] to generation from new facilities

Sector	Average Levelized Subsidy ($/MWh)
New Renewables	5.9
New Clean Coal	8.1
New Nuclear	8.3

[1] NPV of subsidies divided by 20 years of generation (discounted), based on AEO Reference Case

Table 3-13. Net present value ($B) of production and investment subsidies and R&D

	New Renewables	New Clean Coal	New Nuclear
Subsidy	4.9	5.4	4.9
R&D	2.0	1.4	2.1
Total	6.9	6.7	7.0

Direct investment incentives, whether cash subsidies or tax credits, are straightforward in that they allow investors to recover a portion of their initial capital investment based on project cost or project size in megawatts. This type of incentive may be inefficient if capital costs are artificially inflated by investors in order to reduce tax liability, or if actual generation is less than expected generation.[101] Production incentives, which are given for only the electricity generated, provide an option to avoid any inefficiencies with investment incentives. Generally, though, investment incentives have caps by project and technology that limit inefficiency and the potential for abuse.

100 Wohlgemuth & Madlener, 2000.
101 Ibid.

Production incentives provide protection against fraudulent claims, allow for long-term cost recovery, and are relatively low-risk since they are not paid if the generation facility does not produce. However, production incentives may also be less than efficient in certain situations. For example, most renewable-energy projects have a relatively high upfront capital cost and much lower operation and maintenance cost than traditional generation facilities. As a result, a renewable-energy investment can be riskier than a conventional investment, because with a conventional generation technology, the owner can cease production if the plant is unprofitable and thereby avoid operating costs, which are the largest share of conventional technology costs. An owner of a renewable facility has no option to shut down to avoid the majority of his costs; capital costs will continue whether the plant is operating or not. Because potential investors see production incentives as politically uncertain over time, they must factor into their investment decision the risk that the subsidy will not continue and, therefore, the investment may not be profitable. As a result, investors prefer investment incentives to production incentives.[102]

Although the federal government has never ended a production subsidy early that was awarded to an eligible facility for a certain duration, the offer of subsidies has been highly uncertain.[103] Federal production subsidies tend to be authorized for only a few years at a time, which creates a rush to build renewable facilities within the specified timeframe. This rush makes it difficult for technology manufacturers to supply enough equipment, putting upward pressure on prices and undercutting the intent of the subsidy. Manufacturers could expand capacity if they expected the subsidy to continue to be offered for a longer period, but they cannot justify expansion with only short-term subsidies.

Subsidies, whether investment or production, can be given via direct payment or tax credit. Most subsidy recipients prefer a direct cash subsidy, because it is more liquid than a tax credit and does not require a substantial tax portfolio to absorb the full benefit of the tax credit. Kahn (1996) claims that a tax incentive may not be as beneficial, depending on the type of investor—public utility or private investor. A public utility will generally be more willing to accept a tax incentive than a private investor.[104] On the other hand, the administrative burden for the government is less with a tax credit than with a direct payment, because the government can simply reduce the recipient's tax liability rather than collecting all taxes and reallocating the funds to the recipients.[105] Tax incentives may also take the form of accelerated depreciation of capital or reduced property taxes. While tax incentives are the preferable method of allocation for the government, taking advantage of the tax incentive can oftentimes be so complex and cumbersome that extensive legal and financial expertise is required to realize the benefits of the incentive.[106]

Two other ways that government can encourage the growth of renewable, clean coal and nuclear energy are to subsidize R&D and to remove incentive programs for traditional energy production. Although government investment in R&D programs for renewable, clean coal and nuclear energy will not immediately displace traditional generation in the short term, the effects of R&D on the long-term growth of these alternative energy technologies are expected to be positive.[107] Furthermore, there are already a great number of fossil fuel-based energy subsidies, and incentives for alternative-energy technologies will help to "level the playing field."[108] However, with the negative environmental effects caused by many traditional generation sources, many incentives for these sources can now be considered perverse, and eliminating these incentives would be more efficient than ramping up renewable, clean coal and nuclear incentives so that these technologies can better compete.[109]

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102 Ibid.
103 Once a production subsidy is awarded to a facility, that facility will receive it for as long as is specified in the subsidy. The uncertainty is in whether the subsidy will continue to be offered beyond a typical 2 to 3 year period.
104 Kahn, 1996.
105 Wohlgemuth & Madlener, 2000.
106 Audin, 2006.
107 Fischer & Newell, 2004.
108 Birol & Keppler, 1999.
109 United Nations Environmental Program, 2002.

Ultimately, the optimal manner of subsidizing alternative energy generation technologies depends greatly on the source of the generation, who the investor is and whether or not there is a market for the energy that is produced. The United States has adopted many of these different forms of incentives for renewable, clean coal and nuclear energy. Select government incentive programs authorized by the Energy Policy Act of 2005, as well as other related legislation and government programs, are described below.

CURRENT SUBSIDIES FOR RENEWABLE ELECTRICITY GENERATION IN THE UNITED STATES

The United States maintains policies that provide an incentive for the adoption of renewable energy. The EPAct 2005,[110] amending the Energy Policy Act of 1992, provides subsidies to an array of renewable energy technologies through tax credits, direct subsidies and guaranteed loans. Table 3-14 lists select federal renewable electric generation and energy efficiency subsidies.

110 NC Solar Center, 2006.

Table 3-14. Select federal renewable electric generating subsidies

Incentive Name	Incentive Type	Application	Technology Specified	Method of Disbursement	Amount	Maximum	Expiration	Authorizing Bill
USDA Renewable Energy Systems and Energy Efficiency Improvements Program	Investment Incentive	Agricultural producers and small rural businesses	Renewable energy systems and energy efficiency	Tax Credit	25% of total project costs	$500,000 for renewable projects, $250,000 for energy efficiency	12/31/2007	Farm Security And Rural Investment Act of 2002 (Sec. 9006)
USDA Renewable Energy Systems and Energy Efficiency Improvements Program	Investment Incentive	Agricultural producers and small rural businesses	Renewable energy systems and energy efficiency	Guaranteed loans	50% of project costs	10 million per project	12/31/2007	Farm Security And Rural Investment Act of 2002 (Sec. 9006)
Renewable Energy Systems and Energy Efficiency Improvements Grant	Investment Incentive	Agricultural producers and small rural businesses	Renewable energy systems and energy efficiency	Grant funds and guaranteed loans	75% of eligible project costs	$750,000 per individual/entity	12/31/2007	Farm Security And Rural Investment Act of 2002 (Sec. 9006)
Business Energy Tax Credit	Investment Incentive	Commercial and industrial businesses	Solar, geothermal, fuel cells, microturbines	Tax Credit	30% for solar, fuel cells; 10% for microturbines and geothermal	$500 per 0.5 kW for fuel cells, $200 per kW for microturbine	All credits revert to 10% 1/1/2008, expire at this time for fuel cells and microturbines	EPAct 2005
Commercial Buildings Tax Deduction	Investment Incentive	Commercial Buildings	Energy Efficiency and Conservation Improvements	Tax Credit	$0.30-$1.80 per square foot	$1.80 per square foot	12/31/2007	EPAct 2005
Residential Energy Efficiency Tax Credit	Investment Incentive	Residential	Energy Efficiency and Conservation Improvements	Tax Credit	10% of cost of building envelope improvements; 100% for qualified energy property (heating, cooling, water heaters)	Varies by technology; max credit is $500 per household	12/31/2007	EPAct 2005, 26 USC § 25C
Residential Solar and Fuel Cell Tax Credit	Investment Incentive	Residential	Photovoltaics, solar hot water heating, fuel cells	Tax Credit	30% of project costs	$2,000 for solar applications; $500 per 0.5 kW for fuel cells	12/31/2007	EPAct 2005 (Section 1335)

Incentive Name	Incentive Type	Application	Technology Specified	Method of Disbursement	Amount	Maximum	Expiration	Authorizing Bill
Renewable Electricity Production Tax Credit	Production Incentive	Commercial and industrial businesses	Wind, closed-loop biomass, geothermal	Tax Credit	$0.015 per kWh (indexed for inflation)	NA	10 Years	EPAct 2005
Renewable Electricity Production Tax Credit	Production Incentive	Commercial and industrial businesses	Open-loop biomass, small irrigation hydroelectric, landfill gas, MSW, hydropower	Tax Credit	0.0075 per kWh (indexed for inflation)	NA	5 Years	EPAct 2005
Renewable Electricity Production Tax Credit	Production Incentive	Commercial and industrial businesses	Refined-coal facilities	Tax Credit	4.375 per ton (indexed for inflation)	NA	10 Years	EPAct 2005
Renewable Energy Production Incentive (REPI)	Production Incentive	Tribal Government, Municipal Utility, Rural Electric Cooperative, State/ local gov't that sell project's electricity	Renewable Energy Systems	Subsidy	0.015 per kWh	NA	10 Years for project, funds authorized through 2026	EPAct 2005 (Section 202)
Modified Accelerated Cost-Recovery System	Tax Depreciation	Commercial and industrial businesses	Solar, wind, geothermal	Depreciation deductions	Depreciation over between 3-50 years	NA	NA	26 USC § 168
Residential Energy Conservation Subsidy Exclusion	Tax Exemption	Residential	Energy conservation measures	Tax exemption	100% of subsidy	NA	NA	26 USC § 136

Table 3-14 displays a wide variety of federal investment incentives for renewable electric generation and energy efficiency. The government provides investment incentives through EPAct 2005 as well as the Farm Security and Rural Investment Act of 2002. While the former applies to residential, commercial and industrial consumers of energy, the latter specifically provides incentives to agricultural producers and rural small businesses. The Business Energy Tax Credit and the Residential Solar and Fuel Cell Tax Credit provide tax credits for capital investment in specified technologies, namely solar energy applications, geothermal, fuel cells and microturbines. The tax credit for installation of solar technologies and fuel cells is 30 percent of project costs, while the tax credit for microturbines and geothermal is 10 percent for commercial and industrial businesses (there is no tax credit for these technologies for the residential sector). In order to take advantage of these credits, the projects must be in service prior to January 1, 2008. Additionally, the legislation puts a cap on some of the tax credits, and the Business Energy Tax Credit may be reduced if the project is financed by subsidized energy financing or tax-exempt private activity bonds.[111] In addition to tax credits for investment in renewable energy, there are also credits available to residential and commercial property owners who install energy-efficiency improvements. The EPAct 2005 provides tax credits for such improvements in the Commercial Buildings Tax Deduction and the Residential Energy Efficiency Tax Credit. These credits apply to energy improvements, as well as to new construction that include energy-saving technologies that must be in operation before January 1, 2008. The financial incentives for each of these credits are shown in Table 3-14.

The production incentives available from the federal government establish per-kWh tax credits or subsidies that provide the producer of renewable electric generation with long-term financial support. Production incentive programs include the Renewable Electricity Production Tax Credit and the Renewable Energy Production Incentive, both of which are part of the EPAct 2005. The Renewable Electricity Production Tax Credit applies to commercial and industrial businesses, including private electricity generators and nonmunicipal utilities. The EPAct 2005 limits the tax credits available to geothermal generation facilities that also receive funds from the Business Energy Tax Credit program and provides an additional credit of $1.50 per ton for Indian coal production facilities. While the Renewable Electricity Production Tax Credit applies to for-profit commercial and industrial generation, the Renewable Energy Production Incentive provides a $0.015 per kWh[112] direct subsidy for tribal governments, municipal utilities, rural electric cooperatives, and other state and local government operations that produce electricity from renewable sources. This credit is available for the first 10 years the project is in service. However, if there are not enough funds appropriated to fully distribute the subsidy, 60 percent of the available funds will be directed to solar, wind and ocean projects, with the remaining 40 percent distributed among other renewable generation sources.

An increase in market power for renewable-energy and energy-efficiency technologies may be attained via indirect measures that indirectly reduce the cost of equipment and production, increase public awareness or reduce support for competing technologies. The latter two of these are not explicitly discussed in this report and their effect may be difficult to quantify. However, green marketing (both publicly and privately financed) and phase-outs of subsidies for traditional fossil fuel-based generation could have a positive effect on the diffusion of renewable-energy and energy-efficiency technologies.

One manner of indirectly reducing the cost of building or owning renewable energy property or increasing the energy efficiency of current property is to reduce the tax liability from that property. Federal programs that allow for this reduction in total tax liability are the Modified Accelerated Cost-Recovery System and the Residential Energy Conservation Subsidy Exclusion. The first of these programs allows a commercial or industrial business to depreciate solar, wind or geothermal energy systems faster, decreasing the aggregate tax paid on the property.

111 NC Solar Center, 2006.

112 The actual current subsidy is $0.019 cents per kWh to reflect inflation; the subsidy is an extension of the 1992 EPAct when the subsidy was $0.015 cents per kWh.

Qualified properties may be depreciated over three to 50 years, depending on the technology. The second federal program provides a tax exemption for residential customers that receive an energy conservation subsidy (direct or indirect) from a public utility. This exemption increases further the benefits of installing energy-conservation measures, which should, in turn, enhance the incentive to conserve energy.

The federal government and the State of North Carolina provide direct and indirect incentives for the adoption of renewable-energy and energy-efficiency technologies. The effectiveness and efficiency of such incentives rely on the manner in which the incentive is dispersed and whether the incentives apply to investment in the desired technologies or in the production of energy from the technologies.

CURRENT SUBSIDIES FOR CLEAN COAL AND NUCLEAR ELECTRICITY GENERATION IN THE UNITED STATES

Subsidies for clean-coal technology were also included in EPAct 2005 (Table 3-15). Although the act extended a renewable electricity production credit (previously included under the American Jobs Creation Act of 2004) that includes biomass facilities, the definition of qualified biomass facilities excludes co-firing with fossil fuel. Open-loop biomass facilities, which comprise nearly all co-firing facilities, are eligible for a credit of 0.9 cents per kWh during a five-year period beginning on the date the facility is placed in service. However, the definition of open-loop biomass "shall not include closed-loop biomass or biomass burned in conjunction with fossil fuel (co-firing) beyond such fossil fuel required for startup and flame stabilization."[113] Congress also included a number of incentives for integrated gas combined cycle (IGCC) in EPAct 2005. The act offers a 20 percent investment tax credit for the gasification portion of an IGCC plant, which amounts to a 14 percent overall credit for the entire project. The act provides a limit of $800 million in tax credits and supports six IGCC plants.[114] This funding will likely be highly competitive.

EPAact 2005 also gave numerous incentives to build new nuclear power plants (Table 3-15). These incentives were requested by the nuclear and financial communities to make nuclear power cost-competitive and to mitigate the risk associated with such large capital projects. The Secretary of Energy directed an advisory board, the Nuclear Energy Task Force, to assess impediments to building new nuclear power plants. In its report dated January 10, 2005, the task force identified the unavailability of financing as a significant obstacle to new plant construction. Many of the subsidies in EPAact 2005 were an outcome of this task force's suggestions.[115] One important improvement was a 20-year extension of the Price-Anderson Act, which provides insurance protection to the public in the event of a nuclear reactor accident.[116] Construction subsidies contained in the act include up to $750 million for permit delays and up to $1.25 billion from 2006 through 2015 for the construction of plants that produce both hydrogen and electricity.[117]

One of the critical economic subsidies obtained by the sector is a production incentive of 1.8 cents/kWh for an eight-year period. The tax credit is subject to an annual cap of $125 million per year per facility for each 1,000 MW of generating capacity.[118] A federal loan guarantee was made available for up to 80 percent of a new project's eligible costs. This was put in place to make lenders more comfortable in all three types of financing situations, but especially for unregulated utilities and merchant generators. According to the Secretary of Energy Advisory Board,

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113 Oregon Department of Energy, 2004.
114 Wilson, 2005.
115 Carroll & Matthews, 2005.
116 Asselstine, 2006.
117 2005 Energy Policy Act, 2005. Section 638 and 635.
118 Ibid. Title XIII.

a federal loan guarantee appears to have relatively low value for regulated utility financing, medium to high value for the unregulated merchant generating company, and high value for non-recourse project financing.[119]

The outcome of financing the first nuclear plants will depend greatly on how the provisions of EPAact 2005 are implemented. James Asselstine, managing director at Lehman Brothers, said in his testimony to the Senate on May 22, 2006, that "the methodology for determining the cost of the loan guarantee to the project sponsor will be a factor in assessing the availability and value of the loan guarantee. For these reasons, the Department's implementation of the loan guarantee provision is likely to be an important component in ensuring the availability of financing for the initial plants."[120]

Table 3-15. Select federal nuclear and clean coal electric generating subsidies

Incentive Name	Incentive Type	Application	Technology Specified	Amount	Maximum	Authorizing Bill
Credit for investment in Clean Coal/IGCC Facilities	Construction subsidy		Coal	20% credit for gasification portion of facility	$800 Million	EPAct 2005 (Sec. 1307)
Open-loop biomass	Production incentive		Coal	0.009 per kWh		EPAct 2005 (Sec.1301)
Extension of Atomic Energy Act of 1954	Construction subsidy		Nuclear		$10 Billion	EPAct 2005 (Sec. 604)
Financial support for nuclear reactor plant construction delays	Construction subsidy		Nuclear		$500 Million	EPAct 2005 (Sec. 638)
Construction of plants to produce both hydrogen & electricity	Construction subsidy		Nuclear		$1.25 Billion	EPAct 2005 (Sec. 645)
Credit for production from Advanced Nuclear Facilities	Production Incentives		Nuclear	0.018 per kWh	$125 Million per year (allocated based on facility's share of 6,000 MW national limitation)	EPAct 2005 (Sec. 1306)

DISCUSSION

The administration of the incentives described above reduces the aggregate cost of installing and operating renewable, clean coal and nuclear electric generation facilities, as well as adopting energy-efficient technologies. By making such projects more attractive, legislation passed by the federal government and the State of North Carolina attempts to reduce the quantity of electricity produced by traditional fossil fuel technologies. Such a reduction not only would reduce the strain on reserves of traditional fossil fuel resources, but improve air quality and mitigate global climate change. However, the inefficient manner in which some incentives are administered decreases the overall effectiveness of the incentive programs. These programs may not achieve their maximum effect because of the long-term uncertainty of the availability of the programs, the complexity of redeeming the incentive and the reliance on yearly appropriations for federal incentives.

Many federal subsidy programs require that the applicable technology be in operation by a certain date in order to be eligible for the tax credit. For many of the programs authorized by EPAct 2005, the deadline is December 31, 2007, giving applicants less than two years to place the technology in service. For example, investors in new

119 U.S. Department of Energy, 2005.
120 Asselstine, 2006.

commercial buildings under construction that wish to take advantage of the Building Efficiency Tax Credit may not chose to install additional energy-efficiency improvements if there is a risk that the building will not be in operation by the deadline.[121] While it may be possible—or even likely—for Congress to extend the program beyond the current deadline, investors may not be willing to undertake the additional financial risk if there is uncertainty whether the credit will be available. In the case of North Carolina incentives, programs such as NC Green Power rely on private funding for continuation. Some private electric generators may be tentative to install high-cost photovoltaic or wind technology if there is no guarantee that there will be someone such as NC Green Power to purchase the power at premium prices in the long run.

In addition to the risk associated with the short time frame in which to take advantage of certain incentives and the uncertainty of the programs' continuation, the application and certification processes can be quite cumbersome. The use of tax credits as the primary distribution of the incentives creates an additional level of complexity for applicants, since those without a large enough tax portfolio to absorb the entire credit will not receive the full benefits of the incentive.[122] Furthermore, if the installed equipment does not meet the certification standards (in the case of energy efficiency credits), the applicant will have to undertake further upgrades in order to receive the credit.[123] The difficulties that accompany the process of taking advantage of the incentives—as well as the fact that some investors and property owners may not be aware of them—may reduce the positive impact that the incentives could have on the markets for alternative-energy generation systems and energy-efficiency technologies.

The third reason why federal incentives may not reach their optimal effectiveness is that they rely on annual appropriations from Congress to fund the programs. If the political winds change and Congress no longer desires to support one or more of the programs in Table 3-14 and Table 3-15, then those who have invested in these technologies under an assumption that they will be able to recover a portion of their investment costs will be left at a severe economic disadvantage. Also, the development of many technologies can be stalled through reduced appropriations for government programs such as those administered by the Department of Energy's Office of Energy Efficiency and Renewable Energy. While funding alternative technologies alone may not solve resource scarcity or environmental pollution problems, it seems unlikely that market forces alone will expedite the adoption of renewable, clean coal and nuclear energy as well as energy-efficiency technology.

CONCLUSION

The ultimate effectiveness of government incentives should be judged by whether or not the applicable technologies are able to stand on their own in the market in the long run. However, for the time being, it is necessary to provide financial support for some renewable, clean coal and nuclear electricity generation and energy-efficiency projects. The federal government generally provides tax credits to parties that install these types of projects, providing that the technologies meet certain standards. Incentives are also available from individual states, including North Carolina. The effectiveness of both the federal and North Carolina incentives may be jeopardized by uncertainty surrounding how long the programs will be available and how much money will be available to fund them, as well as the difficulty in applying for and receiving some of the tax credits and exemptions. Although the incentive programs described in this report may not achieve optimal efficiency, it still seems clear that there is a need for financial incentives to aid the diffusion of alternative electric generation and energy-efficiency technologies.

121 Audin, 2006.
122 Fischer & Newell, 2004.
123 Audin, 2006.

RESEARCH AND DEVELOPMENT FUNDING

It is widely recognized that the growth and development of technology will be a major factor in achieving greenhouse gas reduction goals under any climate policy.[124] For this reason, subsidization of R&D of alternative technologies is often suggested as part of a comprehensive package of policies to address climate change. However, even in the absence of such incentives, it is likely that development of new technologies will increase in the presence of a climate policy due to increases in the cost of energy.[125] The federal government, therefore, is faced with the several options in tackling greenhouse gas emission: designing policies that promote technology R&D (a "carrot" approach), mandating greenhouse gas reductions (a "stick" approach) or employing a combination of the two approaches. Currently, most major funding of alternative energy technologies comes from the federal government in the form of subsidies and tax credits; some contributions also come from private investors.[126] An overview of the current R&D landscape in the energy sector, as well as insight into the relative economic costs and benefits of R&D subsidization endogenous and exogenous to various climate change policy scenarios, is included below. A brief overview of select federal and private R&D funding sources also is presented.

RESEARCH AND DEVELOPMENT AND CLIMATE CHANGE POLICIES

Economic models have shown a clear link between technology changes and public policy.[127] There is a connection between increases in energy prices and application for new patents, suggesting that as energy prices rise, the development of alternative technologies become more attractive.[128] In light of rising energy prices in the United States, several proposals have been submitted to increase subsidization of R&D in an attempt to drive new technologies in the market in the absence of a climate policy.[129] Subsidization of R&D, however, tends to be a weak policy that fails to reduce greenhouse gas levels by any significant amount in the short run.[130] Linking technology development with climate change policies, though, reduces the cost of the policy.[131] As carbon constraints are tightened, new technology will be critical providing energy at a reasonable cost while complying with emission reduction targets.

Despite recognition of this important fact, funding levels for energy technology decreased significantly between 1980 and 1999 in the United States (58 percent decrease) and the rest of the industrialized world.[132] In addition, the R&D intensity, defined as R&D funding as a percentage of net sales, is extremely low in the energy sector as compared to other technology-intensive sectors. This fact is alarming given the link between R&D investments and application for new patents.[133] EPAct 2005 offers some increases in R&D funding for alternative technologies; however, given the positive knowledge spillover effects (knowledge can be used by all, not just the R&D developer) of many of these technologies, increases in government investment may be necessary.[134] Before examining the amount of funding necessary to achieve greenhouse gas reduction goals, it is important to look at the market failures that affect the adoption of new technologies.

124 Fischer, 2003.
125 Kvendokk et al., 2004.
126 American Association for Advancement of Science, 2006.
127 Popp, 2006.
128 Jaffe et al., 1999.
129 Popp, 2006.
130 Fischer, 2003.
131 Popp, 2006.
132 Margolis & Kammen, 1999.
133 Ibid.
134 Kvendokk et al., 2004.

Market Failures and R&D

Popp[135] suggests that there are two market failures that lead to underinvestment in climate-friendly research and development: environmental externalities and the very nature of new knowledge as a public good ("knowledge spillover"). The idea behind spillover is that a firm investing privately in R&D seeks to maximize the benefits it receives through profit maximization.[136] If the new technology has potential benefit outside of the firm, profits are further increased due to the potential for licensing the technology and social benefit rises as a result of achieving lower greenhouse-gas abatement costs with the technology.[137],[138] However, if the technology can be easily imitated, it is possible that there will be knowledge spillovers—that is, additional entities will receive benefit from the research without the innovator being properly compensated.[139] Given the reduced potential for profits, incentive for private research will decrease, resulting in a large portion of basic and widely applicable research going unfunded. It is to address this market failure that governments decide to subsidize research and development.[140] However, it is important to realize that while subsidies can lead to significant increases in R&D, they will do little to address climate change because they do not offer incentives to adopt new technologies.[141] This occurs because as energy prices increase, companies will seek to develop technologies that reduce their energy costs, but they will give little regard to the carbon content of the fuel used.[142] That is to say, firms will pursue only those technologies that reduce overall energy costs, not necessarily those that reduce greenhouse-gas emissions. Subsidies can, however, improve the efficiency of a climate-change policy that also addresses environmental externalities.[143]

Environmental externalities are best addressed through the adoption of a climate-change policy that seeks to correct the market price of energy by implementing a carbon tax or cap-and-trade program. Through such programs, the price of carbon will raise, thus driving R&D efforts that seek out less carbon-intensive alternatives.[144] Evidence suggests that the response of innovation to energy prices can be swift, but diffusion can be much slower depending on the rate of retirement of older models.[145] Policies that raise the cost of energy will induce diffusion of existing energy-efficient technologies and spark development of new technologies.[146]

Research and Development under Various Climate Change Scenarios

It has been shown that neither subsidies nor climate-change policies alone will work to promote the most efficient level of technology change to achieve greenhouse gas reduction goals. However, a climate-change policy that explicitly addresses R&D needs through subsidization accelerates abatement, reduces the costs of the environmental policy and may lead to positive spillover effects and negatives leakage.[147] With no market failures except for environmental externalities, the cost-minimizing policy would be to use carbon taxes alone to directly target the environmental failure; however, with knowledge spillovers, the optimal policy becomes a combination of a carbon restraint policy and R&D subsidization.[148] The question becomes, under which policy scenario, cap-and-trade system or carbon tax, is R&D most efficient?

135 Popp, 2006.
136 Fischer, 2003.
137 Kvendokk et al., 2004.
138 Fischer, 2003.
139 Ibid.
140 Ibid.
141 Popp, 2006.
142 Kvendokk et al., 2004.
143 Popp, 2006.
144 Jaffe et al., 1999.
145 Ibid.
146 Ibid.
147 Loschel, 2002.
148 Kvendokk et al., 2004.

Fischer[149] offers some interesting insight into the effect of various climate policies on research and development. According to her research, the threat of future regulation can induce some innovation, and performance standards will induce technological development up to the point of meeting the standard, but nothing more. Market-based mechanisms, however, induce the development of cost-effective ways of reducing pollution, thereby achieving lower abatement costs and thus lowering the tax payments (under a carbon tax) by performing abatement at new, lower costs. Innovation will be more readily used under a tax system because a lower cost of abatement reduces the overall tax burden. On the other hand, under a permit system, firms have no incentive to pursue further abatement after the innovation has been introduced because total emissions are set by the cap. Thus, total abatement cost savings will be less under the tax where more abatement will be performed after the innovation. However, as innovation lowers abatement costs, the price of a permit will begin to fall. An interesting effect is that widespread adoption of a technology will induce a lower permit price, thus making it less costly to forego the technology and buy cheaper permits. For this reason, purchasing firms will anticipate this drop in permit price and will therefore pay less for the technology than they would under a tax system. This situation is minimized under an auction system; however, it is difficult to say whether a tax or auction system will be better, as this will depend on the amount of imitation of the technology that is possible. This would suggest that a tax system would result in more development and diffusion of technologies.[150] Under either scenario, government subsidies can help with the diffusion of technology, but more subsidization will be needed under a permit system.[151],[152] Subsidization, while useful, has some important pitfalls that must be addressed when designing a R&D scenario under a carbon policy.

Potential Pitfalls of Research and Development Subsidization

The optimal climate-change policy depends on how the induced technological change will occur and the extent of knowledge spillovers.[153] In the best possible world, the government would be able to identify the technologies with the highest positive spillover effects and would subsidize those technologies. However, for this to work, the government must also have knowledge of potential technologies that will also have high spillover effects, and those should be subsidized as well. Subsidization of existing technologies without regard for potential new technologies actually crowds out innovation of new technologies, which harms social welfare.[154] Given that this is a second-best world and government does not possess all information, subsidization of existing technologies essentially amounts to the government choosing the winning technology, which may not be the most socially optimal technology.[155] For this reason, design of a subsidy program should be cautious in considering the effects of such subsidies on future technology developments.

Research and Development Funding Sources

Funding for R&D is available from government and private foundations, as well as through private investments. Specific funding levels depend on the type of project and the fiscal year in question. Table 3-16 offers an overview of existing sources of R&D funding in the United States.

149 Fischer, 2003.
150 Golombek & Hoel, 2006.
151 Fischer, 2003.
152 Jaffe et al., 1999.
153 Kvendokk et al., 2004.
154 Ibid.
155 Ibid.

Table 3-16. Select R&D funding sources[156]

	Organization	Department	Type of Project	Amt of Funding
Government	Department of Energy	Office of Science	-Biofuels & Solar -Hydrogen	-$150M FY 2007 -$288M FY 2007
		Office of Energy Efficiency and Renewable Energy	Biomass, geothermal, ocean, solar and wind	$300M, FY 2007
	National Science Foundation	N/A	No specific alt. energy funding- but have funded in past	N/A
	Small Business Technology Transfer		Funded by R&D budgets of large govt. programs. Requires business partnership with university or non-profit.	N/A
	Small Business Innovation Research		Funded by R&D budgets of large govt. programs. Principle Investigator employed by business	N/A
Petroleum Foundations	Petroleum Research Fund	Managed by American Chemical Society		
Private Investments	Private venture capitalists			Estimates of $590M in alternative energies from venture-capital related investments in 2005.

CONCLUSION

Research and development of new and alternative technologies is essential to successfully meeting greenhouse gas reduction targets. The government plays an important role in funding technological innovation with high spillover effects that might otherwise go unexplored. Government funding alone, however, will not achieve greenhouse gas reduction targets and must be endogenous to a climate-change policy designed to enhance R&D. The type of policy chosen and the allocation of subsidies can have large impacts on the effectiveness of technological development in tackling climate change; thus, an optimal policy must consider all internal and external results to effect the most efficient and socially beneficial outcome of research and development.

156 American Association for Advancement of Science, 2006.

DEMAND-SIDE TECHNOLOGY POLICIES

As noted above, numerous informational, institutional, regulatory and financial barriers impede the enabling or adoption of energy-efficient technologies or practices. Consequently, there is a continuing need for public policy to address these impediments. The section below further explores a sample of the policies used to encourage energy efficiency, including traditional demand-side management (DSM) programs, "energy-efficient" utilities, public-benefit funds, revenue decoupling, building codes and standards, appliance standards, rebates and tax incentives, and loan-assistance programs.

The policies or programs best suited to encourage energy efficiency depend on the geographic scale in question (e.g., state, regional, national) and the sectors targeted (e.g., residential, commercial, industrial). At the federal level, tax credits and loan-assistance programs have been used to encourage energy efficiency in the home and in the workplace. Also at the federal level, appliance standards and model building codes have provided a basis for nationwide minimums in efficiency. At the regional or utility service area level, DSM programs have been used to encourage energy efficiency and for load management. For a typical state,[157] a number of policies have achieved significant energy savings (Table 3-17).

Table 3-17. State-level energy efficient policy tools and corresponding savings potential[158]

Policy	2020 Savings Potential (TWh)	2020 Savings Potential (mmt CO_2)*
Energy Efficiency Utility Programs	21.75	13.22
Residential Building Code Improvement	1.41	0.86
Appliance Standards+	6.27	3.81
Tax Incentives	2.93	1.78
Total	32.36	19.67

*mmt: million metric tons – Based on an estimate of 1.34 pounds of CO_2 emissions per kWh of electricity (EIA 2002).
+ Includes only those appliances currently not subject to federal regulation.

157 Prindle et al. (2003) define a typical state as one with a population of approximately 5-6 million.
158 Prindle et al., 2003.

Traditional Demand-Side Management Programs

OVERVIEW

Demand-side management programs are those used by electric utilities to modify the end-use of electricity.[159] DSM activities fall into three broad categories, which can overlap. Conservation programs aim for absolute reductions in electricity consumption through the use of energy-efficient technologies.[160] Load-management programs focus on reducing demand, or load, at specific times, such as morning or afternoon when load is at a peak, or in response to resource costs or availability. Load management may also include programs that increase electricity demand or shift demand to off-peak times.[161] Energy information programs provide consumers with education or detailed feedback on energy use, such as usage breakdowns by appliance, historical comparisons and projections based on present usage patterns.[162] Such services are often used to complement conservation and load-management programs. Utilities may choose to offer such programs themselves to help meet increasing demands for electricity at least cost, or they may attempt to harness market powers to provide such services independently. State agencies and other third parties have also increased their involvement in deploying conservation or load-management programs. DSM is attractive to utilities and their partners because of its great potential for reducing energy consumption, pollution and investment in costly infrastructure. This potential, however, is tempered by significant barriers that constrain the growth of DSM programs.

Conservation programs aim to reduce overall demand. Therefore, they are generally oriented toward improvements in the infrastructure of a home or business rather than changes in behavior or usage. Examples include programs to improve insulation or reduce the infiltration of air across a building envelope ("weatherization"). Programs to encourage the purchase of energy-efficient equipment in key areas such as lighting (in commercial applications) and heating, ventilation and air conditioning (HVAC) systems, as well as other energy-efficient products, such as ENERGY STAR[163]-labeled appliances, are also common. Programs that encourage energy-efficient building techniques, such the Leadership in Energy and Environmental Design (LEED) standards, are increasingly being implemented.[164]

Load management, on the other hand, is not concerned with absolute reductions in demand, though absolute reductions may be a byproduct of load-management programs. Instead, load management is based on the principle that electrical power cannot be stored. Electricity must be produced as it is demanded and consumed when generated. Consequently, load management focuses on controlling demand. In doing so, utilities can reduce costs and increase the overall efficiency of their productive capacity.[165] Load management often involves temporarily modifying the behavior or usage patterns of consumers through the use of price signals. For instance, direct-load-control programs enable a utility to interrupt major electrical equipment during peak-usage hours, usually in exchange for a discount in electricity rates.[166] Another example is real-time pricing, a program that charges customers a variable rate for electricity based on the market spot price.[167] Faced with such a price signal, consumers have an incentive to avoid usage during expensive peak hours. There are many variations

159 Energy Information Administration, 1997.
160 Ibid.
161 Ibid.
162 Ibid.
163 EnergyStar® is product labeling program managed by the United States Protection Agency and the Department of Energy. See *http://energystar.gov/*.
164 LEED is promoted by the United States Green Building Council. See *http://www.usgbc.org/DisplayPage.aspx?CategoryID=19*.
165 Depending on the utility system, load management can lead to increased CO2 emissions or decreased CO2 emissions. If load management results in less generation from efficient intermediate and peaking natural gas units and more generation from baseload coal units, then CO2 emissions will likely increase. If load management reduces generation from inefficient natural gas and oil peaking units and increases generation from efficient baseload natural gas combined cycle units or new, efficient coal units, then emissions will likely decline.
166 Freeman, n.d.
167 Ibid.

on the basic models of interruptible service and variable pricing. All approaches allow a utility the flexibility of reducing demand when production is most costly or shifting demand to hours when resources are otherwise underused. To achieve the latter goal, utilities may promote programs that build load during off-peak hours. The recent interest among utilities in plug-in hybrid automobiles is an example of a load-building program.[168] Owners of plug-in hybrids are expected to charge their automobiles batteries by connecting them to the grid overnight, when utilities are generating excess capacity.

Information programs are yet another DSM approach. Education programs, such as energy audits, in which trained surveyors assess the energy use of a home or business and suggest improvements, have been shown to be important to the success of DSM and are often used in conjunction with conservation programs.[169] Direct-feedback approaches incorporate wireless computing technologies to present electricity metering data in an accessible and up-to-date fashion. Such technologies can disaggregate usage by appliance or project monthly bills based on up-to-date usage. This information enables consumers to modify their behavior to reduce energy bills. As a consequence, direct feedback is viewed as especially effective when used in conjunction with load-management programs such as real-time pricing.[170] Indirect feedback presents similar information via electricity bills. Weather-adjusted annual comparisons or comparisons with similar households or companies, as presented on a monthly electric bill, can provide valuable perspective to end-users seeking to reduce consumption.[171]

Strategies to achieve demand-side management vary. Conservation programs are traditionally accompanied by financial incentives such as rebates, special financing or tax credits.[172] Load-management programs attract participants by offering reduced rates in exchange for direct load control or, in the case of real-time pricing, by instituting motivating price signals. Information programs promise the incentive of lower monthly utility bills either through education about energy use or feedback on usage. Information programs can serve as a wedge for a utility's suite of conservation programs. For instance, energy audits or feedback mechanisms can identify conservation or load-management opportunities. Then, the utility may offer cost-effective recommendations based on its DSM programs. Finally, the utility may provide financial incentives for participation in a program.[173]

In general, utility strategies to achieve DSM take on the characteristics of two categories—resource acquisition or market transformation—though the two are increasingly deployed complementarily.[174] The former strategy typically operates as described above, with the utility providing programs that meet demand at a lower cost than adding new generation capacity. Market transformation, on the other hand, sees utilities attempting to encourage an independent market of energy-services providers that serve these functions.[175] A third alternative is the "Energy Efficiency Utility," in which the responsibility for DSM programs is shifted from utilities to state agencies or nonprofit organizations.[176] New York's State Energy Research and Development Authority is an example of such an approach.[177]

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168 Plug-in Partners advocates for a broader market for plug-in hybrid vehicles. Many investor-owned and public utilities participate in the organization. See *http://www.pluginpartners.org/campaignOverview/partnerList.cfm.*

169 Darby, 2000.

170 Ibid.

171 Ibid.

172 Database of State Incentives for Renewable Energy [DSIRE], 2006.

173 Austin Energy, 2005.

174 Blumstein et al., 2003.

175 Ibid.

176 U.S. Environmental Protection Agency, 2006.

177 See *http://ww.nyserda.org/*

PRESENT IMPACT AND FUTURE POTENTIAL

Demand-side energy policies have been estimated to save 4 exajoules (EJ) of energy and reduce carbon emissions by 231 million metric tons of CO_2 equivalent (mmtCO_2e) on an annual basis.[178] The federal Energy Information Administration estimates that nationwide in 2005, DSM energy-efficiency efforts reduced peak loads by 15,351 MW and resulted in energy savings of 58,891 GWh, equal to a cost of $1.17 billion.[179] At the state level, past experience and future potential of DSM varies. The Vermont, for instance, estimates that utility DSM programs reduced consumption by approximately 5 percent and reduced peak demand by 6 percent between 1991 and 1997.[180] Austin Energy credits its DSM programs with saving the equivalent of a 500 MW power plant.[181] The ultimate potential of DSM measures to reduce consumption has been estimated variously to range anywhere from 24 percent to 70 percent.[182] Information programs alone have been estimated as having the potential to reduce consumption by 10 percent.[183] Because DSM reduces or displaces demand, it also has significant environmental co-benefits in the areas of air quality and greenhouse gas emissions mitigation.[184] It also brings economic benefits to utilities, insofar as it defers expenditures on new energy infrastructure, encourages new markets or improves customer service.[185] DSM also brings economic benefits to customers through lower electricity prices, even for customers not actively taking advantage of DSM programs who see lower prices as a result of lower overall demand for electricity.

Considerations of cost-effectiveness and other significant barriers to implementation of DSM programs limit its potential.[186] The most conspicuous barrier is the so-called "throughput" disincentive. This disincentive stems from the principle that utilities (like all firms) have an incentive to increase sales, or "throughput," when marginal revenue exceeds the marginal costs of sales. Because revenues are tied to sales, utilities are concerned that DSM expenses will not be recovered, successful programs will lead to reduced sales and profitable investments will be forgone if resources are devoted to DSM programs.[187] Regulatory policies that require DSM programs to pass certain tests for cost-effectiveness act as corollaries to the throughput disincentive. For instance, the Rate Impact Measure test bars a utility from adopting a DSM measure that results in increased rates. However, due to the relationship between revenue and throughput, rates must often be raised to compensate for the revenue shortfalls projected for a successful DSM program. As a consequence, DSM opportunities subject to such tests are often foregone, even if the capacity gains from DSM are cheaper than building new generation assets.[188] Deregulated markets are also seen as a barrier to DSM implementation. Price competition between producers and transmitters of electricity has been theorized to create an incentive to increase sales volume.[189] Since deregulation, the annual effects of DSM programs on peak load reductions and energy savings have been flat. [190] Further, data compiled by the Energy Information Agency suggest that peak load reductions and energy savings reached a peak in 1996, reflecting the hypothesis that deregulation of electricity markets in the late 1990s has suppressed the potential of DSM. [191] Finally, consumer resistance to DSM programs represents another significant barrier. Evidence suggests that consumers use a high discount rate when considering investments in energy-saving

178 Gillingham et al., 2004.
179 Energy Information Administration, 2006b.
180 Vermont Public Service Department, 1998.
181 Austin Energy, 2006.
182 Nadel, 1992.
183 Darby, 2000.
184 Nichols, 1995.
185 Energy Information Administration, 1999.
186 Nadel, 1992.
187 Dinan & Shackleton, 2005.
188 Deevey & Harlos, 2005.
189 Energy Information Administration, 1997.
190 Energy Information Administration, 2006a.
191 Energy Information Administration, 1997.c

products or programs. As a result, they can be reluctant to engage in DSM programs with even moderate up-front costs.[192]

While the literature contains several prospective estimates of the potential cost effectiveness of demand-side energy policies, retrospective or ex post analyses are somewhat less common. However, in their review of the retrospective segment of the literature, Gillingham et al. (2004) found that utility DSM programs annually save up to approximately 65 petajoules (PJ) of energy and reduce carbon emissions by up to approximately 36 mmtCO_2e.[193] These savings have come at a generalized cost of approximately 3.4 cents per kWh.[194] Still, the researchers note that this price estimate does not include costs to consumers and that 50 percent to 90 percent of reported energy savings may be affected by free-ridership.[195]

192 Ibid.
193 Gillingham et al., 2004.
194 Ibid.
195 Ibid.

DESCRIPTION AND DISTRIBUTION

Nonutility administration of energy-efficiency programs at the state level is a strategy employed by several states to overcome the disincentives for utilities to invest in such programs and to capture the economies of scale from one organization operating statewide.[196] Seven states have opted to remove the administrative responsibility for energy-efficiency programs from electricity and natural gas utilities. Of these, Wisconsin (Focus on Energy[197]), Maine (Efficiency Maine[198]), New Jersey and Ohio administer programs through a state agency. Other states have authorized third-party administration of energy efficiency at the state level, including Vermont (Efficiency Vermont[199]) and Oregon (Energy Trust of Oregon[200]). New York's State Energy Research and Development Authority,[201]) a public-benefits corporation, shares elements of both management strategies. An eighth state, Connecticut, has authorized its Energy Conservation Management Board to approve utility energy-efficiency plans and budgets, effectively shifting a portion of the administrative role to the state.[202]

Nonutility administrators tend to derive their authority from state statutes directed at conservation of energy.[203] They are funded via a public-benefits fund derived from energy rate surcharges.[204] Core functions of nonutility administrators can be grouped into five areas: general administration and coordination; program development, planning and budgeting; program administration and management; program delivery and implementation; and program assessment and evaluation.[205]

PRESENT IMPACT AND FUTURE POTENTIAL

States with nonutility administration of energy-efficient programs generally exceed the national average in terms of energy-efficiency spending per capita, energy-efficiency spending as a percentage of utility revenues and energy-efficiency spending as a percentage of electricity sales (Table 3-18).

Table 3-18. 2003 Energy-efficiency spending in states with nonutility energy-efficiency administrators[206]

State	Spending, per capita		Spending, percentage of utility revenues		Spending, percentage of electricity sales	
	Amount ($)	National Rank	Percentage	National Rank	Percentage	National Rank
VT	28.26	1	2.98%	1	4.77%	8
OR	13.44	6	1.71%	6	6.02%	6
WI	11.33	7	1.39%	7	4.40%	9
NJ	11.31	8	1.35%	8	3.79%	11
CT	10.10	10	1.10%	13	7.81%	1
ME	8.03	15	0.90%	14	0.45%	24
NY	7.46	16	0.81%	15	3.02%	15
OH	1.37	25	0.15%	25	0.26%	26
U.S Average	***4.65***	-	***0.52%***	-	***1.93%***	-

196 U.S. Environmental Protection Agency, 2006.
197 See *http://www.focusenergy.com/*
198 See*http://www.efficiencymaine.com/*
199 See*http://www.efficiency.vermont.com/pages/*
200 See *http://www.energytrust.org/index.html*
201 See *http://www.nyserday.org/*
202 U.S. Environmental Protection Agency, 2006.
203 Wisconsin, Maine, Vermont, Oregon and New York all derived administrative authority from state statutes.
204 Wisconsin, Maine, Vermont, Oregon, New York and Connecticut receive funding in this manner.
205 Blumstein et al., 2003. N.B. - The nonutility administrator does not typically perform all functions, instead choosing to contract out responsibilities as a means of encouraging public-sector involvement in achieving energy-efficiency goals.
206 York & Kushler, 2005.

The variation in approaches taken by each state in administering energy-efficiency programs makes aggregate comparisons difficult. Still, individual states have demonstrated cost-effective improvements in energy efficiency. For example, in its first two years, New York's program invested $17 million in energy-efficiency improvements and generated an annual savings of $12.5 million.[207] The program was also successful in leveraging $3 in private funds for every $1 of public money spent.[208]

207 Prindle et al., 2003.
208 Ibid.

DESCRIPTION AND DISTRIBUTION

As noted above under "Public Utility Funds" within "Supply-Side Technology Policies," a public-benefit fund program typically consists of assessing a small fee[209] (typically called a "system benefit charge" or "public benefit charge") on electricity and/or natural gas consumption. The funds collected are then used to support energy-efficiency and renewable-energy R&D or to financial assistance for low-income households encountering difficulty in paying energy bills. While the role of PBFs in facilitating the development of renewable-energy resources is described in under "Supply-Side Technology Policies," this section focuses primarily on the role PBFs play in encouraging energy efficiency.

Public-benefit funds were first developed by states in the late 1990s as a method to address the negative effect of restructuring and retail competition on individual utility energy-efficiency efforts.[210] Many PBFs were in fact passed into law in conjunction with restructuring policies, though some states have since implemented PBFs without accompanying restructuring legislation.[211] Table 3-19 lists existing state PBF programs with a focus on energy efficiency.[212] Of these states, Arizona, Hawaii, Maine, Michigan, New Hampshire, Nevada, Vermont and Texas have dedicated PBFs to support energy efficiency solely.[213] Other states' PBFs support a mix of energy-efficiency programs, low-income assistance programs and renewable-energy programs. New Mexico and Louisiana, while not included in the table, have PBF programs in development that would support energy efficiency.[214]

Table 3-19. PBFs providing energy efficiency programs, by state, as of October 2006, showing funding sources and areas of specific focus[215,216,217]

State	Funding Source(s)	Low Income
Arizona	system benefits charge	X
California	system benefits charge	X
Connecticut	system benefits charge	X
Delaware	system benefits charge	X
D.C.	system benefits charge	X
Illinois	pro rata basis of sales	X
Maine	system benefits charge	X
Massachusetts	system benefits charge	
Michigan	system benefits charge, securitization	X
Montana	2.4% of utility retail sales revenue	X
Nevada	system benefits charge	X
New Hampshire	system benefits charge	X
New Jersey	system benefits charge	
New York	system benefits charge	X
Ohio	system benefits charge	X
Oregon	3% "public purpose" charge	X
Rhode Island	system benefits charge	X
Texas	system benefits charge	X
Vermont	system benefits charge	X
Wisconsin	system benefits charge	X

209 Nadel & Kushler, 2000. Public benefit charges are on the order of $0.003 - $0.0005.
210 Ibid. Utility funding for energy efficiency programs fell approximately 50% between 1993 and 1998.
211 Ibid.
212 Pew Center on Global Change, 2006. N.B. - the variety of approaches used in state PBFs makes aggregation and comparison difficult. The information listed in Table 23 is based on cross-referenced data from several independent sources.
213 Ibid.
214 Alliance to Save Energy, 2006.
215 Ibid.
216 Kushler, 2004.
217 Pew Center on Global Change, 2006.

Most PBFs assess a charge on the end-use of electricity on a per-kWh basis, or a systems benefit charge (SBC).[218] The SBC is "non-bypassable" in that the charge is applied to the state-regulated distribution system, so all electricity users in the state pay into the fund. This feature adds to the administrative simplicity of a PBF and ensures that program costs are borne evenly by all customers in the state, regardless of the power provider. The SBC operates like a tax at the end-use level, raising the price of electricity and theoretically reducing consumption while generating revenue.[219]

Within each state, PBF programs can be utility-administered, state-administered or administered by an independent third party. Under the first model, funds from the PBF are allocated to utilities, which then administer the programs. As mentioned above, these programs can support energy conservation, renewable energy or low-income assistance. Energy-efficiency programs are oriented either toward resource allocation or market transformation.[220] The latter two administrative models, state-administration and third-party administration, amount to what is often labeled an energy efficiency utility (see "Energy Efficiency Utility" above). Under these models, the energy-efficient utility, rather than the electricity generator, becomes the provider of energy-efficiency programs and incentives.[221] Of the variety of administrative strategies, no one model has yet emerged as the preferable approach. For instance, California's program is utility-administered, while Wisconsin's is administered by the state. Vermont is one of very few states that have contracted with an independent third party to administer its PBF. All three states rank in the top 10 of states with respect to annual kWh savings due to energy-efficiency programs as a percentage of kWh sales.[222] More important than administrative strategy is program spending. Funding is closely correlated with energy savings, with top-spending states saving twice the national average in 1998.[223] Nearly all states listed as examples above each rank in the top 10 of states with respect to spending per capita[224] and as a percentage of revenues.[225]

PRESENT IMPACT AND FUTURE POTENTIAL

A 2005 empirical study by Swisher and McAlpin noted that the rates of energy savings were higher in the year 2000 in states with PBFs than in states without PBFs, whether the states were regulated, deregulated or partially deregulated.[226] The most commonly cited states with successful PBFs are New York, Massachusetts and California, each of which began operation in 1998. New York's program is administered by the New York State Energy Research and Development Administration, a hybrid of the state-administered and third-party administered models. As of 2005, New York had committed $899 million to its energy-efficiency programs, culminating in 1,700 GWh of annual electricity savings, a 1,000 MW reduction in peak demand and $230 million in annual energy bill savings.[227] Massachusetts' programs have been largely administered by power-distribution utilities, although a largely unsuccessful effort has been made to procure services from a third-party competitive market.[228] In Massachusetts, energy-efficiency programs received $113.4 million in 2002 (the most recently reported year) from the commonwealth's PBF, resulting in 241 GWh of annual energy savings and $21 million in annual bill reductions.[229] California is credited with pioneering the PBF with its "public charge fund." About $220 million from its public charge fund is allocated by the California Public Utilities Commission (CPUC) annually to the four investor-owned utilities in the state for energy-efficiency endeavors. Each utility must submit to the CPUC for

218 Khawaja et al., 2001.
219 Ibid.
220 Nadel & Kushler, 2000.
221 U.S. Environmental Protection Agency, 2006.
222 York & Kushler, 2005.
223 Nadel & Kushler, 2000.
224 York & Kushler, 2005. California is actually 12th in this respect.
225 Ibid.
226 Swisher & McAlpin, 2006.
227 New York State Energy Research and Development Administration [NYSERDA], 2005.
228 Division of Energy Resources, 2004.
229 Office of Consumer Affairs and Business Regulation, 2004.

approval a plan for energy-efficiency programs. In 1999, \$200 million was spent on energy efficiency, resulting in 825 GWh of annual electricity savings and a 156 MW reduction in peak demand. according to the California Board for Energy Efficiency (CBEE).[230] However, the CBEE, a division of the CPUC, has not reported on the state's PBF since 1999. A 2005 state Integrated Energy Policy Report attributes more than 40,000 GWh and 12,000 MW in savings in electricity consumption and peak demand, respectively, to the state's energy-efficiency programs, though it does not explicitly describe the PBFs role in funding these programs.[231] The state recently announced a plan to increase funding to \$2 billion between 2006 and 2008 to state utilities for energy-efficiency programs.[232]

The potential for PBFs to produce more energy savings is significant. As of 2003, total state spending on nonutility administration of energy-efficient programs was on the rise.[233] Driven by state and regional commitments to energy-efficiency programs in long-term energy planning, increases in fossil fuel prices and concerns over resource availability, growth is expected to continue in the near term.[234] At the state level, a 2001 report on the remaining energy-efficiency opportunities in Massachusetts estimated that the levels of incremental energy savings over the period 2003-2007 depends greatly on continued ratepayer funding. The report projected 667 MWh of savings with continued ratepayer funding of energy-efficiency programs. Without a PBF, savings were estimated to be roughly half this amount (332 GWh). Savings in the commercial and industrial sector were projected to be 3.5 times greater with a PBF than without one.[235]

The potential of PBFs also extend to climate-change mitigation, due to the significant reductions in energy consumption and demand that PBFs yield. In a 2004 report prepared for the Puget Sound Clean Air Agency Board of Directors, the Climate Protection Advisory Committee (CPAC) analyzed the impact of PBFs programs on CO_2 emission reduction and energy savings. Given a systems benefit charge of 0.09 cents/kWh for electricity and a \$0.001/therm for natural gas, the CPAC estimated that a PBF could reduce greenhouse gas emissions by 27 mmt-CO_2e between 2005 and 2020, at a net present value benefit of \$555 million.

Despite the documented benefits and expected potential of PBFs, the majority of states have not employed such policies. In fact, 90 percent of all ratepayer-funded energy-efficiency program spending comes from just the top 20 states in terms of per capita spending.[236] According to the latest review by the American Council for an Energy Efficient Economy (ACEEE) of rate-payer funded energy efficiency programs (based on 2003 data), five states had no program funding: North Carolina, Kansas, Delaware, Virginia and Wyoming.[237] Within specific regions of the country, spending can also vary significantly. In the Midwest, total state-to-state variation is as high as \$91 million, with Minnesota, Iowa and Wisconsin characterized as having "significant investment with well-established programs"; Illinois, Michigan, Ohio and Missouri having "modest investment with one-off programs"; and Indiana and Kentucky having "little to no investment."[238]

Efforts to institute a federal public-benefit fund or establish a national program to match funds for state public-benefit funds have not been successful, though such legislation has been proposed in Congress.[239] The establishment of a PBF is ultimately a political decision, which can be a significant hurdle to implementation. Political opposition to PBFs often portray them as a tax on utility rate payers, despite evidence that they can and typically do result in net savings to consumers. In addition, the revenues generated by PBFs require the creation of new

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230 Prindle et al., 2003.
231 Jones et al., 2005.
232 California Public Utilities Commission, 2005.
233 York & Kushler, 2005.
234 Ibid.
235 RLW Analytics Inc. & Shel Feldman Management Consulting, 2001.
236 York & Kushler, 2005.
237 Ibid.
238 Jaehn, 2006.
239 U.S. Environmental Protection Agency, 2002.

bureaucracies that may be portrayed as inefficient. Finally, expenditures under such circumstances may not be cost-effective (i.e., they may require large rebates).[240] Another concern regarding PBFs is the need for clear legislative intent regarding how PBFs will be funded (e.g., how long, how much) and operated. For instance, PBFs for energy efficiency have suffered from competition from renewable energy and low-income assistance program goals, with many programs experiencing "raids" on their funding. Such raids have also diverted PBF money to mitigate budget shortfalls in government expenditures unrelated to energy[241]

240 Switzer, 2002.
241 Kushler, 2004.

DESCRIPTION AND DISTRIBUTION

Decoupling[242] is a policy proposal for eliminating the disincentive for investor-owned utilities (IOUs) to support energy conservation and efficiency.[243] This disincentive stems from the principle that IOUs (like all firms) have an incentive to increase sales, or throughput, when marginal revenue exceeds the marginal costs of sales. Because revenues are tied to sales, utilities are concerned that energy-efficiency program expenses will not be recovered, successful programs will lead to reduced sales and profitable investments will be forgone if resources are devoted to conservation programs.[244] Decoupling policies work to remove these disincentives by severing the tie between throughput and revenue. This relationship is replaced by an amount of revenue authorized by a regulatory body that is guaranteed regardless of sales. As a result, IOUs transform from sellers of energy to providers of energy services such as energy-efficiency programs.[245]

While rate cases held by regulatory bodies are intended to limit conditions under which incremental sales are profitable, such hearings are held infrequently enough that the "throughput incentive" is regenerated between each rate case.[246] Thus, the throughput incentive is a product of regulatory lag, and the importance of decoupling policies depends on the frequency of rate cases.[247] Decoupling mechanisms work to break the throughput incentive between rate cases by establishing a balance account which ensures that utilities receive no more and no less than the annual revenue authorized by a regulatory body. In simple terms, excess revenues are returned to ratepayers, while shortfalls may be collected from ratepayers the following year. Since revenues are guaranteed, sales no longer affect the IOUs profitability. The balancing account is a common trait of all decoupling mechanisms. They differ in the way the authorized revenue is adjusted between rate cases to reflect changes in (non-fuel) expenses.[248]

California, Florida, Maine, Montana, New York, Oregon and Washington have all experimented with decoupling mechanisms.[249] However, only California has long-term experience with separating energy revenues from sales, having implemented some form of decoupling from 1982 to 1996, and again since 2002.

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242 Decoupling of varying forms include Electric Rate Adjustment Mechanism (ERAM), ERAM-per-customer, statistical recoupling, revenue indexing, revenue cap or revenue-per-customer cap. Meehan & Olson, 2006.

243 Municipal utilities must ensure that revenue exceeds debts, rather than demonstrate a profitable return on investments, as IOUs must do. Accordingly, it is not clear that municipal utilities face as strong a "throughput" incentive. U.S. Environmental Protection Agency, 2006.

244 Dinan & Shackleton, 2005.

245 Ibid.

246 Ibid.

247 Ibid.

248 Ibid.

249 Meehan & Olson, 2006.

PRESENT IMPACT AND FUTURE POTENTIAL

Experience in California has revealed few negative effects from the use of decoupling on rates.[250] Eto, Stoft and Belden studied the effect of decoupling on rates from 1983 to 1993.[251] They found no significant difference between rates with decoupling and a projection of rates without decoupling. In the case of two of the three investor-owned utilities studied, the standard deviation of rates with decoupling was less than the standard deviation without, suggesting that decoupling actually reduced rate volatility. Finally, the researchers calculated the effect of decoupling on the standard deviation of utilities' profits and show a decrease from 4.4 percent to 1.4 percent. Combined with their results regarding rates, the researchers conclude that decoupling has not shifted risk from utilities to ratepayers; on the contrary, decoupling in California has reduced rate risk to customers and profit risk to utilities. In addition to these results, a 2005 ranking of state energy-efficiency performance shows that California is a leader in energy conservation, ranking in or near the top 10 in expenditures on energy-efficiency programs and electricity savings as a percentage of sales.[252] Nevertheless, the relationship between California's decoupling program and energy-efficiency performance is not clear. Accordingly, the claim that no evidence exists to support the idea that decoupling is a necessary condition for successful utility-funded conservation programs is often made by opponents of decoupling mechanisms.[253] Indeed, despite the relative success seen in California, many states' experiences with decoupling have been more mixed. Florida and Montana have not vigorously pursued their decoupling plans,[254] while Maine and Washington were compelled to abandon their programs.[255] Nevertheless, a number of states are now considering (re)implementing some form of decoupling, including Colorado,[256] Utah,[257] New York,[258] Maine[259] and Washington.[260]

The experience of Maine and Washington in particular highlight some of the major criticisms directed toward decoupling plans. Decoupling is viewed by some observers as a way for utilities to guarantee recovery of their fixed costs, while shifting risk to consumers.[261] In Maine, for example, decoupling coincided with a general economic downturn in the state economy that reduced sales. Central Maine Power (CMP) fell well short of its authorized revenues and was able to collect them from ratepayers via a large rate change.[262] Further, during this period CMP's avoided costs were less than the cost of demand-side management programs due to the recession and the opening of a nuclear power plant in New Hampshire, which was generating excess capacity. As a result, CMP's investment in DSM programs actually declined from $25 million to $17 million.[263] In effect, decoupling shifted the risks posed to CMP's revenue by changes in economic activity and weather to the customer—with no attendant benefit to energy conservation attributable to the program.[264] Washington's program was more successful; for instance, utilities met the conservation goals set forth in the state's decoupling legislation.[265] Nevertheless, the program suffered from design flaws that resulted in price volatility that angered ratepayers.[266] In 1991 and 1992, rates increased by 3 percent and 7 percent, respectively. While decoupling per se accounted for only 19 percent of the increase, and spending on DSM contributed only another 23 percent, the decision to include these costs with the primary cause of the rate increases—power-supply costs (53%)—resulted in rate

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250 Ibid.
251 Dinan & Shackleton, 2005.
252 York & Kushler, 2005.
253 Costello, 2006.
254 Meehan & Olson, 2006.
255 U.S. Environmental Protection Agency, 2006.
256 A Bill for an Act Concerning Integrated Resource Planning for Electric and Natural Gas Utilities, 2006.
257 Utah Public Service Commission, 2006.
258 New York State Consumer Protection Board, 2006.
259 An Act to Encourage Energy Independence for Maine, 2006.
260 Brosch, 2006.
261 Costello, 2006.
262 U.S. Environmental Protection Agency, 2006.
263 Hudson et al., 1995.
264 Ibid.
265 Ibid.
266 U.S. Environmental Protection Agency, 2006.

volatility that was perceived to be attributable to revenue decoupling.[267] This experience suggests that power-supply costs or fuel-adjustment mechanisms should not be included in the design of decoupling mechanisms.[268] In general, price volatility has been singled out by critics such as Graniere and Cooley as a probable consequence of decoupling. They suggest that these effects could erode the cost-saving benefits of decoupling.[269] While the Maine and Washington experience present a more complicated relationship between price volatility and decoupling (i.e., economic conditions and design flaws may be stronger contributors to price volatility than decoupling), and the evidence from California gainsays such a relationship, consumer groups tend to oppose decoupling for this reason.[270] Meanwhile, gas utilities, which have seen reduced sales due to gains in end-use efficiency and price volatility, have become prominent supporters of decoupling.[271]

Despite the perceived drawbacks, major trends (e.g., increasing demand for energy, rising commodity prices, increasingly strained distribution networks and unrealized efficiency potential) imply that incentives for utilities to invest in demand reduction remain important. Such reasoning was cited recently by the New York Public Service Commission in its decision to reverse its opinion in 2003 to oppose decoupling; it has subsequently proposed a new decoupling plan for New York[272]

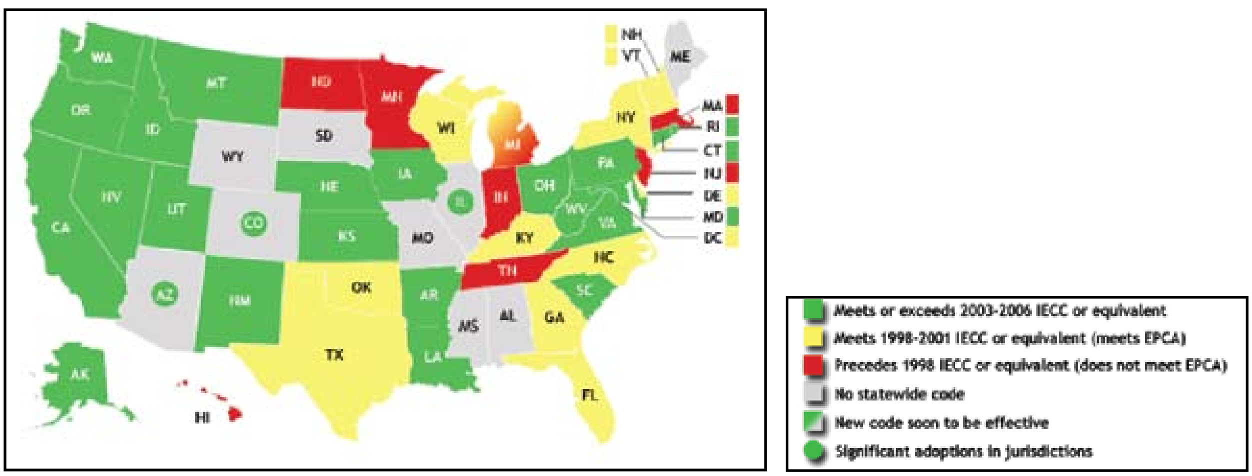
267 Hirst, 1993.
268 Ibid.
269 Graniere & Cooley, 1994.
270 Costello, 2006.
271 Ibid.
272 New York State Consumer Protection Board, 2006.

DESCRIPTION AND DISTRIBUTION

As noted above, mandatory, enforceable codes govern the construction of buildings in the United States and are key drivers in energy efficiency. Standards—benchmarks or recommendations—also are key drivers in achieving cost-effective energy savings in building construction and operation. Through consensus-based processes, organizations such as the International code Council (ICC) and the American Society of Heating, Refrigerating, and Air-Conditioning Engineers (ASHRAE) develop model building codes and standards. These model codes and standards can then be adopted wholesale or with modifications by states and local communities. Alternatively, some states, such as California and Florida, have chosen to create their own building codes and standards for energy efficiency.

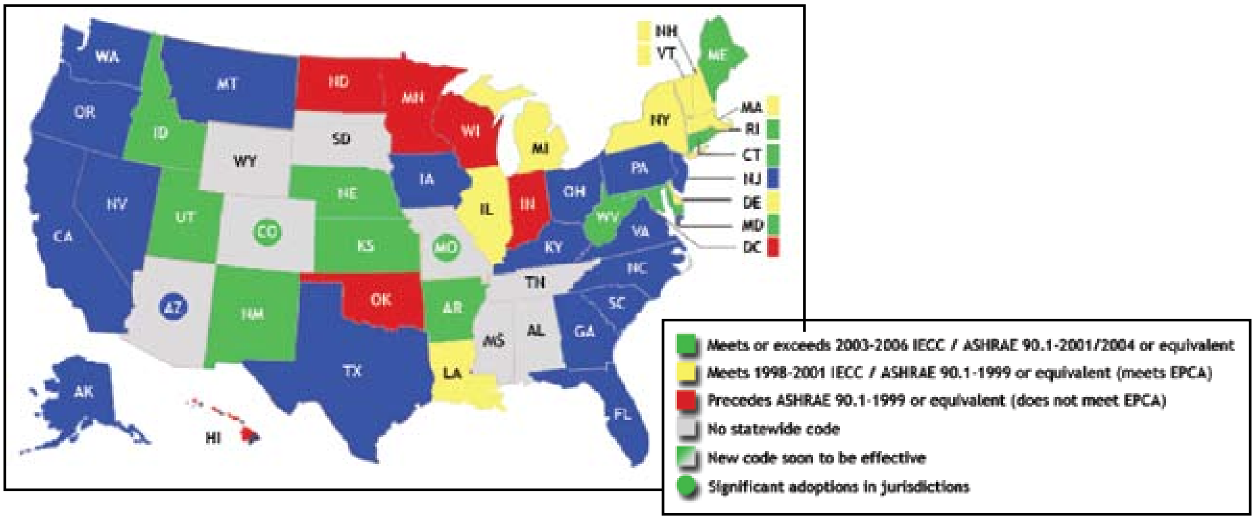
Building codes and standards, covering everything from energy efficiency to accessibility to plumbing and storm proofing, are continually modified or refined. Building energy efficiency is specifically addressed within the ICC's International Energy Conservation Code (IECC) and ASHRAE 90.1 & 90.2. The IECC covers window u-factors, insulation R-values, duct insulation, vestibule enclosure, infiltration control, lighting and equipment efficiency. ASHRAE 90.1-2001 and 90.2-2001 cover construction of new buildings and systems, specifically HVAC, water heating, motors and lighting. Despite the existence of these model codes and standards, the decision to adopt a particular one, or alternatively to modify the model or develop an entirely new set of codes or standards, varies from state to state (Figure 3-7 and Figure 3-8).

Figure 3-7. 2006 status of residential state energy codes[273]



273 Building Codes Assistance Project, 20067777.

Figure 3-8. 2006 status of commercial state energy codes[274]



PRESENT IMPACT AND FUTURE POTENTIAL

Between 1991 and 2005, building codes covering energy efficiency are credited with saving over $7.435 billion in energy costs.[275] For 2000 alone, savings are estimated at 528 PJ.[276] In California, energy-efficiency standards have achieved $56 billion in electricity and natural gas savings since 1978.[277] Approximately 25 percent of current annual state energy savings are attributable to the state's Title 24 standards.[278] Title 24 is one of the best enforced code systems in the country, achieving an 88 percent compliance rate.[279] Flexibility has been cited as a key driver in the success of the Title 24 program; the system is performance-based, allowing builders to choose the most-cost effective means for meeting requirements.[280] Florida has implemented a similar performance-based program. While Florida has a lower compliance rate than California (77 percent), this rate is somewhat offset by above-code construction in a significant percentage of other structures.[281] In Texas, the adoption of IECC 2001 is credited with significant energy savings. One component of the adopted code, a solar heat gain standard, has the potential to save 1.8 billion kWh and avoid 1,220 MW of peak demand over 20 years.[282]

The Alliance to Save Energy estimates that between 2005 and 2020, residential and commercial codes and standards have the potential to save up to 5 EJ of energy.[283] The annual savings by 2020 are estimated at 897 PJ, $6.8 billion in energy cost savings, along with a 51 million metric ton reduction in CO_2 emissions.[284] A full realization of these potential savings is impeded by uneven code adoption across states and other jurisdictions.[285] Lax enforcement of existing building codes by local building officials also impedes increased energy savings.

274 Ibid.
275 Loper et al., 2005.
276 Ibid.
277 California Energy Commission, 2006.
278 Prindle et al., 2003.
279 Ibid.
280 Ibid.
281 Ibid.
282 Ibid.
283 Loper et al., 2005.
284 Ibid.
285 Ibid.

Appliance Standards

DESCRIPTION AND DISTRIBUTION

As noted above, federal appliance standards were instrumental in setting consistent national energy-efficiency standards. Federal standards currently apply to refrigerators, freezers, air conditioners, furnaces, water heaters, space heaters, clothes washers/dryers, dishwashers, ranges/ovens, pool heaters, some lamps, lamp ballasts, electric motors and commercial HVAC.[286] Federal standards are required by law to be set at the "maximum level that is technically feasible and economically justified."[287] Various state standards apply to transformers, traffic lights, commercial refrigerators and freezers, exit signs, plumbing fixtures and fittings, space heaters and demand control ventilation devices.[288] If a state wishes to set more stringent standards on a product already covered by federal regulations, it must apply for a waiver from the Department of Energy.

In addition to meeting efficiency standards, refrigerators, freezers, dishwashers, clothes washers, water heaters, furnaces, boilers, central air conditioners, room air conditioners, heat pumps and pool heaters must display an EnergyGuide label to indicate the range of energy performance for a given product line, as well as the performance and annual energy cost of a particular model. EnergyGuide labeling has been required on certain appliances since 1980 and provides an easily recognized indication of energy efficiency, enabling consumers to make more informed purchase decisions.

PRESENT IMPACT AND FUTURE POTENTIAL

Research shows that national appliance standards are a cost-effective mechanism to reduce energy use. Gillingham et al. (2004) examines the available ex ante and ex post literature on appliance standards, from which they estimate an annual energy savings of 1.2 quadrillion BTUs (quads) at a cost of 3.8 cents per kWh.[289] Annual reductions in carbon emissions are estimated at 65.3 mmtCO_2e.[290] As newer, more efficient appliances replace older, less-efficient models, energy savings are likely to increase. Even without tightening, year 2000 standards have the potential to save 3.1 quads of energy, including 245 terawatt-hours (TWh) of electricity, in 2015.[291] Nonetheless, current appliance efficiency standards can be made more stringent in a cost-effective manner by 2010. Increasing the minimum efficiency of residential refrigerators and lighting, among other product classes, can be less expensive than the cost of generating electricity.[292] The same is true for a variety of commercial HVAC units, lighting and refrigeration.[293] Increasing standards for this subset of residential and commercial appliances, fixtures and equipment has potential to provide cumulative energy savings of 27 EJ between 2010 and 2030 and a net consumer benefit of $44 billion.[294]

The American Council for an Energy Efficient Economy has identified additional energy savings that can be achieved by adopting energy-efficiency standards for products currently without federal standards. These products include bottle dispensers, commercial hot food holding units, compact audio products, DVD players, transformers, metal-halide lamps, hot tubs, pool pumps, power supplies, state-regulated

286 Rosenquist et al., 2004.
287 See, e.g. 42 U.S.C. §6295 (o)(2).
288 Rosenquist et al., 2004.
289 Gillingham et al., 2004.
290 Ibid.
291 Sustainable Energy Coalition, 2000.
292 Rosenquist et al., 2004.
293 Ibid.
294 Ibid. Consumer benefit is in $2,000 and assuming a 7 percent discount rate.

incandescent reflector \lamps, and walk-in refrigerators and freezers.[295] Setting national standards for these products at ACEEE-recommended levels would result in electricity savings of 52 TWh, reduce national electricity generating capacity by 12 GW and reduce emissions by 44 mmtCO_2e in 2020.[296]

295 Nadel et al., 2006. Estimate of potential savings include increasing current existing federal standards for commercial boilers, pool heaters, and residential furnaces and boilers.

296 Ibid.

DESCRIPTION AND DISTRIBUTION

The majority of federal incentives for energy efficiency take the form of tax benefits implemented through the Internal Revenue Code. Many of these incentives are tax credits enacted via EPAct 2005 and are set to expire on December, 31, 2007. The credits instituted through EPAct 2005 are targeted to commercial and residential tax payers. Tax credits for individuals cover windows and doors, roofing, HVAC systems, insulation and water heaters. Commercial credits encourage energy efficiency in specific sectors, such as appliance manufacturers and home builders. For example, home builders are eligible for a $2,000 tax credit for new homes that demonstrate 50 percent energy savings for heating and cooling over the 2004 International Energy Conservation Code (at least one-fifth of the energy savings must come from building envelope improvements). Credits are also available for energy-efficient improvements to both commercial and residential buildings. Commercial buildings that reduce energy costs by 50 percent or more may be eligible for tax deductions of up to $1.80 per square foot.[297] Beyond the incentives authorized by EPAct 2005, the Internal Revenue Code stipulates that subsidies or rebates received from energy utilities are exempt from federal taxation.[298]

Since taxation at the state level goes beyond taxation of income, incentives at this level take a wider variety of forms, including personal and corporate income tax credits[299] as well as state sales tax holidays[300] and property tax relief.[301] States also offer rebates to commercial and/or residential entities to encourage energy-efficient machinery or appliances,[302] energy-efficient construction and retrofitting practices,[303] or, as in the case of Oregon, weatherization upgrades.[304]

Private and, in particular, municipal utilities in a great majority of states also offer rebate programs designed to foster energy-efficient activities.[305] As with states, rebates are offered to commercial and residential entities for energy-efficient building and retrofitting, energy-efficient appliances and machinery, and weatherization measures. At the utility level, the approach to rebates is even more diverse. For example, some utilities target specific commercial entities, such as dry cleaners, grocers, farmers, landlords, home builders and developers. In addition, energy-efficiency rebates are sometimes directed at specific technologies, such as vending machines, traffic signals (e.g., switching to LED technology) and irrigation systems. In a few instances, incentives are even devised to encourage fuel switching (e.g., from electricity to natural gas, and vice versa).[306]

PRESENT IMPACT AND FUTURE POTENTIAL

At the state level, Oregon has demonstrated success with its residential and business tax-credit programs. In 2001, 512 million kWh and 548 billion BTU of natural gas and other fuels were saved as a result of business credits, while 17 million kWh and 33 billion BTU of natural gas were saved as a result of residential credits.[307]

297 EnergyStar, n.d.
298 Database of State Incentives for Renewable Energy [DSIRE], 2006.
299 AZ, CA, ID, MD, MA, MT, NY, OK, OR, and DC offer personal and/or corporate income tax credits to state/district residents. See, for example, Alliance to Save Energy, 2005.
300 FL and GA have instituted non-recurring, week-long sales tax holidays in 2006.
301 MD, NV, and NY offer property tax relief for structures that exhibit energy saving features.
302 ME, NJ, NY, NC, RI, VT, and WI all offer rebates to either commercial or residential entities that install energy-efficient machinery or appliances.
303 LA, NJ, NY, VT, and WI each offer rebates tied to the Energy Star Homes program.
304 Database of State Incentives for Renewable Energy [DSIRE], 2006.
305 Utilities in AK, AR, DE, IN, LA, MD, MI, NJ, ND, OH, PA, SC, VA, WV, and the District of Columbia (about 30% of the states) do not offer energy-efficiency rebate programs.
306 Database of State Incentives for Renewable Energy [DSIRE], 2006.
307 Prindle et al., 2003.

Importantly, a survey of participants in residential tax-credit programs indicated the programs had influenced the purchase behavior of 63 percent of respondents.[308]

Despite the documented success in Oregon, empirical research on the effect of tax credits on energy-conserving home improvements continues to be scarce. Walsh (1988) finds no support for the hypothesis that tax credits lead to increased energy-efficient home improvements,[309] while Hasset & Metcalf (1992), studying the period 1979-1981, describe energy tax credits as a statistically significant predictor of investment in residential energy conservation.[310] Williams and Poyer (1996) in a study of Hispanic and African-American households finds a positive effect on the installation of insulation, while detecting a correlation between the use of tax credits for home improvements and wealth.[311] Brown et al. (2002) also find that energy tax credits (offered over the period 1978-1985) are more likely to be claimed by wealthier homeowners.[312] Further, they contend that a large portion of the tax credits are claimed by households that would have made energy-saving home improvements in any case, indicating that tax credits may suffer from a free-rider problem.

Despite this mixed record of such incentives, Brown, et al. advocate increased use of sales and income tax credits at the state level for efficient products and for green-construction practices, stressing the potential of such incentives to correct failures in the market for energy-efficient products, improve electric system reliability and provide environmental benefits. This conclusion is echoed by the recent National Action Plan for Energy Efficiency, which views energy-efficiency incentives as key to energy-efficiency program design and delivery and as having a strong synergistic effect in conjunction with education about the benefits of energy efficiency.[313]

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308 Ibid.
309 Walsh, 1988.
310 Hassett & Metcalf, 1992.
311 Bradley et al., 1991.
312 Brown et al., 2002.
313 U.S. Environmental Protection Agency, 2006.

Loan-Assistance Programs

DESCRIPTION AND DISTRIBUTION

The Energy Efficient Mortgage (EEM) was developed more than 20 years ago to promote the construction of energy-efficient new homes and to improve the efficiency of existing homes through renovation.[314] Fannie Mae, Freddie Mac, the Federal Housing Administration (FHA) and the Veterans Administration (VA) have each developed distinct programs to support EEMs on the secondary market. Each program is based on the recognition that energy-efficient homes cost homeowners less to operate on a monthly basis than typical homes, due to lower electric utility bills. This lower operating cost is substantiated by the Home Energy Rating System (HERS), which is performed by a state-certified energy rater. Lenders use this data to improve the credit profile of a borrower.

For example, Fannie Mae's EEM program permits monthly energy savings, as documented by the HERS, to be added to the borrower's income. In general, this increases the borrowing power of a mortgage applicant. The market value of the energy-saving features of a home can also be added to the appraised value of the property, further improving lending terms. These underwriting adjustments can be applied to the majority of mortgage products that Fannie Mae supports, including those aimed at lower-income borrowers.[315] FHA and VA versions of the EEM, which serve a narrower market of potential borrowers, offer similar terms.[316], [317] While secondary-market support for EEMs has been available for years, they are not and have not been widely known among lenders and borrowers alike. While information is itself a limiting factor for EEMs, the programs' low profile is also the result of a number of historical barriers. These barriers include the added complexity of processing an EEM application, the limited availability of HERS raters, the limited availability of contractors knowledgeable about or interested in energy-efficient building practices, and a lack of retail mortgage products that incorporate the benefits of EEMs. For example, special rates or incentives have rarely been offered by lenders in conjunction with EEMs. As a result, few EEMs have been written over the past two decades.[318]

Many finance programs are offered at the state level, and these programs, in some cases, work to supplement EEMs and reduce barriers to their acceptance. For instance, Alaska offers an interest rate reduction for energy-efficient homes. However, most state programs are directed toward improvements for existing residential homes for energy-saving appliances and weatherization. These loans are often small, unsecured, and carry low fixed interest rates. Loans directed toward major facilities upgrades for public facilities and commercial entities are also common.[319] Utilities offer similar loan programs in about half of the states. Many states, however, offer no financing programs, and utility programs are by their nature regional.[320] Consequently, availability of state and utility loan programs is not evenly distributed across the nation.

PRESENT IMPACT AND FUTURE POTENTIAL

Empirical studies on the effect of EEMs or other forms of energy-efficiency financing on adoption of energy-saving practices are practically nonexistent. This is understandable in light of the historically low utilization rate of EEMs.[321] In theory, however, such finance tools are attractive. Research indicates that energy consumers have a much higher discount rate than commercial interest rates and that consumers' discount rate is inversely related

314 Residential Energy Services Network, 2006.
315 Fannie Mae, 2000.
316 U.S. Department of Housing and Urban Development, 2003.
317 Veterans Benefits Administration, 2005.
318 Fasey, 2000.
319 Database of State Incentives for Renewable Energy [DSIRE], 2006.
320 Ibid.
321 Fasey (2000) cites HUD/FHA and NREL estimates that less than 1/10th of 1% of homes have utilized EEMs.

to income.[322] Financing of energy-efficiency improvements, which allows conversion of first costs into a stream of monthly payments, or amortization into a home mortgage, is ideally suited to overcoming such barriers.[323] Further, as of 2000 the use and availability of EEMs was increasing significantly because of streamlined underwriting guidelines and an increase in the availability of HERS inspections.[324] Presently, high energy costs and a softening housing market may be creating an environment in which the supply and demand for loan-assistance programs for energy-efficiency are both increasing. [325] Lenders may view EEMs as a way to differentiate their services from competitors and to increase business for themselves and their partners in the home-construction industry.[326]

CONCLUSION

Support for traditional demand-side management programs, revenue decoupling, energy efficiency utilities, public-benefits funds, financial incentives and special financing, and higher building and appliance codes and standards are representative of an array of public policy measures available to reduce barriers to implementation of energy-efficiency technologies and programs. Such policies are complementary and in conjunction may facilitate attainment of the potentials identified at the outset of this chapter.

DSM programs have now been employed by utilities for more than 20 years. Through the 1990s, utilities were able to realize significant savings from their demand-side programs.[327] Continuing support for DSM can help such programs reach a technical potential of 24 percent to 70 percent reductions in consumption nationally.[328]

Such support could come in the form of revenue decoupling, which ensures a fair financial return to a utility pursuing a successful DSM programs. State experiments with revenue decoupling have been limited, with mixed results. However, interest in the policy has remained strong and many states are poised to implement revenue decoupling measures in the near future.[329]

Alternatively, responsibility for DSM programs can be shifted away from utilities entirely. Instead, conservation programs can be implemented by state agencies or independent third parties. So-called Energy Efficiency Utilities face no split-incentives with respect to energy conservation and revenue. They may also reap returns to scale from specialization and statewide operations. Evidence from the states suggests that Energy Efficiency Utilities are performing well.[330]

Energy-efficiency technologies and programs, whether implemented by utilities or Energy Efficiency Utilities, benefit from increased funding.[331] Public-benefit funds are one method of supplying such funding. States with PBFs have been successful in reducing energy consumption and demand relative to states without them.[332] Further, evidence suggests that they are a key element in realizing higher energy-efficiency potentials.[333]

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322 Reddy, 1990.
323 Ibid.
324 Plimpton, 2000.
325 Stuart Williams (SunTrust Mortgage), Rick Brown (Chase Home Mortgage), Lori Allen (VyStar Credit Union), Brian Stout (Countrywide Home Mortgage), Joel Wiese (Indigo Financial Group), personal communication, June – August, 2006
326 Ibid.
327 Energy Information Administration, 2006a.
328 Nadel, 1992.
329 An Act to Encourage Energy Independence for Maine, 2006; A Bill for an Act Concerning Integrated Resource Planning for Electric and Natural Gas Utilities, 2006; Brosch, 2006; New York State Consumer Protection Board, 2006; Utah Public Service Commission, 2006.
330 York & Kushler, 2005.
331 Nadel & Kushler, 2000.
332 York & Kushler, 2005.
333 RLW Analytics Inc. & Shel Feldman Management Consulting, 2001.

First-cost is a major concern for consumers of energy-efficiency technologies and programs. Financial incentives such as tax benefits or rebates and special financing targeted to energy-efficient products can encourage wider investment in energy efficiency. While the present impact of such measures is unclear, their potential to spur markets for energy=efficient products and services is significant.[334]

Revised standards and codes for building and appliances are another way to boost energy performance cost effectively. Huge savings in consumption are achievable.[335]

A suite of complementary approaches are required to address the varying barriers to implementation of energy-efficiency technologies and programs. Many pioneering states have experience with a number of the above policies, and further experimentation and research is under way. The lessons learned suggest that public policy measures can successfully remove some barriers and lead to significant reductions in consumption and demand for energy.

334 Brown et al., 2002; Plimpton, 2000; U.S. Environmental Protection Agency, 2006.
335 Loper et al., 2005; Rosenquist et al., 2004.

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Notes

the Climate Change Policy Partnership

The Climate Change Policy Partnership (CCPP) was established at Duke University in October 2005 through a $2.5 million, 4-year gift from Duke Energy. The CCPP's focus is to address questions on climate change science and policy and initiate research to fill data gaps. The project is intended to leverage the resources of Duke University to determine practical strategies to respond to the pressing challenges of global climate change.

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