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16. Abstract
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Texas Energy Sector: Past and Future

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Chapter 1. Introduction

Texas has been known as an energy state ever since the Lucas Number 1 well blew mud, gas, and oil 200 feet into the air at Spindletop on January 10, 1901. Since then, the oil and gas industry has contributed greatly to the state's Gross Domestic Product (GDP). From the oil discoveries in North, East, and West Texas during the early 1900s to recent natural gas discoveries in the Barnett Shale region of Arlington and Fort Worth, the Haynesville Shale region of East Texas, and the Eagle Ford Shale of South Texas, the oil and natural gas industries have been a significant factor in Texas's economic success.

Today, Texas produces 30% of the natural gas consumed in the U.S. and accounts for 19% of total U.S. oil production (Governor's Competitiveness Council, 2008). At the same time, coal-generated power plants produce a significant share of the electricity in the state. More than half of the coal feedstock is low sulfur Wyoming coal that is brought to the state by Union Pacific (UP) and Burlington Northern Santa Fe (BNSF) on long, heavy unit trains. Increasing concerns over energy affordability, air quality, and carbon emissions have resulted in the Texas legislature adopting policies that promote the generation of renewable energies. Texas is now the number one producer of wind energy in the U.S., with a rated capacity of approximately 10,000 megawatts (MW) installed in West Texas and the Texas Panhandle. Other renewable energy sources, such as biomass electricity generation, biofuel production, solar energy, and geothermal energy are also being promoted in different regions of the state.

The emphasis on renewable energy sources has changed the economic and demographic profile of the state in the last decade. Historically rural and agricultural regions, such as the Texas Panhandle, have become development sites for wind farms and biofuel plants. Similarly, West Texas—from Abilene to El Paso—has seen an extraordinary amount of wind farm development. Finally, high oil prices resulted in a resurgence of oil production activity in the Permian Basin, while the Barnett Shale area is now producing over 3.75 billion cubic feet of natural gas per day and the Haynesville Shale area is expected to be one of the largest producers of natural gas in the U.S. by 2015 (Chesapeake Energy, n.d.).

The energy sector has placed significant demands on Texas's transportation system. The oil and gas industry, for example, requires the movement of equipment and water to the drilling sites, and brine water from the sites. This movement has raised concerns about the damage done by trucks and has resulted in many cities requiring payment bonds from energy companies drilling in, for example, the Barnett Shale area to maintain the integrity of the roadway infrastructure. Similarly, rural roads in West Texas and the Texas Panhandle are experiencing an increased number of oversized and overweight (OS/OW) truck traffic generated by the development of wind farms. Both the provision/construction of the enabling infrastructure and the daily operations of the different energy industries impact Texas's transportation infrastructure. It is thus imperative to understand how Texas's transportation system serves the energy sector, how the sector impacts the transportation system, and the future transportation needs of the energy sector.

The objectives of this research study were to (a) illustrate and quantify the impacts imposed by the energy sector on Texas's transportation system and (b) identify key energy demand indicators by energy source that TxDOT can track in an effort to anticipate the associated future transportation impacts on Texas's transportation system. This report describes how Texas's energy sector uses the transportation system and quantifies the impact imposed by the energy sector on Texas's road infrastructure. It is, however, also important to understand what the future holds—which industries within the energy sector are expected to grow, which industries are expected to decline, and how Texas's transportation system could be impacted in the future. The focus of this report is the development of four energy scenarios that reflect different assumptions and outcomes for Texas's future energy sector over a 20- to 30-year period. Analyses of several factors, referred to as *drivers*, that may impact the energy sector in the future are presented. The drivers include the following:

- Texas's energy portfolio and goals,
- current and historic energy demand,
- enabling infrastructure,
- improvements in energy extraction technologies,
- current and historic energy price trends,
- socio-economic impacts of the energy sector,
- environmental regulations, and
- tax and other government incentives.

Information regarding each of these drivers is presented in this report, followed by implementation of these drivers in developing plausible future scenarios for Texas's energy sector.

1.1 Report Structure

This report includes four energy scenarios for Texas that reflect different assumptions and outcomes for Texas's future energy sector and the associated impacts on Texas's transportation system. Chapter 2 provides a detailed overview of Texas's energy sector, including a review of historic, current, and anticipated future energy production and demand. Chapter 3 discusses enabling energy infrastructure with specific emphasis on the future of electricity transmission in the state. Chapter 4 discusses advances in energy extraction technologies and Chapter 5 provides information on historic and anticipated energy price trends. Chapter 6 discusses the socio-economic impacts of Texas's energy sector by industry. Chapter 7 provides an overview of eight sets of proposed rules that will impact energy production and consequently may create future impacts on Texas's transportation network. Chapter 8 lists the numerous financial incentives available to the energy sector. Chapter 9 describes scenario planning and the four scenarios that were developed. Chapter 10 summarizes the work completed and recommends key energy demand indicators that TxDOT can track to anticipate future transportation impacts on Texas's transportation system. Finally, two appendices are included in this report. Appendix A provides more detailed information on the proposed environmental regulations that can impact Texas's energy sector in the future and Appendix B lists the air quality rules that have been promulgated and proposed since 2010.

Chapter 2. Texas's Energy Sector

To conceptualize potential plausible futures for Texas's energy sector, it is important to develop an understanding of the energy sector. Texas's energy sector can be characterized in terms of production and consumption. Both have a significant impact on how energy is managed within the state. The production sector can be further broken down by fuel source, and the consumption sector can be classified in terms of who consumes the energy (see Figure 2.1). This chapter of the report provides a detailed overview of Texas's energy sector, including a review of historic, current, and anticipated future energy production and demand.

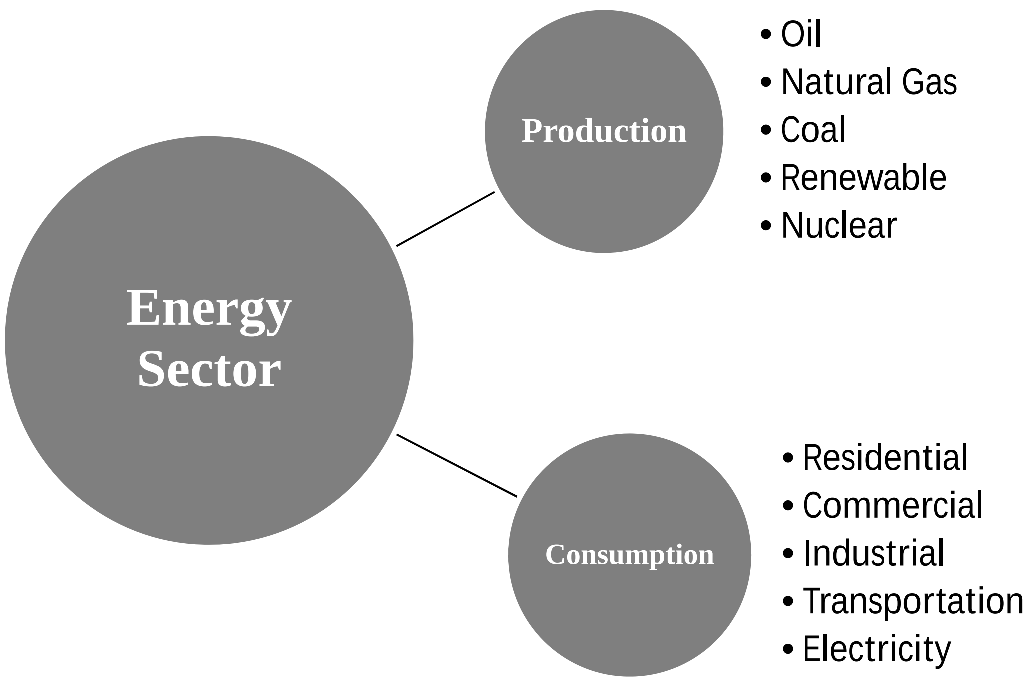


Figure 2.1: The Energy Sector

2.1 Energy Production in Texas

Energy production—i.e., the energy content of the fuel extracted or the energy physically produced—in Texas has been generally declining since the 1970s. The fuel sources used to produce energy in the state include coal, conventional natural gas[1], nuclear electricity, crude oil, and renewable energy. The average declining trend in energy production (see Figure 2.2) can be primarily attributed to aging energy infrastructure and the depletion of conventional resources. Since 2005, however, energy production has leveled off and experienced a slight increase due to upgrades to existing power plants, the installation of new capacity, advances in enhanced oil recovery, and the mining of unconventional natural gas (i.e., Barnett Shale, Haynesville Shale, and Eagle Ford Shale)[2].

[1] Conventional natural gas refers to the production of natural gas from common, easily accessed sources.
[2] According to the U.S. Energy Information Administration, unconventional natural gas resources were not contributing to the total natural gas production until 2008. Gross withdrawals from gas wells have steadily

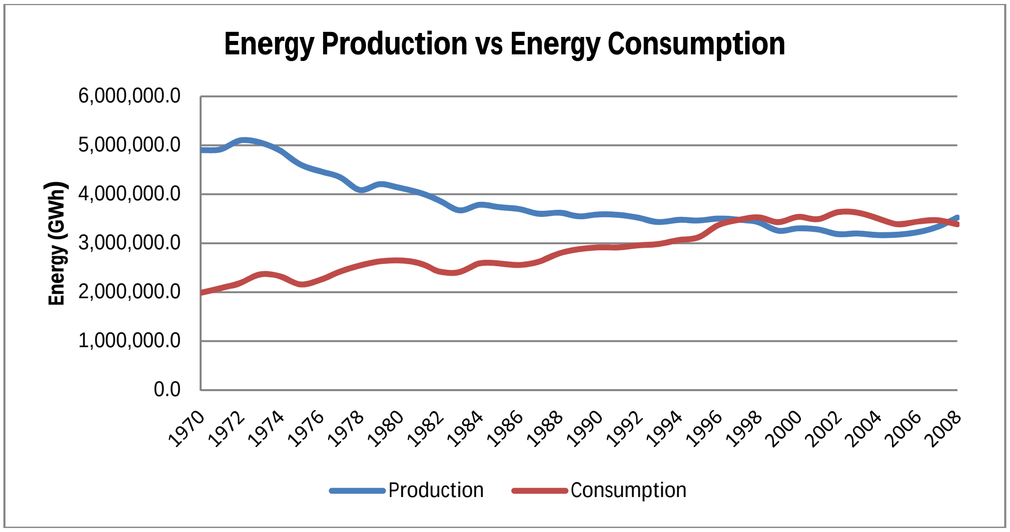
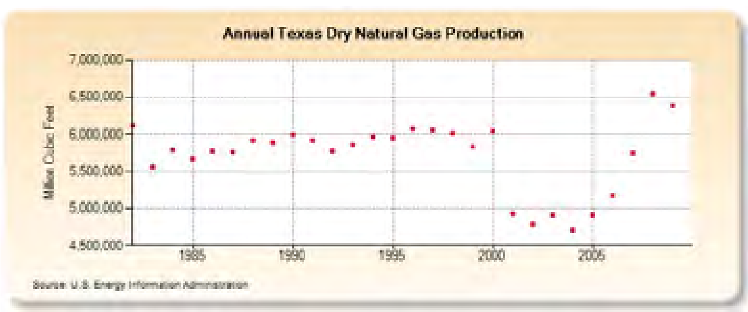


Figure 2.2: Energy Production and Consumption in Texas

Figures 2.3 to 2.7 illustrate Texas's energy production by source. Figure 2.3 illustrates that annual dry natural gas production in Texas fell sharply between 2001 and 2004, but increased after 2006 to reach about 6.5 trillion cubic feet in 2008. Production from gas wells has continued to decrease, but supplemental sources of natural gas, such as unconventional shale gas and oil well natural gas, have contributed to the increase seen after 2005. As of July 2010, the U.S. Energy Information Administration (EIA) reported that approximately 30% of total U.S. natural gas production occurs in Texas (EIA, 2010).

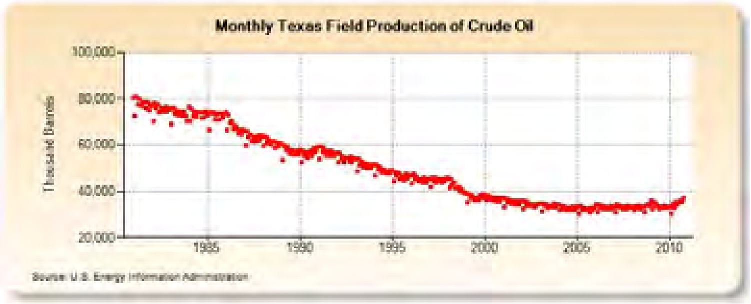


Source: EIA Texas Dry Natural Gas Production

Figure 2.3: Dry Natural Gas Production

Representing 11.5% of U.S. total oil consumption and 21.3% of U.S. total oil production, Texas has been leading the nation in both activities. For example, 21 of the nation's most productive oil fields are found in the oil-producing Permian Basin of West Texas (Susan Combs, Energy Report: Crude Oil, 2008). But the state's crude oil reserves are maturing and crude oil production has been steadily decreasing between 1980 and 2005. Recent increases in crude oil prices have, however, resulted in the leveling off of the decreasing trend and an increase in crude oil production in Texas since 2007 (see Figure 2.4).

decreased, while gross withdrawals from oil wells and unconventional sources have increased since 2005 (Natural Gas Gross Withdrawals and Production, Texas , 2011).

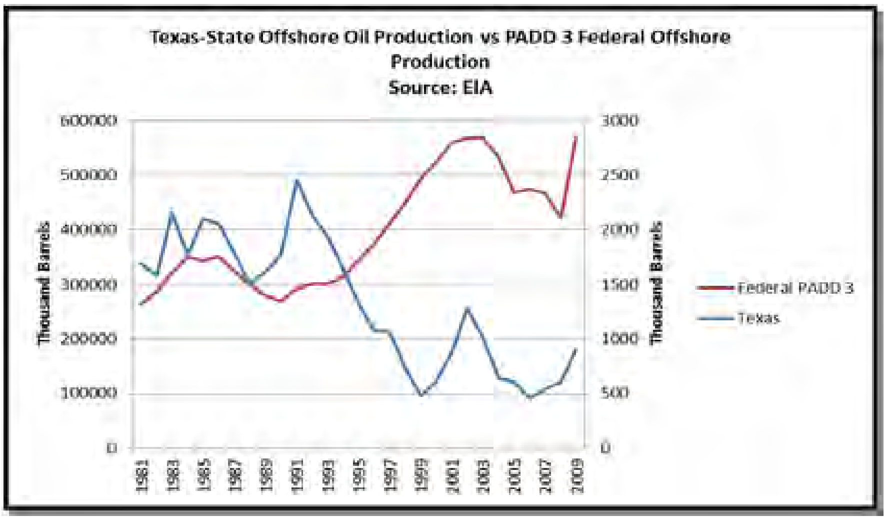


Source: EIA Texas Field Production of Crude Oil

Figure 2.4: Monthly Texas Field Production of Crude Oil

In addition, offshore oil production in the Gulf of Mexico could also have a significant role in the future of Texas's oil sector. The ownership of offshore oil and gas reserves in the Gulf of Mexico is shared between the federal government and nearby states. Texas owns the coastal territory extending 10.5 statute miles from its shore. Leasing and drilling in the federal offshore seabed is controlled by U.S. Minerals Management Services. Leases are awarded to the oil and gas company offering the highest payment to the government. In 2006, offshore oil reserves in Texas's portion of the Gulf totaled 158 million barrels, representing 26% of U.S. offshore capacity. Figure 2.5 illustrates oil production from the Gulf of Mexico region near Texas. Petroleum Administration for Defense District 3 (PADD 3), as defined by the Petroleum Administration for Defense, is the geographic region that contains Texas. President George H.W. Bush issued an executive moratorium restricting federal offshore leasing between 1990 and 2000 in certain parts of the country, including Texas. This moratorium partially explains the drastic decline in the offshore oil production in Texas during that period (see Figure 2.5). In 2006, the Gulf of Mexico Energy Security Act declared most of the central and eastern Gulf of Mexico off limits to oil and gas leasing until 2022 (Bureau of Ocean Energy Management, Regulation and Enforcement, 2010).

In March 2010, however, the Obama Administration estimated that the Gulf of Mexico holds 36 to 41.5 billion barrels of oil and 161 to 207 trillion cubic feet of natural gas, representing 70% of the nation's economically recoverable oil and 82% of the nation's economically recoverable gas reserves. Thus pressure increased to develop the oil and gas resources in the Gulf of Mexico, as part of a comprehensive plan to ensure energy security and facilitate domestic energy production. In May 2010, the Texas Railroad Commission (RRC) reported the following offshore oil production statistics for Texas: 97 fields, 39 leases, 13 wells, and a year-to-date production of 91,888 billion barrels of crude oil (Railroad Commission of Texas, 2010). The explosion on the BP Deepwater Horizon Rig on April 20, 2010, however, has resulted in much debate concerning the future of offshore drilling in the Gulf of Mexico. In its AEO 2010, the EIA argued that producers will be motivated by rising world oil prices to increase both onshore and offshore U.S. crude oil production. It is anticipated that deepwater offshore fields in the Central Gulf of Mexico holds substantial potential to offset the decline in mature fields. Nevertheless, drilling in the Gulf of Mexico is contingent upon removal of the Congressional moratorium, high oil prices, and technology advancements.



Source: EIA, 2010

Figure 2.5: Texas's Offshore Oil Production (1981–2009)

During the 1990s, Texas saw significant growth in nuclear power generation with the construction and licensing of the state's two nuclear power plants: Comanche Peak Nuclear Power Plant and the South Texas Project. The South Texas Project (STP), located 90 miles outside of Houston in Bay City, is a two-unit power plant that began operation in 1988–1989 with a capacity of 2,820 MW. Comanche Peak Nuclear Power Plant, located in Glen Rose, is also a two unit facility that began operation in 1990–1993 with a capacity of 2,350 MW (Operating Nuclear Power Reactors (by Location or Name), 2011). In 2008, electric power generated by nuclear power plants accounted for 10% of electricity produced in Texas. Figure 2.6 illustrates the growth of nuclear power in Texas since the initial construction of Comanche Peak and STP. Nuclear power production has leveled off since 1994, only growing slightly from 1998 to 2008, as a result of a standstill in the building of new plants.

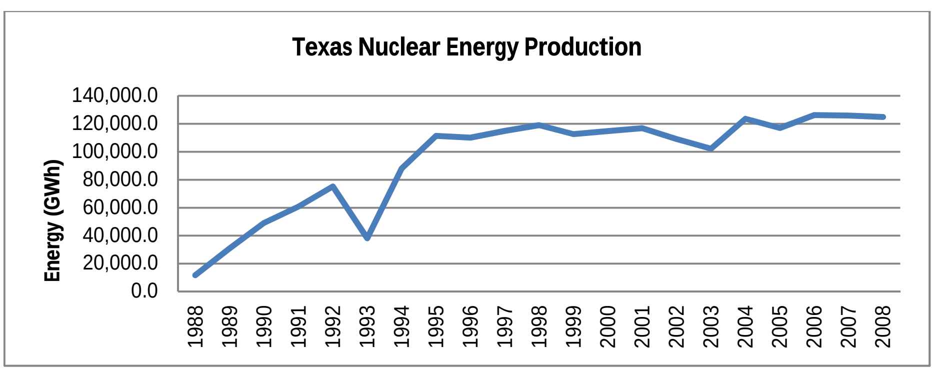


Figure 2.6: Texas Nuclear Energy Production

Figure 2.7 illustrates the renewable energy produced in Texas between 2004 and 2008. As Figure 2.7 indicates, renewable energy production (specifically, wind energy) increased substantially between 2004 and 2008. This increase can be partly explained by the Energy Policy Act (EPACT) of 2005 that created a Renewable Fuel Standard (RFS), which set a baseline for U.S. renewable fuel use of 7.5 billion gallons (SECO, 2010). In 2007, the Energy Independence and Security Act (EISA) increased the RFS for the U.S. to a required use of 36 billion gallons of renewable fuels by 2022. The increase in wind energy production is consistent with the requirements of EISA's and Texas's Renewable Portfolio Standard.

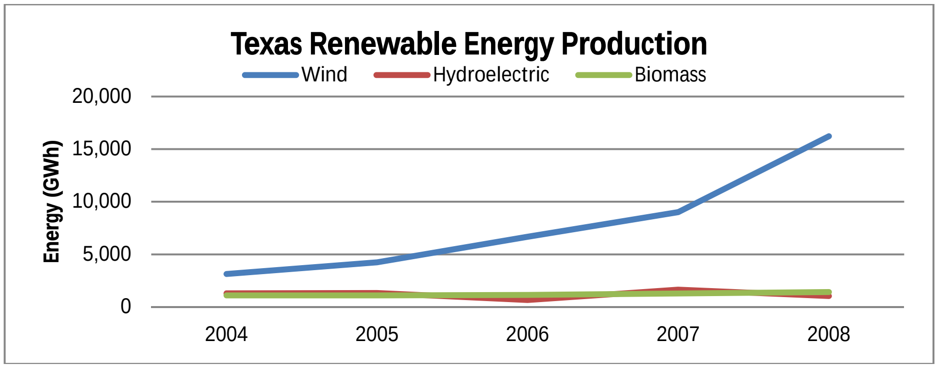


Figure 2.7: Texas Renewable Energy Production

As of July 2010, Texas had 9,707 MW of installed wind energy generation capacity—more than any other U.S. state and more than three times the installed capacity in California (American Wind Energy Association, 2010). Table 2.1 lists the 10 highest capacity wind developments in operation or planned in Texas.

Table 2.1: Ten Largest Wind Developments in Terms of Generation Capacity (2008)

Name	Location	Power Capacity (MW)	Units	Turbine Mfr.	Developer	Owner	Power Purchaser	Year Online
Horse Hollow II	Taylor County	299	130	Siemens	FPL Energy	FPL Energy	market	2006
Gulf Wind		283.2	118	Mitsubishi	Babcock & Brown	Texas Gulf Wind LLC		2009
King Mountain Wind Ranch		278.2	214	Bonus	Cielo Wind Power/Renewable Energy Systems	FPL Energy	Texas-New Mexico Power, Reliant Energy, Austin Energy	2001
Pyron (Roscoe III)		249	166	GE Energy	E.On Climate & Renewables	E.On Climate & Renewables		2009
Buffalo Gap II	Taylor County	232.5	155	GE Energy	AES Corp.		Direct Energy	2007
Horse Hollow III	Taylor County	223.5	149	GE Energy	FPL Energy	FPL Energy	market	2006
Capricorn Ridge (GE Energy)		214.5	143	GE Energy	FPL Energy	FPL Energy		2007
Horse Hollow Wind Energy Center	near Abilene	210	140	GE Energy	FPL Energy	FPL Energy		2005
Roscoe		209	209	Mitsubishi	E.On Climate & Renewables	E.On Climate & Renewables	Luminant	2008
Penescal II		201.6	84	Mitsubishi	Iberdrola Renewables			2010

Source: AWEA, U.S. Wind Energy Projects-Texas, 2010

In terms of bio-fuels, four ethanol plants are operating in Texas (see Table 2.2). An ethanol producer, Panda Ethanol, had planned to operate a third plant in Hereford. However, disputes arose between Panda Ethanol and the plant's general contractor, and the plant failed to open due to bankruptcy in 2009 (Farrell, 2010).

Table 2.2: Texas Ethanol Plants

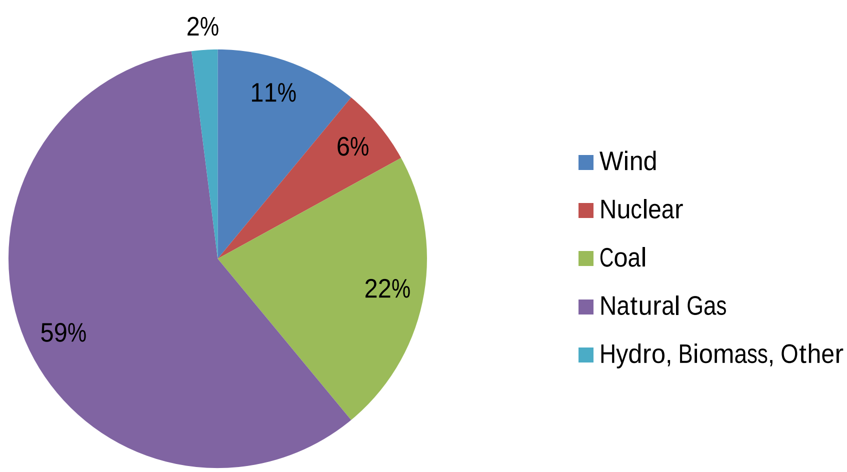
Producer	Location	Feedstock	Capacity (Million Gallons/Year)
White Energy Hereford LLC	Hereford	Corn/Milo	100
Hereford Renewable Energy LLC	Hereford	Corn	105
White Energy Plainview LLC	Plainview	Corn/Milo	100
Levelland Hockley County Ethanol	Levelland	Corn/Milo	40

Source: Ethanol Producer Magazine

In addition, Texas is the largest producer of biodiesel in the country with a production capacity of approximately 100 million gallons per year. Figure 2.8 illustrates the location of Texas's largest biodiesel refineries.

Figure 2.8: National Biodiesel Board Map of Biodiesel Plants (blue circles) in February 2007

Finally, electricity generation is of special interest when considering Texas's energy future. Currently, the majority of Texas's electricity needs are met by the Energy Reliability Council of Texas (ERCOT)—an independent system operator for 86% of Texas's energy load. As of 2010, ERCOT had an installed capacity of 84,237 MW with a reserve margin of 18,500 MW (2010 Demand and Energy, 2010). A breakdown of the installed capacity by fuel source is provided in Figure 2.9.



Source: ERCOT 2009 Annual Report

Figure 2.9: ERCOT Installed Capacity by Fuel Source, 2010

Figure 2.10 illustrates an increasing trend in Texas's electric power generation between 1990 and 2008. It also clearly demonstrates that Texas relies heavily on coal and natural gas for electric power generation (see also Figure 2.9).

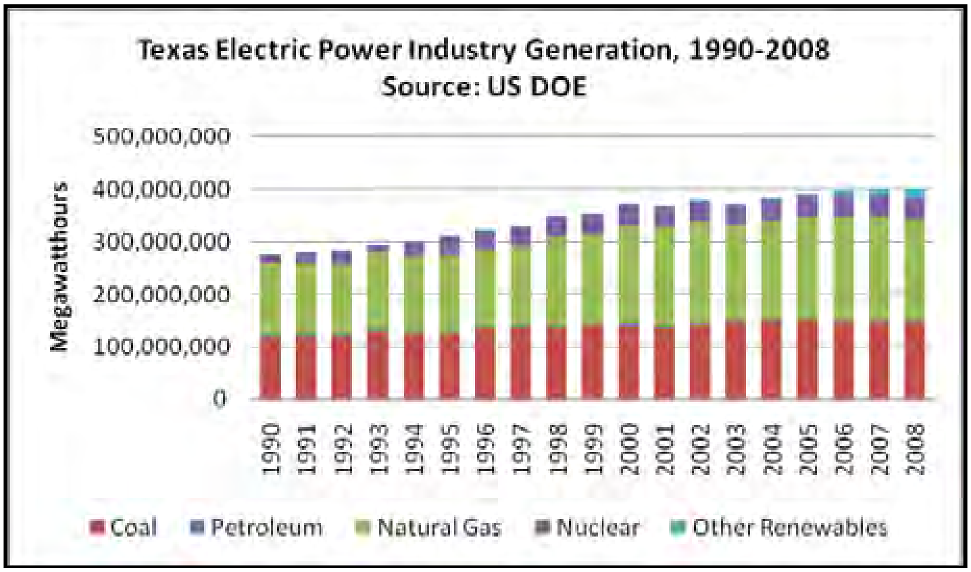


Figure 2.10: Texas Electric Power Generation (1990–2008)

In fact, the majority of Texas's largest electricity generating plants is fueled by coal or natural gas. Table 2.3 lists Texas's top ten electricity plants in terms of generating capacity (as of 2008).

Table 2.3: Ten Largest Plants by Generation Capacity, 2008

Plant	Primary Energy Source or Technology	Operating Company	Net Summer Capacity (MW)
1. W A Parish	Coal	NRG Texas Power LLC	3,667
2. South Texas Project	Nuclear	STP Nuclear Operating Co	2,560
3. Martin Lake	Coal	TXU Generation Co LP	2,418
4. Comanche Peak	Nuclear	TXU Generation Co LP	2,367
5. P H Robinson	Gas	NRG Texas Power LLC	2,211
6. Monticello	Coal	TXU Generation Co LP	1,931
7. Sabine	Gas	Entergy Texas Inc.	1,814
8. Limestone	Coal	NRG Texas Power LLC	1,689
9. Fayette Power Project	Coal	Lower Colorado River Authority	1,641
10. Forney Energy Center	Gas	FPLE Forney LP	1,640

Source: EIA, Form EIA-860, "Annual Electric Generator Report."

Texas has 40 coal-fired generators at 20 locations, totaling 21,240 MW in capacity (Shuster, 2010). In 2010, Texas's coal-fired power plants produced approximately 44 million MWh, which represents about 7.3% of total U.S. coal-fired power production (EIA, 2010). High natural gas prices in 2000 resulted in a renewed emphasis on the construction of new coal-fired electricity plants. However, growing concerns over the environment and the release of toxic emissions have fueled a nationwide resistance to the construction of new coal-fired electricity plants. In 2008, the National Energy Technology Laboratory published a list of 151 proposed new coal plants. As of April 2010, 99 of those proposed plants had been cancelled—eight of which were proposed in Texas. Also, by 2010, only 40 of the 151 proposed new plants were in operation (Shuster, 2010).

Four of the new plants are in Texas: Oak Grove, Sandow Unit 5, Sandy Creek, and J.K. Spruce Unit 2 (Shuster, 2010). Construction of the Oak Grove Power Plant in Franklin was completed on July 8, 2010. This 1,600 MW plant is designed to have lower emissions than any other lignite plant in the state and will be operated by Luminant Power (WORLDWIDE, 2010). Luminant is also operating the Sandow 5 plant, which has a 581 MW capacity and is fueled by lignite. The plant went into full operation in September 2009 (O'Grady, 2009). The Sandy Creek plant is an 800 MW pulverized coal plant in Riesel operated by LS Power Development. The plant is still under construction with a projected opening service year of 2012. However, the future of the Sandy Creek plant is controversial, because the developers failed to obtain a Maximum Achievable Control Technology (MACT) determination for the plant, which is a violation of the Clean Air Act (SourceWatch, 2010). Finally, in 2006, CPS Energy began construction on the 750 MW second unit of its J.K. Spruce Power Plant at Calaveras Lake. The conventional plant will be fueled by Wyoming's Powder River Basin coal, but it will include $200 million in environmental controls, such as a wet gas desulfurization scrubber and a selective catalytic reduction unit (Peltier, 2008).

2.2 Energy Consumption in Texas

In 2008, approximately 3.4 million Gigawatt-hours (GWh) of energy were consumed in Texas. To put this number into perspective, three million GWh equates to the energy consumed by approximately 152 million four-person households in a single year (Energy Consumption in Texas Homes, 2008). In reality, this energy was consumed largely by five energy consumption sectors. Figure 2.11 illustrates the energy consumption breakdown in Texas. As is evident from Figure 2.11, Texas's industrial and transportation sectors are the largest consumers of energy at 49% and 25% of the total energy consumed in Texas in 2008.

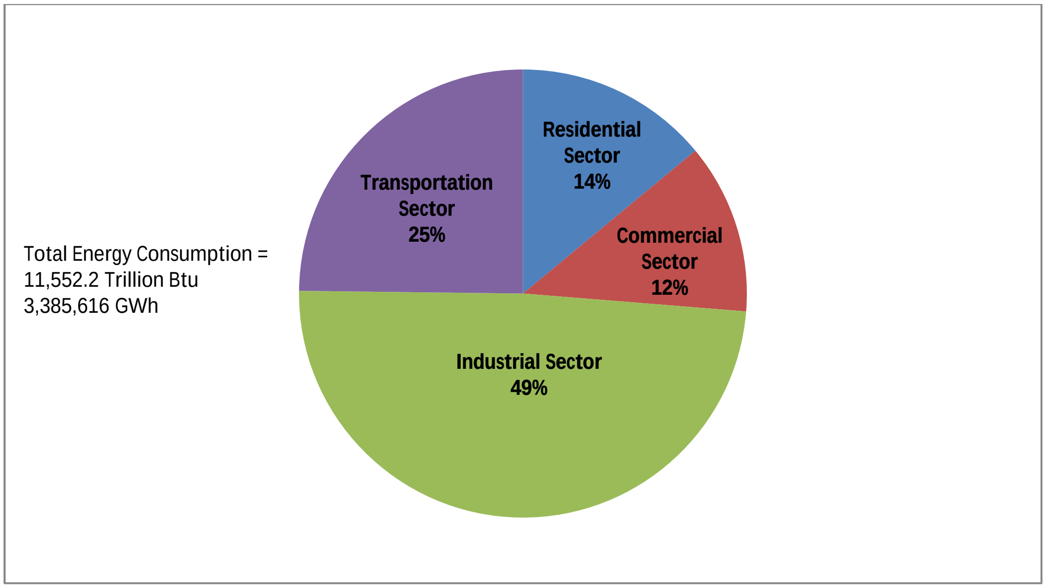


Figure 2.11: Energy Consumption by Sector

The breakdown of energy consumed in Texas by source and sector is illustrated in Figure 2.12. For example, Figure 2.12 illustrates that approximately 97.6% of Texas's coal energy is consumed as electricity.

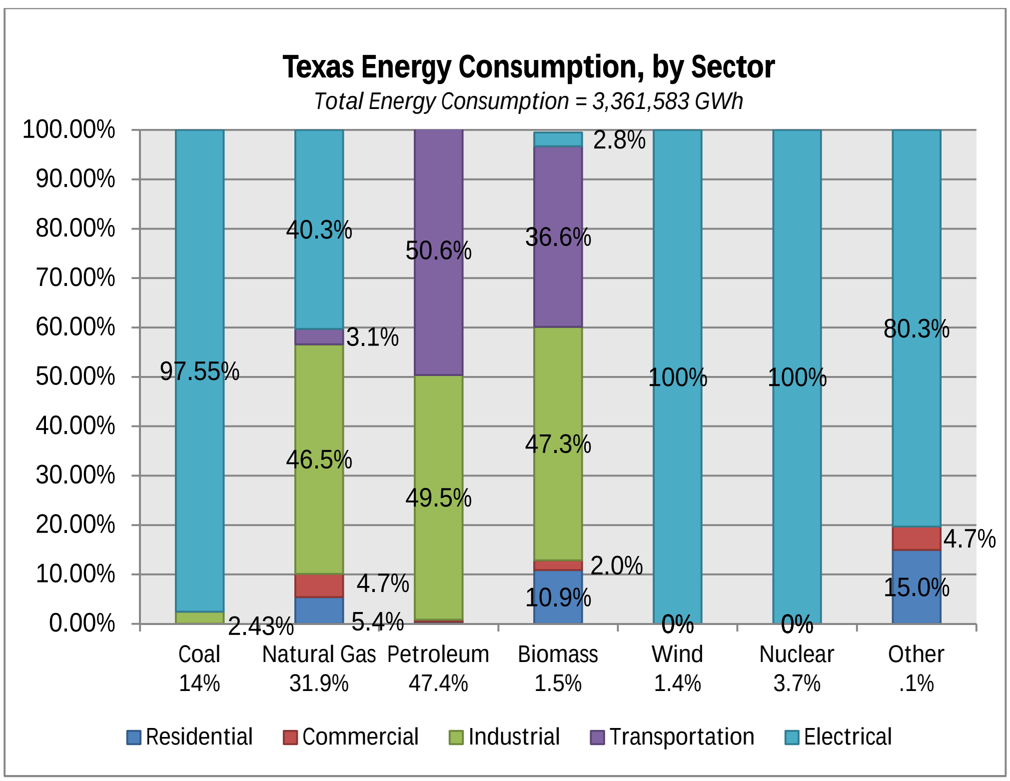
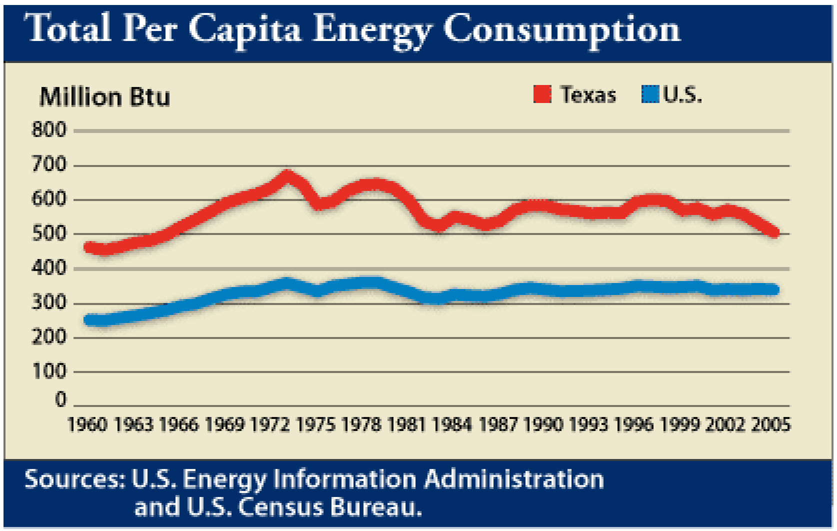


Figure 2.12: Texas Energy Consumption by Source and Sector

In addition to the current energy consumed in Texas, the research team explored historical trends in the energy consumption of Texas and the U.S. to gain insight into how and why future energy demand might change. In the U.S., energy consumption per capita has steadily increased since the 1960s. From 1960 to 2005, the total energy consumed grew at an approximate annual rate of 2.2%, with the demand for transportation fuel growing at approximately 2.7% (The Energy Report 2008, 2008). Although energy demand has been growing at a similar rate in Texas, energy consumption per capita has been almost double the national average in Texas (see Figure 2.13). This trend is due in part to Texas's large industrial sector.

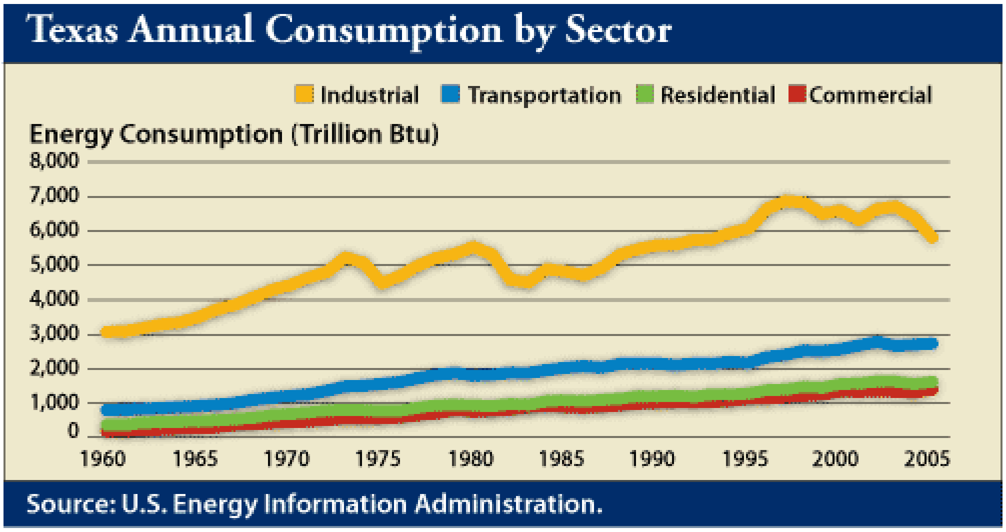


Source: The Energy Report 2008

Figure 2.13: Total per Capita Energy Consumption, 1960–2005

With industries such as cement production, petroleum refining, forestry product processing, and aluminum and glass production, the industrial sector in Texas is a major energy consumer. The industrial sector accounts for approximately 50% of all energy consumed in the state. The national average is significantly lower at 32% (The Energy Report 2008, 2008). Because of the sector's large contribution to the state's energy demand, the trend in industrial consumption is potentially a significant factor in the overall future energy consumption of the state.

As is evident from Figure 2.14, the average annual energy consumed by the transportation, residential, and commercial sectors has been increasing at a steady rate over the past 45 years. The energy consumed by the industrial sector—although increasing overall—has experienced annual fluctuations. The fluctuations can be partly attributed to variations in energy prices.



Source: The Energy Report 2008

Figure 2.14: Texas Annual Energy Consumption by Sector

Figure 2.15 illustrates the relationship between the price of petroleum and the energy consumed by the industrial sector. Figure 2.15indicates that during periods of high petroleum prices, industrial energy consumption declined. For example, between 2003 and 2005, a significant increase in energy prices compelled the industrial sector to reduce its energy consumption. During this period, the industrial sector invested in energy efficient technologies and consumption decreased by 13.3% (The Energy Report 2008, 2008).

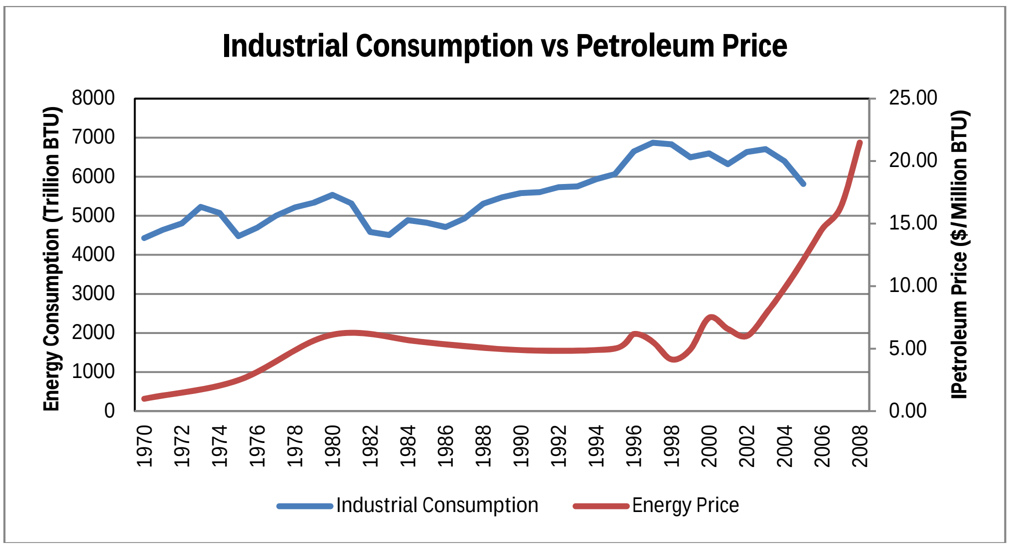


Figure 2.15: Industrial Consumption vs. Energy Price

As mentioned earlier, in 2008, the transportation, residential, and commercial sectors in Texas accounted for 24%, 14%, and 12% of the state's energy consumption, respectively. Energy consumption in these sectors has increased at a steady rate since the 1960s (see Figure 2.16). However, the energy consumed by the transportation sector has increased at a slightly higher rate than the energy consumed by the residential and commercial sectors. This can be partly attributed to an increase in vehicle ownership and an increase in vehicle size.

Figure 2.16 also evidences that Texas's population has been growing at a faster rate than each sector's energy consumption. Texas's population has been growing at an average rate of 3.25%, which is higher than the energy consumption rate of the residential, commercial, and transportation sectors. The deviation appears to begin in the 1970s, a period in which the price of oil increased substantially due to global conflict. In the 1970s, energy efficient measures and investments were made in all sectors. For example in the transportation sector, a national speed limit was instituted, the size of luxury automobiles was decreased, and awareness of energy consumption increased (1973 Oil Crisis, 2011).

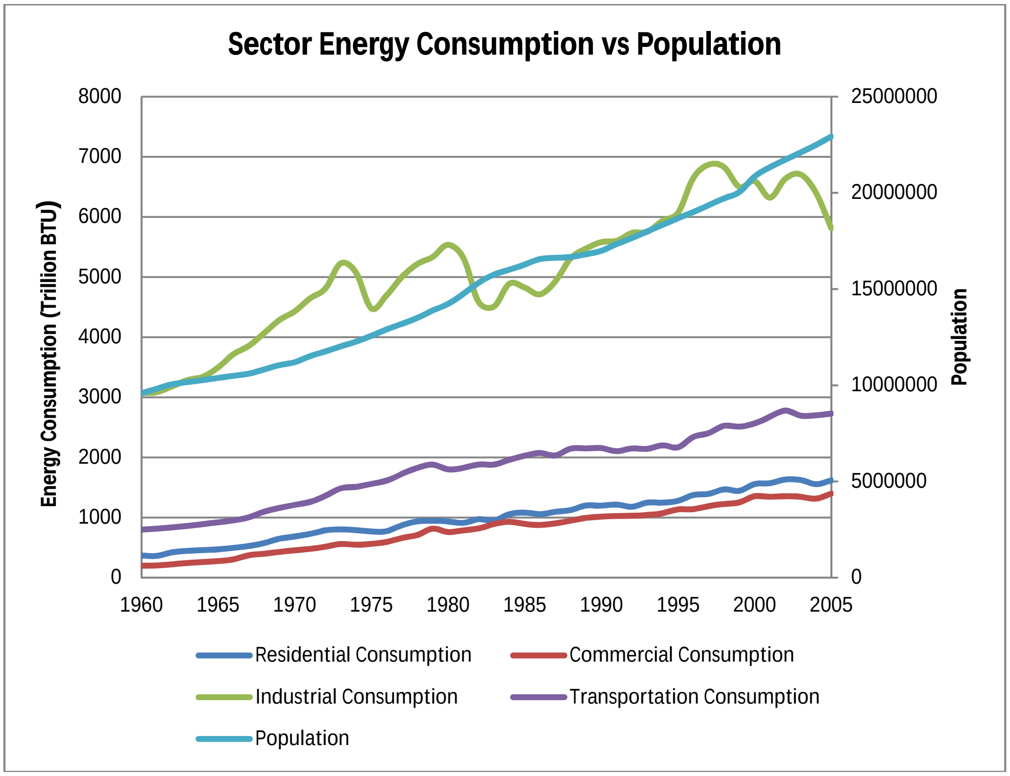


Figure 2.16: Sector Energy Consumption vs. Population

In terms of electricity consumption, historic trends clearly demonstrate a correlation between electricity consumption and population growth (see Figure 2.17). As is evident from Figure 2.17, between 1980 and 2004, Texas's population grew at an average rate of 2.45% while electricity consumption grew at a rate of 2.4% (Electric Power and Renewable Energy in Texas, 2010). Furthermore, by 2040, Texas's population is expected to grow by 71.5% from its 2000 value to reach 35.8 million. This estimated 2040 value represents a 151% increase from Texas's 1980 population (Texas Data Center, n.d.). Given a growing Texas population, it would thus be safe to assume that electricity consumption will also continue to grow in Texas.

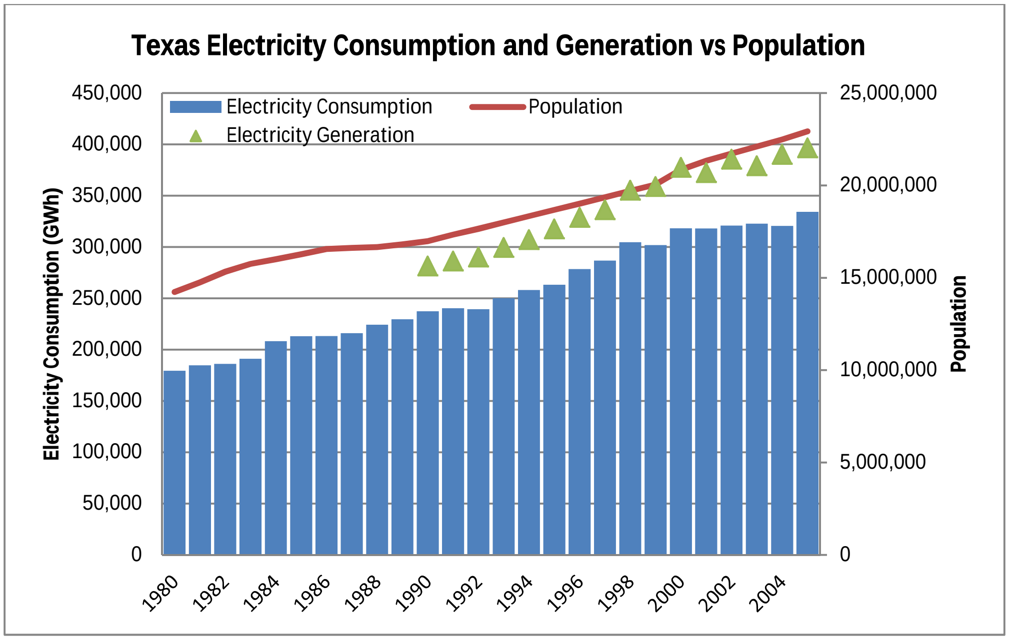


Figure 2.17: Texas Electricity Consumption and Generation vs. Population

Finally, Figure 2.18 illustrates Texas's energy consumption by source between 1998 and 2008. Figure 2.18 indicates that petroleum and natural gas consumption showed a general decreasing trend during this period. This can be partly attributed to the increase in petroleum prices and the economic slowdown[3]. Nuclear and coal energy exhibit a relatively constant consumption trend. On the other hand, the renewable energy sector experienced substantial growth in consumption. The latter can be partly explained by the requirements of Texas's Renewable Portfolio Standards (RPS) and the trend towards "cleaner" energy.

[3] Texas's industrial sector consumes approximately 46.5% and 49.5% of the natural gas and petroleum consumed in Texas, respectively (see Figure 2.12).

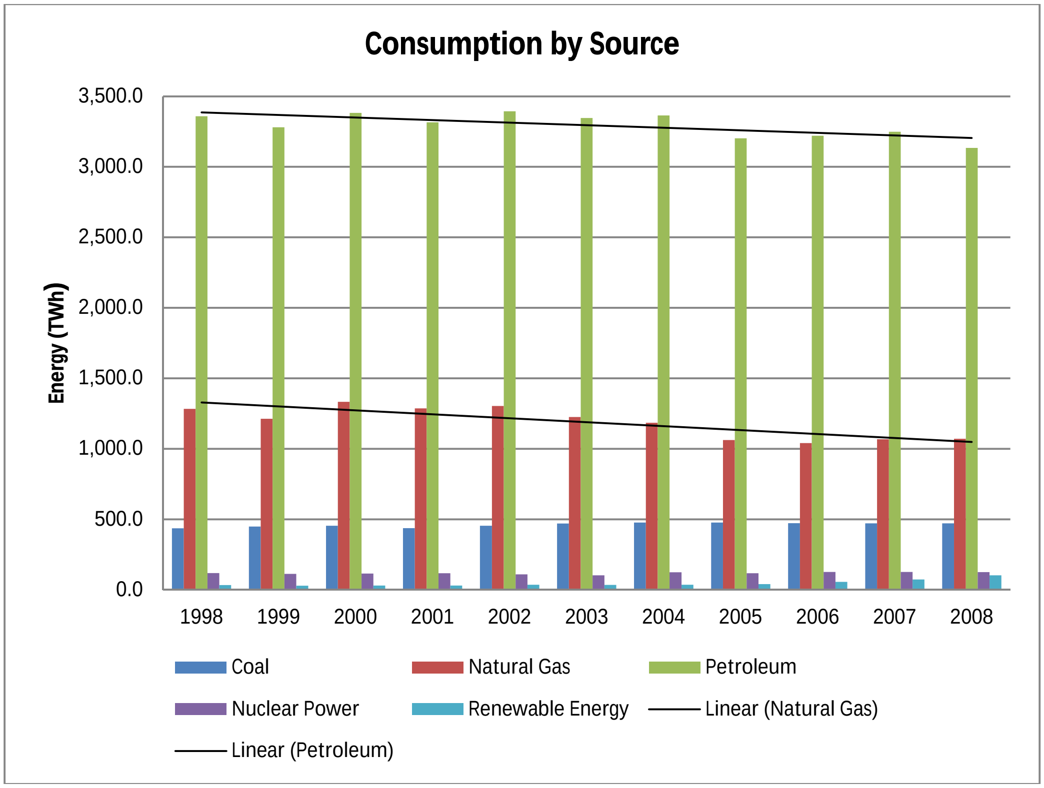


Figure 2.18: Energy Consumption by Source

2.3 Energy Production and Consumption

The EIA produces an AEO (AEO) report each year that provides future estimates for the national and state energy sectors. In the 2010 edition of this report, five scenarios were developed for Texas's future energy sector. These scenarios include a Reference Case, a High Oil Price Case, a Low Oil Price Case, a High Economic Growth Case, and a Low Economic Growth Case. The EIA's assumptions for these energy scenarios are summarized in Table 2.4.

Table 2.4: AEO 2010 Energy Scenarios

Scenario	Basis
Reference Case	Baseline economic growth of 2.4% per year from 2008 through 2035, baseline world oil price of $133 (2008 dollars) per barrel in 2035, a 1.1% growth from 2008, and baseline technology assumptions[4].
Low Economic Growth	Real GDP grows at an average annual rate of 1.8% from 2008 to 2035. Other energy market assumptions are the same as in the Reference Case.
High Economic Growth	Real GDP grows at an average annual rate of 3.0% from 2008 to 2035. Other energy market assumptions are the same as in the Reference Case.
Low Oil Price	More optimistic assumptions for economic access to non-OPEC resources and OPEC behavior than in the Reference Case. World light, sweet crude oil prices are $51 per barrel in 2035, compared with $133 per barrel in the Reference Case (2008 dollars). Other assumptions are the same as in the Reference Case.
High Oil Price	More pessimistic assumptions for economic access to non-OPEC resources and OPEC behavior than in the Reference Case. World light, sweet crude oil prices are about $210 per barrel (2008 dollars) in 2035. Other assumptions are the same as in the Reference Case.

Source: AEO 2010

Figure 2.19 summarizes the estimated total energy consumption in each scenario until 2035.

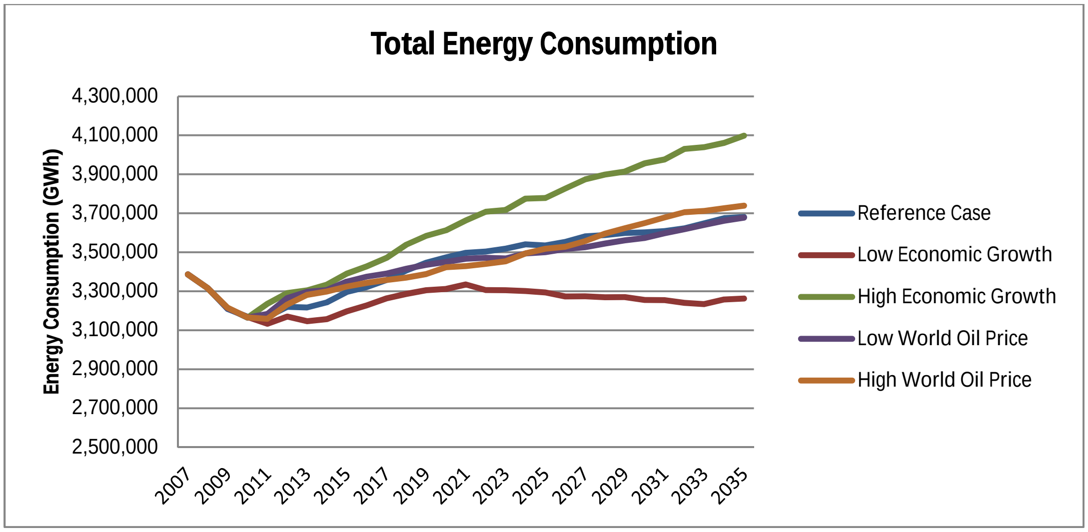


Figure 2.19: Total Future Energy Consumption Scenarios

[4] Baseline technology assumes that the availability and efficiency of energy equipment is locked at 2009–2010 levels (Assumptions to the Annual Energy Outlook 2010).

Table 2.5 provides estimated future energy consumption by source for Texas.

Table 2.5: Future Texas Energy Consumption by Energy Source

	Reference Case	Low Economic Growth	High Economic Growth	Low Oil Price	High Oil Price
Total Consumption (GWh)	3,680,830.5	3,263,017	4,098,595	3,677,725	3,738,792
Petroleum	45%	45%	47%	48%	43%
Natural Gas	32%	31%	30%	32%	30%
Coal	15%	16%	14%	14%	17%
Nuclear Power	4%	5%	4%	4%	4%
Biofuels	2%	1%	3%	0%	4%
Renewable Energy	2%	2%	2%	2%	2%

2.3.1 Oil

Although Texas may have reached its oil production peak in the early 1970s, the Texas Comptroller of Public Accounts (2008) believes conventional fossil fuels will continue to supply the state's energy needs for many years to come. Similarly, the AEO 2010 Reference Case assumes a recovery of the global economy, total liquid oil consumption returning to its 2008 levels, and an average annual increases in real world oil prices of approximately 0.7% between 2008 and 2020 and 1.4% between 2020 and 2035, which equates to a world oil price of $133 per barrel in 2035 (in real 2008 dollars). The Low Oil Price Case assumes increased oil production from both OPEC and non-OPEC countries, reduced investments in unconventional fuels, and an average world oil price of $51 per barrel in 2035 (in real 2008 dollars). The High Oil Price Case assumes a rebounding global economy, restrictions on the production of conventional fuels, and an average world oil price of $210 per barrel in 2035 (in real 2008 dollars) (EIA, 2010). These three scenarios are illustrated in Figure 2.20.

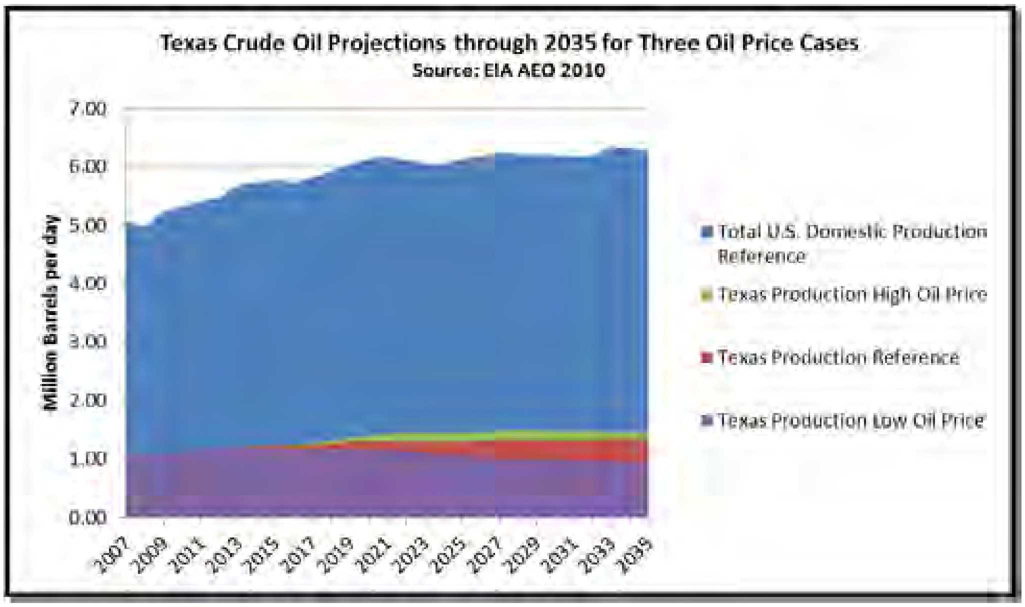


Figure 2.20: Texas Crude Oil Projections through 2035

Figure 2.20 indicates that the Reference Case projects total U.S. domestic oil production at 6.27 million barrels (Mbbl) per day and total crude oil production at 1.34 Mbbl per day in Texas by 2035. The High Oil Price Case yields a daily production of 1.47 Mbbl per day for Texas and the Low Oil Price Case yields a value of 0.93 Mbbl per day (EIA, 2010).

2.3.2 Coal

The AEO 2010 considered three economic situations in determining Texas's future coal-fired electricity generation capacity and overall coal consumption through 2035. Three economic cases were considered, because the economic situation typically impacts overall electricity demand, which determines the need for coal-fired electricity generation. For example, economic growth typically corresponds with increased energy consumption due to increases in population, commercial expansion, or increased industrial production. Figure 2.21 illustrates Texas's potential for coal-fired electricity generation under the three economic cases through 2035. The Reference Case results in 23.8 GW of electricity generated from coal in 2035, the High Economic Growth Case suggests 25.7 GW, and the Low Economic Growth Case suggests 22.9 GW of coal produced electricity by 2035 (EIA, 2010).

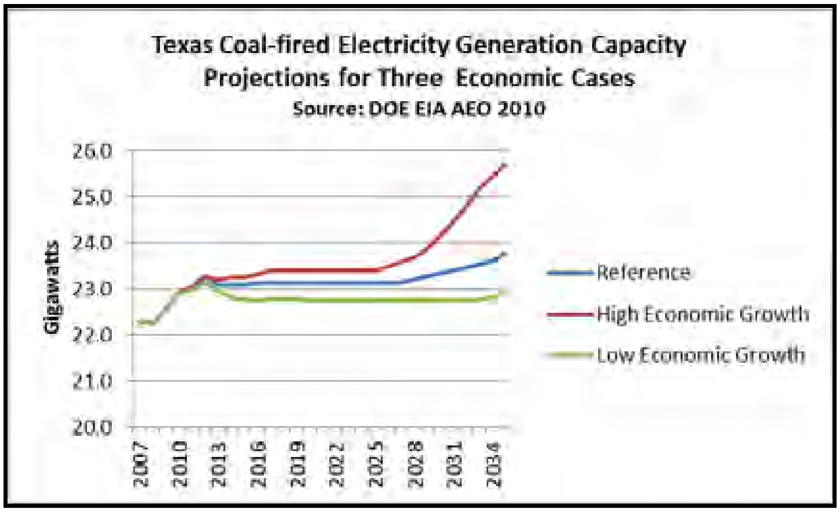


Figure 2.21: Texas's Coal-fired Electricity Capacity Projections

Texas consumes more coal than any other state. In 2007, the total coal consumption in Texas amounted to approximately 105 million short tons, or about 9.3% of the total U.S. coal consumption (EIA, 2009). Although Texas has 11 surface mines, which produce a significant amount of the coal consumed, much of the unmet need is imported via rail from other states, specifically Wyoming. Given the estimates of Texas's future use of coal to generate electricity, the AEO 2010 subsequently projected how much coal the state will consume under the Reference Case, a High Economic Growth Case, and a Low Economic Growth Case (EIA, 2010).

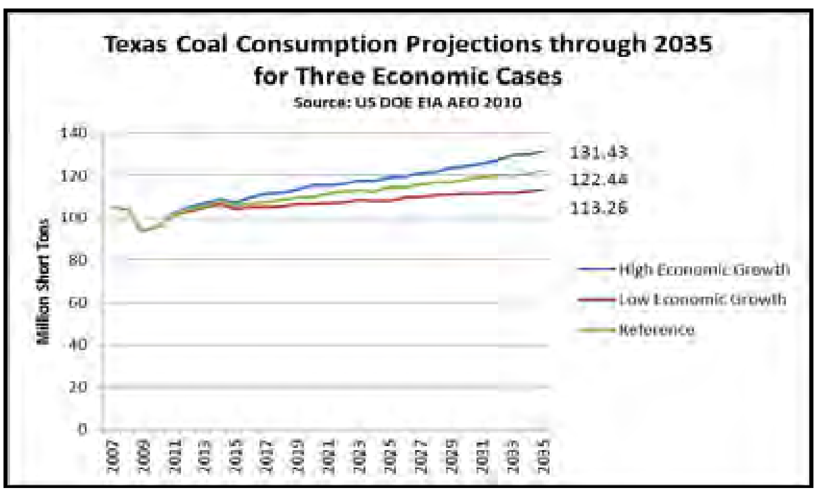
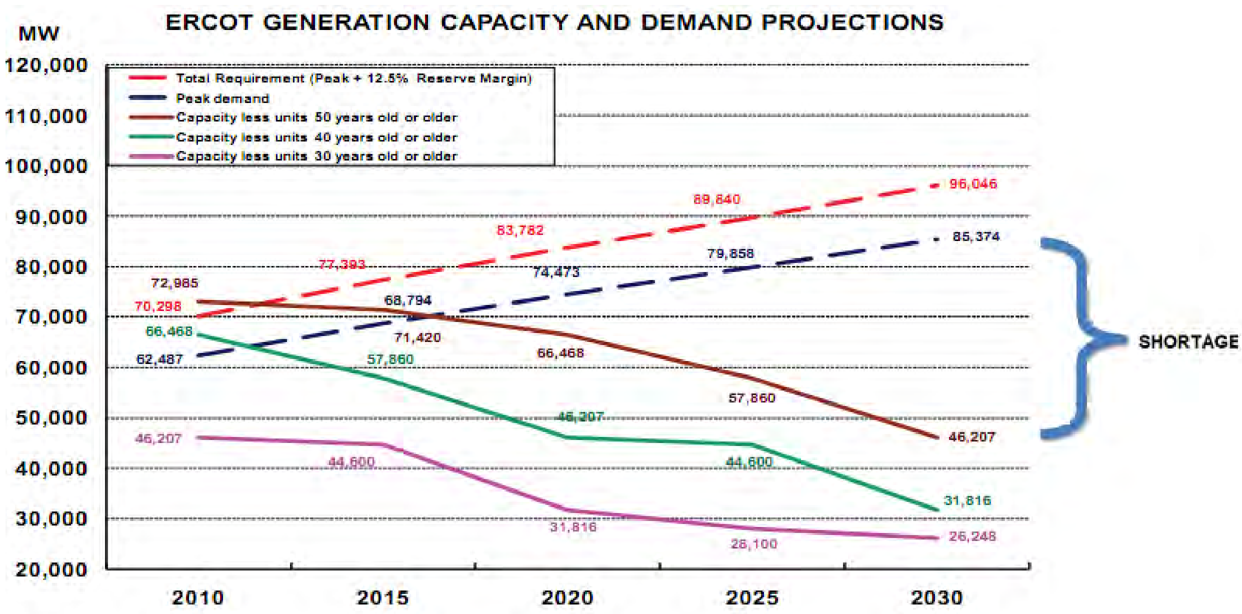


Figure 2.22: Texas's Coal Consumption Projections Through 2035

For electricity specifically, ERCOT projected the base case electricity generation capacity and demand projections until 2030 in *Report on the Capacity, Demand, and Reserves in the ERCOT Region: May 2010*. The projections were based on historic demand growth rates and the state of the current electricity generation system. The results are presented in Figure 2.23. ERCOT reported that without the addition of new electricity generation capacity, generation in plants less than 60 years old will fall below the required 12.6% reserve margin by 2012 and below actual demand by 2016.



Source: Report on the Capacity, Demand and Reserves in the ERCOT Region: May 2010

Figure 2.23: ERCOT Generation Capacity and Demand Projections

As is also evident from Figure 2.23, ERCOT foresees a great increase in peak demand and estimates that by 2029 peak demand will exceed ERCOT's electricity generation capacity (excluding units 50 years old or older) by almost 50,000 MW.

2.3.3 Renewable Energy

In general financial incentives and tax credits are believed to be a major determinant in the future growth of the renewable energy sector and specifically the wind industry. Renewal or expiration of the EPACT of 2005 will thus have a major policy impact on the future of wind energy. Currently, EPACT authorizes loan guarantees for technologies that avoid emitting Greenhouse Gases (GHGs) and provides subsidies for wind and other alternative energy producers. Specifically, $2.7 billion was allocated to extend the renewable electricity Production Tax Credit (PTC) (U.S. Department of Energy, 2010). Created by the Energy Policy Act of 1992, the PTC provides a federal income tax credit for wind generation in the first 10 years of a wind facility's operation. As of May 2010, the PTC was valued at about $0.022/kWh of wind energy. The PTC is set to expire in 2012. The American Wind Energy Association (AWEA) has stated that the PTC is *"a critical factor in [the] financing of new wind farms"* and the Texas Comptroller has argued that the PTC has been *"the main driver behind wind energy expansion in Texas."* Clearly, the renewal or expiration of the PTC in 2012 will have a major impact on the wind energy industry in Texas and the U.S. In addition, the American Recovery and Reinvestment Act (ARRA) of 2009 provided another incentive for wind energy production. Taxpayers eligible for the PTC could choose between receiving a federal business energy investment tax credit (ITC) or a grant from the U.S. Treasury Department instead of receiving the PTC for new installations (U.S. Department of Energy, 2010).

In its AEO 2010, the EIA (2010) analyzed the impacts of the renewal/expiration of tax credits and financial incentives on the wind energy industry in Texas. The AEO 2010 Reference Case is best described as a “current laws and regulations” case as it generally assumes the future will hold no big legislative changes. The No Sunset Case assumes an extension of the renewable PTCs, ITCs, and tax credits for energy efficient technologies through 2035. Specifically, the No Sunset Case assumes that the renewal of the PTC would provide 2.2 cents per kWh of wind energy generated. The Extended Policies Case adopts the same assumptions as the No Sunset Case, and assumes additional requirements for energy efficiency and GHG reductions. The EIA predicted that the Extended Policies Case would result in lower overall energy consumption, increased use of renewable fuels, particularly for electricity generation, and reduced GHG emissions. For the AEO 2010, ERCOT projected the wind energy generating capacity for Texas through 2035 given the three policy cases. Figure 2.24 displays the impact of the renewal/expiration of tax credits and other financial incentives on the wind energy industry in Texas. Similar to the EIA’s findings, ERCOT projected that the Extended Policies Case would result in an increased use of wind energy for electricity generation by 2035 (EIA, 2010).

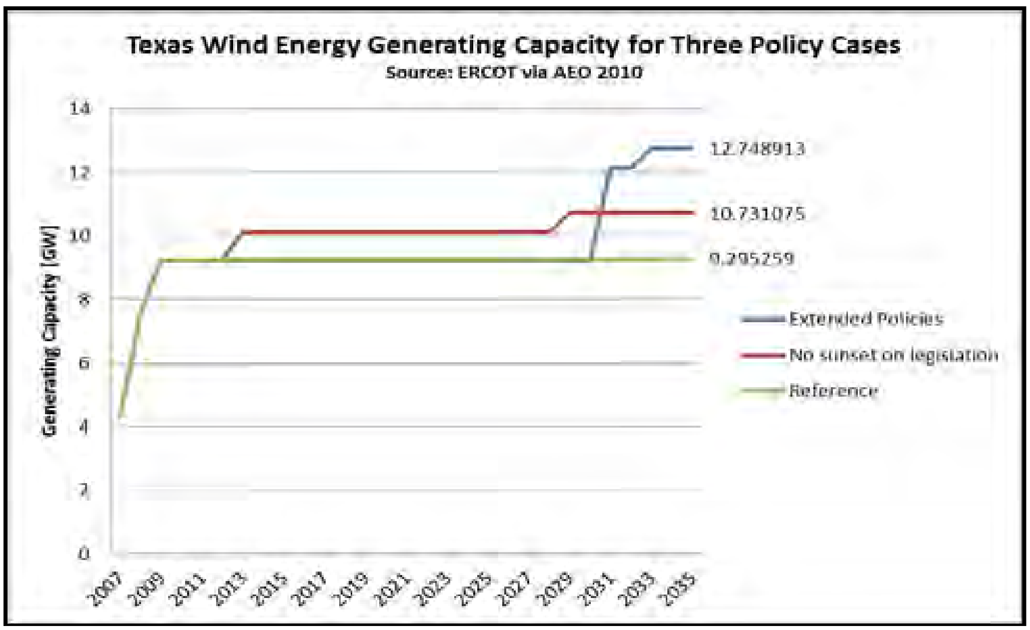


Figure 2.24: Texas’s Wind Energy Capacity Through 2035

Finally, the AEO 2010 predicted that the RFS goal in EISA of 36 billion gallons of biofuel use by 2022 will not be met. In the AEO 2010 Reference Case only 27.5 billion RFS credits are earned in 2022 (Figure 2.25). This figure is partly attributable to a depressed economy and technological factors that hinder cellulosic biofuel production. Of the projected 27.5 billion RFS credits, ethanol would earn up to 14.2 billion credits and biodiesel would represent approximately 6.9 billion credits.

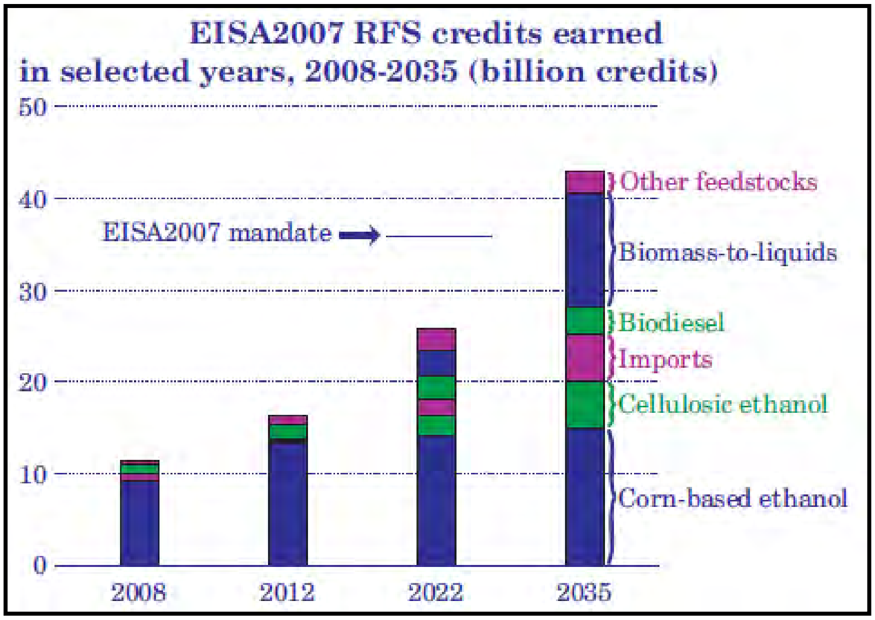


Figure 2.25: Projected Renewable Fuel Standard Credits Earned in Selected Years

2.3.4 Natural Gas

As illustrated in Figure 2.3, dry natural gas production declined between 2000 and 2004. However, discovery of new natural gas reserves has been increasing. The discrepancy in production and reserves is a result of an increase in unconventional natural gas production. The newly discovered reserves are located in deeper wells and tighter deposits not easily accessible with today's drilling technology. Thus, the future growth of natural gas production is believed to be dependent on the availability of advanced drilling technologies and unconventional natural gas wells.

In the AEO 2010, the EIA analyzed several scenarios regarding the future of the natural gas industry. The Rapid Technology Case and the Slow Technology Case cover the improvement in availability and development costs of natural gas drilling and production. These scenarios will be discussed in detail at a later point in this report. An additional four scenarios are analyzed based on the availability of unconventional natural gas wells and the import of additional sources (Figure 2.26). The No Low Permeability Natural Gas Drilling Case and the No Shale Gas Drilling Case both analyze a future where no low permeability or shale gas drilling is permitted beyond 2009. The High Shale Resources Case analyzes a future where shale gas resources and drilling grow at a rate of 19.6% compared to the 10% growth projected in the Reference Case (Annual Energy Outlook 2010, 2010).

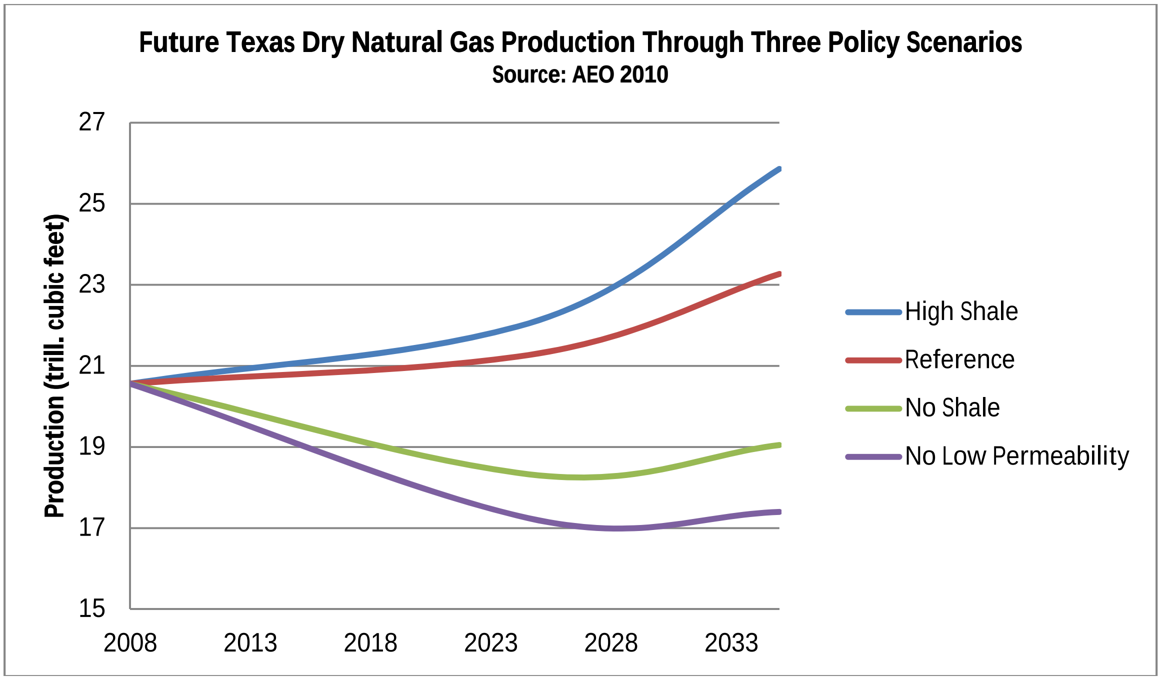


Figure 2.26: Future Texas Dry Natural Gas Production (Permeability Scenarios)

The High LNG Supply Case analyzes a future in which liquid natural gas imports are greatly increased beyond the Reference Case by a specified factor from 2010 onward: 1.0 in 2010 to 5.0 in 2035. This scenario is illustrated in Figure 2.27.

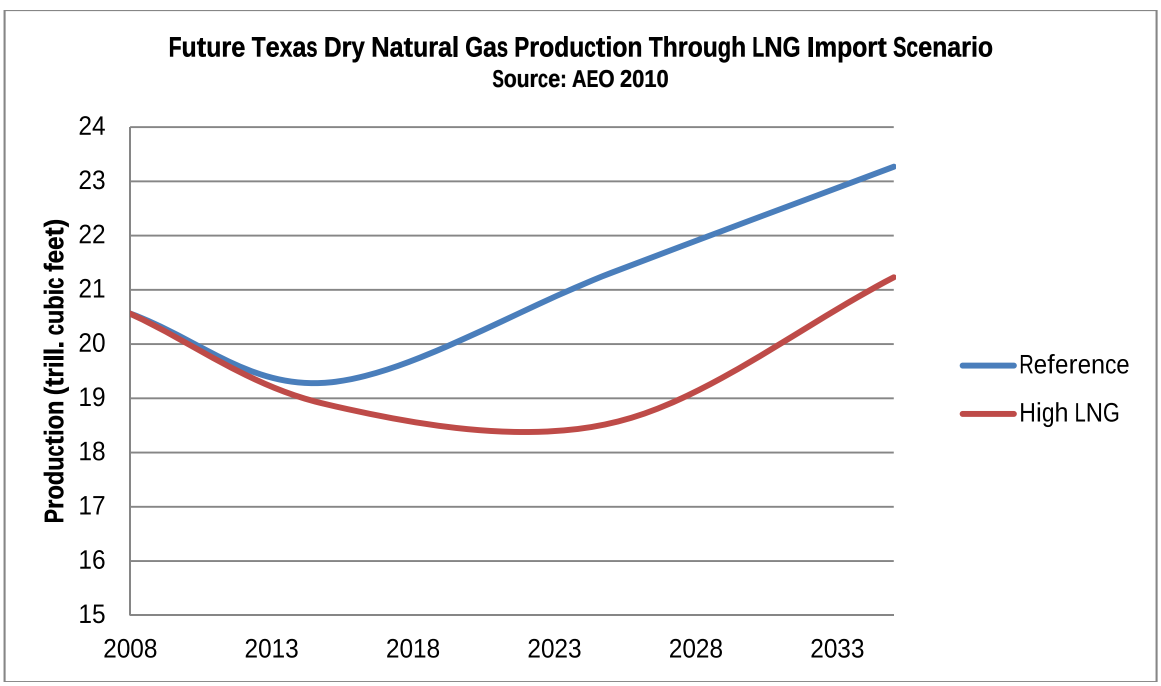


Figure 2.27: Future Texas Dry Natural Gas Production (High LNG Supply Case)

2.4 Energy Efficiency

Energy efficiency measures and advancements in energy efficiency technologies are important factors when considering future energy consumption in Texas. The National Academy of Sciences, along with the National Academy of Engineering and the National Research Council, created a committee that compiled a report that summarized the future of the energy sector in the United States. This report, *America's Energy Future* (AEF), discusses current energy production and consumption trends, as well as the effect of future changes on the energy sector. According to this report, energy efficiency breakthroughs could save approximately 30% of the energy consumed nationwide by 2030 (National Academy of Sciences, National Academy of Engineering, National Research Coucil, 2009). Specifically, it was reported that if energy prices remain high enough, or public policy supported investments in efficiency materialize, nationwide energy consumption could be lowered by 15% by 2020 and by 30% by 2030 relative to the EIA's Reference Case projections illustrated in Figure 2.19. Currently, Texas leads the U.S. in overall energy consumption and advances in energy efficiency could therefore substantially reduce energy consumption in Texas.

As mentioned earlier, the residential and commercial sectors account for 14% and 12% of Texas's total energy consumption, respectively. The AEF concluded that the residential and commercial sectors nationwide could save approximately 25 to 30% of consumed energy relative to the EIA's AEO Reference Case projections. This savings could be achieved through advances in space heating, cooling, water heating, and lighting.

According to the Texas State Comptroller, per capita energy consumption in Texas is significantly higher than the national average. However, while the population and energy consumption has been increasing, the total energy intensity, or energy use per dollar of Texas's Gross State Product, has been decreasing since 1960 (The Energy Report 2008, 2008). This suggests an increase in energy efficiency. A continued emphasis on energy efficiency in the residential and commercial sectors could thus contribute to an overall decrease in energy consumption. On the other hand, several barriers to increase energy efficiency in the residential and commercial sectors exist. For example, a major barrier is information. Information on energy efficient practices and products are not always readily available to the consumer (National Academy of Sciences, National Academy of Engineering, National Research Coucil, 2009). Also, energy efficient investments tend to require a large, upfront monetary investment that can take years to recover. Many residential and commercial consumers cannot always afford this up-front cost. Others, such as landlords and building owners, are not necessarily interested in energy savings when they are not responsible for paying the utilities. Increased energy costs, greater environmental awareness, improved building codes, improved appliance efficiency standards, and improved state and local utility programs are thus required to improve energy efficiency in the residential and commercial sectors (National Academy of Sciences, National Academy of Engineering, National Research Coucil, 2009).

Although the energy consumed in every sector in Texas has been increasing since 1960, the energy consumed by the transportation sector has been increasing at a faster rate—i.e., approximately 2.7% compared to an increase in the overall energy consumed of approximately 2.2%. The transportation sector accounts for approximately 25% of the energy consumed in Texas and 10.2% of the transportation fuel consumed in the U.S. each year (The Energy Report 2008, 2008). Many opportunities exist to increase fuel efficiency in both the passenger and freight transportation sectors—some of which become more feasible as the price of fuel increases. In the case of passenger transportation, changes in consumer trends and technologies could increase fuel efficiency. Improvements to the spark ignition vehicle, diesel engines, and the introduction of hybrid vehicles have been shown to potentially have the largest impact on energy consumption. For example, the turbocharged diesel engine is 10 to 15% more fuel efficient than the spark ignition equivalents and gasoline hybrid-electric vehicles are 30% more efficient. Currently, corporate average fuel economy (CAFE) standards require that all new vehicles must achieve 35 miles per gallon (mpg) by 2020, which translates into a 30% reduction in fuel consumption. Improvements to the traditional spark ignition vehicle show substantial promise, with a decrease in energy consumption of approximately 20 to 30% (National Academy of Sciences, National Academy of Engineering, National Research Coucil, 2009). In the case of freight transportation, the AEF concluded that a 10 to 20% reduction in fuel consumption is feasible. The reduction can be achieved by advances in engine technologies and a transition to rail transportation, which is 10 times as efficient as the other modes of freight transportation (National Academy of Sciences, National Academy of Engineering, National Research Coucil, 2009). In addition to technology advancements, Texas is also using policy incentives, such as a competitive grant program, to encourage the purchase of alternative fuel vehicles and equipment under the Alternative Fuels Project to proactively decrease fuel consumption by the transportation sector (Alternative Fuels Program). On the other hand, the major barriers to enhancing fuel efficiency in the transportation sector include unstable oil prices, a lack of production capacity, and the desire for size and performance over fuel efficiency. Specifically, any expectation of lower future oil prices will slow attempts to increase fuel efficiency or use of alternative fuels (National Academy of Sciences, National Academy of Engineering, National Research Coucil, 2009).

The industrial sector is the largest energy consumer in Texas, accounting for 49% of the total energy consumed in the state. Thus, energy efficiency improvements in this sector hold great promise to reduce overall energy consumption in the state. For example, the AEF projected a potential energy use reduction of 14 to 22% by 2020 given cost-efficient investments in the key industries in Texas—particularly the chemical, petroleum, and cement processing industries. High temperature reactors, advanced system controls, corrosion resistant materials, and overall energy efficient practices in the chemical and petroleum processing industries could improve efficiency by 10–20%. In the cement processing industry, significant upgrades of the current equipment are needed, as well as further research into alternative types of cement to achieve a 10–20% increase in efficiency. These investments are currently being promoted by Texas Industries of the Future, a partnership between the U.S. Department of Energy and State Energy Conservation Office of Texas. The program provides outreach, technical training, and technical assistance to Texas's industrial energy customers. These programs could thus contribute to a reduction in industrial energy consumption in the future. On the other hand, the major barriers to implementing energy efficiency improvements include the high initial costs of energy efficiency improvements, a lack of expertise and knowledge regarding energy efficiency measures and technologies, and high risks associated with the introduction of new technologies. Given policy changes and available information, these barriers can, however, be overcome (National Academy of Sciences, National Academy of Engineering, National Research Coucil, 2009).

2.5 Concluding Remarks

This chapter provided detailed information about Texas's energy sector. The sector was characterized in terms of production capacity by source and consumption by sector. The chapter provided historical data, but also included the EIA's future estimates for Texas's energy sector.

The chapter concludes with a brief discussion on energy efficiency measures and advancements in energy efficiency technologies that may impact future energy consumption in Texas. The next chapter discusses the capacity and need for enabling energy infrastructure with specific emphasis on electricity transmission infrastructure.

Chapter 3. Enabling Energy Infrastructure

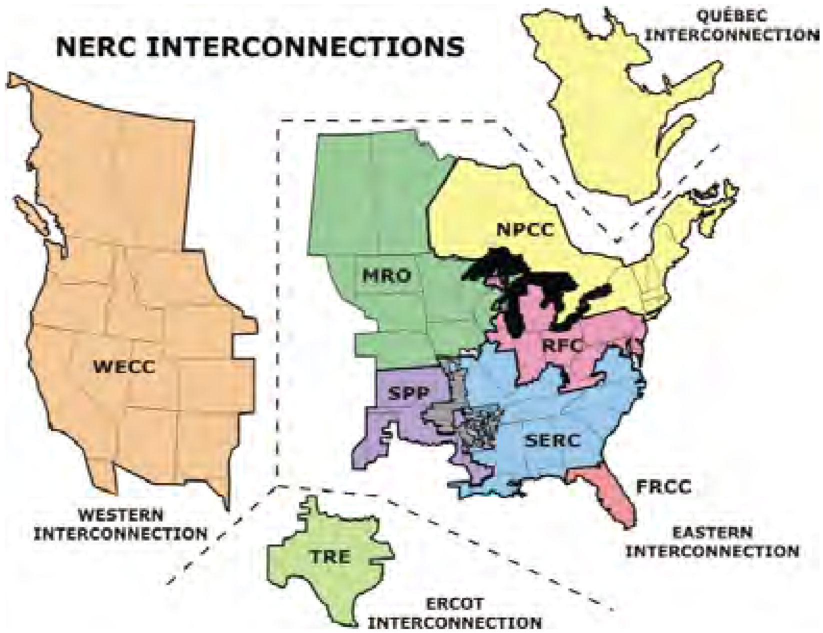
Texas's energy portfolio goals are incorporated into a state policy known as Texas's Renewable Portfolio Standard (RPS). The RPS requires that retail electricity providers in the state produce a certain amount of their energy from renewable sources. Currently, most renewable energy sources are more expensive than the fossil fuel alternative. Without some type of incentive, electricity producers would not choose the financially more expensive energy option. The ultimate goal of the RPS is thus to promote renewable energy as a financially competitive energy resource.

An important limitation to the expansion of renewable energy is the capacity of the current electric transmission infrastructure. For example, the existing transmission network has significantly slowed wind investments in West Texas and the Panhandle—the area known as the "Western Congestion Management Zone" (2009 Annual Report, 2010). Existing transmission lines servicing this area have a very low energy capacity, limiting transmission to only 4,500 MW (2009 Annual Report, 2010). This issue was addressed in the 2005 revision of the RPS. In addition to increasing the renewable energy goals, Senate Bill 20 mandated the development of Competitive Renewable Energy Zones (CREZs) and an investment in transmission infrastructure to move the wind energy produced from these zones to large load centers (Thornley, 2008). CREZs are areas in the state that have adequate wind-generating capacity to warrant an investment in transmission infrastructure. As a result, five areas throughout West Texas and the Panhandle were identified as areas with high future wind generating potential.

This chapter provides information about enabling energy infrastructure with specific emphasis on the electricity transmission infrastructure that serves the CREZs.

3.1 Current State of Texas's Electricity Transmission Infrastructure

Texas's electricity transmission infrastructure is unique in that it is the only state in the continental U.S. with its own power grid. This independence from the rest of the national grid has been critical in the state's view on energy production. For example, it has allowed the state to incorporate renewable energy sources, such as wind, that the larger national grids would find challenging. The Electric Reliability Council of Texas (ERCOT) is the independent system operator for the region and is responsible for providing electricity to over 22 million consumers across Texas. Approximately 85% of the electricity transmission falls under ERCOT, or about 75% of the land area (ERCOT Quick Facts, 2011). ERCOT thus assumes responsibility for approximately 40,000 circuit miles of transmission lines and 550 operating power plants. The remaining 15% of Texas's electricity is produced by surrounding state grids, including the Western Electric Coordinating Council (WECCC), the Southwest Power Pool (SPP), and the Southeastern Electric Reliability Council (SERC). The components of the national electricity grid system are illustrated in Figure 3.1.

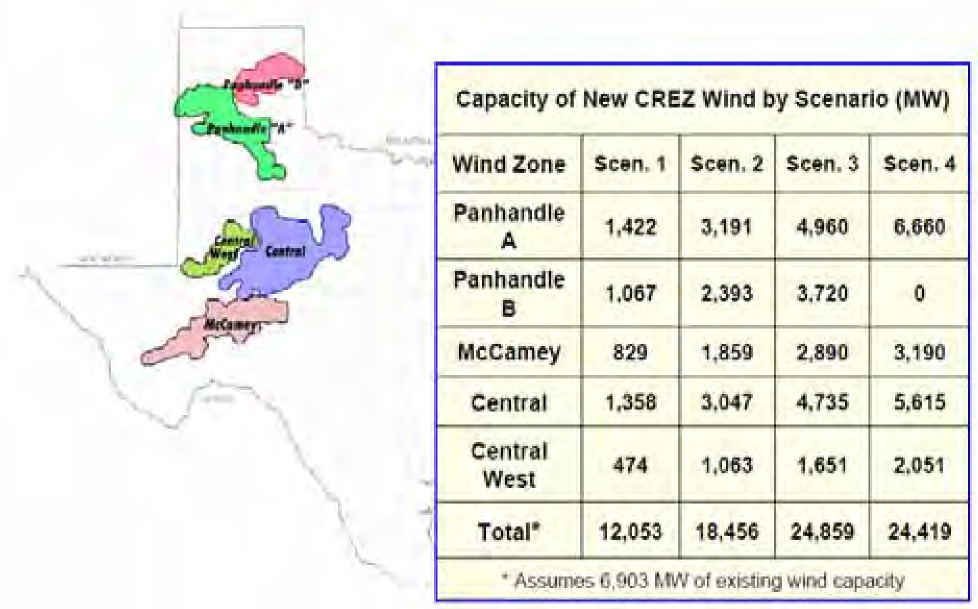


Source: The Smart Grid in Texas, 2011

Figure 3.1: North American Electric Reliability Corporation (NERC) Interconnections

3.2 Competitive Renewable Energy Zones (CREZ)

An important impetus for investments in Texas's transmission and distribution network was the development of the Competitive Renewable Energy Zones (CREZs). As was mentioned earlier, the CREZs are areas across the state with adequate wind-generating capacity to warrant investments in transmission infrastructure. To facilitate investments in wind farms, a plan to construct transmission infrastructure to serve heavy load areas was developed. Together with the Public Utilities Commission of Texas (PUCT), ERCOT developed several plans for the future CREZs. PUCT developed four scenarios for the potential wind zones, which are illustrated in Figure 3.2. ERCOT evaluated system reliability, the available transmission capacity, and cost-effectiveness in determining a sufficient plan for each of the proposed PUCT scenarios. The result of the study produced two plans for Scenario 1, a low cost plan and an expandable plan, and one plan each for Scenarios 2 through 4 (Woodfin, 2008). Table 3.2 summarizes each plan.



Capacity of New CREZ Wind by Scenario (MW)				
Wind Zone	Scen. 1	Scen. 2	Scen. 3	Scen. 4
Panhandle A	1,422	3,191	4,960	6,660
Panhandle B	1,067	2,393	3,720	0
McCamey	829	1,859	2,890	3,190
Central	1,358	3,047	4,735	5,615
Central West	474	1,063	1,651	2,051
Total*	12,053	18,456	24,859	24,419

* Assumes 6,903 MW of existing wind capacity

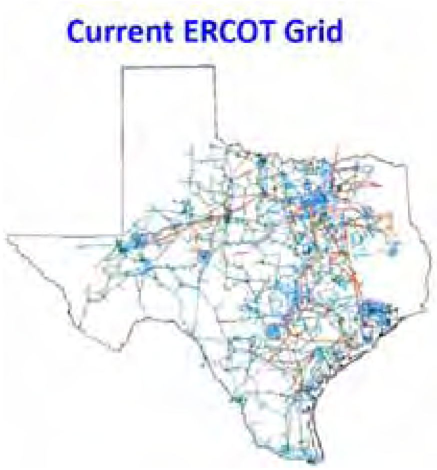
Figure 3.2: PUCT Scenarios for Potential Wind Zones

Table 3.1: ERCOT Plan Summary

Scenario	Wind Installed (GW)	Transmission Cost ($B)	Collection Cost ($B)	Total New ROW (Miles)	Regions
1 – Plan A	12.053	2.95	0.35–0.41	1,638	All 5
1 – Plan B	12.053	3.78	0.41–0.53	1,831	All 5
2	18.456	4.93	0.58–0.82	2,376	All 5
3	24.859	6.38	0.72–1.03	3,036	All 5
4	24.419	5.75	0.67–0.94	2,489	No Panhandle B

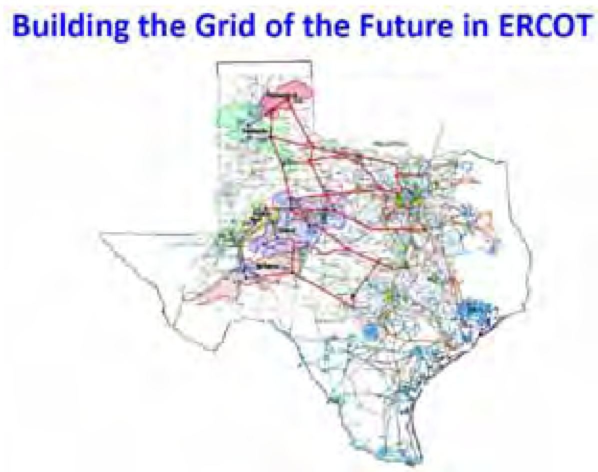
Ultimately, the Scenario 2 plan was chosen. This plan, which is slated for completion in 2015, involves the construction of more than 2,300 circuit miles of transmission lines that will be able to transmit over 18,000 MW from areas of abundant wind energy potential to heavy energy load centers (Building the Grid of the Future, 2010).

Figure 3.3 illustrates the current ERCOT electric grid. Figure 3.4 illustrates the future grid after the addition of the CREZ transmission lines. The addition of these transmission lines will potentially facilitate investments in additional wind farms/developments in West Texas and the Panhandle.



Source: Building the Grid of the Future, 2010

Figure 3.3: ERCOT Grid before CREZ



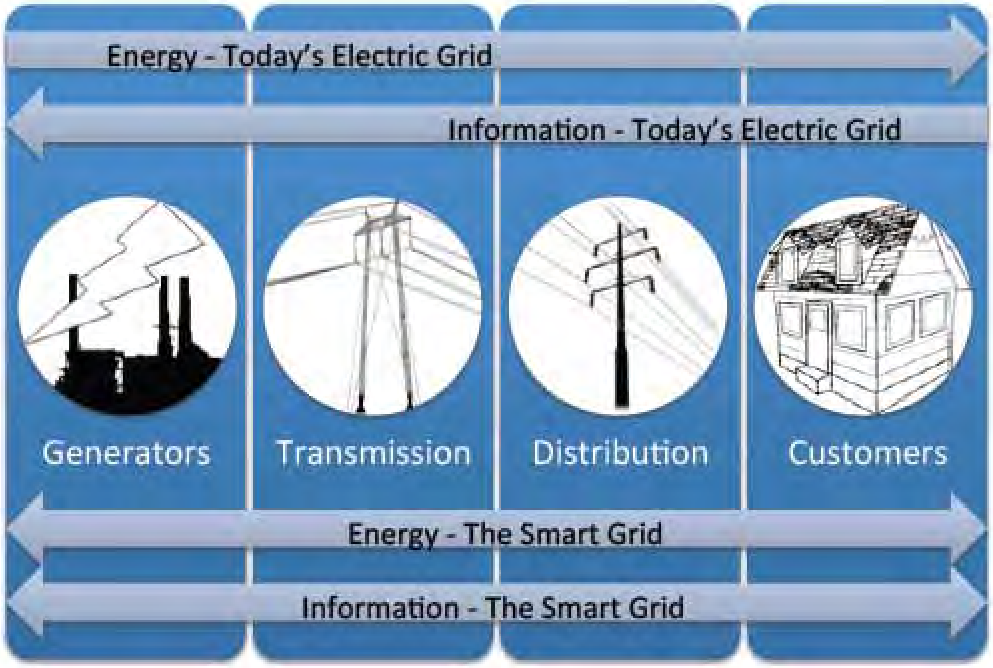
Source: Building the Grid of the Future, 2010

Figure 3.4: ERCOT Grid after CREZ

3.3 The Future of Electricity Transmission

Texas's electricity grid was designed and built decades ago, with the last major addition added in the 1980s (Lott, Seaman, Upshaw, & Haron, 2011). Since then, electricity demand has increased substantially and the grid's increasingly outdated technology has been deteriorating and struggling to supply the demand. ERCOT has acknowledged the issues concerning Texas's aging transmission infrastructure and has elected to invest in smart and high efficiency technologies as opposed to repairing and maintaining the current grid configuration.

The main component of the new electricity transmission project is the implementation of smart grid technology. Current transmission technology only allows for one-way communication between the consumer and the utility companies. In other words, the utility provides the electricity needed to the consumer and the consumer provides information on total usage to the utility. The smart grid would allow for two-way, active communication between the consumer and utilities using smart meters. Current electricity meters are electromechanical and need to be manually read each month. The smart meter is digital and automatically transmits data to the utility provider. Thus, instead of obtaining a monthly meter reading, the smart meter can produce readings every 15 minutes, thereby making the consumer more aware of energy consumption. Figure 3.5 illustrates the current and proposed flow of information using smart grid technology.



Source: The Smart Grid in Texas, 2011

Figure 3.5: Smart Grid Information Flow Chart

Planners anticipate that these smart meters would eventually communicate with household appliances and regulate energy consumption during peak hours (Customer Facts: Smart Meters or Advanced Metering Systems (AMS), 2010). The widespread use of these smart meters could thus reduce residential and commercial energy consumption substantially. As of September 2010, over 2.1 million smart meters have been installed throughout Texas. By the end of 2013, it is believed that six million more will be in use (Smitherman B. , Building the Grid of the Future, 2010).

Another step that ERCOT and PUCT have taken towards the implementation of smart electric transmission technology is through building a more efficient grid. As of 2009, over 1,300 circuit miles of transmission lines have been added or improved. An additional 2,800 circuit miles are anticipated to be improved or added by 2013 (Smitherman B. , ERCOT Energy Seminar 2009, 2009). However, further transmission line improvements will be needed to bring the grid completely up to date. A number of advances in transmission technology are available to further enhance the efficiency of these improvements. For example, the transmission and distribution (T&D) of electricity over high voltage power lines is an area that has seen significant improvements in efficiency. With the current technology, an overall T&D energy loss of 6% to 8% is considered normal (Energy Efficiency in the Power Grid, 2007). This translates into a loss of approximately 24 to 32 million MWh due to T&D in Texas in 2008. This loss can be reduced by, among other measures, the use of more energy-efficient materials. Table 3.2 lists T&D technology advances and their associated efficiency increases.

Table 3.2: Advances in T&D Technology

Technology	Description	Efficiency Increase
Distribution Transformers	New efficiency standards are in place requiring all new distribution transformers to conform to new efficiency regulations	Approximately 4% less energy loss compared to current transformers
High-Voltage Direct Current Lines (HVDC)	High capacity transmission lines that would replace current high voltage alternating current lines	Approximately 25% line loss and 2–5 times the capacity of HVAC lines
FACTS Devices	Devices that increase efficiency on transmission lines and allow increased capacity on current lines without disturbances	Approximately 20–40% increase in current HVAC line capacity
Gas-Insulated Substations	Decreases the size of substations and the effect of stepping down voltages	Unknown
Super Conductors	High temperature super conductors can conduct electricity at a significantly lower loss and increased capacity. Can also be used in transformers to decrease losses	90–94% reduction in transmission loss 2–5 times the capacity of conventional lines 70% reduction in loss in transformers

Source: Energy Efficiency in the Power Grid, 2007

3.4 Concluding Remarks

Texas's increasingly outdated transmission technology has been struggling to supply increased electricity demand in the state. Inadequate transmission technology has also been an important limitation to the expansion of renewable energy sources—specifically wind. This chapter provided information about the current state of Texas's electricity transmission infrastructure, the plans for expanding Texas's transmission infrastructure to serve the CREZs, and finally the steps that ERCOT is taking to invest in smart and high efficiency technologies to increase the capacity of Texas's electricity grid.

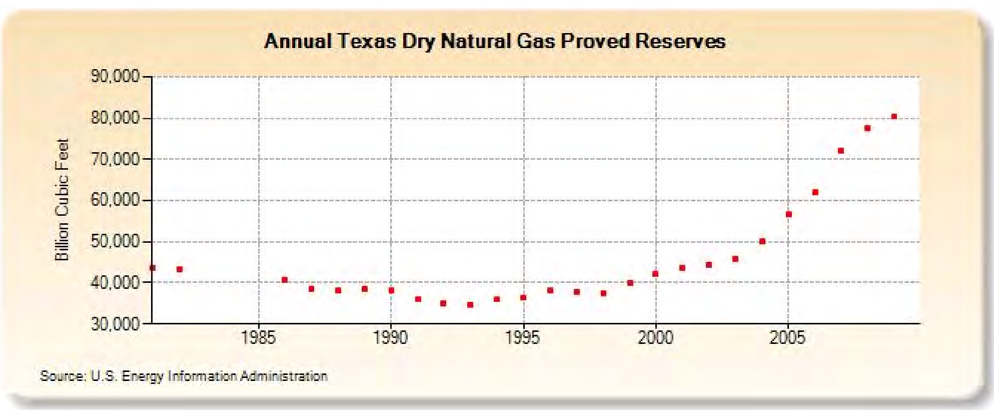
Chapter 4. Advancements in Energy Technology

Texas's energy sector consists of the following industries: oil, natural gas, coal, wind, solar, bio-fuels, and nuclear. This chapter highlights the technology advancements by industry that could impact the future of Texas's energy sector.

4.1 Natural Gas Extraction Technology

In 2008, the EIA estimated that Texas has 21,595 billion cubic feet of shale gas reserves, which represented more than two-thirds of the estimated 32,825 billion cubic feet of U.S. shale reserves in 2008 (EIA, 2009). Forecasts for the next several decades predict that natural gas will assume an increasing share of the U.S. fuel mix, with large unconventional resources, particularly shale gas, playing an increasing role.

In Texas, natural gas accounts for approximately 59% of the electricity produced each year. In addition, Texas's industrial sector is a large consumer of natural gas. With a growing population and economy, it is thus foreseen that there will be an increasing demand for natural gas in the next 20 to 30 years. Figure 4.1 illustrates Texas's proven dry natural gas reserves.



Source: Natural Gas, 2011

Figure 4.1: Texas Dry Natural Gas-Proved Reserves

In recent years, the use of innovative, unconventional technologies and the mining of unconventional natural gas fields (i.e., Barnett Shale and Eagle Ford Shale) have resulted in an increase in natural gas production. Unconventional natural gas is a broad term that comprises all sources of natural gas that are not easily extracted. Table 4.1 lists the types of unconventional natural gas (UCG) that are found in Texas.

Table 4.1: Unconventional Natural Gas

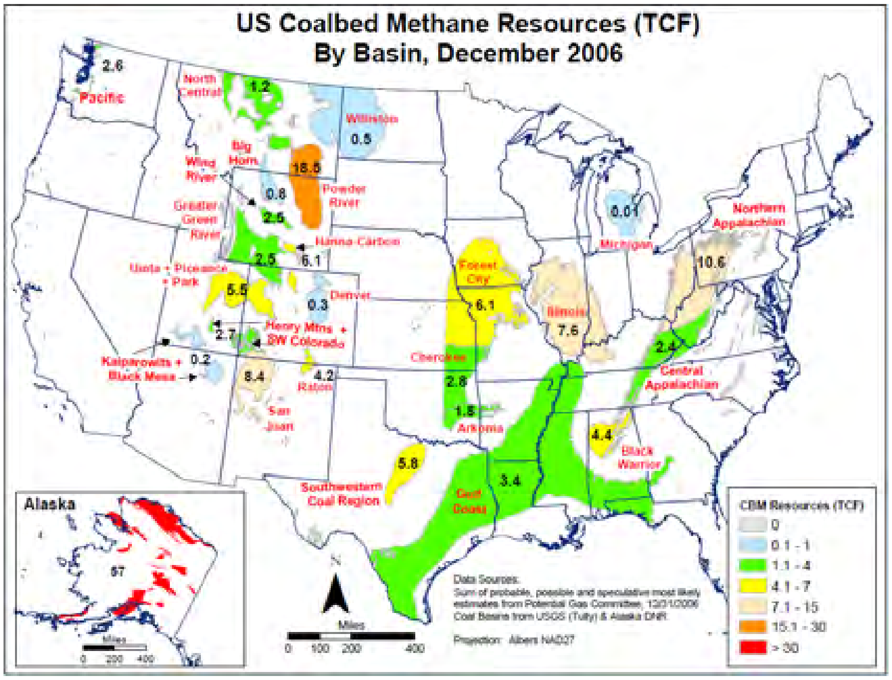
Type of UCG	Description	Extraction Technology
Deep Natural Gas	Natural gas located deeper than conventional natural gas wells. Depth of 15,000 feet or deeper.	Deep drilling technologies are available but extremely expensive. Research into decreasing cost will promote further use of this technology.
Tight Natural Gas	Natural gas located in dense, impermeable rock formations. Represents approximately 21% of total recoverable natural gas in the US.	Fracturing and acidizing technologies are currently in use, but are very costly.
Shale Gas	Natural gas located in dense, shale rocks.	Horizontal drilling and fracturing are already in use today. Major issues that need to be addressed due to fracturing are the impacts on the surrounding environment.
Coal Bed Methane	Methane trapped in coal mines.	Methane produced in the coal wells can be extracted and injected into natural gas pipelines for resale.

Source: Natural Gas Supply Association, 2010

Currently, shale gas is mined extensively in the Barnet Shale[5], Eagle Ford Shale, and Haynesville Shale plays. Tight natural gas and deep natural gas are also found and have some potential in Texas. However, more advances are needed in terms of drilling technologies to ensure the financial feasibility of these mining operations over the long term.

Coal bed methane, though not widely extracted, is found in Texas's coastal region. For example, estimates suggest that approximately 3.4 trillion cubic feet (TCF) of methane can be recovered by collecting the methane normally released from coal mines (US Coal Bed Methane, 2007). The location of the coal bed methane is illustrated in Figure 4.2.

[5] In a 2009 report concerning the Barnett Shale play, the Perryman Group argued that production in the Barnett Shale had not yet peaked. The Perryman Group projected that production will increase to 8 to 9 billion cubic feet per day by 2018 (The Perryman Group, 2009).



Source: US Coal Bed Methane

Figure 4.2: Coal Bed Methane Potential

Improvements in technology and decreasing drilling and production costs, will increase the productive capacity of wells and potentially the number of productive wells. Technology improvements are particularly relevant to the production of shale gas; although the incremental costs are lower, extracting the natural gas from shale formations requires high capital expenditures relative to conventional gas extraction.

In its AEO 2010, the EIA predicted the effect of three technology scenarios on the future supply of natural gas production in the Gulf Coast Region, which includes Texas. The Reference Case assumes no substantial technology improvements and a continuation of historical trends. The Rapid Technology Case assumes accelerated production growth given decreasing exploration and development costs. Technology improvements result in natural gas production at higher rates, which translates into lower natural gas prices and increased consumption. Increased consumption subsequently motivates the industry to produce more natural gas and the cycle continues. The Slow Technology Case assumes higher exploration and development costs than for the Rapid Technology Case, translating into higher natural gas prices and lower consumption (EIA, 2010). Figure 4.3 illustrates the estimated natural gas production in the Gulf Coast through 2035 under the three technology cases.

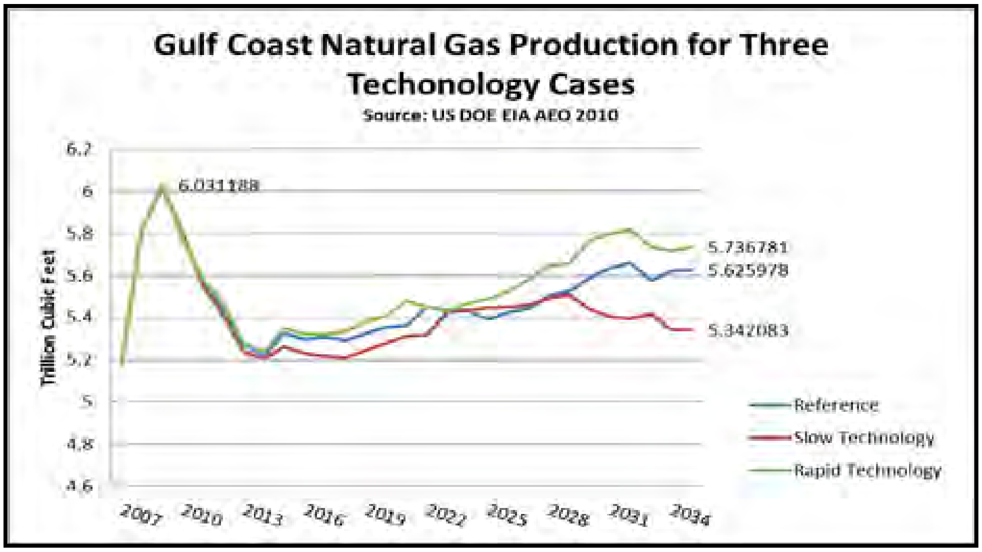


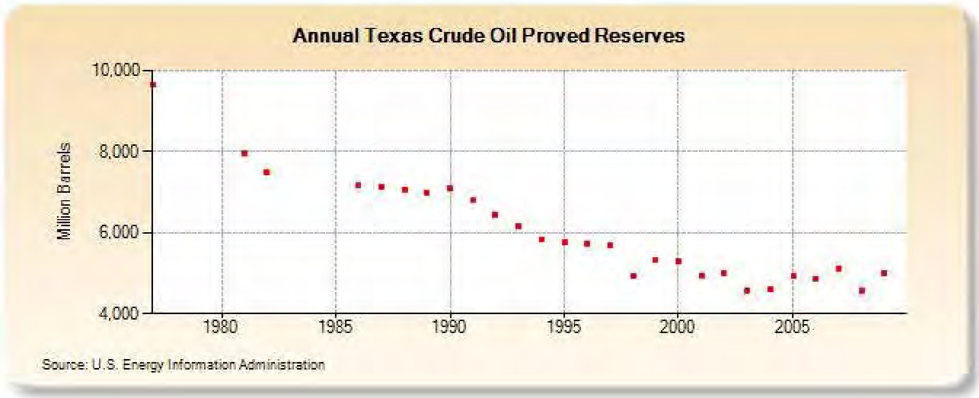
Figure 4.3: Estimated Gulf Coast Natural Gas Production Through 2034

Given rapid technology advancements, the EIA estimates that the Gulf Coast would be producing 5.74 trillion cubic feet of natural gas by 2035, which is about 0.4 trillion cubic feet higher when assuming slow technology advancements (EIA, 2010).

4.2 Oil Extraction Technology

In 2010, approximately 62% of the crude oil consumed in the U.S. was imported. Given the level of U.S. demand and the political instability in the source regions, domestic sources of crude oil are critical.

In Texas's Permian Basin, the extraction of conventional oil over the past 80 to 100 years have resulted in the decline of many of the conventional resources and many wells being deemed mature. Texas's oil production (as was shown in Figure 2.4) and proven reserves (see Figure 4.4) have thus been declining, implying the need for the discovery of new reserves or to increase the output of current wells. In its most recent (2007) assessment of the Permian Basin, the U.S. Geological Survey (USGS) estimated a mean of 1.3 billion barrels of technically recoverable oil in new fields. The recovery of these unconventional resources or further extraction from mature wells will, however, be largely a function of the national and global supply and demand for oil, the price of oil, improvements to extraction technologies to increase the output of mature wells, and energy-focused legislation.

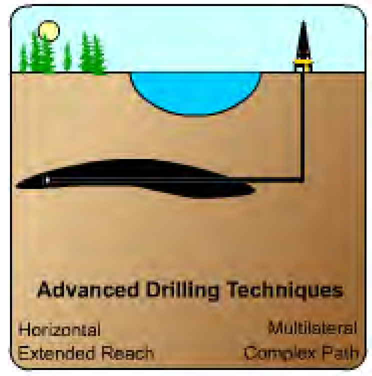
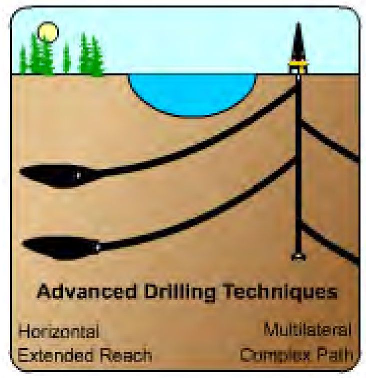
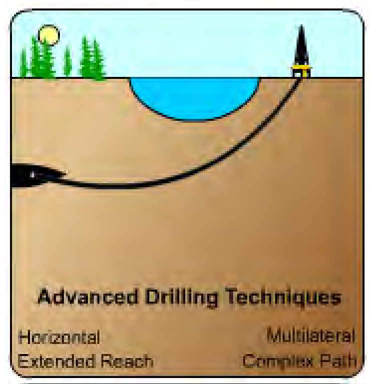
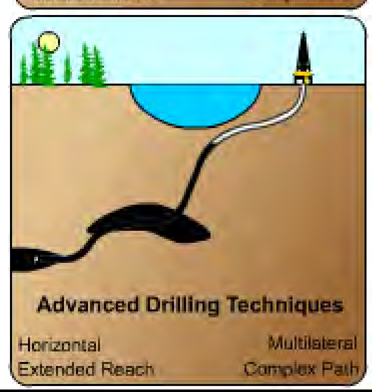


Source: Petroleum and Other Liquids, 2010

Figure 4.4: Annual Texas Crude Oil Proved Reserves

Enhanced oil recovery technologies and advanced drilling technologies have the highest potential for increasing oil production. The advanced drilling technologies currently available or under development are summarized in Table 4.2. With these, previously unreachable oil reserves can be reached.

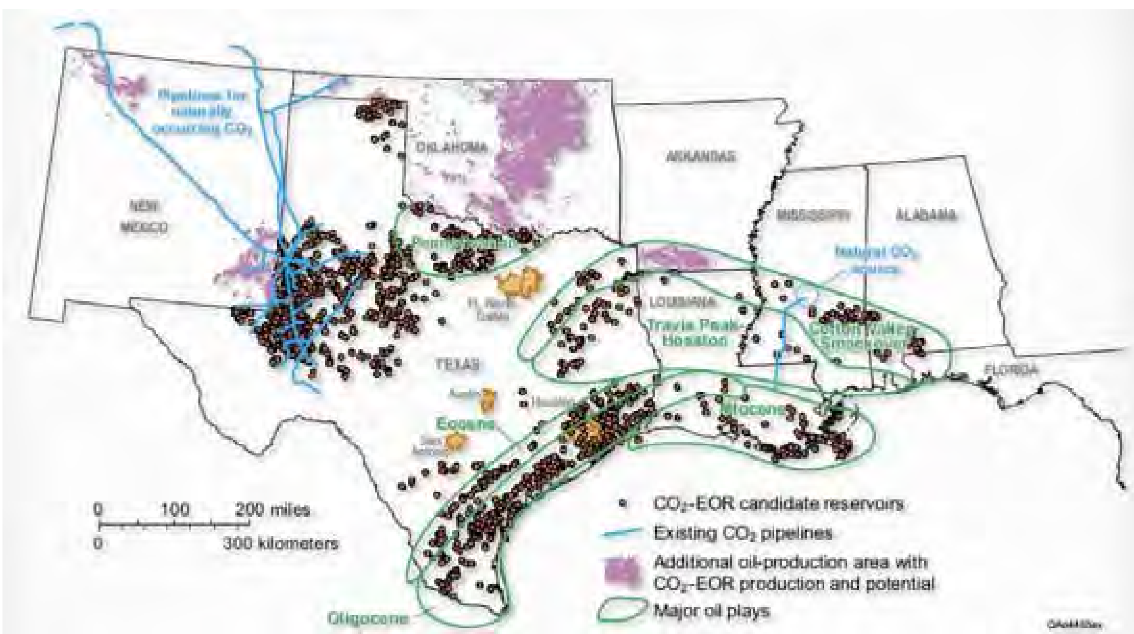
Table 4.2: Advanced Oil and Natural Gas Drilling Techniques

Type of Drilling	Description	Example
Horizontal Drilling	A standard vertical well with an extension that runs horizontally to the natural gas or oil source. The horizontal portion can be up to a mile long.	
Multilateral Drilling	A standard vertical well with several extensions at different depths to access several layers of natural gas or oil reservoirs.	
Extended Reach Drilling	A semi-horizontal well that allows access to reservoirs located at great distances from the original well. Can reach over five miles, which reduces the need for offshore platforms that would be within 5 miles of the coast.	
Complex Path Drilling	Allows for a well to be drilled with several twists and turns to avoid obstructions that would historically have prevented access to certain reservoirs.	

Source: Advanced Drilling Techniques, 2009

Enhanced oil recovery (EOR) is another option for increasing oil production in Texas. Crude oil recovery has three distinct phases: primary, secondary, and tertiary. The primary and secondary phases of crude oil recovery occur during every drill. However, during these phases only 20 to 40% of the oil in the well is extracted (Enhanced Oil Recovery/CO2 Injection, 2011). The tertiary phase, or the EOR phase, is the next step. EOR technologies allow for the extraction of 30 to 60% or more of the oil in the well. Three types of EOR technologies—i.e., thermal recovery, gas injection, and chemical injection—have been used successfully to increase oil production from existing wells. During thermal recovery, high temperature steam is injected into the well to decrease the viscosity of the oil in place. Gas injection EOR uses gasses—e.g., natural gas, nitrogen, or carbon dioxide (CO_2)—to either increase the pressure in the well or decrease the viscosity of the in place oil to force out additional oil. Finally, chemical injection involves injecting polymers into the well that reduces the resistance of the oil to movement, thereby increasing production.

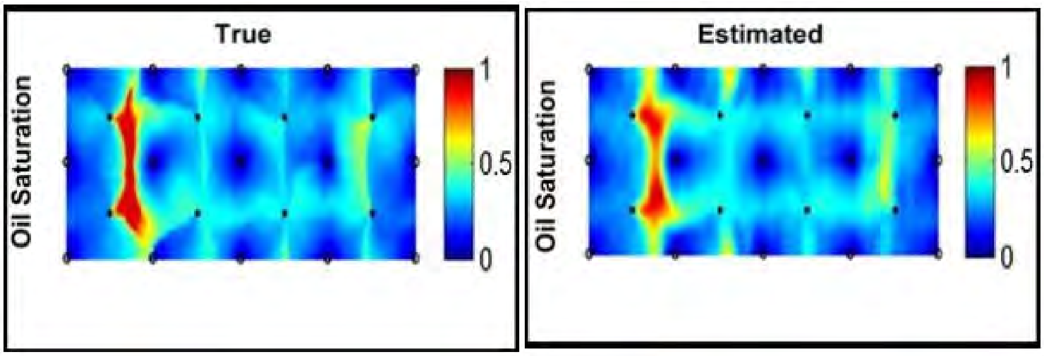
Gas injection EOR has been widely used across the country because of the relatively high costs and inconsistent results with the other two types of EOR. In Texas, CO_2-EOR has been used successfully since the 1970s (FutureGen). According to the University of Texas's Bureau of Economic Geology, 15% of Texas's yearly production is extracted using CO_2-EOR (FutureGen). Furthermore, in 2006, the U.S. Department of Energy's Office of Oil and Natural Gas estimated that nearly 74 billion barrels of oil are remaining in mature reservoirs in East and Central Texas that could be accessed using CO_2-EOR. Figure 4.5 provides a map of the regions in Texas with the greatest potential to use CO_2-EOR technology. The majority of these reservoirs reside in the Permian Basin area and along the Gulf Coast.



Source: CO_2-Norway, 2008

Figure 4.5: CO_2-EOR Candidate Reservoirs in Texas

To enhance the efficiency of EOR methods, more accurate well mapping technologies are needed. Current research being conducted by the Massachusetts Institute of Technology's (MIT) Civil and Environmental Engineering Department aims to develop a mapping tool that would create a realistic representation of the oil reservoir using information from surrounding wells. The images in Figure 4.6 illustrate the actual reservoir information (True) and the estimated reservoir information. Exact information about wells is typically not known, resulting in inefficiencies in drilling and EOR operations. More robust information about reservoirs will allow for more precise drilling, more accurate use of EOR technologies, and an increase in the oil recovered (Improving Oil Extraction With New Mapping Technology, 2009).



Source: Improving Oil Extraction with New Mapping Technology, 2009

Figure 4.6: McLaughlin/Jafarpour Well Mapping Approach

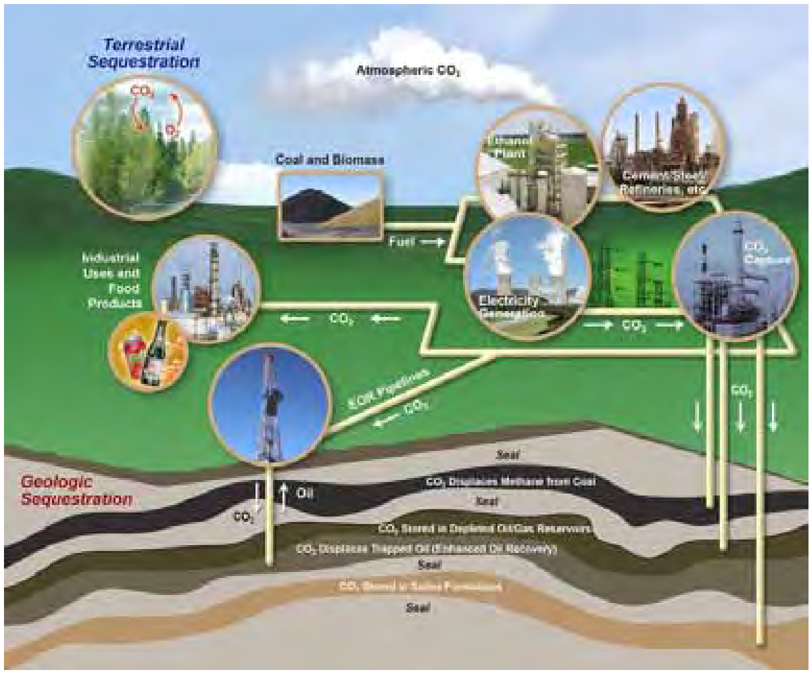
4.3 Coal Energy Technology

The U.S. has an estimated minimum of 261 billion short tons of recoverable coal reserves. Based on EIA projections, consumption of coal will increase at a rate of 1.1% per year until 2035. Thus, without the discovery of new reserves, the current coal supply will last approximately 119 years (Energy Explained, 2011). Abundant supplies and relatively inexpensive extraction costs have resulted in the price of coal being less volatile than either petroleum or natural gas prices, making coal a popular source for electricity generation. However, the burning of coal is a large contributor of GHG and other pollutants. Given growing environmental concerns, the future of coal as an energy source is therefore uncertain. This section of the report discusses new processing and pollution reduction technologies that aim to reduce the environmental impacts of coal usage.

Coal gasification technologies have been a major research and development area. Instead of burning the coal directly, coal gasification requires that the coal first be converted into a gas and then cleaned of a majority of its impurities. The new gaseous fuel, referred to as Syngas, is then converted into electricity similarly to natural gas, resulting in increased efficiencies. With further research and development, it is estimated that the efficiency of future coal gasification plants could reach 60%, compared to current coal plant efficiencies of approximately 30% (U.S. Department of Energy, 2011). The burning of coal in its gas form produces significantly less GHG and particulate pollutants. The process also produces hydrogen gas, which could be used in the development of hydrogen fuel cells. A number of coal gasification electricity plants are currently operating in the U.S. Should the focus on cleaner energy gain more popularity, more research and development into this technology will make it an even more viable option in the future.

CO_2 is the major GHG being released into the atmosphere by the burning of fossil fuels. Approximately one-third of carbon emissions in the U.S. are released by fossil power plants

(Carbon Capture R&D, 2011). If future legislation requires carbon emissions reductions, the price of coal-generated electricity will potentially increase, resulting in coal becoming a less desirable fuel source. Thus, research into the separation and storage of CO_2—e.g., carbon capture and storage (CSS)—has become important over the last several years. CCS involves the separation of CO_2 gas from the other emissions released by power plants and storing the CO_2 in underground geological formations. The CCS process is illustrated in Figure 4.7. The CO_2 gas captured can also be used in CO_2-enhanced oil recovery operations.



Source: Carbon Capture and Storage R&D Overview, 2011

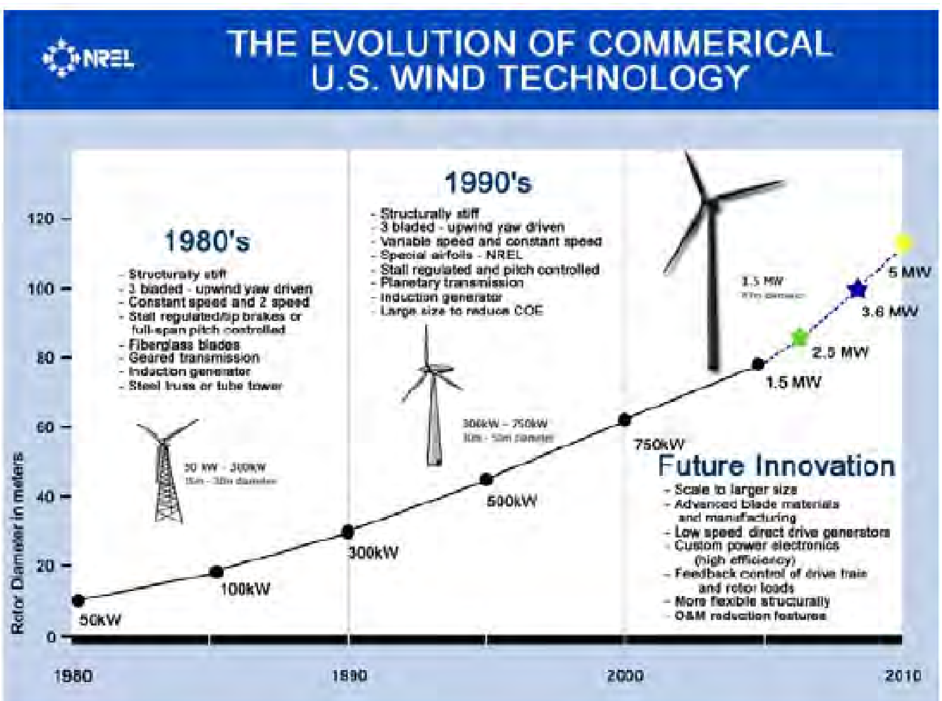
Figure 4.7: Carbon Capture and Storage Cycle

In June 2010, the U.S. Government Accountability Office reported that widespread implementation of CCS technology may not be ready for 10 to 15 years (Gaffigan & Office, 2010). Specifically, the high costs associated with the implementation of coal gasification power plants and CCS has limited the adoption of these technologies. In addition to the cost of building new power plants, retrofitting older ones, and developing the infrastructure and developing storage locations, the technology to gasify coal and separate CO_2 emissions is still very expensive. The future of this technology is thus contingent on economic feasibility and technical research. Nonetheless, two new coal-fired electricity generation plants with CCS technology are planned for Texas with construction hinging on the approval of the air permits. The Tenaska Trailblazer Energy Center near Sweetwater would have a 600 MW capacity, burn imported Powder River Basin coal, consume 10 million gallons of water daily, and capture 85 to 90% of its CO_2 emissions (Susan Combs, 2008). Summit Power's Texas Clean Energy Project (TCEP) will be located in the Permian Basin in Penwell. TCEP will be a 400 MW Integrated Gasification Combined Cycle plant using synthetic gas from gasified coal. Summit Power stated a 90% carbon capture rate for the plant, yielding three million tons of anthropogenic CO_2 to be used for EOR in the Permian Basin (Texas Clean Energy Project, 2010).

Furthermore, over the longer term as environmental awareness increases, federally funded research into these clean technologies holds the potential to reduce future costs. According to FutureGen (2011), Texas has received several research grants over the past few years to study CCS and near-zero-emissions coal power plant technologies. Given this type of investments in clean energy, coal will remain a feasible energy source in the future.

4.4 Wind Energy Technologies

Approximately 11% of ERCOT's installed electricity capacity is wind generated. Current wind turbines are large and extremely heavy, and one trend in future wind technology aims to increase the capacity—and therefore size—of wind turbines. Over the past three decades, an increase in wind turbine power ratings and tower heights have resulted in an increase in the size of the mechanical components. For example, the evolution of rotor diameter size over the past 30 years is illustrated in Figure 4.8. The larger the diameter, the larger the individual components, and the more challenging the transportation of the individual components becomes. Turbine size and structural capacity limitations of the tower foundations have sparked an interest into the development of smaller, lighter wind turbine components. For example, the National Renewable Energy Laboratory (NREL) is developing lighter, stiffer rotor blades, as well as alternative generator configurations with a goal to decrease the overall size of future wind towers (Thresher & Laxson, 2006). Standard 1.5 MW generators have a diameter of approximately 10 meters. Researchers have built a full scale prototype of a generator with the same rating with a diameter of only 4 meters, and they have a preliminary design of a generator with a diameter of 2 meters—a size reduction of 60 to 80% (Thresher & Laxson, 2006)



Source: Advanced Wind Technology: New Challenges for a New Century, 2006

Figure 4.8: Wind Turbine Rotor Diameter Evolution

On the other hand, research has been conducted on alternative self-erection concepts to overcome some of the challenges in erecting and maintaining very large wind turbines (Thresher & Laxson, 2006). Two self-erection concepts are illustrated in Figure 4.9. Additionally, concrete-steel hybrid towers are under development to determine the added costs and benefits. If the research proves the concept feasible, it will facilitate the erection of even larger wind turbines. Although these self-erection turbines will reduce the need for heavy machinery to install and repair the towers, thereby reducing heavy construction traffic, it would potentially increase the number of OS/OW loads required to move the various components to the wind farms.

Source: Advanced Wind Technology: New Challenges for a New Century, 2006

Figure 4.9: Innovations in Tower Construction

Wind energy is notoriously unpredictable, surpassing the capacity of the grid at some points and almost completely ceasing production at others. Thus, wind energy storage is another area of research that is important to the future of wind power in Texas. Currently, large-scale battery facilities, compressed air energy, and hydrogen storage are three key storage technologies that are under development.

Compressed air energy storage (CAES) and hydrogen storage are systems designed to store energy in the form of compressed gas. Several options are available for compressing and storing the gas in CAES. However, for this report, the option of interest involves pumping the compressed gas into large, natural underground formations or large underground storage containers. With CAES, excess power is taken from the grid to run compressors that pressurize the gas to 1,000 to 15,000 PSI (Wind In Reserve, n.d.). With hydrogen storage, excess electricity is taken from the grid to create hydrogen and then pressurize it. The gas and hydrogen can be stored in the underground facility until the electricity demand is greater than what can be produced by wind power, at which time the pressure is released to run a power generator to add power to the grid. CAES technology has been around since the 1970s. It has, however, been gaining popularity given its benefits to the wind energy industry (Gardner & Haynes, 2007). In the case of Texas wind energy, the State Energy Conservation Office (SECO) performed a study in 2005 to determine the applicability of CAES in Texas. This study was able to show that CAES would "significantly improve the delivery profile of renewable energy to the grid, ameliorate the impacts of wind energy on system ramping, [and] provide transmission benefits in excess of the cost of any transmission upgrades required by the CAES plant itself" (Wind In Reserve, n.d.). However, hydrogen storage has yet to be demonstrated on a large scale and thus needs further development before it can be a reliable option (Pieper & Rubel, 2010).

Storing excess energy from wind farms can also be achieved with the use of advanced battery technology. An important innovation in battery technology is the sodium-sulfur battery. Each battery can store approximately 7 MWh of power, with 20 batteries able to provide approximately 1 MW of energy (Biello, 2008). Similarly to CAES, wind energy can be stored during periods of excessive production and released when the demand is high. Currently, this technology is still too expensive to be cost effective. Until more research is conducted on making sodium-sulfur batteries less expensive, alternative battery technologies will continue to be the focus for wind energy storage, especially in Texas. In the spring of 2011, Duke Energy proposed a large-scale battery project at the Notrees Wind Power Project in West Texas. This project, deemed Xtreme Power, will provide the wind farm with a 36 MW capacity battery system to collect excess energy. This project is expected to be operational by the end of 2012 (Energy Matters, 2011). A summary of these storage technologies is provided in Figure 4.10.

	Technological maturity	Key application focus	Site limitations	Public concerns
A-CAES[1]	Partially mature	Mainly for large-scale centralized applications	Most developed countries have the necessary potential storage caverns; Japan and Spain have very few potential sites, however	Little concern expected
Hydrogen storage	Has yet to be demonstrated on a large scale	Generally, very flexible in terms of capacity; particularly suitable for decentralized applications	No specific geological requirements	Potential for safety concerns; however, reference projects are running safely
Stationary batteries	NaS is relatively mature; redox flow remains to be demonstrated on a large scale[2]	Generally, very flexible; particularly suitable for decentralized applications	No specific geological requirements	Few environmental concerns expected except for those related to the disposal of chemicals
Pumped hydroelectric storage	Mature	Very well suited for centralized applications; not yet implemented on a small scale	Europe, including Norway, has a limited number of potential sites left	Potential for environmental concerns, given the profound impact on landscapes

key disadvantage   key advantage

Source: BCG analysis.
[1]A-CAES = adiabatic compressed air energy storage.
[2]NaS = sodium sulfur.

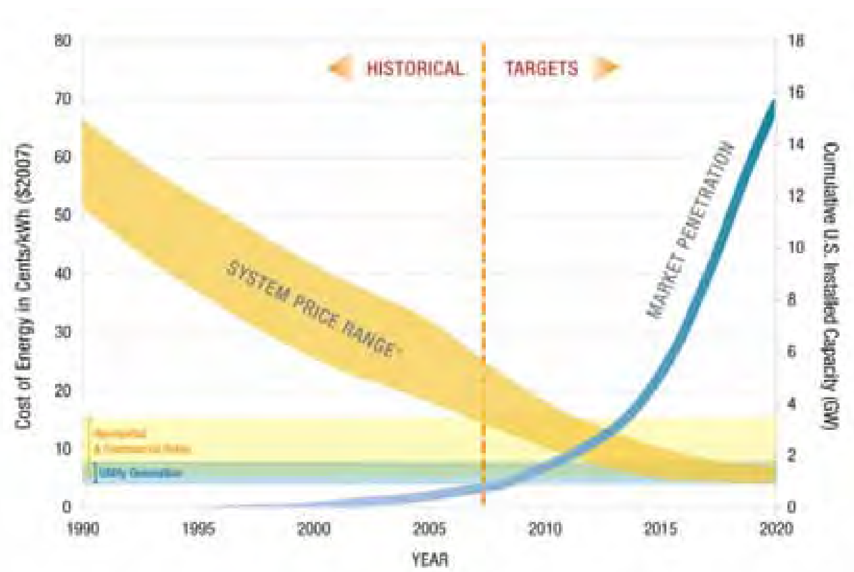
Source: Pieper & Rubel, 2010

Figure 4.10: Large-Scale Storage Technologies

4.5 Solar Energy Technology

According to SECO, Texas has the highest potential for solar power generation in the nation. Two types of solar power are of interest to this project: solar photovoltaic (PV) and concentrated solar power (CSP). Solar PVs are large, flat plates and thin films that are used to convert solar energy directly into electricity. This type of solar energy can be used on a small scale for direct residential use or it can be used on a large scale for utilities. Market PV cells have an efficiency of 12 to 18% and future developments are striving for higher efficiency at lower production costs. Some of the barriers to the more widespread use of this power source include the high initial cost to home owners (in the case of residential applications) and the large land area needed to make it financially feasible for utilities. CSP uses mirrors in an array of shapes and formations to focus the sun's heat energy on a single point to produce steam and electricity. The latter is a utility scale solar technology for regions with high solar flux. Design improvements in high temperature and optical materials, as well as energy storage technologies, will potentially improve the cost effectiveness of CSP (Kimbis, 2008).

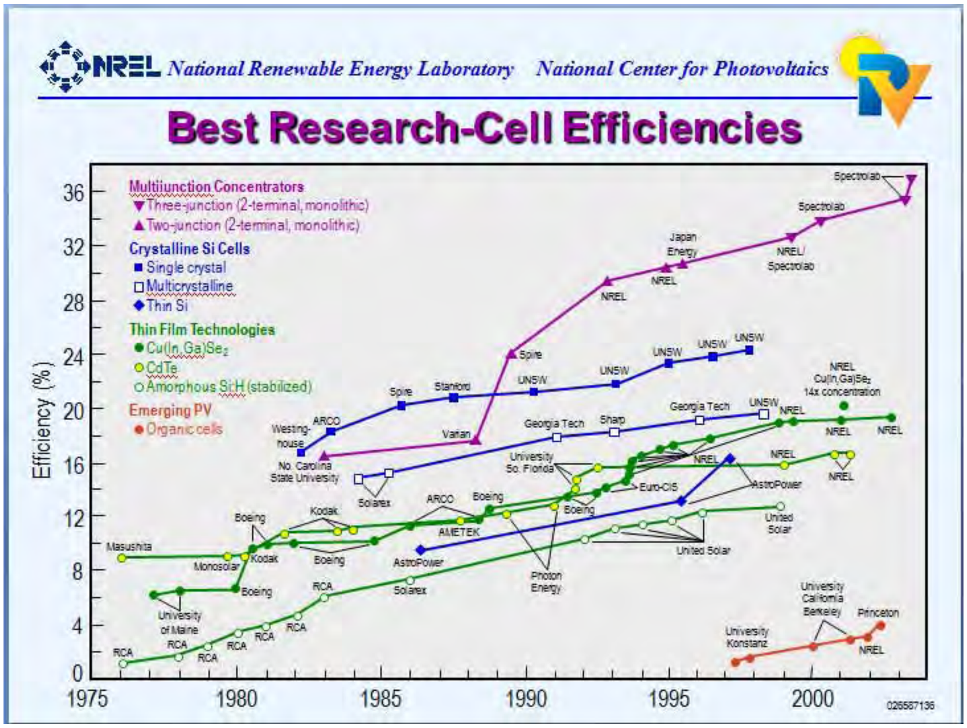
The U.S. Department of Energy has created a Solar Energies Technology Program (SETP) to research, develop, and deploy solar technologies across the nation. According to the SETP, the average system price for solar power has been decreasing over the past 10 years. SETP anticipates that, as solar power research continues, the projected cost and market penetration would continue to decrease and increase, respectively (Kimbis, 2008). The latter is illustrated in Figure 4.11.



Source: Solar Energies Technology Program, 2008

Figure 4.11: Solar System Price and Market Penetration due to SETP Research

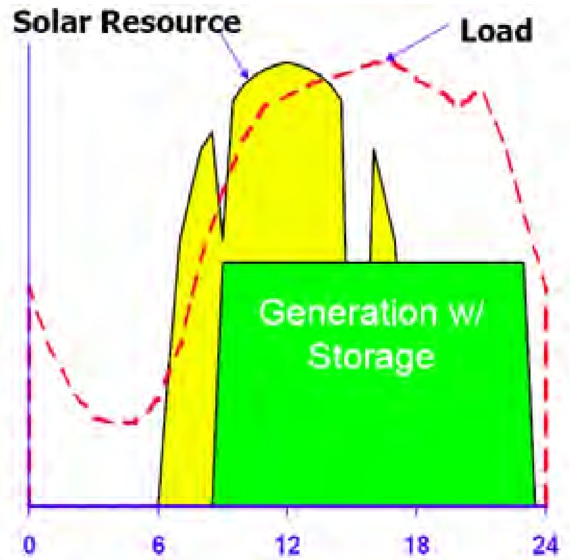
In addition, research cell efficiencies have approached 40% compared to the average efficiency of 12 to 18% (see Best Research Cell Efficiencies-NREL, 2004). If these research cells can be transformed into commercially viable cells, the cost of solar energy would further decrease (see Figure 4.12). Although the cost of solar energy has been decreasing, it is still significantly higher than the current cost of conventional electricity. More research is thus needed to improve the design and reliability of solar power units.



Source: Best Research Cell Efficiencies-NREL, 2004

Figure 4.12: Best Research-Cell Efficiencies

Another barrier to the large-scale deployment of solar power is its intermittency. Incorporating intermittent power into the current electricity grid is challenging and requires upgrades to control systems, as well as energy storage alternatives. Energy storage is especially important to the large-scale CSP projects. In the case of CSP, thermal energy storage (TES) is potentially important (see Figure 4.13). TES uses oil or molten salt as a heat transfer medium in place of water. Instead of heating the water into steam to drive a turbine, the concentrated light transfers its heat into the oil or molten salt, thereby storing it as thermal energy until it is later needed (U.S. Department of Energy, 2011). With TES, a solar power plant can increase its capacity by 25% and better distribute the power to peak energy use times needing to integrate “back up” natural gas electricity production (Kimbis, 2008). In addition to TES, battery storage, CAES, and hydrogen storage are options for storing excess solar energy. These technologies were discussed in Section 4.4, Wind Energy Technologies.



Source: Solar Energies Technology Program, 2008

Figure 4.13: Increasing the Dispatching of CSP Using Thermal Storage

Despite the known difficulties with using solar as an energy source, Texas has a large solar program in place. As of July 2011, Texas has 16 MW of utility scale solar power in operation, with another 90 MW under construction and 340 MW under development (Solar Energy Industries Association, 2011). With advances in these solar technologies, further investment in the future of Texas utility scale solar may be possible.

4.6 Bio-fuel Technology

Ethanol produced from corn grain is a gasoline alternative and bio-diesel from soybeans is a diesel fuel alternative. However, because these biofuels use corn and soybeans as a feedstock, concern has been expressed about the impact of ethanol and bio-diesel production on the food and animal feed markets. In addition, some scientists have argued that the energy required to produce ethanol outweighs any benefits derived from the fuel.

Because of the potential negative impacts on the food and feedstock markets resulting from bio-fuels derived from corn and soybeans, alternative feedstocks have become the focus of recent research. One such alternative bio-fuel that holds great potential is cellulosic ethanol. Non-grain crops and municipal waste can be converted into cellulosic ethanol without impacting the food and feedstock markets. Waste generated from agriculture, forestry, and urban areas can thus be used instead of corn and soybeans. Texas thus has the potential to be a major producer of cellulosic ethanol. The state’s prime agricultural regions include areas along the Gulf Coast, the central Blackland, the High Plains of the Panhandle, and the delta lands near the mouth of the Rio Grande. In addition, waste from the foresting industry, such as bark, wood chips, and sawdust, and urban waste that would otherwise be sent to a landfill abound in Texas. Table 4.3 shows current and potential future feedstock for cellulosic ethanol.

Table 4.3: Potential Cellulosic Feedstock for Future Bio-fuels

Fuel Product	Current Technologies	Available by 2020
	(millions of tons)	
Corn stover	76	112
Wheat and grass straw	15	18
Hay	15	18
Dedicated fuel crops	104	164
Woody biomass	110	124
Animal manure	6	12
Municipal solid waste	90	100
Total	**416**	**548**

Source: Liquid Transportation Fuels from Coal and Biomass, 2009

Some researchers estimate that, if cellulosic ethanol can be mainstreamed, approximately 1.7 million barrels of gasoline equivalent transportation fuel can be produced per day by 2030 nationwide. This translates into a 20% reduction in oil used by light duty vehicles given current consumption levels. In addition, cellulosic ethanol produces less GHG than conventional petroleum fuels (Liquid Transportation Fuels from Coal and Biomass, 2009).

However, although the feedstock for cellulosic ethanol is abundant, the technology to convert the feedstock material into cellulosic ethanol is still largely experimental. As of 2008, the conversion process could only be achieved in the laboratory. Demonstration on a commercial scale will thus largely be the deciding factor as to whether cellulosic ethanol is a viable substitute for corn grain ethanol or conventional gasoline. The Panel on Alternative Liquid Transportation Fuels, who contributed to the America's Energy Future Initiative mentioned previously, predicts that cellulosic ethanol will be commercially deployable by 2020 and fully penetrate the transportation fuel market by 2030 (Liquid Transportation Fuels from Coal and Biomass, 2009).

To further research in this area, government legislation has been passed at the state and national level. For example, in 2007, the Texas Legislature passed House Bill 1090, which authorized $30 million per year for Department of Agriculture grants to farmers and loggers that provide adequate agricultural biomass, forest wood waste, and urban wood waste. In 2008, the U.S. Congress passed the Food, Conservation and Energy Act—the U.S. Farm Bill—to support the commercialization of advanced bio-fuels, including ethanol, and the production of crops that can be used to generate biomass energy (SECO, 2010). Specifically, the Volumetric Ethanol Excise Tax Credit (VEETC) and a $0.54 per gallon ethanol tariff on imported ethanol are incentives for the domestic ethanol market. The VEETC provides a $0.45 per gallon tax credit for ethanol blenders and is a key component in keeping ethanol prices competitive[6] (SECO, 2010). Given further government support, biomass fuels may thus become a more viable alternative transportation fuel (Liquid Transportation Fuels from Coal and Biomass, 2009).

[6] A study commissioned by the Renewable Fuels Association in 2010 estimated that elimination of the ethanol tax incentive would result in a 17.8% decrease in the net revenue of ethanol producers, causing some producers to reduce or cease operations. The latter could amount to a 38% reduction in domestic ethanol output, equating to about four billion gallons (State Energy Conservation Office, 2010).

4.7 Nuclear Technology

Nuclear energy constitutes a clean source of electricity and represents approximately 10% of Texas's energy produced per year. Texas has two operating nuclear power plants: Comanche Peak in Somervell County and the South Texas Project in Matagorda County. Unlike biomass and other forms of renewable energy, no major research and development needs to be conducted to deploy nuclear power. Several issues, however, surround the widespread use of nuclear. The two main issues are cost and public concern about radiation exposure. The future of nuclear thus depends on decreasing construction costs, public education about the risks involved, and successful experiences (National Academy of Sciences, National Academy of Engineering, National Research Coucil, 2009).

The America's Energy Future Initiative estimated that by 2020 U.S. nuclear power generation can increase between 12 and 20% given the addition of new plants and upgrades to existing plants. However, 24% of the U.S's current nuclear capacity will be retired by 2035, including the four reactors in Texas. Assuming support for the development of nuclear energy, it is estimated that five plants can be constructed per year between 2026 and 2035—more after that if the construction proceeds well. Building a nuclear power plant is, however, extremely expensive. Investments in future plants will be limited if cost overruns occur or if the electricity produced is not competitive in the market. The future of nuclear thus partially depends on the experiences that companies will have in the next few years (National Academy of Sciences, National Academy of Engineering, National Research Coucil, 2009).

A major obstacle with nuclear power is nuclear waste disposal. Each energy-producing industry produces waste. Coal, wood, and petroleum-based energy cycles all release GHG as well as waste particulates into the atmosphere. This is also the case with nuclear energy. However, because of the radioactive characteristics of the waste, special precautions must be taken to protect the environment and population. After the nuclear fuel is spent, the waste must be contained on site in a deep pool of water or a dry concrete bunker for up to 50 years to allow for most of the harmful radiation to wear off. After the radioactivity has been brought to a manageable level, the fuel needs to be transported to a storage facility—typically naturally occurring, underground formations—where it will be isolated from the environment for at least 1,000 years. Currently, no such facilities exist for the long-term storage of nuclear wastes. In 1987, after extensive research on locations for a waste site, Congress settled on Yucca Mountain, Nevada. However, due to budget overruns, objections from neighboring populations, and changes to radiation regulations, the future of Yucca Mountain as a waste site is uncertain (Timeline — The Nuclear Waste Policy Dilemma). Without a site for long-term disposal of nuclear waste, the stockpiles of spent fuel continue to grow and increase uncertainty about the future of nuclear power as an energy source.

Another major obstacle that nuclear energy faces is public concern about radiation exposure. Incidents such as those at Three Mile Island, Chernobyl, and Fukushima Daiichi have left a lasting impression on the public that nuclear energy is very dangerous. Specifically, the recent disaster involving the Fukushima Daiichi power plant in Japan in March 2011 that resulted in radiation leakage has spurred a safety review all U.S. nuclear power plants by the U.S. Nuclear Regulatory Commission. Prior to this disaster, six new nuclear reactors were planned to be constructed in Texas over the short term. However, the planning process has either been suspended or reduced in scope for four of the six reactors. The future of these projects is thus largely unknown. The only project that is moving ahead is the expansion of the Comanche Peak nuclear power plant (Hamilton, 2011).

4.8 Concluding Remarks

Technology advancements offer the potential to (a) increase the supply of natural gas production in Texas; (b) provide more robust information about reservoirs and increase the tertiary oil recovered in the Permian Basin; (c) remediate environmental concerns concerning the use of coal as an energy source; (d) increase wind turbine power ratings and improve wind energy storage; (e) decrease the cost and improve the efficiency of solar technologies; and (f) move the experimental production of cellulosic ethanol to viable commercial production. The next chapter illustrates the trend in energy prices and provides information about anticipated future energy prices.

Chapter 5. Energy Price Trends

An important driver to consider is the trend in energy prices. This chapter provides information on historic energy price trends on anticipated future energy prices.

5.1 Historic Energy Price Trends

Figures 5.1 to 5.9 illustrate several price trends by energy source. Figure 5.1 illustrates energy prices by source in the U.S. between 1989 and 2008.

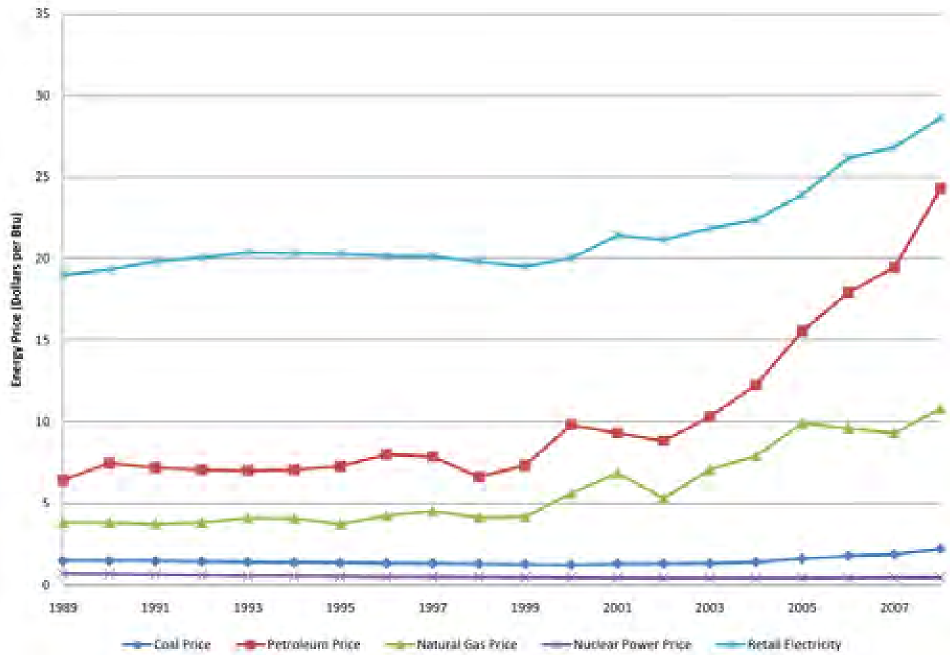


Figure 5.1: Energy Prices, 1989–2008

Figure 5.1 indicates that the price of petroleum and electricity increased substantially in the U.S. since 2002. The price of natural gas increased between 2002 and 2005 but declined in 2006 and 2007 before increasing again in 2008. The price of coal increased marginally between 2003 and 2008, while the price of nuclear power remained constant between 1989 and 2008.

Figure 5.2 illustrates the price of coal in the U.S. and domestic coal production between 1989 and 2007. Figure 5.2 evidences that the U.S. coal price decreased between 1989 and 1999, while domestic production was only marginally lower in 1999 compared to 1989. On the other hand, the price of coal increased sharply between 2003 and 2007 at a time when coal production declined substantially.

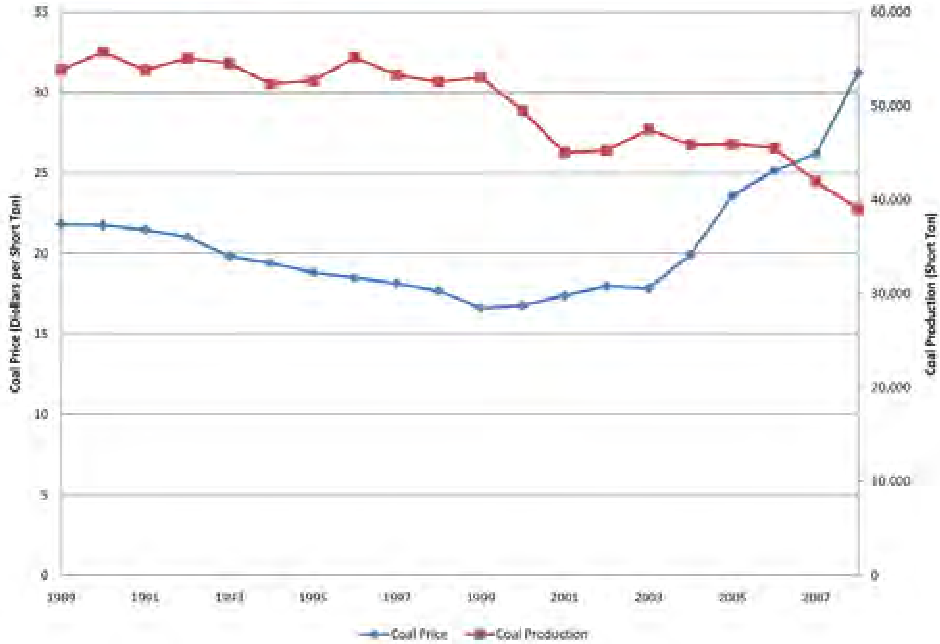


Figure 5.2: Coal Price and Domestic Coal Production

Figure 5.3 illustrates the price of petroleum and domestic crude oil production between 1989 and 2007. Figure 5.3 indicates that domestic crude oil production has been declining between 1989 and 2005—after which it has remained relatively constant. This trend may be partially attributable to the sharp increase in the price of petroleum since 2002.

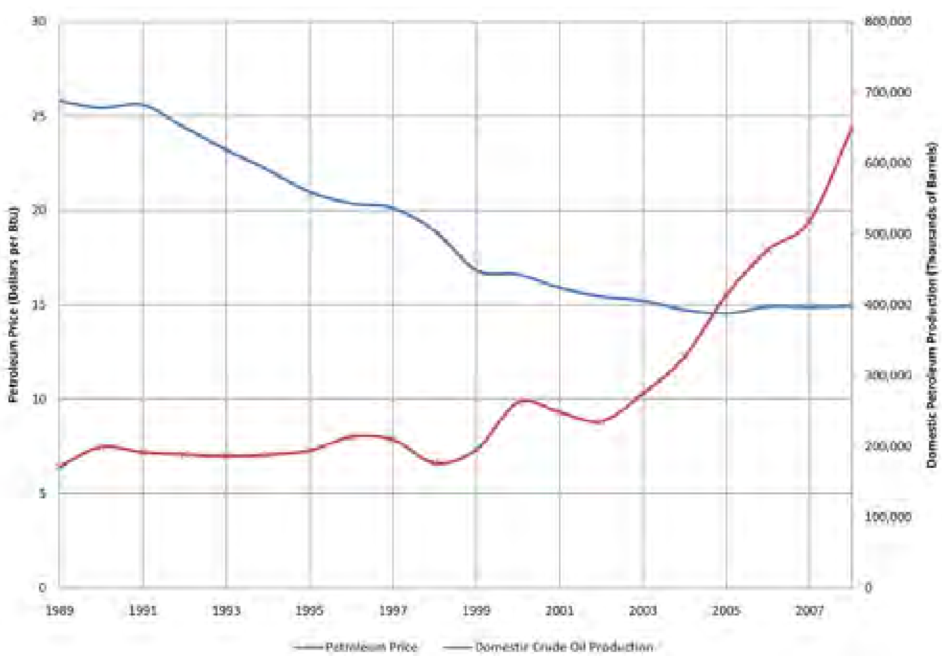


Figure 5.3: Petroleum Price and Domestic Crude Oil Production

Figure 5.4 illustrates residential electricity consumption and the price of electricity between 1989 and 2007, showing that both the price of residential electricity and residential electricity consumption has been generally increasing between 1989 and 2007.

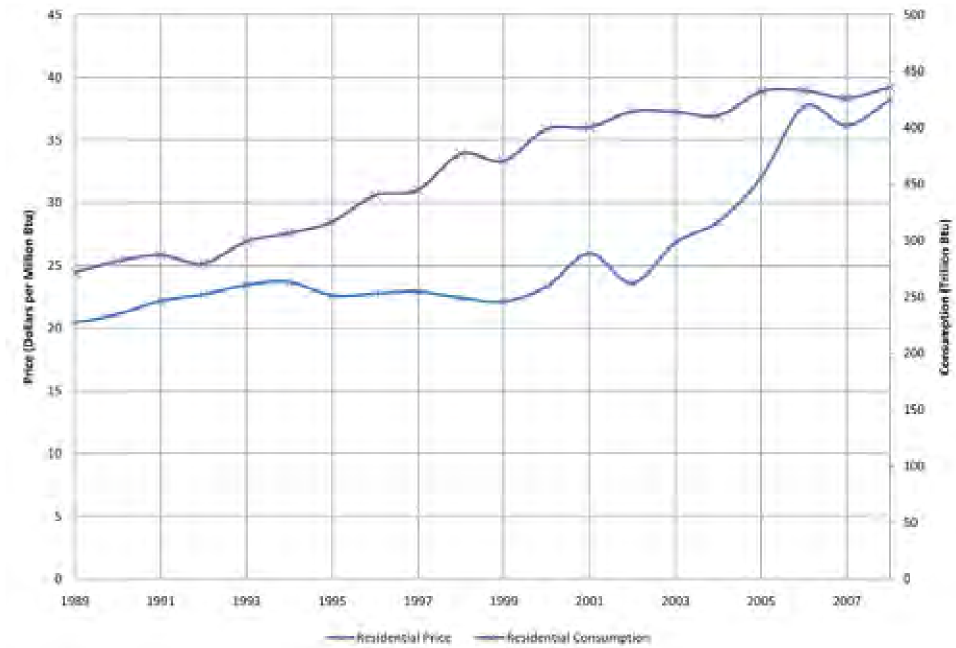


Figure 5.4: Residential Electricity Consumption and Price

Figure 5.5 illustrates commercial electricity consumption and the price of electricity between 1989 and 2007. Although exhibiting more fluctuation—similar to residential electricity consumption—both commercial electricity consumption and the commercial price of electricity increased between 1989 and 2007.

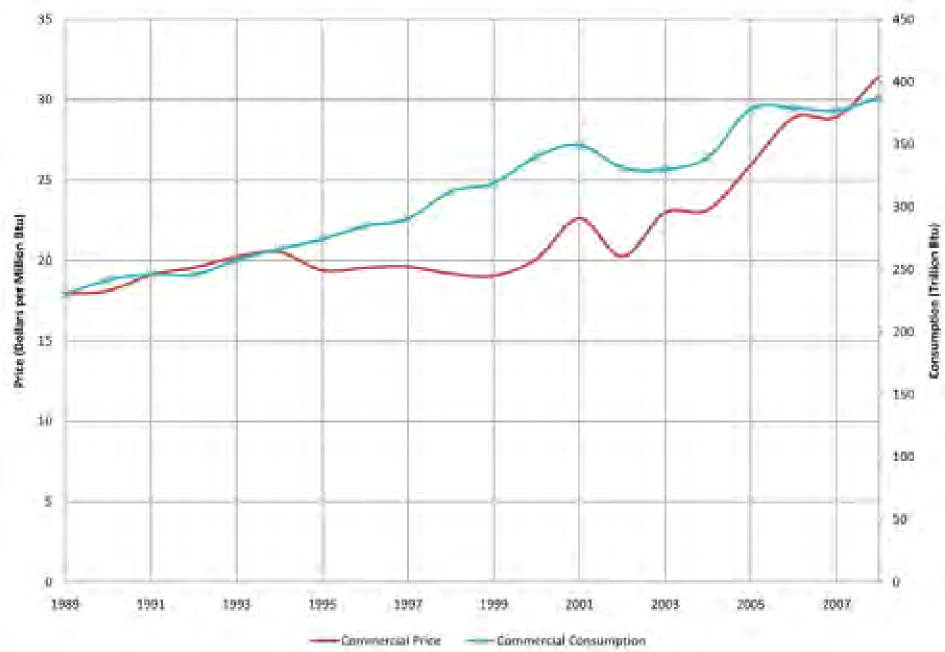


Figure 5.5: Commercial Electricity Consumption and Price

Figure 5.6 illustrates industrial electricity consumption and the price of electricity between 1989 and 2007. Although industrial electricity consumption and the price of electricity also show generally increasing trends, Figure 5.6 makes clear that industrial electricity consumption is more sensitive to the price of electricity. For example, 2002 saw a clear reduction in industrial electricity consumption given the increase in the price of electricity in that year.

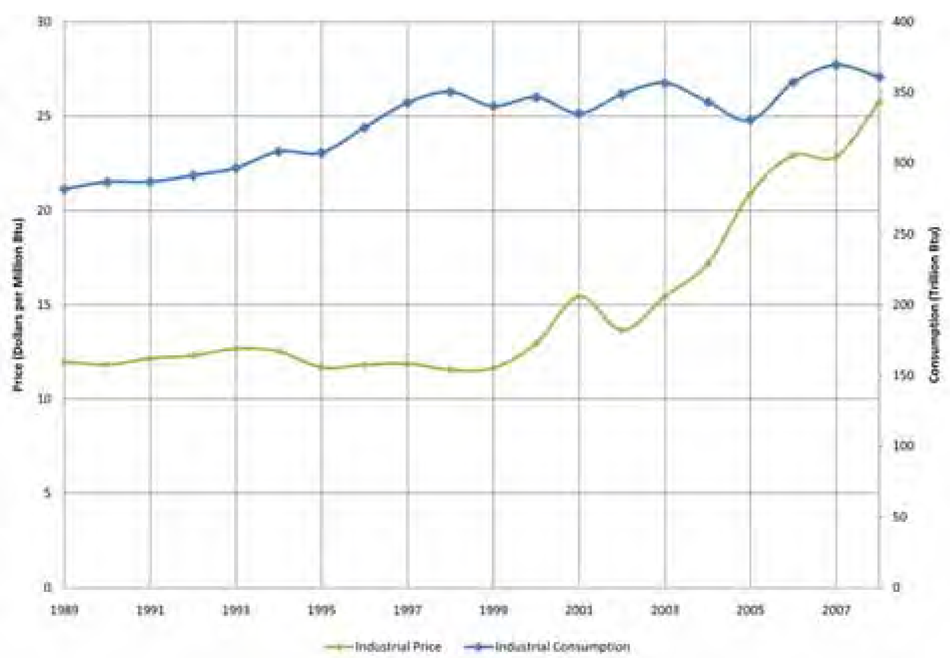


Figure 5.6: Industrial Electricity Consumption and Price

Figure 5.7 illustrates the retail price of electricity by sector (i.e., residential, commercial, and industrial) between 1989 and 2007. Figure 5.7 clearly demonstrates the significant increase in the retail price of electricity for all sectors between 2002 and 2005 after a decade of relatively constant electricity prices between 1989 and 1999.

Figure 5.7: Retail Electricity Price by Sector

Figure 5.8 illustrates the price of natural gas and domestic natural gas production between 1989 and 2007. Although the price and domestic production of natural gas in the U.S. has seen substantial fluctuation, a general increase in both the price and production of natural gas is evident between 2004 and 2007.

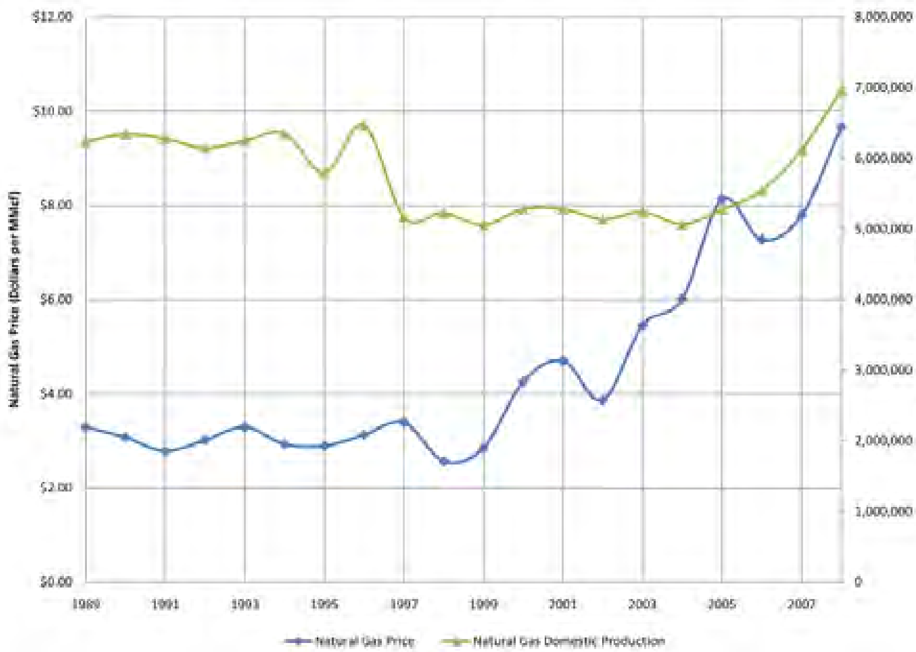


Figure 5.8: Natural Gas Price and Domestic Production

5.2 Anticipated Energy Price Trends

The EIA compiles the AEO that contains information about the energy future of the U.S. and the states. The AEO 2010 includes price projections by energy source until 2035, given different scenarios. Figures 5.9 to 5.12 provide the anticipated average price for electricity, natural gas, motor gasoline, and the price of coal, respectively, between 2007 and 2035.

Figure 5.9: Average Electricity Price, 2007–2035

Figure 5.9 and Figure 5.10 indicate that the average price of electricity and the average natural gas price are anticipated to increase substantially between 2007 and 2035 irrespective of the scenario. Because a substantial share of electricity is produced from natural gas, this trend is to be expected.

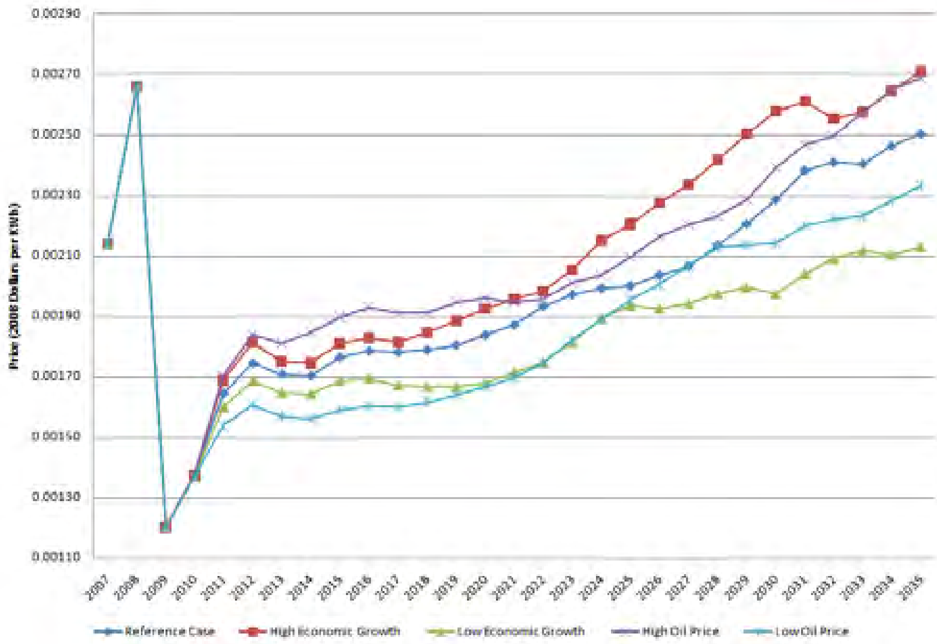


Figure 5.10: Average Natural Gas Price, 2007–2035

Figure 5.11 illustrates the anticipated trend in the average price of motor gasoline between 2007 and 2035. Figure 5.11 evidences that three of the four scenarios anticipate an increase in the average price of motor gasoline—the exception being the low oil price scenario. Also, Figure 5.10 indicates that the high economic growth, the Reference Case, and the low economic growth scenarios predict a substantially lower average motor gasoline price than the high oil price scenario.

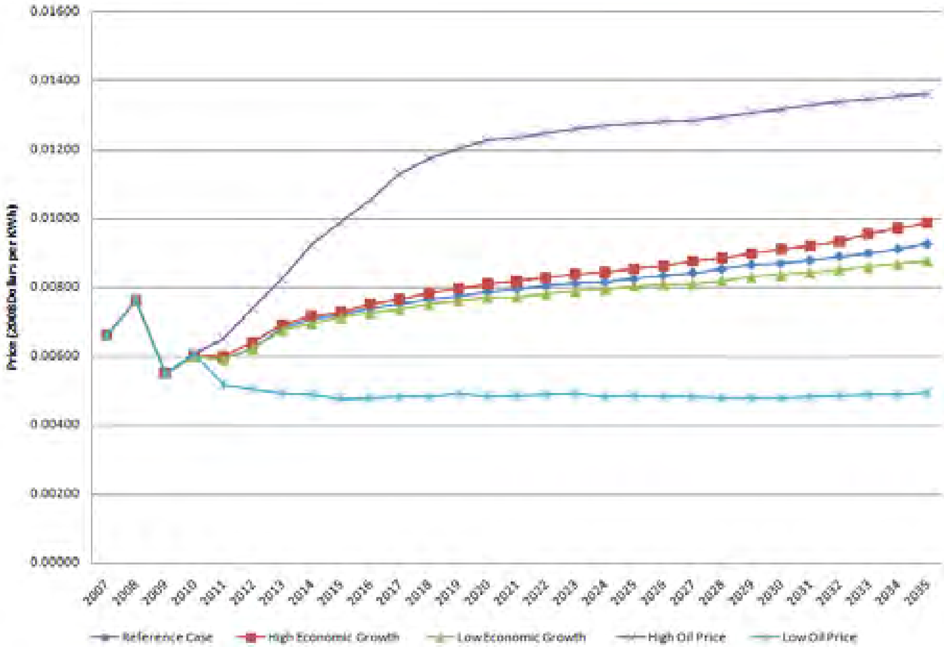


Figure 5.11: Average Motor Gasoline Price, 2007–2035

Figure 5.12 illustrates a generally anticipated increase in the price of coal given all four scenarios—albeit a lower increase in the price of coal under the low oil price scenario. The highest increase in the price of coal is anticipated in the high oil price scenario.

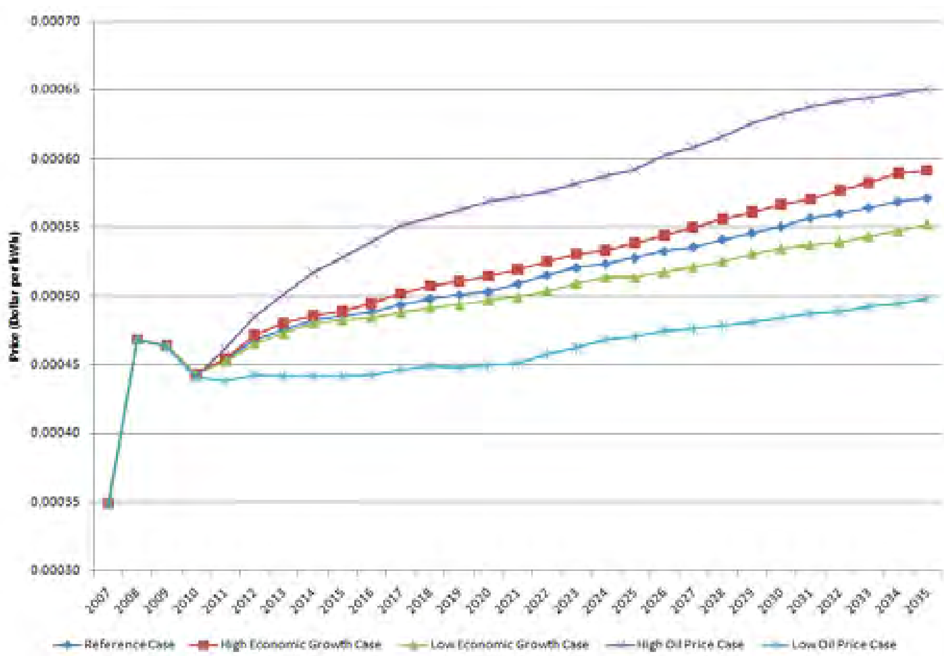


Figure 5.12: Average Price of Coal, 2007–2035

Historic trends have shown a relationship between natural gas electricity generation and the price of oil. Typically, an increase in oil prices has resulted in the substitution of petroleum products for natural gas, thereby increasing natural gas demand. Also, because natural gas is often a byproduct of oil extraction, crude oil price increases often lead to increased natural gas prices and thus a significant flow of cash into the natural gas market. Increasing cash flows facilitates more drilling and the development of additional natural gas projects, resulting in a futher increase in natural gas production (EIA, 2010). Figure 5.13 illustrates ERCOT's projections for future electricity generation from natural gas given the price of distallate and residual fuel oil.

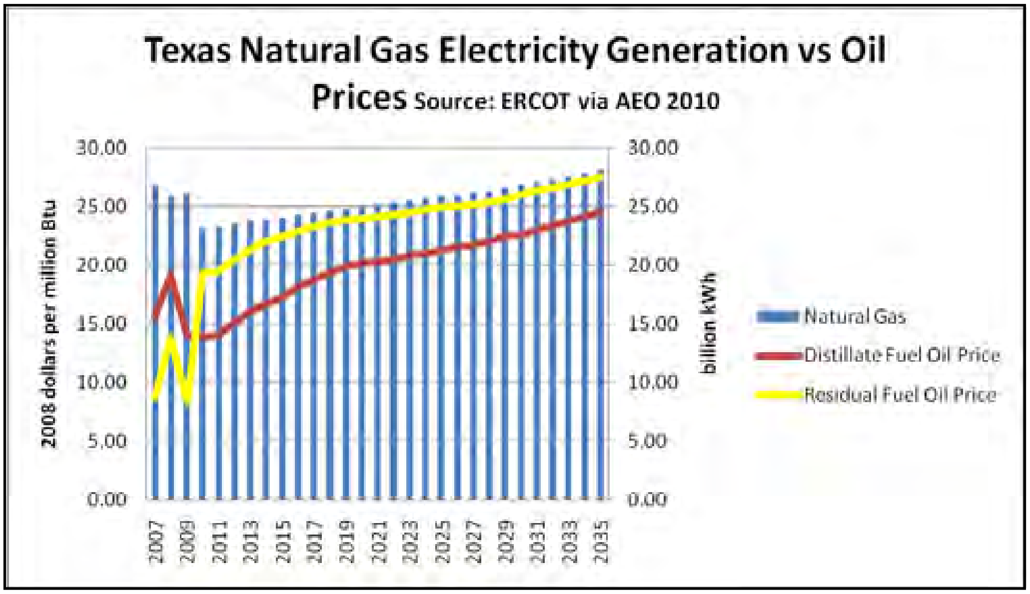


Figure 5.13: Natural Gas Electricity Generation in Texas Given the Oil Price through 2035

Figure 5.13 indicates that an anticipated increase in the price of distillate and residual oil through 2035 will result in the increased use of natural gas for electricity generation in Texas (EIA, 2010). Given Texas's abundant natural gas resources, it can thus be hypothesized that increasing oil prices will also result in increased natural gas extraction in the state.

Figure 5.14 illustrates ERCOT's estimates of electricity generated from wind and anticipated Gulf Coast oil and natural gas prices through 2035. Specifically, ERCOT anticipates that Gulf Coast oil prices will increase to $123 per barrel by 2035 and that Gulf Coast natural gas prices will reach $8 per thousand cubic feet by 2035 (Annual Energy Outlook 2010, 2010). The increased oil and natural gas prices will provide an impetus for deriving electricity from wind. Figure 5.14 indicates that ERCOT projects that wind energy will generate about 24 billion kWh of electricity between 2010 and 2035 (EIA, 2010).

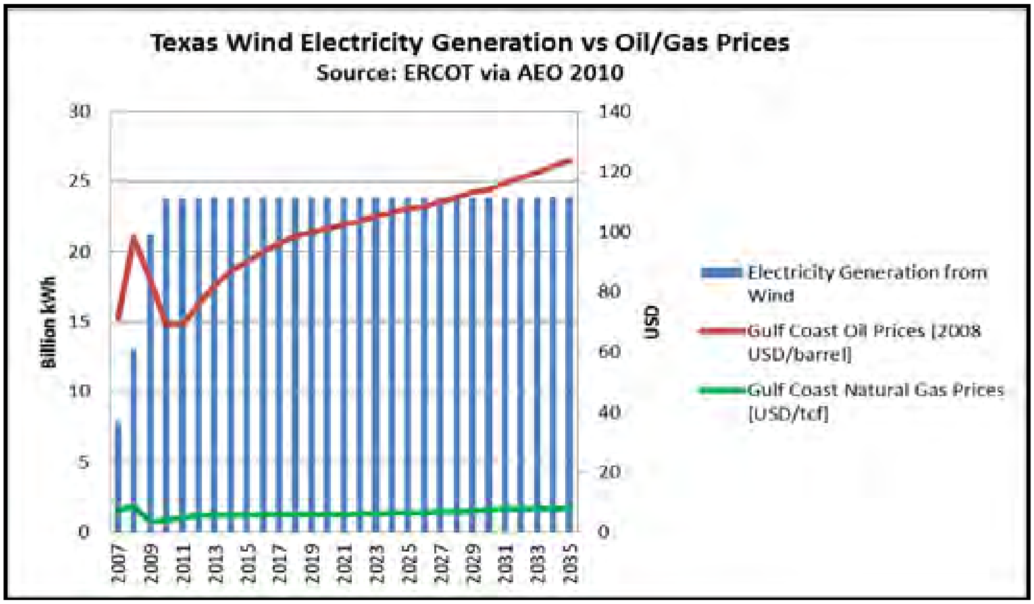


Figure 5.14: Wind Electricity Generation in Texas Given Gulf Coast Oil and Natural Gas Prices through 2035

5.3 Concluding Remarks

This chapter illustrated that energy prices have been increasing since 2002 and are largely anticipated to continue to increase in the future given all four scenarios—i.e., high economic growth, low economic growth, high oil price, and low oil price—of the EIA's AEO. The exception is the average price of motor gasoline under the low oil price scenario. The next chapter provides information about the socio-economic impacts of Texas's energy sector.

Chapter 6. Socio-Economic Impacts of the Energy Sector

Since the beginning of the 20th century, energy production has played an important role in the development of Texas and has shaped the economic base of many communities throughout the state. Concurrent with the development of new forms of energy, primarily wind, Texas is currently experiencing a boom cycle in oil and gas drilling activity not seen since the early 1980s. In 2007, over 20,000 wells were drilled in Texas, which were the most holes drilled within a year since 1985 (Texas Renewable Portfolio Standard). The purpose of this chapter is to analyze the socio-economic impacts of energy development on Texas communities. The analysis was limited to the impacts of oil and gas production (primarily drilling activity) and wind energy due to their relative size and likelihood of continued widescale development within Texas. In this chapter, the socioeconomic impacts and the framework within which these impacts are measured are first defined, followed by an overview of the demographic and socioeconomic characteristics of the oil and gas industry labor force. A discussion of the potential demographic and economic consequences of energy development in regions within Texas is subsequently provided. Next is a case study analysis of selected counties impacted by energy developments. These case study counties are compared to counties with similar characteristics with the exception of energy development. This general outline is then repeated for the wind energy sector.

The broad scope and multiple dimensions of this study limited the research team's ability to understand all of the potential impacts to communities. In addition, except for a few cases, oil and gas production is occurring in or near areas of previous production. Even though the new technologies may present new challenges for and impacts on local areas, the infrastructure for oil and gas development (in both physical and human capital) is already in place and thus the impacts are limited to those experienced within a boom cycle. Wind farms are located primarily in areas in West Texas—the same areas where oil and gas production is occurring. In addition, data on this nascent industry is limited. Finally, both the development of wind farms and oil and gas production have occurred only recently (since 2005) and thus the full impacts of these developments have not been felt and the data on many dimensions are not available.

6.1 Framework for Understanding Socio-economic Impacts from Energy Development

Socio-economic impacts refer to those that affect (a) the social organization and interactions within a community; (b) the economic well-being of an area (such as changes in employment and local business income); and (c) the size, distribution, and composition of local populations (Murdock & Leistritz, 1979). Socio-economic impacts include direct economic impacts from the new activity (such as the development of a new wind farm) and additional economic, fiscal, and social impacts brought about by changes to a community as a result of the direct activity. These impacts include changes in the business activity, public sector demand, governmental finances, and social organizations (such as changes in local leadership). New economic activity may increase tax revenues to local governmental entities but may also bring about increased demand for governmental services that may or may not be covered by the increases in tax revenues. The full extent of the demand is dependent upon the changes (if any) in the population—including the rate of change in the total population, changes in the composition of the population (age, sex, family, and household characteristics), and changes in settlement patterns. Finally, impacts of development are typically felt in the early stages of development and less so over time.

While the development of new wind farms and oil and gas wells may provide an overall positive impact on a community, not all impacts are positive. In addition, impacts must be understood within the context of the geographical areas in which the impact is felt. Drivers commuting on local roads near gas fields and experiencing increased truck traffic may perceive the impact of gas development to be negative while those employed within the industry may perceive that same impact to be positive. Still others may not perceive any impacts because they are travelling on roads far from the drilling areas.

Two general frameworks have been used to analyze the socio-economic impacts of energy development: the boomtown model and a model of more diffused socio-economic impacts. Much of the socio-economic impact literature can be traced to the 1970s and early 1980s when many rural communities in western states were experiencing rapid population growth as a result of the development of new energy discoveries (Albrecht, 1978; Murdock & Leistritz, 1979). Rural communities experience rapid population growth (typically 10 to 15% per year), which, in turn, affects the social structure of the community. These rapidly growing populations increased demand for services that were not necessarily covered by the new energy development (Murdock & Leistritz, 1979; Freudenberg, 1982; Leistritz & Murdock, Local Economic Changes Associated with Rapid Growth, 1982). While new developments in some communities may bring about population changes such as those of a boomtown model (as experienced by communities in the Eagle Ford play), much of the current energy development is occurring in rural areas of previous energy development (and thus the human capital and physical infrastructure is in place) or within metropolitan areas with more diverse economies. In addition, drilling crews in these new developments may commute from other areas and remain in the local community only temporarily. Thus the impacts may not be as great (and have a more diffused impact) than those felt within a boomtown (Wynveen, 2011; Gramling & Brabant, 1986).

6.2 Socio-Economic Impacts of Oil and Gas Drilling

The oil and gas industry is integrated across several sectors of the economy, to include extraction, manufacturing, distribution, transportation, and wholesale and retail trade. Measuring the full impacts of the industry in Texas and in communities in Texas would require a much larger task than that presented here. In this section, as much as possible, the analysis was limited to the impacts of drilling activity in local areas. The sectors in this portion of the industry include (a) oil and gas extraction, (b) drilling oil and gas wells, (c) support activities for oil and gas operations, and (d) oil and gas pipeline and related structures construction.

The following sections break down the oil and gas industry into job codes from the North American Industry Classification System (NAICS): “the standard used by federal statistical agencies in classifying business establishments for the purpose of collecting, analyzing, and publishing statistical data related to the U.S. business economy.”

6.2.1 NAICS 211, Oil and Gas Extraction

This subsector includes establishments involved in the exploration of crude oil and natural gas (including oil or gas extracted from sands and shale) and in all activities related to the drilling, completion, and equipping of oil and gas wells or other activities related to the preparation of oil and gas up to the point of distribution from a producing property.

Establishments in this sector operate oil and gas wells for others on a contract basis or on their own account.

6.2.2 NAICS 213111, Drilling Oil and Gas Wells

Establishments in this subsector drill (i.e., drilling, redrilling, spudding, and directional) for oil and gas on a contract fee basis.

6.2.3 NAICS 213112, Support Activities for Oil and Gas Operations

Establishments in this subsector provide support services for oil and gas operators on a contract fee basis (excluding site preparation and construction). These establishments can be involved in activities such as exploration (excluding geophysical surveying and mapping); excavating slush pits and cellars; well surveying; running, cutting, and pulling casings, tubes, and rods; cementing wells; shooting wells; perforating well casings; acidizing and chemically treating wells; and cleaning out, bailing, and swabbing wells.

6.2.4 NAICS 23712, Oil and Gas Pipeline and Related Structures Construction

Establishments in this subsector construct oil and gas pipelines, mains, refineries, and storage tanks. These establishments may be engaged in the construction of new lines or the repair or reconstruction of old lines. Specialty trade contractors may be included in this subsector if their primary activities are related to oil and gas pipeline construction. Establishments involved in the construction of any structures that are integral parts of the oil and gas network (e.g., storage tanks, pumping stations, and refineries) are included in this subsector.

Table 6.1 shows the major occupations and average wages for workers in the oil and gas drilling and support industry. Wages at the low end of the occupational scale are more than double that of the national minimum wage of $7.25 an hour. Drilling workers are primarily male and younger than in the overall oil and gas industry. According to estimates derived from the American Community Survey of 2005–2009, the median age for drilling related workers in Texas was 36.6 and 44% of these workers were under the age of 35 (see Figure 6.1). This figure compares to a median age of 42 for the oil and gas industry as a whole (and a median age of 38.7 for all workers in Texas). Thirty-three percent of all workers in the oil and gas industry were below the age of 35 while 39% of all workers were below the age of 35.

Drilling-related workers and workers in the oil and gas industry as a whole are more likely to be married than all workers. An estimated 63% of drilling related workers and 69% of oil and gas industry workers were married in the 2005–2009 period, compared to 55% of all workers in Texas (see Table 6.2). These age and marital characteristics of the workforce impact family characteristics. Although not statistically significant, drilling related workers had larger average family sizes (3.1) than the industry as a whole (2.9) and all workers combined (3.0). This means that, on average, drilling-related workers in Texas support 2.1 additional people.

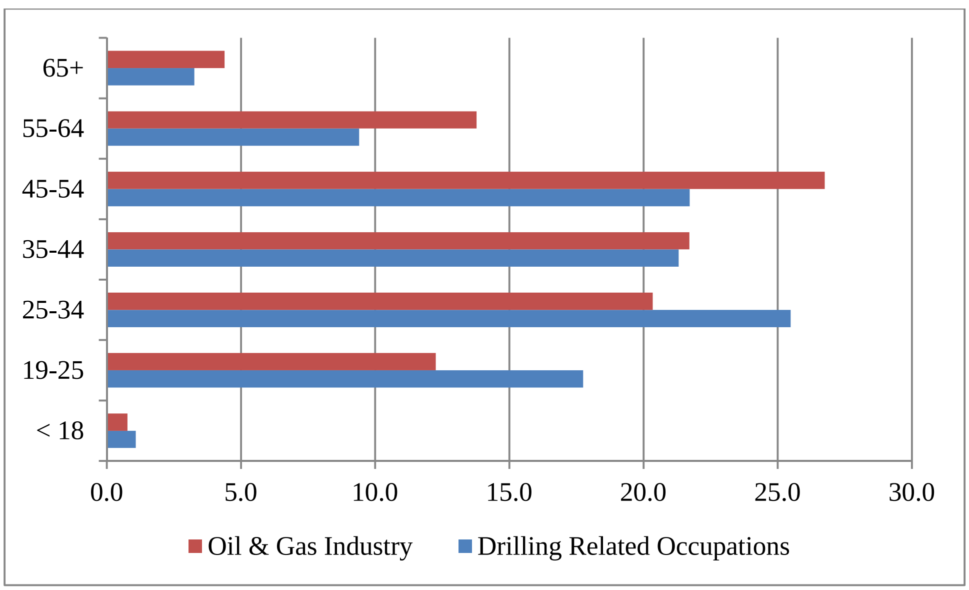
The impact on local communities is dependent upon the numbers of wells drilled nearby and the number of workers employed. The actual numbers may vary according to the well location and many people may be involved in some aspect of well drilling and completion. According to surveys of natural gas companies operating in the Marcellus Shale play in Pennsylvania, on average, 13 full time equivalent (FTE) workers are involved in the drilling and completion of one gas well (Jacquet, 2011; Marcellus Shale Education Training Center, 2009;

Marcellus Shale Education and Training Center, 2010).[7] Once wells are completed, an estimated 0.18 employees per well are needed to manage wells during the production phase.

Table 6.1: Major Occupations and Wages in the Oil and Gas Drilling Industry

Occupation	Oil and gas extraction	Support activities for mining
General and operations managers	$53.57	$46.43
First-line supervisors/managers of construction trades and extraction workers	$31.58	$30.42
Operating engineers and other construction equipment operators	$25.30	$17.58
Service unit operators, oil, gas, and mining	$22.56	$17.70
Helpers—extraction workers	$16.06	$16.39
Truck drivers, heavy and tractor-trailer	$16.99	$15.99
Rotary drill operators, oil and gas	$22.01	$24.23
Derrick operators, oil and gas	$19.97	$20.25
Wellhead pumpers	$19.28	$17.63
Roustabouts, oil and gas	$15.21	$14.78

Source: BLS, Career Guide to Industries, 2010–11 http://www.bls.gov/oco/cg/cgs004.htm, BLS Occupational Employment Statistics, May 2008



Source: American Community Survey, 2005–2009 IPUMS

Figure 6.1: Age Characteristics of Employees in Drilling Occupations and the Oil and Gas Industry as a Whole

[7] A full time equivalent worker (FTE) is equivalent to one worker working full time for a year.

Table 6.2: Marital Status of Workers by Percent of All Workers within Selected Groups

Marital Status	Drilling Related Workers	Oil & Gas Industry Workers	All Workers
Married, Spouse Present	59.2	63.1	51.4
Married, Spouse Absent	4.1	2.9	3.2
Single, Never Married	22.0	18.7	28.5
Single, Once Married*	14.7	15.3	16.9
Number of Workers	95,132	211,232	13,834,648

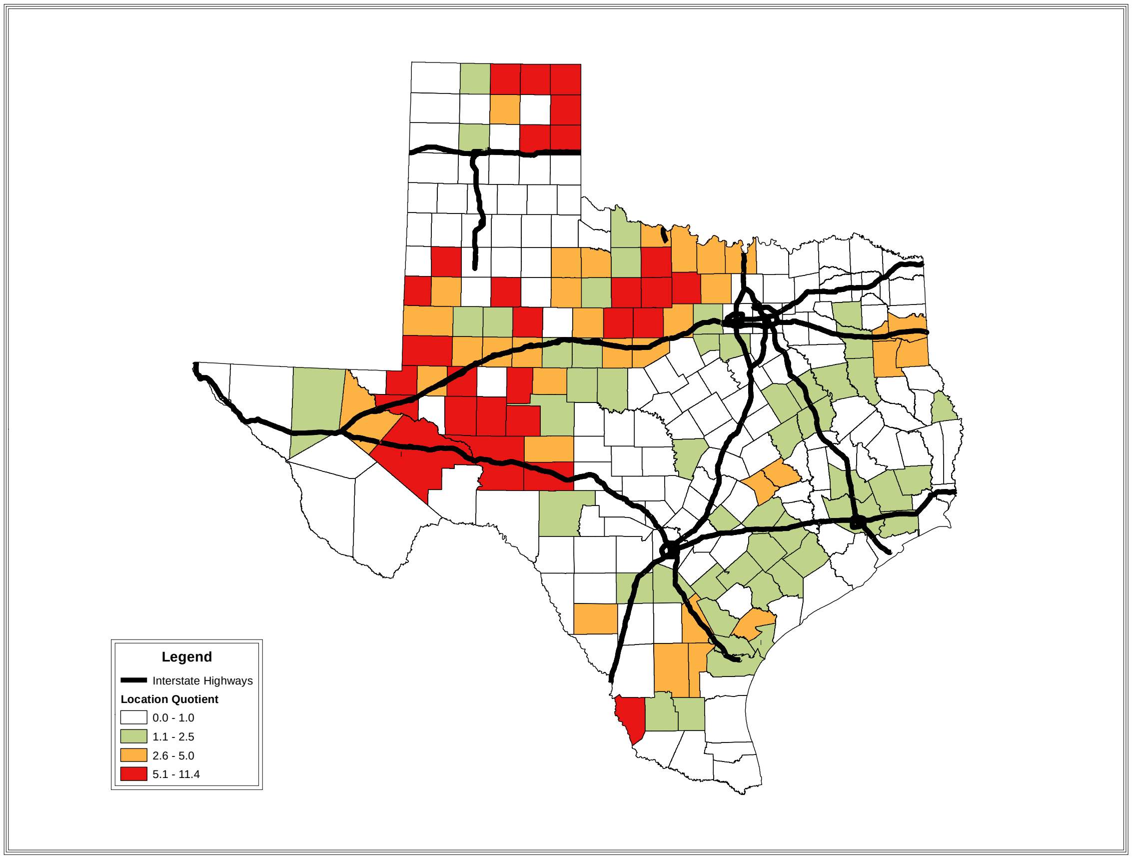
*Includes divorced and widowed.

Source: Ruggles et al. American Community Survey, 2005–2009 IPUMS

6.2.5 Regional Impacts of Oil and Gas Drilling

New shale plays have extended the reach of oil and gas producing regions. At the same time, increases in oil and gas prices have led companies to re-work fields previously abandoned using hydraulic fracturing and CO_2 injection techniques. One way to understand the regional and local economic impacts is to measure the relative size of an industry in a local county to the state or nation as a whole. Location quotients are one way of understanding these relative sizes. Figure 6.2 shows the location quotients for mining employment in counties in Texas.[8] Counties with location quotients greater than 1 have greater employment in mining than the state as a whole. Counties with specialization in mining employment are located in the Permian Basin, in the Barnett Shale region near Fort Worth, in the gas fields in the northeastern Panhandle region, and in developed oil fields and new shale plays in East and South Texas. The impacts of development in the Permian Basin and Barnett Shale regions are discussed in the following section.

[8] Mining employment includes oil and gas extraction as well as mining of other mineral deposits such as gravel, stone, coal, and graphite. However, in most counties in Texas, this broad industry consists primarily of oil and gas workers. One exception to this is Burnet County in central Texas. Burnet County has a higher location quotient for the mining industry, primarily as a result of employment in graphite and stone quarries in the county.



Source: Bureau of Economic Analysis, Regional Economic Information System, 2011

Figure 6.2: Location Quotients for Mining Employment (2009)

6.2.6 Population Change in the Permian Basin and Barnett Shale Regions

In the Permian Basin region, 15 of 27 counties gained population between 2000 and 2010 (see Table 6.3). Overall, the Permian Basin region saw an increase of 42,000 people between 2000 and 2010 (a 9.5% increase). Most of that population growth occurred in the metropolitan counties of Midland and Ector (Odessa), which added a combined total of 37,000 people between 2000 and 2010 (a 16% increase). Overall, 57% of the region was located in the metropolitan areas of Midland and Odessa with the remaining located in rural counties throughout West Texas.

In contrast to the Permian Basin, a much larger percentage of the Barnett Shale regional population in 2010 was located in metropolitan areas (95%); see Table 6.4. Between 2000 and 2010, only 3 of the 24 counties experienced population decline. Of the 12 major producing counties, only 1 experienced population decline between 2000 and 2010.

Table 6.3: Population and Population Change in the Permian Basin Region, 2000–2010

	Total Population		Change 2000–2010		Percent of Region Population	
County	**2000**	**2010**	**Numeric**	**Percent**	**2000**	**2010**
Ector (Odessa MSA)	121,123	137,130	16,007	13.2	27.5	28.5
Midland (Midland MSA)	116,009	136,872	20,863	18.0	26.4	28.4
Metropolitan Population	**237,132**	**274,002**	**36,870**	**15.5**	**53.9**	**56.9**
Andrews	13,004	14,786	1,782	13.7	3.0	3.1
Borden	729	641	-88	-12.1	0.2	0.1
Brewster	8,866	9,232	366	4.1	2.0	1.9
Crane	3,996	4,375	379	9.5	0.9	0.9
Crockett	4,099	3,719	-380	-9.3	0.9	0.8
Culberson	2,975	2,398	-577	-19.4	0.7	0.5
Dawson	14,985	13,833	-1,152	-7.7	3.4	2.9
Gaines	14,467	17,526	3,059	21.1	3.3	3.6
Glasscock	1,406	1,226	-180	-12.8	0.3	0.3
Howard	33,627	35,012	1,385	4.1	7.6	7.3
Jeff Davis	2,207	2,342	135	6.1	0.5	0.5
Loving	67	82	15	22.4	0.0	0.0
Martin	4,746	4,799	53	1.1	1.1	1.0
Mitchell	9,698	9,403	-295	-3.0	2.2	2.0
Pecos	16,809	15,507	-1,302	-7.7	3.8	3.2
Presidio	7,304	7,818	514	7.0	1.7	1.6
Reagan	3,326	3,367	41	1.2	0.8	0.7
Reeves	13,137	13,783	646	4.9	3.0	2.9
Scurry	16,361	16,921	560	3.4	3.7	3.5
Sterling	1,393	1,143	-250	-17.9	0.3	0.2
Terrell	1,081	984	-97	-9.0	0.2	0.2
Upton	3,404	3,355	-49	-1.4	0.8	0.7
Ward	10,909	10,658	-251	-2.3	2.5	2.2
Winkler	7,173	7,110	-63	-0.9	1.6	1.5
Yoakum	7,322	7,879	557	7.6	1.7	1.6
Non-Metropolitan Population	**203,091**	**207,899**	**4,808**	**2.4**	**46.1**	**43.1**
Permian Basin Region	**440,223**	**481,901**	**41,678**	**9.5**	**100.0**	**100.0**

Source: U.S. Census PL94-171 File, 2000 and 2010

Table 6.4: Population and Population Change in the Barnett Shale Region, 2000–2010

	Total Population		Change 2000–2010		Percent of Region Population	
County	**2000**	**2010**	**Numeric**	**Percent**	**2000**	**2010**
Archer (Wichita Falls)	**8,854**	**9,054**	**200**	**2.3**	**0.2**	**0.2**
Clay (Wichita Falls)	**11,006**	**10,752**	**-254**	**-2.3**	**0.2**	**0.2**
Coryell (Temple-Killeen)	**74,978**	**75,388**	**410**	**0.5**	**1.5**	**1.3**
Dallas (DFW)	**2,218,899**	**2,368,139**	**149,240**	**6.7**	**45.8**	**41.5**
Denton (DFW)*	**432,976**	**662,614**	**229,638**	**53.0**	**8.9**	**11.6**
Ellis (DFW)	**111,360**	**149,610**	**38,250**	**34.3**	**2.3**	**2.6**
Johnson (DFW)*	**126,811**	**150,934**	**24,123**	**19.0**	**2.6**	**2.6**
Parker (DFW)*	**88,495**	**116,927**	**28,432**	**32.1**	**1.8**	**2.0**
Tarrant (DFW)*	**1,446,219**	**1,809,034**	**362,815**	**25.1**	**29.9**	**31.7**
Wise (DFW)*	**48,793**	**59,127**	**10,334**	**21.2**	**1.0**	**1.0**
Metropolitan Population	**4,568,391**	**5,411,579**	**843,188**	**18.5**	**94.3**	**94.7**
Bosque	**17,204**	**18,212**	**1,008**	**5.9**	**0.4**	**0.3**
Comanche	**14,026**	**13,974**	**-52**	**-0.4**	**0.3**	**0.2**
Cooke	**36,363**	**38,437**	**2,074**	**5.7**	**0.8**	**0.7**
Eastland*	**18,297**	**18,583**	**286**	**1.6**	**0.4**	**0.3**
Erath*	**33,001**	**37,890**	**4,889**	**14.8**	**0.7**	**0.7**
Hamilton	**8,229**	**8,517**	**288**	**3.5**	**0.2**	**0.1**
Hill*	**32,321**	**35,089**	**2,768**	**8.6**	**0.7**	**0.6**
Hood*	**41,100**	**51,182**	**10,082**	**24.5**	**0.8**	**0.9**
Jack*	**8,763**	**9,044**	**281**	**3.2**	**0.2**	**0.2**
Montague	**19,117**	**19,719**	**602**	**3.1**	**0.4**	**0.3**
Palo Pinto*	**27,026**	**28,111**	**1,085**	**4.0**	**0.6**	**0.5**
Shackelford	**3,302**	**3,378**	**76**	**2.3**	**0.1**	**0.1**
Somervell	**6,809**	**8,490**	**1,681**	**24.7**	**0.1**	**0.1**
Stephens*	**9,674**	**9,630**	**-44**	**-0.5**	**0.2**	**0.2**
Non-Metropolitan Population	**275,232**	**300,256**	**25,024**	**9.1**	**5.7**	**5.3**
Barnett Shale Region	**4,843,623**	**5,711,835**	**868,212**	**17.9**	**100.0**	**100.0**

*Major producing counties.

Source: U.S. Census PL94-171 File, 2000 and 2010

6.2.7 Selected Socio-economic Impacts in Case Study Counties of the Permian Basin and Barnett Shale Regions

Four counties in the Barnett Shale and Permian Basin region were selected for comparative analysis with two additional counties that did not have significant oil or gas development. These counties included Andrews and Scurry Counties in the Permian Basin (matched with Lamb County in West Texas) and Johnson and Wise Counties in the Barnett Shale (matched with Navarro County southeast of Dallas). These comparison counties were similar in size or located near the impact counties. Table 6.5 shows selected characteristics of the impact and comparison counties.

Table 6.5: Case Study Counties

County	County Type	Population (2010)	Population Change 2000–10 (%)	Well Count (2010)	Estimated Employment in Mining as a Percent of Total Non-Farm Employment (2009)
Andrews	Permian Basin	14,786	13.7	13,172	25.2
Lamb	Comparison	13,977	-5.0	106	---
Scurry	Permian Basin	16,921	3.4	4,952	19.6
Johnson	Barnett Shale	150,934	19.0	2,937	3.8
Navarro	Comparison	47,735	5.8	48	2.8
Wise	Barnett Shale	59,127	21.2	4,468	12.0

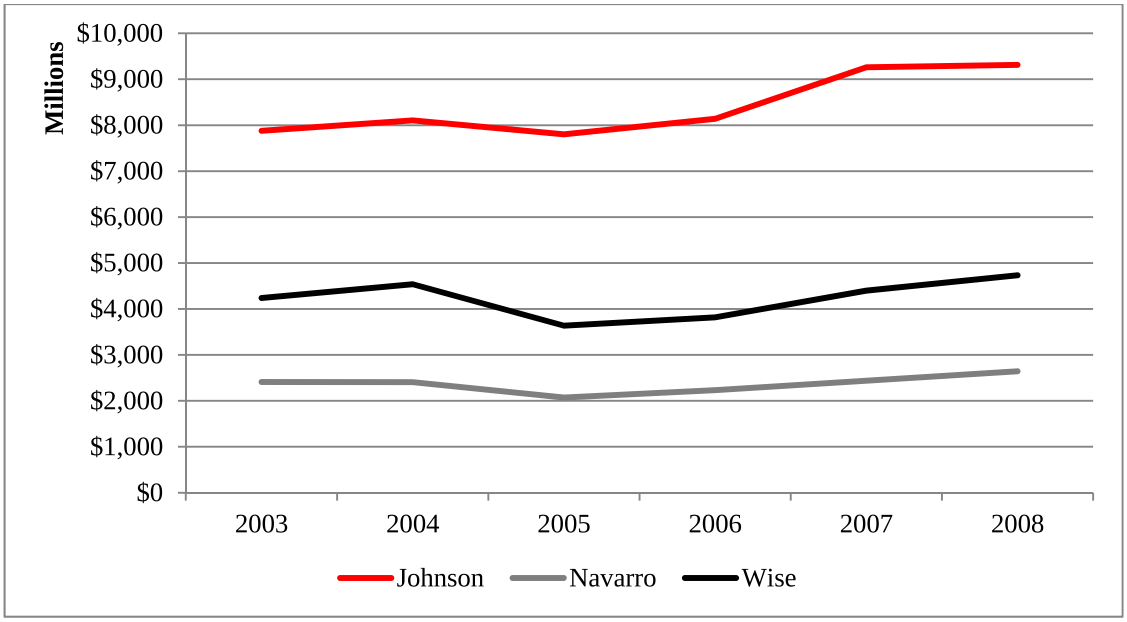
Andrews and Scurry Counties were selected for case study analysis. These two counties are located within the Permian Basin. Scurry County lies over the Canyon Reef oil field, which was initially opened to drilling during the late 1940s and early 1950s—a time when the county's population more than doubled (Leffler, n.d.). Scurry County experienced another small boom during the 1970s. During this time CO_2 injection techniques were used to enhance oil recovery (EOR) in the SACROC oil field west of the county seat of Snyder (Bureau of Economic Geology Gulf Coast Carbon Center, 2011). While discovered as early as 1929, oil was not drilled in Andrews on a wide scale until the late 1940s and 1950s (Hunt, n.d.). Like Scurry County, the population of the city and county of Andrews more than doubled during this time. Similarly, EOR techniques were used to extract oil during the 1970s—leading to a small boom and population growth of 28.5% between 1970 and 1980. Both Andrews and Scurry Counties experienced population growth between 2000 and 2010. In 2010, 14,786 and 16,921 people were living in Andrews and Scurry Counties, respectively. In contrast, Lamb County lost population during the past decade (from 14,709 in 2000 to 13,977 in 2010). Lamb County is located north of both Scurry and Andrews Counties on the South Plains. Oil was discovered in Lamb County during the 1940s but activity never increased to a level seen in Andrews and Scurry Counties. Agriculture remains an important part of Lamb County's economy (Abbe, n.d.).

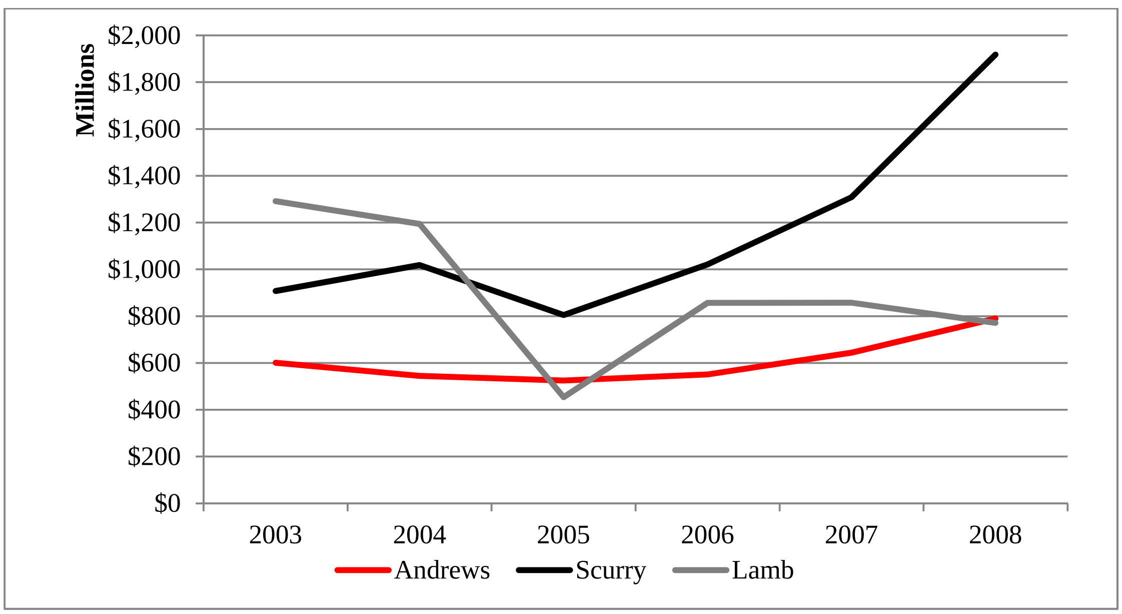
Johnson and Wise Counties are located in the Dallas-Fort Worth-Arlington Metropolitan Statistical Area and within the Barnett Shale region. While oil and gas production had occurred in Wise County since the early part of the 20th Century, oil and gas production accelerated beginning in the early part of the 21st century (England, n.d.). Although not in the metropolitan statistical area, Navarro County is only 40 miles southeast of Dallas and similar in size to Wise County. Oil was first extracted from Navarro County in the 1890s and had been pumped from the county for over 100 years. Gas production increased significantly in Wise County beginning in about 2004 and later, in Johnson County, as the deposits in the Barnett shale were exploited. Johnson and Wise Counties—where Barnett development occurred during the 2000s—experienced much higher rates of growth (19% or greater) than Navarro County.

Changes in selected economic indicators are shown in Table 6.6. These indicators show changes for the 2000 to 2010 period and since major development occurred during the latter period of the last decade (i.e., 2006–2010). In some cases, data are not available for the given dates so changes are shown for those dates for which data are available. In general, the patterns for the changes for the counties in the Permian Basin area are positive and greater than those of the comparison county. No clear distinction can be made for the Barnett Shale counties and Navarro County. Changes in these indicators are also shown in Figures 6.3 through 6.6.

Table 6.6: Change in Selected Indicators, 2000–2010

	Gross Retail Sales Per Capita		Employment		Per Capita Income		Appraised Real Estate Value	
	2002–10	2006–10	2000–10	2006–10	2000–9	2006–9	2003–08	2006–08
Andrews	54.3	10.1	25.2	2.2	33.2	14.2	31.3	43.3
Lamb	-39.8	-35.9	-1.7	-3.8	3.2	4.8	-40.3	-10.0
Scurry	34.4	9.2	8.9	10.5	27.7	12.0	111.3	87.8
Johnson	273.38	57.69	8.7	0.3	2.0	1.3	18.2	14.4
Navarro	15.53	23.59	-0.7	-0.2	9.2	9.8	9.6	18.3
Wise	-13.40	-22.92	6.5	-2.3	15.2	4.2	11.6	24.0





Source: Texas Comptroller of Public Accounts

Figure 6.3: Appraised Values for All but Mineral Properties, 2003–2008

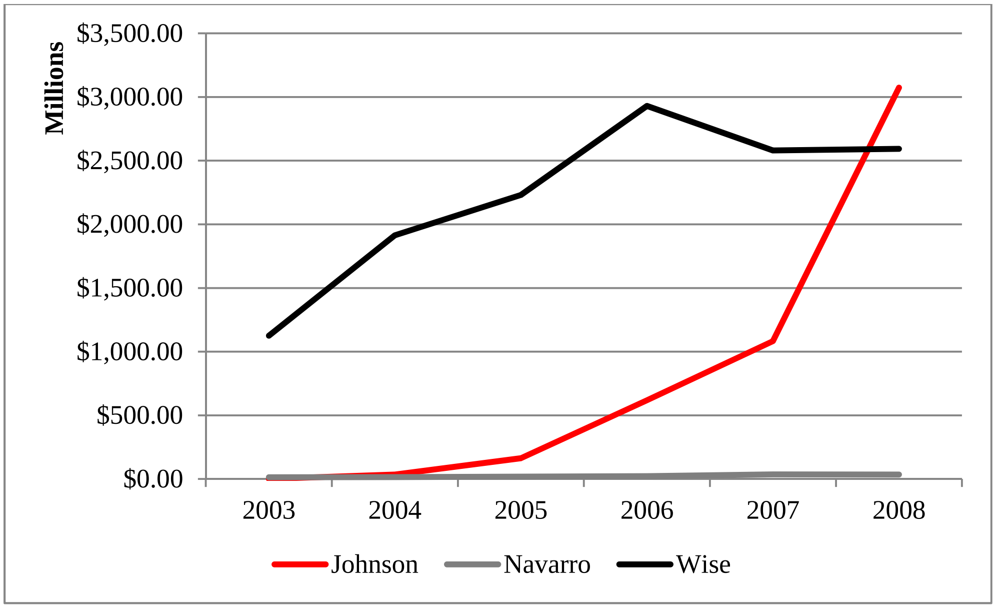
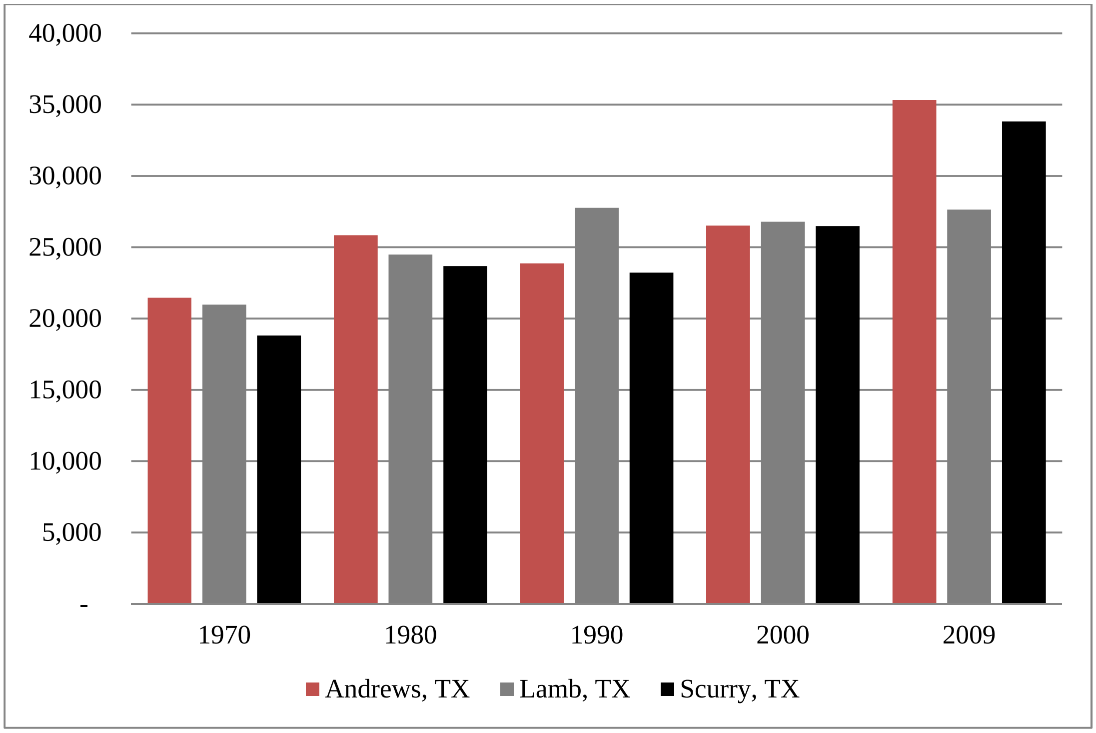


Figure 6.4: Appraised Values of Mineral Properties, 2003–2008



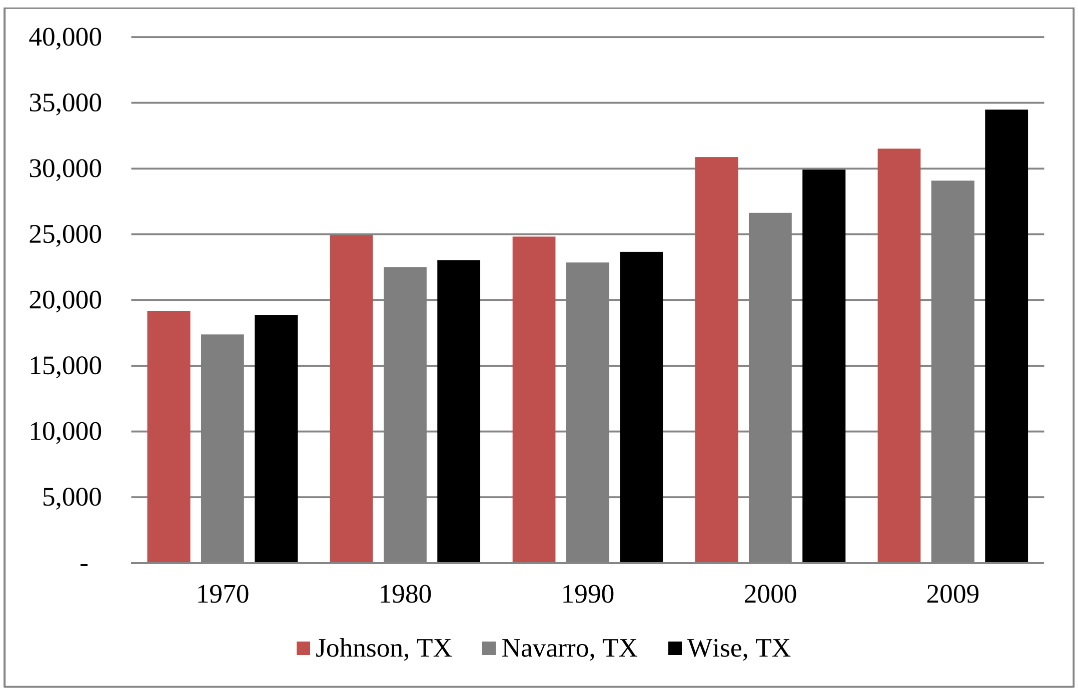


Figure 6.5: Per Capita Income, 1970–2009

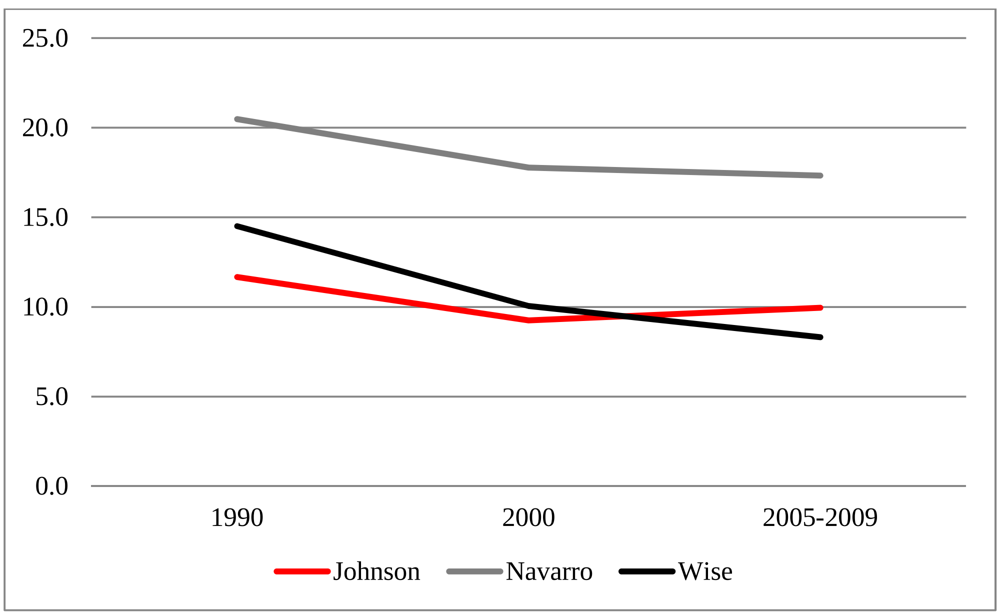


Figure 6.6: Poverty Households as a Percent of All Households, 1970–2009

Gene Theodori and colleagues interviewed key informants in Johnson and Wise County and conducted a household survey of residents in both counties during the spring and summer of 2006 (Theodori, Paradoxical Perceptions of Problems Associated with Unconventional Natural Gas Development, 2009a). Both the interviewed leaders and the household respondents identified increased truck traffic and the quantity of water used as the most negative impacts of gas drilling (Theodori, Local Leaders' Perceptions of Energy Development in the Barnett Shale, 2009b; Wynveen, 2011; Theodori, Local Leaders' Perceptions of Energy Development in the Barnett Shale, 2009b; Theodori, Paradoxical Perceptions of Problems Associated with Unconventional Natural Gas Development, 2009a). At the same time, they identified several positive factors attributable to gas drilling: decreases in poverty; improved local police and fire protection; additions to medical and health care facilities; improved quality of local schools; and availability of good jobs (Theodori, Local Leaders' Perceptions of Energy Development in the Barnett Shale, 2009b; Wynveen, 2011; Theodori, Paradoxical Perceptions of Problems Associated with Unconventional Natural Gas Development, 2009a).

One means of measuring the economic impact of oil and gas on local areas is to measure the relative importance of an industry to a local community. Industries pay workers, who in turn, spend a portion of their pay in their local community. In addition, industries purchase some or all of the services and supplies from local businesses. The extent of the impact is dependent upon the extent that those businesses are available within the local community. The IMPLAN model is a widely used input-output model for measuring these interdependencies and the overall impact of a business or industry on a local area. The IMPLAN model was used to measure the impact of the oil and gas industry on Andrews, Scurry, Wise, and Johnson Counties (MIG, Inc, 2009). Table 6.7 summarizes these impacts. The oil and gas drilling industry employed over 1,000 people in each of the four counties. Additional jobs were supported in these counties from this initial activity as a result of spending by the industries (for supplies and services) and spending by households. The overall employment multiplier for these activities ranged from 1.5 in Andrews County to 2.2 in Scurry County. The higher multiplier effect in Scurry County can be attributed to the fact that a major oil field service company (i.e., Patterson-UTI) has a major base operation in the county. The total output and labor income impacts for this industry in these counties ranged from $576 million in Johnson County to $1.3 billion in Wise County and the total labor income impacts ranged from $127 million in Andrews County to $280 million in Wise County.

Table 6.7: Estimated Economic Impacts of Oil and Gas Drilling in Selected County

Labor				
County	**Direct**	**Additional**	**Total**	**Multiplier**
Andrews	1,300	599	1,899	1.46
Scurry	1,082	1,285	2,366	2.19
Johnson	1,338	1,087	2,424	1.81
Wise	2,320	2,130	4,450	1.92
Output				
County	**Direct**	**Additional**	**Total**	**Multiplier**
Andrews	$526,363,585	$87,614,979	$613,978,564	1.17
Scurry	$1,004,359,188	$178,872,818	$1,183,232,006	1.18
Johnson	$445,131,392	$131,696,380	$576,827,772	1.30
Wise	$1,028,020,256	$255,640,628	$1,283,660,884	1.25
Labor Income				
County	**Direct**	**Additional**	**Total**	**Multiplier**
Andrews	$99,207,946	$27,508,517	$126,716,462	1.28
Scurry	$86,319,539	$61,054,969	$147,374,508	1.71
Johnson	$98,087,730	$41,911,132	$139,998,862	1.43
Wise	$190,917,066	$88,709,248	$279,626,314	1.46

6.3 Socio-economic Impacts of Wind Farm Development

Widespread development of wind farms has only occurred fairly recently with major wind farm development first occurring in West Texas during the late 1990s. Like oil and gas drilling, the impacts of wind farms are felt in two major phases: the development or construction phase and the producing phase. Wind farm development requires a temporary construction labor force to site and construct towers and complete tower structures. Once the wind turbines are constructed, a smaller labor force is needed to maintain turbine operations—typically less than half of the construction labor force. Table 6.8 shows the estimated employment impacts of selected wind farms within the country. These estimated impacts were measured after the projects were developed and operating. On average, approximately one employee is needed to maintain eight turbines (0.13 employees per turbine) (Leistritz, Socioeconomic Impacts of the Langdon Wind Energy Center, Agribusiness and Applied Economics Report No. 627, 2008; Northwest Economic Associates, 2003; Peden, 2006).

Table 6.8: Job Impacts in Selected Wind Farm Areas

	Size		Jobs		Operational Jobs Per	
Wind Farm Location	**MW**	**Turbines**	**Constr-uction**	**Operations (Per Year)**	**MW**	**Turbine**
Lincoln County, MN	107	143	7.5	32.1	0.30	0.22
Morrow and Umatilla Counties, OR	225	38	36.0	6.0	0.03	0.16
Culberson County, TX	120	40	26.0	6.0	0.05	0.15
Kittias County, WA	390	260	95.2	22.0	0.06	0.08
Langdon Wind Energy Center, ND	159	106	269.0	10.0	0.06	0.09
Foote Creek Rim Projects, CO	85	133	0.0	18.0	0.21	0.14
Pecos County, TX	403	474	90.0	32.5	0.08	0.07
Average	**213**	**171**	**75**	**18**	**0.11**	**0.13**
Median	**159**	**133**	**36**	**18**	**0.06**	**0.14**

Sources: M. Peden, *Analysis: Economic Impacts of Wind Applications in Rural Communities*, National Renewable Energy Laboratory, 2006; F. Larry Leistritz, *Socioeconomic Impacts of the Langdon Wind Energy Center*, Agribusiness and Applied Economics Report No. 627, May 2008; Northwest Economic Associates, *Assessing the Economic Development Impacts of Wind Power*, 2003.

The primary occupations employed during the development phase can be seen in Table 6.9. Except for construction laborers, the wind energy sector employs individuals with advanced skills, including engineers and electricians (Bureau of Labor Statistics, 2011). During the operations phase, wind turbine technicians (individuals who have specialized knowledge in understanding how to maintain and repair wind turbines) are needed.

Table 6.9: Wind Farm Occupations and Wages

Occupation	Median annual wages
Construction	
Construction laborers	$29,110
Operating engineers and other construction equipment operators	$39,530
Crane and tower operators	$47,170
Electricians	$49,800
Operations and Maintenance	
Wind Turbine Technicians*	$35,000–$40,000

*BLS does not currently have earnings data. Estimated from industry sources.

Source: Bureau of Labor Statistics, *Careers in Wind Energy*, accessed on June 15, 2011 at http://www.bls.gov/green/wind_energy/

6.3.1 Household Income and Tax Impacts of Wind Farm Development

An estimated 4,910 turbines are installed in the core wind energy production area located in West Texas. At 0.14 jobs per turbine, an estimated 687.4 permanent operations and maintenance jobs are supported in the core area. This industry is a relatively new industry and only in the last few years has the Bureau of Labor Statistics defined wind service technicians as an official occupation. In addition, relative to other industries, the number of people employed in this occupation is small. Thus, data on the characteristics of these employees do not exist within governmental data sources at this time (such as the ACS).

The impacts of wind farm development include employment—both temporary employment in the siting and construction of wind turbines and permanent employment involved in the operations and maintenance of the wind turbines. In addition, the development presents an opportunity for additional employment in manufacturing and other service-related industries as a result of geographical specialization in this nascent industry. Land owners also receive revenues in the form of lease payments from energy companies. Typically, lease payments are based on a percentage of gross revenues for the development—often increasing in later years (National Wind Energy Coordinating Committee, 1997; Northwest Economic Associates, 2003). A contract may include a minimum payment per turbine or per acre with the remaining lease payments based upon a share of gross revenues per year. Lease payments typically range from 2.5% to 10% of annual gross revenues. At the same time, owners may give up some revenue from agricultural uses of their property; however, this loss appears to be minimal in most cases (Northwest Economic Associates, 2003). Loss of revenue from agricultural production is dependent upon the prior use of the land and the actual footprint of wind turbine placements. However, land owners and others may experience negative impacts from noise pollution from the wind turbines as well as changes in the aesthetics of the natural environment. In fact, previous research found that

> [w]hile there were differences between the study areas in the mix of annual leases and permanent easements and the size and type of payment, the annual revenue received by households in the areas was a significant source of household income and had a significant total effect on the economies. In all cases, the cost of foregone opportunities from farming and livestock grazing was small compared to the revenues obtained (National Wind Energy Coordinating Committee, 1997).

In addition, governmental entities receive tax revenues from the wind farm developments—both directly from the wind farms themselves and indirectly from sales taxes as a result of expenditures within a community. Many governmental entities have, however, deferred tax revenues so that the wind farms could be developed (through tax abatements).

Wind farm development requires staff to site turbines and to negotiate land leases. In addition, the developments require labor to help construct the turbine and related facilities. Once turbines are in place, technicians are required to maintain the facilities. The impact of these labor force needs is dependent upon the number of people needed for the work that cannot be filled by local labor. The labor requirements of wind farms are greater during the initial development—and may subsequently only require a labor force that migrates to the area temporarily or commutes from other nearby communities. Table 6.10 shows the 2000 and 2010 populations, changes in these populations, and proportion of wind energy county population for those counties with major commercial wind farms. Overall, 15 of the 29 counties lost population between 2000 and 2010. In the core wind energy corridor, 12 of the 21 counties lost population.

Table 6.10: Population and Population Change in Major Wind Farm Counties, 2000–2010

	Total Population		Change 2000–2010		Percent of Region Population	
County	**2000**	**2010**	**Numeric**	**Percent**	**2000**	**2010**
Callahan (Abilene)*	12,905	13,544	639	5.0	1.7	1.6
Jones (Abilene)*	20,785	20,202	-583	-2.8	2.7	2.4
Taylor (Abilene)*	126,555	131,506	4,951	3.9	16.4	15.7
Carson (Amarillo)	6,516	6,182	-334	-5.1	0.8	0.7
Ector (Odessa)*	121,123	137,130	16,007	13.2	15.7	16.4
Irion (San Angelo)*	1,771	1,599	-172	-9.7	0.2	0.2
Lubbock (Lubbock)*	242,628	278,831	36,203	14.9	31.4	33.4
Metropolitan Population	**532,283**	**588,994**	**113,898**	**15.7**	**68.8**	**70.5**
Borden*	729	641	-88	-12.1	0.1	0.1
Dickens*	2,762	2,444	-318	-11.5	0.4	0.3
Eastland*	18,297	18,583	286	1.6	2.4	2.2
Erath*	33,001	37,890	4,889	14.8	4.3	4.5
Garza*	4,872	6,461	1,589	32.6	0.6	0.8
Glasscock	1,406	1,226	-180	-12.8	0.2	0.1
Hansford	5,369	5,613	244	4.5	0.7	0.7
Howard*	33,627	35,012	1,385	4.1	4.3	4.2
Hutchinson	23,857	22,150	-1,707	-7.2	3.1	2.7
Jack	8,763	9,044	281	3.2	1.1	1.1
Martin*	4,746	4,799	53	1.1	0.6	0.6
Mitchell*	9,698	9,403	-295	-3.0	1.3	1.1
Moore	20,121	21,904	1,783	8.9	2.6	2.6
Nolan*	15,802	15,216	-586	-3.7	2.0	1.8
Oldham	2,185	2,052	-133	-6.1	0.3	0.2
Pecos*	16,809	15,507	-1,302	-7.7	2.2	1.9
Runnels*	11,495	10,307	-1,188	-10.3	1.5	1.2
Scurry*	16,361	16,921	560	3.4	2.1	2.0
Shackelford*	3,302	3,378	76	2.3	0.4	0.4
Sherman	3,186	3,034	-152	-4.8	0.4	0.4
Sterling*	1,393	1,143	-250	-17.9	0.2	0.1
Upton*	3,404	3,355	-49	-1.4	0.4	0.4
Non-Metropolitan Population	**241,185**	**246,083**	**4,898**	**2.0**	**31.2**	**29.5**
Wind Farm Areas	**773,468**	**835,077**	**61,609**	**8.0**	**100.0**	**100.0**

*Core wind energy producing area.

Source: U.S. Census PL94-171 File, 2000 and 2010

6.3.2 Impacts in Case Study Counties

Two counties were selected for further analysis. Both of these counties are located in the core wind energy corridor of West Texas: Scurry County and Upton County. Wind turbines were first constructed in Upton County in 1999. A total of 322 turbines are currently installed in

Upton County—supporting an estimated 45.08 jobs in the county. Wind farm development in Scurry County did not begin until 2004, when the Brazos Wind Farm was established. Development of wind farms within Scurry County has continued into 2011 and includes a portion of the largest wind farm developed to date—the Roscoe Wind Complex of E.ON Energy. This development is centered on Roscoe in Nolan County and the development stretches over four counties (i.e., Scurry, Nolan, Mitchell, and Fischer Counties). The two wind farm development counties were matched for comparison to two counties nearby that had similar economic and other characteristics as the wind farm counties. Reagan County was matched with the adjacent Upton County. Its core economic base is primarily oil and gas. Andrews County is also located in the Permian Basin and has a population similar to Scurry County. Selected statistics for changes in these counties are shown in Tables 6.11 through 6.13 and in Figures 6.7 and 6.8.

Andrews, Reagan, and Scurry Counties experienced population growth between 2000 and 2010, while Upton County experienced a 1.4% decline in the population during that same decade. All of the counties saw increases in the labor force and in employment as well as unemployment as a result of the recession that began in 2008. For Scurry County, employment growth occurred during the last part of the decade at a much greater rate than that of Andrews County. This period coincided with the development of the wind farms. Both counties experienced growth in employment in the oil and gas sector with increases in drilling in both counties. Growth in per capita income and in per capita retail sales in Scurry County were similar to what occurred in Andrews County during the last part of the decade. At the same time, real estate values skyrocketed in Scurry County. Leaders in Scurry County attributed this change in real estate values to the following factors: (a) an addition of a power plant supplying electricity to the Kinder-Morgan CO_2 complex, (b) changes in the way that drilling rigs were valued and taxed according to location (affecting rigs stored by Patterson UTI), and (c) increases in residential property valued due to a limited supply of housing. For Upton County, changes in real estate values and per capita income over the decade were similar to that of Reagan County, while per capita gross retail sales saw significant increases over the period with overall losses in Reagan County. In Scurry County, the appraised value of industrial real estate changed from $280 million to $822 million.

Table 6.11: Case Study Counties

County	County Type	2010 Population	2000–10 Population Change (%)	Year of First Development	Number of Turbines	Estimated Yearly Operations Employment
Andrews	Comparison	14,786	13.7	--	--	--
Scurry	Recent Wind (2007)	16,921	3.4	2004	397	52
Reagan	Comparison	3,367	1.2	--	--	--
Upton	Established Wind (1999)	3,355	-1.4	1999	322	42

Table 6.12: Change in Selected Indicators, 2000–2010

	Gross Retail Sales Per Capita		Employment		Per Capita Income		Real Estate Value	
	2002–10	2006–10	2000–10	2006–10	2000–10	2006–10	2003–08	2006–08
Andrews	54.3	10.1	25.2	2.2	33.2	14.2	31.3	43.3
Scurry	34.4	9.2	8.9	10.5	27.7	12.0	111.3	87.8
Reagan	-14.1	-16.9	55.4	9.3	42.0	12.5	-12.2	12.0
Upton	63.8	39.6	22.9	14.3	46.3	22.3	-16.1	7.8

Table 6.13: Employment Change

	2000 Estimates			2010 Estimates			Percent Change, 2000–2010		
	Labor Force	Employ-ment	Unemploy-ment	Labor Force	Employ-ment	Unemploy-ment	Labor Force	Employ-ment	Unemploy-ment
Andrews	5,614	5,336	278	7,108	6,682	426	26.6	25.2	53.2
Scurry	7,218	6,868	350	7,990	7,478	512	10.7	8.9	46.3
Reagan	1,622	1,565	57	2,536	2,432	104	56.4	55.4	82.5
Upton	1,507	1,434	73	1,856	1,763	93	23.2	22.9	27.4
Texas	10,347,847	9,896,002	451,845	12,136,384	11,141,903	994,481	17.3	12.6	120.1

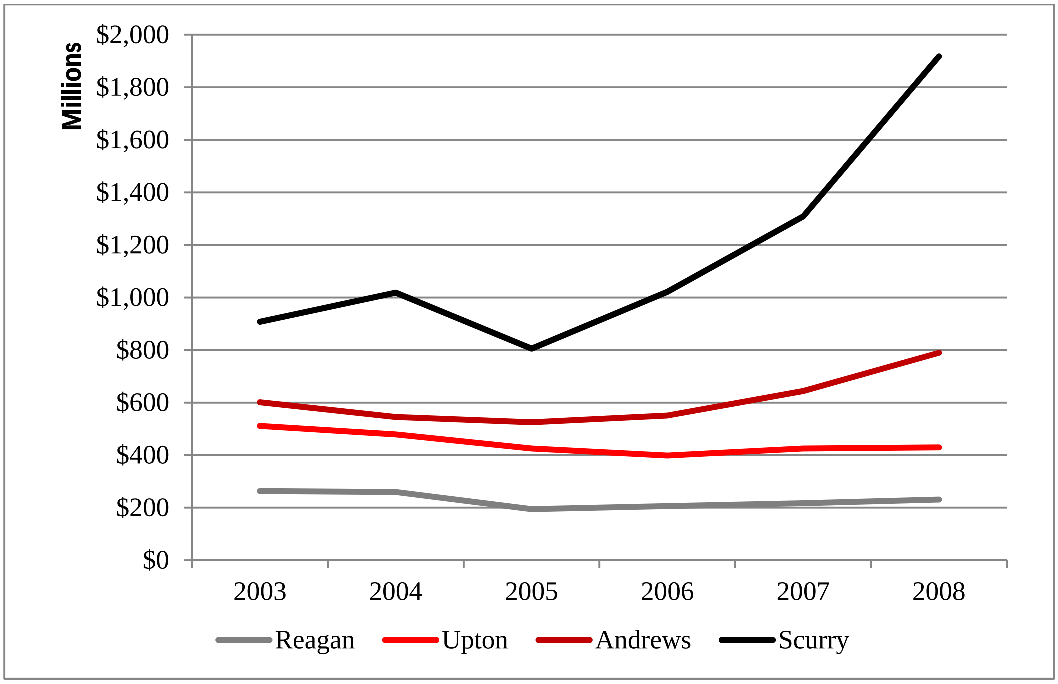


Figure 6.7: Change in Appraised Values for All but Mineral Properties, 2003–2008

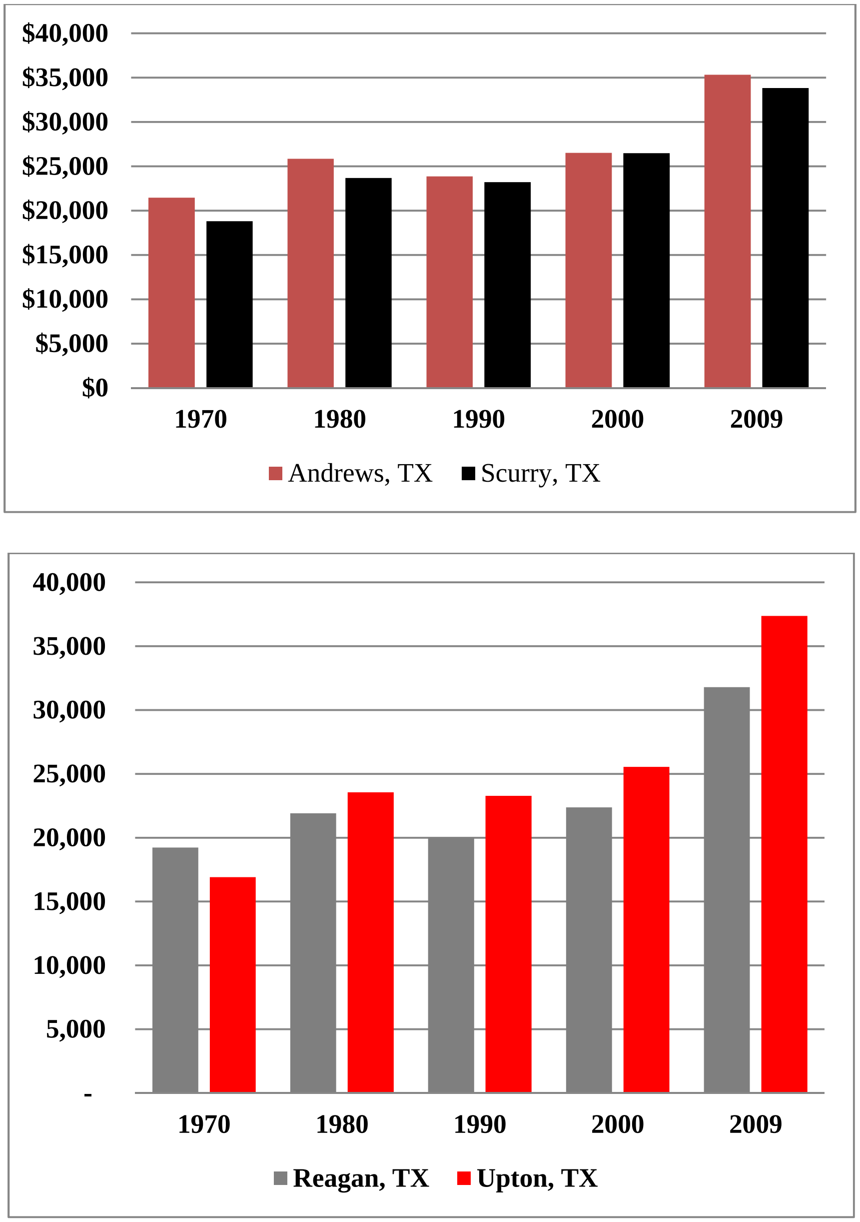


Figure 6.8: Per Capita Income, 1970–2009

The economic impacts of the operations and maintenance activity of the wind farms in Scurry and Upton Counties were estimated using the IMPLAN input-output model (MIG, Inc, 2009). These estimates do not include the economic impact of the construction of wind farms. These estimates also assumed an average employment level for operations and maintenance as shown in Table 6.14. With additional spending as a result of the initial employment impacts, a total of 95 jobs are supported in Scurry County and 68 are supported in Upton County. Overall, the wind farms add $6.6 million in labor income and over $28 million in output. These estimates do not include the additional spending from households that occur as a result of lease revenue.

Table 6.14: Estimated Economic Impacts of Wind Farm Operations in Selected Counties

Labor Force				
County	**Direct**	**Additional**	**Total**	**Multiplier**
Scurry	52	43	95	1.84
Upton	42	26	68	1.62
Output				
County	**Direct**	**Additional**	**Total**	**Multiplier**
Scurry	$24,201,639	$4,705,095	$28,906,734	1.19
Upton	$27,144,909	$3,187,469	$30,332,377	1.12
Labor Income				
County	**Direct**	**Additional**	**Total**	**Multiplier**
Scurry	$5,029,036	$1,577,800	$6,606,836	1.31
Upton	$5,662,290	$941,840	$6,604,140	1.17

6.4 Concluding Remarks

Counties in Texas are being impacted by the current boom in energy development. Increases in oil and gas prices and the extensive use of unconventional drilling techniques have extended the reach of oil and gas drilling to new communities and have increased drilling activity in older oil and gas fields. Relative to oil and gas drilling, the impacts of wind energy development, though important, are small. However, this industry is relative young. As the industry develops, some areas in Texas have potential for specialization in this industry with broader impacts than those seen here. The oil and gas industry has been and continues to be an important part of the Texas economy and for regions and counties within the state. As such, increases in drilling positively impact employment growth due to the experience of the labor force. Development in new areas may bring about additional impacts due to the need to expand infrastructure to meet the demands of the newly developed fields (such as the Eagle Ford). Unfortunately, as many of these impacts are currently being felt, measure the full impacts of oil and gas drilling in newly developed areas is difficult.

Chapter 7. Environmental Regulations

Over the past year and a half (2010–2011), a plethora of environmental rules regarding air quality, emissions, water quality, and waste management that apply to energy production facilities has been issued by the U.S. Environmental Protection Agency (EPA). Some of these rules have been issued to comply with federal circuit court orders. This chapter briefly describes the various rules—proposed or issued—and discusses potential impacts expected. In addition, Appendix A provides more detailed information about the various rules and Appendix B provides information about the air quality rules proposed and promulgated since 2010.

7.1 Regulations for Energy Production Facilities

Eight main sets of promulgated/proposed rules have direct impact on energy production, and consequently may create future impacts on the transportation network. Many of the rules are in response to court vacateur decisions, which have strict compliance dates, with some deadlines for compliance starting in 2012, and working till 2018. Table 7.1 shows the proposed costs for installation and maintaining controls under the various rules.

Table 7.1: Proposed Rules and Estimated Costs per Year

Rule	Cost (per year)
Clean Air Transport Rule	$2.8 billion (2006 $)
Ozone Standards Under NAAQS	$7.6 to $8.8 billion annually in 2020 (achieve 0.075 ppm). 2010 rule requires 0.060–0.070 ppm).
Industrial Boiler Maximum Achievable Control Technology (MACT)	
Major source boilers	$1.4 billion
Area source boilers	$487 million
Commercial and industrial solid waste incineration units including solid waste and recycling in commercial and industrial solid waste incinerator units	$232 million
Portland Cement Kiln MACT	
Installing and operating	$350 million in 2013
Installing operating + indirect social costs	$926 million to $950 million by 2013
Utility Maximum Achievable Control Technology (MACT) (also known as the Toxics Rule)	$109 billion in 2015 ($2007 dollars) in annual incremental compliance cost
Coal Combustion Residuals (adding together Subtitle C – Special Waste + Subtitle D + Subtitle D – Prime)	$1,474 million (Special waste) $587 million (Subtitle D) $236 million (D Prime)
Cooling Water Intake Rule (the EPA analyzed only two hypothetical outcomes for site-specific BTA determinations under Option 1: (a) cost of closed cycle at the 76 largest fossil fuel plants withdrawing from tidal waters and (b) variant on this scenario involving 46 facilities assuming only base load and load following facilities would retrofit to closed-cycle cooling).	$762 million (76 largest fossil fuel plants) $480 million (variance of 46 plants)
Greenhouse Gas Tailoring Rule:	
Industrial Permit Costs	$46,400 per permit (new); $1,700 thousand for permit revision
State/Local/Tribal Permit Costs	$19,700 per permit (new); $9.8 thousand new commercial/residential; and $1,800 for permit revision

7.2 Regulatory Developments: Air

The EPA issued new rules 2010 through July 2011 under the Clean Air Act pertaining to stationary sources regarding Particulate Matter (PM), Hazardous Air Pollutants (HAPs), National Emission Standards for Hazardous Air Pollutants (NESHAPS), Maximum Achievable Control Technology (MACT), and National Air Attainment Quality Standards (NAAQS). These rules are expected to impact existing and new site development for power plants and other industries that utilize boilers and produce regulated and hazardous pollutants and GHGs.

7.2.1 Clean Air Transport Rule

The Clean Air Transport Rule (CATR) will limit the interstate transportation of nitrogen oxide (NO_x) and sulfur dioxide (SO_2) from 32 states in the eastern U.S. that affect the ability of downwind states to attain/maintain compliance with the PM and Ozone NAAQS (75 Fed. Reg. 45,210). The EPA proposes to limit emissions through Federal Implementation Plans (FIPs) that regulate electric generating units in the 32 states (and includes Texas for Ozone NAAQS). The EPA's method for emission reductions requires each state to limit its emissions, allowing emissions trading within a state and limited inter-state trading among power plants given four trading programs: seasonal NO_x, annual NO_x, and two for SO_2. This approach reduces uncertainty, ensures that electric reliability does not suffer, minimizes control costs, and keeps electricity prices low.

7.2.2 Ozone Standards under NAAQS

In January 2010, the EPA proposed to strengthen the NAAQS for ground-level ozone. The proposal is to strengthen the 8-hour primary ozone standard to a level within the range of 0.060–0.070 parts per million (ppm). The EPA proposes establishing a distinct cumulative, seasonal 'secondary' standard (to protect sensitive vegetation/ecosystems) within the range of 7–15 ppm-hours. The final rule and implementation of new designations of attainment is expected to occur by December 2013; between 2014 and 2031, states would be required to meet the primary standard. The EPA has noted that they intend to set a final standard by July 2011 (EPA (a) no date).

7.2.3 Industrial Boiler MACT Rules

In February 2011 the EPA issued a final MACT rule for standards for boilers to reduce emissions of air pollutants: specifically, mercury, PM (as a surrogate for non-mercury metals), and carbon monoxide (as a surrogate for organic air toxics) from existing and new boilers and commercial and industrial solid waste incinerators (CISWI). The U.S. has approximately 187,000 existing boilers at over 92,000 facilities and 2,400 new source boilers are expected to be constructed over the next 3 years. The rule covers area and major source facilities, as well as CISWI units. Boilers are regulated by design and the heat input capacity methodology. Under this rule, the EPA also issued four rules to provide for reductions in HAPs. They also issued rules for Portland Cement kilns in November 2010 to reduce emissions of mercury, air toxics, total hydrocarbons, hydrochloric acid, and particle forming pollutants from new and existing kilns (75 Fed. Reg. 54,970). The rules also limit emissions of ozone and particle forming pollutants from new kilns along with reductions in NO_X and SO_2. The EPA projects that 181 Portland cement kilns will operate at approximately 100 facilities in the U.S. by 2013. The amended air toxics rule will apply to 158 of those kilns. The remaining kilns are subject to a separate regulation for kilns that burn hazardous waste. Seven kilns will be subject to New Source Performance Standards (NSPS). The deadline will be in in 2013 (EPA (b), no date).

7.2.4 Utility MACT Rules—The "Air Toxics Rule"

In May 2011, the EPA proposed national emission standards for NESHAPs from coal and oil-fired electric utility steam generating units and proposed revised NSPS for fossil-fuel-fired units (76 Fed. Reg. 24,976). Known as the Air Toxics Rule, it requires newly constructed or reconstructed units/sources at existing facilities to be subject to CAA §112(g) requirements if they have the potential to emit HAPs in "major" amounts (i.e., 10 tons or more of an individual pollutant or 25 tons or more of a combination of pollutants). Sources/facilities subject to the rule would need to meet air pollution control requirements, referred to as new source MACT control, which is required to be no less stringent than the *best controlled similar source or facility*. The standards will result in additional reductions of SO_2 and metals, including mercury, arsenic, chromium, nickel, and acid gases, including hydrogen chloride and NO_x. The EPA estimates annual incremental compliance cost for the Air Toxics Rule at $10.9 billion in 2015 (2007 dollars).

7.2.5 Greenhouse Gas Rules

During September 2009 the EPA announced a proposal focused on large facilities that emitted over 25,000 tons of GHG annually. Facilities will be required to obtain permits to demonstrate they are using best practices/technologies to minimize GHG emissions (EPA, 2009). The rule proposes new thresholds for GHG emissions permits under the New Source Review and Title V operating permit rules. The rule would apply to new and existing facilities. During December 2010 the EPA issued rules to set the regulatory framework in place to ensure that industrial facilities can get CAA permits covering their GHG emissions, and facilities emitting GHGs at levels below those established in the Tailoring Rule do not need to obtain permits. Thresholds are tailored in the permit program to limit which facilities are required to obtain operating permits and would cover nearly 70% of the national GHG emissions from stationary sources, including power plants and cement production facilities. The proposed rule covered emissions from six GHGs that could be controlled or limited: carbon dioxide (CO_2); nitrous oxide (N_2O); sulfur hexafluoride (SF_6); hydroflurocarbons (HFCs); perfluorocarbons (PFCs), and methane (CH_4).

Under the proposed emissions thresholds, the EPA estimates 400 new sources and modifications would be subject to review for GHG emissions. In total, approximately 14,000 large sources would need to obtain operating permits for GHG emissions under the program. About 3,000 of these sources would be subject to new operating permit requirements. The majority of these sources are municipal solid waste landfills (75 Fed Reg. 31,514). The GHG Tailoring Rule requires Title V permits for major sources with GHG emissions of 100,000 tons per year or more of CO_2 equivalents. The phased-in approach of the Tailoring Rule provides time for large industrial facilities and state governments to develop the capacity to implement the permitting requirements.

7.3 Regulatory Developments: Waste

7.3.1 Coal Combustion Residuals

In June 2010 the EPA co-proposed two options for regulating the disposal of coal combustion residuals (CCRs)—commonly known as coal ash—generated from the combustion of coal at electric utilities and independent power producers. Under the first proposal, the EPA would reverse its August 1993 and May 2000 Bevill Regulatory Determinations regarding CCRs and list these residuals as special wastes subject to regulation under the Resource Conservation and Recovery Act (RCRA) when they are destined for disposal in landfills and surface impoundments. Under the second proposal, the EPA would leave the Bevill regulatory determinations in place and regulate the disposal of materials under subtitle D of RCRA by issuing national minimum criteria. Under both alternatives, the EPA proposed not to change the

May 2000 Regulatory Determination for beneficially used CCRs, which are exempt from the hazardous waste regulations (75 Fed. Reg. 31,128). In assessing the environmental justice impacts of this rule, the EPA noted that of the 495 electric utility plants, 383 of the plants (77%) operate CCR disposal units onsite (i.e., onsite landfills or onsite surface impoundments), 84 solely transport CCRs to offsite disposal units operated by other companies, and 28 generate CCRs that are solely beneficially used rather than disposed of.

7.4 Regulatory Developments: Water

In April 2011 the EPA proposed the Cooling Water Intake Rule for all existing power generating facilities and manufacturing industrial facilities (EPA (c) no date). This applies to all existing power generating facilities (and manufacturing and industrial facilities) that withdraw more than two million gallons of water per day and use at least 25% of the water withdrawn exclusively for cooling purposes. The proposed national requirements apply to the location, design, construction, and capacity of cooling water intake structures at these facilities and should reflect the Best Available Technology (BAT) for minimizing adverse environmental impact. In other words, the facilities would be subject to an upper limit on how many fish can be killed by being pinned against intake screens or other parts of the facility. Existing facilities that withdraw very large amounts of water—at least 125 million gallons per day—would be required to conduct studies to help their permitting authority determine whether and what site specific controls would be required to reduce the number of aquatic organisms sucked into cooling water systems (entrainment).

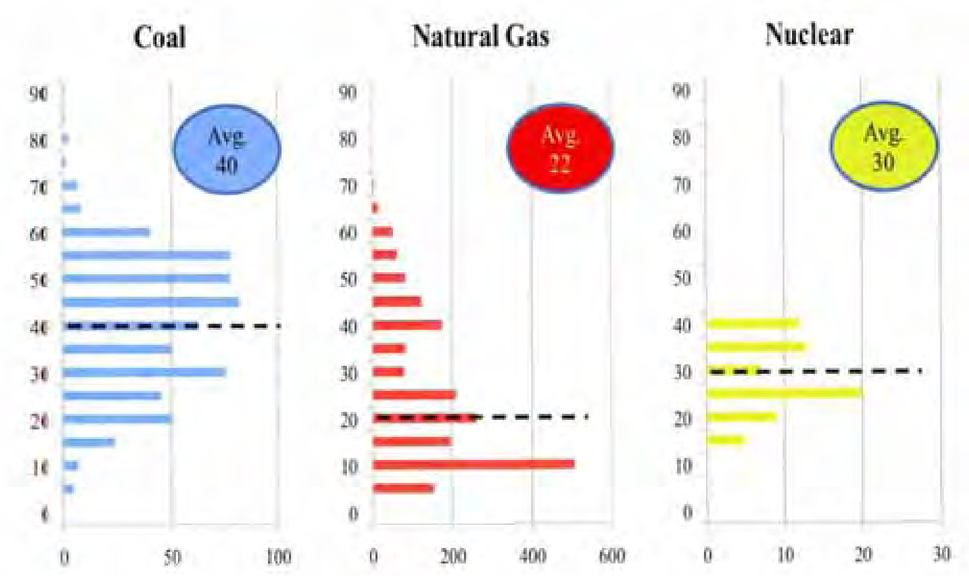
The proposed rule constitutes the EPA's response to the court's remand of the Phase II existing facility rule and the court's remand of the existing facilities portion of the Phase III rule. In addition, the EPA is also responding to the decision in *Riverkeeper I*, proposing to remove from the Phase I new facility rule the restoration-based compliance alternative and the associated monitoring and demonstration requirements. The EPA expects this proposed regulation would minimize adverse environmental impacts, including substantially reducing the harmful effects of impingement and entrainment. The technology basis for the regulation center around four primary options based on review of the BAT. Three of the options would require strict impingement mortality standards, but would vary the approach to entrainment mortality controls. The fourth option would allow both impingement and entrainment mortality controls to be established on a site-specific best practice basis for facilities with a design intake flow (DIF) of less than 50 million gallons a day.

The EPA is also currently developing permitting guidance for oil and gas hydraulic fracturing activities that use diesel fuels. This rule is being developed under the parameters of the Safe Drinking Water Act (SDWA) Underground Injection Control (UIC) Class II Regulations. Stakeholder meetings were held during spring 2011, including a series of webinars where the EPA worked with stakeholders to gather information to assist the permit writers. The draft guidance is expected to be developed during summer 2011 and the public comment period is proposed for fall 2011.

7.5 Commentary: Air, Energy, and Waste

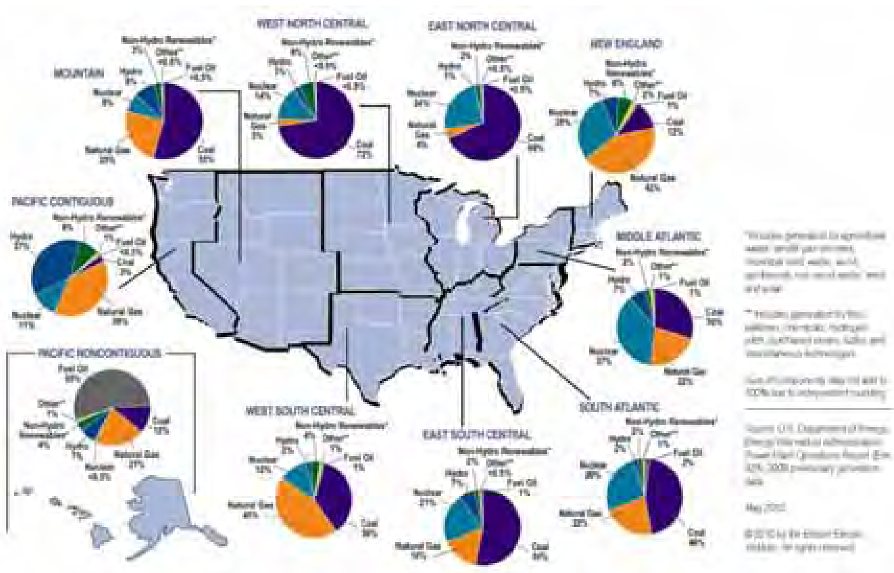
Much commentary has issued from many sources regarding the new rules that have been issued by the EPA over the past year and a half. The *Wall Street Journal*, for example, on March 4, 2011 led with the headline "An EPA Regulatory Spree Unprecedented in U.S. History" (WSJ, 2011). The North American Electric Reliability Corporation (NERC) issued two reports in 2010 that looked at reliability scenario assessments and impacts of climate change, and the reliability impacts of four of the new regulations (NERC 2010 (a) and (b)). They estimated that just four of the EPA's rules could force the retirement of up to 77 Gigawatts (GW) of electric generating capacity by 2015. The Edison Electric Institute also reviewed the potential impacts of GHG regulation on the generating fleet and concluded that the impending regulations of HAPS, MACT, and GHG will cause large numbers of coal plants to retire. Depending on a variety of scenarios modeled, between 33–75GW of unplanned coal-plant retirements will occur by 2015, growing to between 36–96GW by 2020 (Edison, 2011).

As Table 7.1 showed, the compliance costs may run into the billions, and some groups have argued that the combination of the rules on air, waste, and water will cause plants to close and impact generating margin rules, resulting in fines. This issue is also compounded by the blend of fuels used to generate electricity in the U.S. and the age of generating facilities. Figure 7.1 shows the average age of coal, natural gas, and nuclear power generating plants in the U.S. Figure 7.2 shows the blend of fuels used in different regions of the country.



Source: NERC, July 2010 (b).

Figure 7.1: Age Profile of U.S. Fossil and Nuclear Generation Plants



Source: Shea, 2010

Figure 7.2: Fuel Blends Used in the U.S.

NERC's 2010 special reliability report was designed to (i) evaluate the potential impacts on Planning Reserve Margins (PRM) assuming that there would be no industry actions in the near term to address compliance issues or market response, and (ii) identify the need for additional resources in light of industry responses to the regulations individually and in aggregate. NERC looked at the following four rules vis-à-vis impact on MW generation:

- Cooling Water Intake Structures
- Coal Combustion Residuals (CCR) Disposal Regulations
- Clean Air Transport Rule (CATR)
- National Emission Standards for HAP (NESHAP) MACT Standard

NERC's major findings were that the proposed regulations may have a significant impact on PRM and that rule implementation timelines should consider reliability impacts. It found that the Cooling Water intake rule would have the most impact on planning reserve margins and that MACT, CCR, and CATR would contribute to reductions in generating capacity (NERC, 2010 (a)).

Two scenario cases of the EPA regulation(s) analysis (Moderate and Strict Case) were used to provide a range of sensitivities, with the Strict Case incorporating more stringent rule assumptions and higher compliance costs. The reliability assessment used a plant-by-plant assessment. Cost factors for each unit were generic, based on size and location, and did not include engineering-level cost factors. Potential retirements and PRM were assessed for the two cases. The assessment did not examine the possibility that the industry may be unable to meet the tight proposed compliance deadlines. The assessment objectives were the following:

1. Identify potential future outcomes of the EPA's active rulemaking for each of the Cooling Water Intake Rule, CCR, CATR, and MACT rules, and other air toxics individually and in aggregate (combined EPA regulation scenario).
2. Quantify and project impacts on PRM for two sensitivity cases for each regulation, as well as combined impacts for years 2013, 2015, and 2018.
3. Examine impacts of potential unit retirement on regional reliability, and the PRM to measure relative impacts to resource adequacy across NERC regions and sub-regions.
4. Provide results to stakeholders, industry, policymakers, regulators, and the public.

Scenario results found that the EPA rules may have significant economic impacts on generating units as measured by declines in PRMs. Based on the assessment design, overall total compliance cost impact would place between 40 and 69 GW of existing capacity (441–761 units) as "economically vulnerable" for accelerated retirement due to more cost-efficient compliance alternatives by 2018 (NERC 2010 (a)). On-site station loads for equipment operation rate the net generating capacity of the retrofitted units by 6.7–7.4GW. The overall affect would be a total of 46–76 GW in capacity reductions, significantly affecting PRMs if no additional resources are built beyond plans issued in NERC's 2009 reliability assessment. The potential retirement and deratings affect resource portfolios in all eight NERC regions, but especially in the ERCOT (Texas), MRO, NPCC, SERC, and NPCC regions. The most significant impacts are due to the Cooling Water Intake Rule, followed by MACT, CATR, and then CCR (NERC 2010 (a)). NERC also broke down the scenario results by Rule. ERCOT impacts are shown in Tables 7.2 through 7.6.

Table 7.2: Cooling Water Intake Structures Rule Impacts

Cooling Water Intake Structures Rule—ERCOT Predicted Impacts

- Moderate Case Scenario would increase unit production costs above replacement power costs at 347 stations, retiring 33 GW in current generating capacity.
- Spread across rule implementation period 2014–2018.
- Majority of economically vulnerable units are older oil/gas steam units: 253 units with 30 GW capacity.
- 94 additional coal steam units (2.5 GW) are also economically vulnerable.
- Remaining 688 would incur a 5GW capacity derating to suport increased station loads.
- ERCOT, SERC-Delta, RFC, and WECC-CAA account for 65% of unit retirements.

Predicted Impacts 2015 (MW)

Moderate			Strict		
Derated	Retired	Total	Derated	Retired	Total
187	556	743	187	752	939

Predicted Impacts 2018

Moderate			Strict		
Derated	Retired	Total	Derated	Retired	Total
322	5,055	5,377	316	5,295	5,611

Table 7.3: Maximum Achievable Control Technology Rule (Toxics Rule)

MACT—ERCOT Predicted Impacts
• Moderate Case Scenario varies for MACT emission rate limitations by coal type. • Assessment asumes the EPA deadline of January 1, 2015. In Moderate Case only 40% of units that will retire will do so by the January 2015 deadline. • Moderate Case assumes no forced retirements by 2013. 20% of units retire by 2014, reaching 40% by January 2015 with 20% following each subsequent year until all designated units are retired by January 2018 deadline. • In 2015, the impact of Moderate Case is roughly 2.1 GW of existing coal-fired capacity; 59 units are economically vulnerable for retirement, although another 0.8 GW may be derated. • Figure triples to 6.6 GW by 2018 for coal capacity retirements, and 1.8GW derated for total impact of 8.4 GW. • Strict Case assumes no waivers are granted, and all units must be in compliance by January 2015. Waivers assumed to be difficult to obtain as **the** EPA has only granted one sector-wide exemption in the past. Assumes all retirements occur in 2 years leading up to deadline (2013–2014). Increases compliance costs by 25%. • Two above assumptions are significant changes, which leads to 14.9 GW of coal-fired capacity made economically vulnerable for retirement by 2015, and 2.8 GW derated—for total of 17.6GW. • MACT depicts greatest variation between two cases of all the EPA regulations. There is a 12 GW difference in capacity loss between Moderate and Strict Cases by 2015, and a 9 GW difference by 2018.

Predicted Impacts 2015 (MW)

Moderate			**Strict**		
Derated	Retired	Total	Derated	Retired	Total
73	0	73	73	0	73

Predicted Impacts 2018

Moderate			**Strict**		
Derated	Retired	Total	Derated	Retired	Total
73	0	73	73	0	73

Table 7.4: Clean Air Transport Rule

CATR—ERCOT Predicted Impacts

- Aplies to fossil fuel units with greater than 25 MW capacity. The EPA preferred selection used was for Moderate Case.
- Rule has greatest impact on utilities that relied heavily upon purchased allowances for the Acid Rain program compliance. Limiting out-of-state purchases/banked allowances after 2013 would force some utilities to retrofit FGD and SCR emission controls on larger units or retire them.
- Extension of retirements triggered by CATR is linked to flexibility provided to affected sources, and final budget state cap. The EPA-preferred option would result in retirement of five coal-fired units (538 MW) by 2013 and 18 coal-fired units (2,740 MW) by 2015.
- If the EPA pursued emission rate limitations on coal fired units, they provide no ability to trade and forced retrofits. Coupled with NAAQS Strict Case assumes the EPA will adopt stricter limits on all coal-fired capacity. Capital cost would increase by 25%. 86 units (5,221 MW) would have operating costs pushed above new replacement capacity and force retirement.

Predicted Impacts 2013 (MW)

Moderate			Strict		
Derated	Retired	Total	Derated	Retired	Total
0	0	0	64	0	64

Predicted Impacts 2015

Moderate			Strict		
Derated	Retired	Total	Derated	Retired	Total
0	0	0	91	0	91

Table 7.5: Coal Combustion Residuals Rule

CCR

- Additional capital and annual operating cost increases under both scenarios.
- Economically vulnerable coal-fire capacity located in only four NERC regions (not Texas).
- Large number affected in Strict Case; Moderate Case affects only plants using ponds for ash disposal. Strict Case assumes all coal plants will be required to store coal combustion byproducts in landfill.

ERCOT Predicted Impacts 2018 (MW)

Moderate			Strict		
Derated	Retired	Total	Derated	Retired	Total
0	0	0	0	0	0

NERC also computed a combined cumulative effect of the impact of the four rules.

Table 7.6: Combined Case of Four Rules

Combined Case (Cooling Water Intake, CATR, MACT, and CCR)					
• Cumulative effect assessed for 3 years. In 2015 anywhere from 31–70 GW of existing fossil fuel capacity (351–678 units), beyond the 28 GW of retirements already announced, are economically vulnerable for retirements • Additionally 273–700 units of continuing operation will be derated by a toal of 2.4–7.3 GW from the increased parasitic loads from control operations. • Projected retirements are lower in 2013 and significantly higher for Moderate Case in 2018.					
ERCOT Predicted Impacts 2013 (MW)					
Moderate			**Strict**		
Derated	Retired	Total	Derated	Retired	Total
0	0	0	91	0	91
ERCOT Predicted Impacts 2015 (MW)					
Moderate			**Strict**		
Derated	Retired	Total	Derated	Retired	Total
246	5,055	5,301	480	5,295	5,775
ERCOT Predicted Impacts 2018 (MW)					
Moderate			**Strict**		
Derated	Retired	Total	Derated	Retired	Total
366	5,055	5,421	480	5,295	5,775

Critiques of the electric industry have argued that the potential for alternative resources has also not been taken into account in the "doomsday" type claims regarding MW disruption (Yeh, 2011). Tierney and Cicchetti, in May 2011, concluded that the Edison Electric Institute report entitled *Potential Impacts of Environmental Regulation on the U.S. Generation Fleet* (Edison, 2011) was based on worst-case assumptions that have not materialized, and upon climate change legislation never enacted into law. They found that the report "does not adequately distinguish between the non-environmental drivers of changes in the electricity industry and the various EPA rulemakings." Tierney et al.'s analysis evaluated the report findings in light of the proposed Utility Air Toxics and Cooling Water Intake Regulations issued in March 2011 (Tierney et al., 2011).

7.6 Concluding Remarks

The regulatory playing field for energy production will continue to change over the next 3 to 15 years. In some instances new rules may have positive impacts on the transportation network through reduced deliveries and the use of alternative fuels. However, some rules may change the amount and type of fuel used, and thus the mode for delivery of the fuel source. As an example, any shift-up in the utilization of coal could impact the use of rail, and consequently impact the highway network at grade crossings and within rail yards. As has recently been seen with the natural gas and oil production ramp-ups, the use of carbon fuels is still paramount in the U.S. This may, however, be challenged, by some of the states who are starting to implement moratoriums on fracturing activities given citizen concern. New Jersey's Governor Chris Christie imposed a one-year conditional veto on hydraulic fracturing in August 2011, while state and federal agencies review the issue comprehensively (Christie, 2011). The Securities and Exchange

Commission (SEC) has also jumped into the fray and is asking drillers for specific information, including chemicals used in this process. News analysis during August 2011 discussed why the SEC was asking questions, and commented that if in the process of drilling the company pollutes drinking water, cleaning up the mess would be expensive. Also, some argue that publically traded companies should warn investors of such financial risk in advance (Block, 2011 and Lammick, 2011).

Chuck Barlow, Associate General Counsel for Entergy Services Inc., succinctly summed up the landscape of forthcoming environmental regulations of energy production in February 2011:

> Minds that are knowledgeable on the debate regarding the country's energy future disagree on the magnitude of the impact that these air and water regulations will have on the availability and stability of our electric generation and delivery systems. The perception of whether the cost of compliance will be justified by the sometimes debated environmental benefits varies greatly depending on the viewer. But there is no doubt that the impacts will be significant and costly; and that the implementation of EPA's anticipated rules should proceed in a coordinated manner that considers the sequencing and timing of the various rules and the probability that, waiting somewhere in the wings, is the wild card of greenhouse gas regulation.

Chapter 8. Tax and Other Incentives

It is often argued that the future of the U.S. and Texas's energy sector will be determined by technology advancements, financial incentives, policy changes, and the rising costs of fossil fuels. For some energy industries—specifically the wind and biomass industries—the continuance of federal and state incentive programs is critical to their continued growth.

For example, the Texas RPS is one of the most successful in the country and is a primary contributor to the rapid growth of the wind energy industry in the state[9]. The first version of the Texas RPS was included in Senate Bill 7 in 1999. Implemented by the Public Utilities Commission of Texas (PUCT), it required that retail electricity suppliers in Texas produce 2,000 MW of renewable energy from wind, solar, biomass, geothermal, hydroelectric, or tidal energy by the year 2009. This renewable energy goal was achieved in 2005—4 years before the intended date. As a result, the RPS was revised and passed with Senate Bill 20 in 2005. The revised Texas RPS called for an increase in the renewable energy production to 5,880 MW by 2015 and to 10,000 MW by 2025. Because of the increased emphasis on wind energy to meet the RPS, less emphasis was placed on the non-wind sources. Senate Bill 20 thus specifically required that 500 MW of the renewable energy had to be produced from sources other than wind to allow for advances in solar and biomass energy production. To support the RPS regulations, a Renewable Energy Credit (REC) trading program was established to allow utility companies to meet RPS targets by buying or selling credits. The REC trading program is, however, set to expire in 2019, which may present a challenge for utility companies.

Similarly, the oil and gas industry will be impacted by the elimination of a number of financial incentives. For example, in President Obama's 2011 budget, he proposed to eliminate nine different tax expenditures that primarily benefit the oil and gas industry. The elimination of these tax expenditures is estimated to result in savings of $45 billion over the next 10 years. Following are some of the expenditures targeted for elimination (Gandhi, 2010):

- the deduction of certain types of intangible costs associated with the drilling and preparing of wells for the production of oil and gas;
- the subsidization of the costs for tertiary injectants used in enhanced oil recovery;
- the allowance of an independent oil company to deduct from its taxes about 15% of the revenue generated from a well (i.e., percentage depletion allowance); and
- the deduction of geological and geophysical expenditures associated with searching for oil over a 2-year period.

This chapter lists the various federal and state incentives available to the energy sector.

[9] Since the inception of the Texas RPS in 1999, the state's wind capacity has grown significantly. As of 2010, the state has achieved its 2025 RPS goal with over 10,000 MW of installed wind energy capacity and over 900 MW of non-wind renewable energy capacity (Texas Renewable Electricity Profile, 2010). Competitive pricing, expansive resources, the RPS requirements, and available tax incentives have thus allowed the wind energy industry to experience significant growth. However, continued investments to further increase the production of wind and non-wind renewable energy requires the revision of the current RPS and an extension of existing or additional incentives. Future growth in renewable energy capacity may thus largely be dependent on a new RPS.

8.1 Federal and State Incentives

Table 8.1 provides a list of the federal and state sector incentives available to the energy industry. Appendices C and D provide a list of the federal and state incentives for eligible technologies and an explanation of the incentives, respectively.

8.2 Concluding Remarks

In general it is believed that financial incentives and tax credits will be a major driver in the future growth of the renewable energy sector and specifically the wind and biomass industries in Texas. This chapter provided a list of the numerous financial incentives available to the energy sector. The next chapter provides the four scenarios that were developed based on different assumptions about Texas's "energy futures" and how these futures might be realized.

Table 8.1: Available Federal and State Sector Incentives

(Not including local incentives/utility rebate programs or personal exemptions)

				Sector														
Authority	**Name**	**Summary**	**Incentive Type**	**Res.**	**Comm.**	**Indus.**	**Trans**	**Gov**	**Other**	**Amount**	**Maximum**	**Enacted-Effective**	**End Date**	**Statute/Funding**				
Federal	Business Energy Investment Tax Credit (ITC)	11	Corporate Tax Credit		X	X			X	Varies based on energy source (see summary)		2008	12/31/2016	26 USC Section 48	IRS Instruction	IRS Form 3468		
Federal	Renewable Electricity Production Tax Credit (PTC)	13	Corporate Tax Credit		X	X				Varies based on energy source (see summary)		1992	Varies by technology	26 USC Section 45				
Federal	U.S. Department of Treasury - Renewable Energy Grants	14	Federal Grant Program		X	X			X	30% of property that is part of qualified fuel cell, solar or wind property; 10% of all other property	$1,500 per 0.5 kW for qualified fuel cell. $200 per kW for qualified microturbine	1/1/2009-12/17/2010	2011	HR 4853	HR 1: Div. B, Sec. 1104 &1603	US Dep of Treasury: Grant Program		
Federal	USDA - Rural Energy for America Program (REAP) Grants	16	Federal Grant Program		X			X	X	Varies	25% of Project Cost	2003	N/A	7 USC Section 8106	USDA			
Federal	Clean Renewable Energy bonds (CREBs)	17	Federal Loan Program					X	X	Varies	N/A	8/8/2005	11/1/2010	26 USC Section 54	26 USC Section 54A	26 USC Section 54C	IRS Notice 2009-33	IRS Announcement 2010-54
Federal	Qualified energy Conservation Bonds (QECBs)	19	Federal Loan Program					X		Varies	N/A	2/17/2009		26 USC Section 54A	26 USC Section 54D	IRS Notice 2009-29	26 USC Section 6431	IRS Notice 2010-35
Federal	U.S. Department of Energy -Loan Guarantee Program	20	Federal Loan Program		X	X		X	X	Varies ($25 million+ Projects)	N/A	2005	Periodically Offered	42 USC Section 16511	10 CFR 609	DOE		
Federal	USDA - Rural Energy for America Program (REAP) Loan Guarentees	21	Federal Loan Program		X				X	Varies	$25 million	2003	Periodically Offered	7 USC Section 8106				
Federal	Qualifiying Advanced Energy Manufacturing Investment Tax Credit	23	Industry Recruitment/Support		X	X				30% of Qualified Investment	$2.3 Billion	2/17/2009	Expired (01/2010)	26 USCS Section 48C	DOE			
Federal	Renewable Energy Production Incentive (REPI)	24	Performance-Based Incentive		X	X		X	X	2.2 cents /kWh	Ends after 10 years in service.	10/24/1992	10/1/2016	42 USC Section 13317	10 CFR 451			

				Sector														
Authority	Name	Summary	Incentive Type	Res.	Comm.	Indus.	Trans	Gov	Other	Amount	Maximum	Enacted-Effective	End Date	Statute/Funding				
State	Solar and Wind Energy Device Franchise Tax Deduction	1	Corporate Deduction		X	X				10% of Amortized Cost from Income or Full Cost from Capital	None	1981-1982	N/A	Texas Tax Code Section 171.107				
State	Solar and Wind Energy Business Franchise Tax Exemption	2	Industry Recruitment/Support		X	X				Exemption from franchise tax	N/A	1981-1982	N/A	Texas Tax Code Section 171.056				
State	Renewable Energy Systems Property Tax Exemption	3	Property Tax Incentive	X	X	X				Exemption of energy device value from property tax	N/A	1981-1981	N/A	Texas Tax Code Section 11.27				
State	Memorial Day Weekend Sales Tax Holiday	4	Sales Tax Incentive	X	X					100% of Sales and Use Tax	Limit on Cost of Product	2007	N/A	Texas Tax Code Section 151.333				
State	Department of Rural Affairs - Renwable Energy Demonstration Pilot Program	5	State Grant Program					X		Varies (Project Budget of $681,000 in 2011)	N/A	2010	N/A	Federal Community Development Block Grant Funding				
State	LoanSTAR Revolving Loan Program	6	State Loan Program					X		Varies (Project Budget of $126 Million)	$5 Million	1989	N/A	Petroleum Violation Escrow Funds; ARRA				
State	Oncor Electric Delivery - City and School Matching Grant Program	7	Utility Grant Program					X		Cities: Up to $50,000 matching grant; Schools: up to $25,000	N/A		N/A	Take a Load off Texas				
Federal	Energy Efficient Commercial Building Tax Deduction	8	Corporate Deduction		X			X		$0.30-$1.80 per square foot	$1.80/Sq. Ft	8/8/2005-1/1/2006	12/31/2013	26 USC Section 179D				
Federal	Modified Accelerated Cost Recovery System (MACRS) + Bonus	9	Corporate Depreciation		X	X			X	50% Bonus Depreciation in 2012		1986	2012	26 USC Section 168	26 USC Section 48	H.R. 4853	IRS Rev. Proc. 2011-26	
Federal	Residential Energy Conservation Subsidy Exclusion	10	Corporate Exemption	X						100% of Subsidy		1992-2003		26 USC Section 136				
Federal	Energy Efficient New Homes Tax Credit for Home Builders	12	Corporate Tax Credit	X					X	$1,000-$2,000	$2,000	8/8/2005-1/1/2006	12/31/2011	HR 4853	26 USC Section 45L			

				Sector														
Authority	**Name**	**Summary**	**Incentive Type**	**Res.**	**Comm.**	**Indus.**	**Trans**	**Gov**	**Other**	**Amount**	**Maximum**	**Enacted-Effective**	**End Date**	**Statute/Funding**				
Federal	USDA - High Energy Cost Grant Program	15	Federal Grant Program	X	X			X	X	$75,000-$5,000,000	$5 Million	2000	N/A	USDA				
Federal	Energy Efficient Mortgages	18	Federal Loan Program	X							N/A			Energy Star Program				
Federal	Energy Efficient Appliance Manufacturing Tax Credit	22	Industry Recruitment/Support			X				Varies (See Summary)	$25 million per manufacturer	1/1/2007	12/31/2011	26 USC Section 45M	HR 4853	IRS Website		
State	Clean Vehicle and Infrastructure Grants	25	State Grant Program				X	X					Periodically Offered	Texas Commision on Environmental Quality				
State	Alternative Fuel and Advanced Vehicle Grants	26	State Grant Program				X	X					Periodically Offered	Texas Commision on Environmental Quality				
State	Clean Fleet Grants	27	State Grant Program				X	X					Periodically Offered	Texas Commision on Environmental Quality				
Federal	Alternative Fuel Infrastructure Tax Credit	28	Tax Credit	X	X					Varies (See Summary)	Varies (See Summary)		12/31/2011	IRS Form 8911 and/or IRS Form 3800				
Federal	Alternative Fuel Excise Tax Credit	29	Tax Credit		X		X			$0.50 per gallon			12/31/2011	IRS Publication 510, IRS Forms 637, 720, 4136 and 8849				
Federal	Alternative Fuel Mixture Excise Tax Credit	30	Tax Credit		X		X			$0.50 per gallon			12/31/2011	IRS Publication 510, IRS Forms 637, 720, 4136 and 8849				
Federal	Alternative Fuel Tax Exemption	31	Tax Exemption		X	X	X	X	X					IRS Publication 510				
Federal	Improved Energy Technology Loans	32	Loan Guarantee Program				X							Loan Guarantee Program				
State	Alternative Fueling Infrastructure Grants	33	State Grant Program		X					50% of eligible costs	$500,000		8/31/2018	Texas Commision on Environmental Quality				
State	Natural Gas Vehicle (NGV) and Fueling Infrastructure Grants	34	State Grant Program		X					Varies (See Summary)	Varies (See Summary)		8/31/2017	Texas Commision on Environmental Quality				

				Sector														
Authority	Name	Summary	Incentive Type	Res.	Comm.	Indus.	Trans	Gov	Other	Amount	Maximum	Enacted-Effective	End Date	Statute/Funding				
State	Heavy-Duty Natural Gas Vehicle (NGV) Grants	35	State Grant Program				X	X					8/31/2012	Texas General Land Office				
State	Natural Gas Fuel Rates and Alternative Fuel Promotion	36	State Grant Program					X	X					Texas General Land Office				
State	Natural Gas Fuel Rate Reduction and Infrastructure Maintenance - Clean Energy	37	Utility Grant Program		X													
State	Natural Gas Vehicle (NGV) and Fueling Infrastructure Rebates - Texas Gas Service	38	Utility Grant Program	X	X		X			Varies (See Summary)	Varies (See Summary)							
State	Natural Gas Infrastructure Technical Assistance - Atmos Energy	39	Utility Grant Program		X													
State	Natural Gas Infrastructure Technical Assistance - CenterPoint Energy	40	Utility Grant Program		X													
Federal	Biodiesel Mixture Excise Tax Credit	41	IRS Tax Credit		X	X	X			$1.00/gallon			12/31/2011	IRS Publication 510 and IRS Forms 637, 720, 4136, 8849, and 8864				
Federal	Biodiesel Income Tax Credit	42	Income Tax Credit		X					$1.00/gallon			12/31/2011	IRS Publication 510 and IRS Forms 637 and 8864				
Federal	Small Agri-Biodiesel Producer Tax Credit	43	IRS Tax Incentive		X	X				$0.10/gallon			12/31/2011	IRS Publication 510 and IRS Forms 637 and 8864				
Federal	Advanced Energy Research Project Grants	44	Advanced Research Projects Agency - Energy						X									
Federal	Improved Energy Technology Loans	45	Loan Guarantee Program		X	X	X			100% of the loan amount				See Summary				

				Sector														
Authority	**Name**	**Summary**	**Incentive Type**	**Res.**	**Comm.**	**Indus.**	**Trans**	**Gov**	**Other**	**Amount**	**Maximum**	**Enacted-Effective**	**End Date**	**Statute/Funding**				
Federal	Advanced Biofuel Production Grants and Loan Guarantees	46	Biorefinery Assistance Program		X						$250,000,000			See Summary				
Federal	Advanced Biofuel Production Payments	47	Bioenergy Program for Advanced Biofuels		X	X								See Summary				
Federal	Biodiesel Education Grants	48	Biodiesel Fuel Education Program						X					See Summary				
Federal	Biomass Research and Development Initiative	49	National Institute of Food and Agriculture						X					See Summary				
Federal	Value-Added Producer Grants (VAPG)	50	Office of Rural Development, US Department of Agriculture		X				X					See Summary				
Federal	Biobased Transportation Research Funding	51	Surface Transportation Research, Development, and Deployment						X					See Summary				
Federal	Cellulosic Biofuel Producer Tax Credit	52	IRS Tax Incentive		X	X				Varies (See Summary)	$1.01/gallon		12/31/2012	IRS Publication 510 and IRS Forms 637 and 6478				
State	Renewable Fuel Production Grants	53	State Grant Program		X	X	X			$0.20/gallon				See Summary				
State	Diesel Fuel Blend Tax Exemption	54	State Grant Program		X					Exemption from Diesel Fuel Tax				See Summary				
Federal	Volumetric Ethanol Excise Tax Credit (VEETC)	55	IRS Tax Incentive		X	X				$0.45/gallon of pure ethanol			12/31/2011	IRS Publication 510 and IRS Forms 637, 720, 4136, 6478, and 8849				
Federal	Small Ethanol Producer Tax Credit	56	IRS Tax Incentive		X	X				$0.10/gallon of ethanol			12/31/2011	IRS Publication 510 and IRS Forms 637 and 6478				
Federal	Ethanol Infrastructure Grants and Loan Guarantees	57	Rural Energy for America Program		X				X	See Summary	See Summary			Office of Rural Development, US Department of Agriculture				

Chapter 9. Texas's Potential Energy Futures

Texas's thriving energy sector is the product of many decades of resource discoveries and innovative production, all supported by the state's transportation system. Whether importing out-of-state coal, using Farm-to-Market roads to reach natural gas wells, or transporting wind turbine components, the transportation system plays a major role in supporting Texas's energy sector. With the assumption that Texas's energy sector—conventional and renewable—will experience substantial growth over the next couple of decades, it is crucial to the state's success that TxDOT consider a variety of energy outcomes and their potential impact on the transportation system. This chapter describes four potential "energy futures" that were developed for Texas.

9.1 Scenario Development

Scenario development is a tool used in planning for the future, and can be used in developing varying alternatives for Texas's "energy futures" and how these futures might be realized. Upon developing scenarios, their results can be analyzed with regard to transportation needs to predict the system changes that need to happen to support one scenario versus the others. The purpose of scenarios is not to precisely forecast future events and their implications, but rather to answer exploratory questions, such as the following:

- How will the state's population change in the future? Will a growing Texas population require more energy?
- Will oil and natural gas resources be adequate to meet rising demands? If not, when will their reserves mature?
- What technological developments will be the gateway to feasible and economically attractive renewable energy implementation?
- With economic recovery, what changes will be realized in the energy industry?
- Will concerns over energy security and the climate motivate governments to draft legislation impacting the energy industries? If so, what policy changes will have the greatest ramifications?

Seeking answers to these questions, this chapter discusses the future of Texas's energy industries and the impact their outcomes might have on the state's transportation system. Historic energy consumption, production, and price trends have been compiled and analyzed in the preceding chapters of this report. Although scenarios rely on historical and projected trends, they do not represent factual predictions of the future. The subsequent sections attempt to predict the changes in energy production and demand that legislation, technology, and socio-economics could imply for each energy industry. These motivating changes are considered the "drivers," and are the main impetus for scenario development. Table 9.1 presents some of the most important drivers considered in the development of the scenarios.

Table 9.1: Drivers Considered in the Scenario Development

Driver Type	**Driver Details**
Energy Portfolio Goals of the State	Will Texas pursue conventional fuel markets, such as oil and natural gas? Or will the renewable markets receive greatest interest?
Energy Demand	Will the state's growing population lead to increased energy demand?
Technology Advancements	What technology advancements will revive maturing oil reserves and diminishing gas wells? And how could technology breakthroughs benefit renewable markets?
Environmental Regulations	If Greenhouse Gas legislation is enacted, what will it mean for Texas's energy sector?
Fuel Price Trends	What effect will fluctuating oil/natural gas/coal prices have on Texas's energy sector?
Enabling Infrastructure	How will investments in transmission infrastructure impact the different energy sources?
Taxes and Financial Incentives	Will the renewal of tax credits motivate renewable energy production? Conventional energy production?

In developing future energy scenarios for Texas, the drivers were considered and analyzed in terms of their potential impact on each of Texas's individual energy industries. These results were then incorporated with those from the analysis of other industries to form a framework for a potential scenario. The framework was then evaluated and refined to produce a general scenario concept, which evolved into a potential Texas energy scenario. Four scenarios were developed. These four scenarios present different assumptions with regard to the future of oil, coal, natural gas, wind, and biofuels in the U.S. and within Texas. Scenario 1 is characterized by substantial growth in the oil and gas industries, Scenarios 2 and 4 are characterized by substantial growth in the natural gas and renewable energy industries, while Scenario 3 is characterized by substantial growth in the oil, natural gas, and coal industries. The following sections elaborate upon each scenario. Table 9.2 provides an overview of the characteristics of each scenario with respect to the drivers.

Table 9.2: Potential Texas Energy Futures

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Scenario Drivers	Fossil Fuels Future	Renewable Future (Market Driven)	Carbon Future	Renewable Future (Regulatory Driven)
Population Growth	Reference (2.3%)	High population (2.7%)	Reference (2.3%)	High population (2.7%)
Economy	Reference (2.4%)	High growth (3.0%)	Low growth (1.8%)	Reference (2.4%)
Energy Demand	Reference (2.2%)	Reference (2.2%)	Reference (2.2%)	Reference (2.2%)
Environmental Regulations	Current laws and regulations; lifting of off-shore moratorium	Mostly current laws and regulations, although some implementation of MACT	Current laws and regulations	Extended policies (including, revised RPS, GHG emissions and requirements for efficiency)
Incentives (including tax incentives)	Expiration of renewable tax credits	Additional renewable tax credits, RPS, and R&D funding	Expiration of renewable tax credits	Existing renewable tax credits and R&D funding
Technology Advancements	Moderate technology advancements	Substantial technology advancements (including investment in energy efficient technologies)	Slow technology advancements	Substantial technology advancements (including investment in energy efficient technologies)
Energy Costs	High oil price \$210 (2008)	Reference Case oil price \$133 (2008)	High oil price \$210 (2008)	Overall cost of energy increases

9.2 Scenario 1—Fossil Fuels Future

Scenario 1 assumes that an abundant supply of oil and natural gas is available to U.S. and Texas consumers at reasonable prices. The state's population continues to increase at the past rate of about 2.3%. With an increasing population, energy demand increases similarly to past trends (1.0; 2.2%). The economy recovers to pre-recession levels and continues to grow at past rates.

In this energy scenario, Texas energy producers devote the majority of their resources to extracting oil and natural gas. High oil prices allow for the more widespread use of more costly drilling techniques, such as EOR and hydraulic fracturing. Offshore oil drilling moratoriums are removed and Gulf Coast deep-water reserves provide additional oil capacity. The state's natural gas is largely sourced from the Barnett Shale, Eagle Ford Shale, and the Haynesville Shale. Natural gas production increases by 40 to 45%.

Current laws and regulations apply and few of the EPA regulations proposed in 2010/11 are implemented. Specifically, no legislation to restrict GHG emissions is adopted. Finally, no additional investments are made to increase the production capacity of wind energy beyond 12,000 MW and no biofuel plants are constructed. This is mostly due to the expiration of a number of incentives for renewable energy, of which the most important is the expiration of the renewable tax credit.

Table 9.2 displays the main changes in the drivers that could result in this scenario. In general, however, this scenario is driven by growing energy demand and relatively high oil prices that result in increased oil and natural gas production in the Permian Basin, the coastal areas, and the shale regions (i.e., Barnett Shale, Eagle Ford Shale, and Haynesville Shale). Table 9.3 illustrates the additional transportation impacts associated with the Fossil Fuels Future. Table 9.3 indicates that a substantial increase in activity will be imposed on Texas's highway system (specifically, the lower functional road classes because of increased natural gas activity), Texas's ports and the access roads to Texas's ports, as well as the state's pipeline infrastructure.

Table 9.3: Additional Transportation Impacts—Fossil Fuels Future

Energy Sector	Energy Impacts	Additional Transportation Impacts
Oil	Substantial increase in activity (Gulf Coast deep-water reserves)	Ports and access roads to ports (e.g., "last mile"), pipelines
Natural Gas	Substantial increase in activity (Barnett Shale, Eagle Ford Shale, and Haynesville Shale); production increases by 40 to 50%	Roads and highway system (specifically lower functional road classes will be critically impacted), pipelines, and ports
Coal	Sustained activity levels	
Renewables (mostly wind)	Substantial slowdown in activity	

9.3 Scenario 2—Renewable Future (Market Driven)

Scenario 2 is driven by market demands, technological breakthroughs, and additional incentives for renewable energy sources. Texas experiences an economic recovery led by a rapidly growing population and an improved employment outlook. Energy demand increases, but concerns over energy security/climate change motivate Texans to adopt energy efficiency measures. State leaders increase the Texas RPS to 25,000 MW and allocate funds to develop efficiency-improving and GHG-reducing technologies. In response to new RPS mandates, increased funding is spent on research and development (R&D) to make the use of renewable energy feasible.

The federal government renews existing renewable electricity PTCs and ITCs and allocates additional funding to support further development. Texas completes an adequate transmission network to service the CREZs. The state's wind energy industry experiences substantial growth. Wind energy developers invest substantially in wind farm developments in West Texas, the Panhandle, and along the coast.

Concerns about global warming result in the closure of Texas's oldest coal-fired electricity generation plants, resulting in a loss of 5,000 MW. However, renewable energy sources, such as wind and solar, are supplemented by clean coal electricity. Substantial R&D funding results in major technology advancements and the installation of CCS in coal-fired electricity generation plants becomes the standard for any coal plant development.

Moderate oil prices result in a slowdown of activity in the Permian Basin, while increasing environmental concerns over oil security and climate change also result in consumers seeking to limit conventional gasoline usage, increasingly relying on alternative fuels.

Table 9.2 displays the main changes in the drivers that could result in this scenario. In general, however, this scenario is driven by high economic growth, technology breakthroughs, and increased concern over the environment and energy security that result in increased incentives for the renewable energy industry. Table 9.4 illustrates the additional transportation impacts associated with this Renewable Energy Future. Table 9.4 indicates this scenario will result in increased activity in Texas's natural gas regions and CREZs, impacting all modes of transportation. However, an increase in natural gas production and increased development of wind energy could substantially impact Texas's lower functional road classes.

Table 9.4: Additional Transportation Impacts—Renewable Future (Market Driven)

Energy Sector	**Energy Impacts**	**Additional Transportation Impacts**
Oil	Slowdown in activity levels	
Natural Gas	Substantial increase in activity levels (Barnett Shale, Eagle Ford Shale, and Haynesville Shale)	Roads and highway system (specifically lower functional road classes will be critically impacted), pipelines, and ports
Coal	Sustained activity levels	
Renewables (mostly wind)	Substantial increase in activity (CREZs, but also some off-shore wind developments)	Roads and highway system, rail, and ports

9.4 Scenario 3—Carbon Future

In Scenario 3, disruptions in the energy sector are spurred by global conflicts. Foreign oil supplies prove to be highly unstable, resulting in high oil prices that affect the U.S. economy.

Texas's population continues to increase at the past rate of about 2.3% and energy demand grows with the increased population at about 2.2%. High foreign oil prices result in a global recession affecting the U.S. and Texas's economies. On the other hand, Texas's oil and natural gas industries experience significant growth, and the Permian Basin, Barnet Shale, Eagle Ford Shale, and Haynesville Shale see an increase in output. This partially tempers the impact of the global recession on the state's economy. Nonetheless, a low economic growth rate of 1.8% is experienced.

The ailing economy precludes incentives for the renewable energy industries and a number of financial incentives for the oil and gas industry are eliminated. Texas's renewable energy industry—specifically wind—declines as federal and state policies (Renewable Portfolio Standards) are not renewed. The wind and biofuels industries lose their appeal sans financial incentives and tax credits.

The ailing economy also precludes the promulgation of the numerous EPA regulations anticipated in 2010 and 2011. Specifically, no legislation to restrict GHG emissions is adopted. U.S. energy policy also seeks to increase electricity generation from coal because of its domestic availability, its low resource cost, and existing coal-fired plants. Texas's coal energy industry experiences a significant increase in activity and both the production and imports of coal increase substantially.

In Scenario 3, Texas's oil and natural gas industry see record-setting levels of production given high oil prices. On the other hand, the ailing U.S. economy and low economic growth in Texas have a negative impact on the renewably energy industries. The latter is largely because of the elimination of a number of financial incentives and tax credits. Finally, high natural gas prices and increased concerns over energy security given global conflicts result in a renewed emphasis on the construction of new coal-fired electricity plants. Table 9.2 displayed the main changes in the drivers that could result in this scenario; Table 9.5 illustrates the additional transportation impacts associated with a Carbon Future.

Table 9.5: Additional Transportation Impacts—Carbon Future

Energy Sector	**Energy Impacts**	**Additional Transportation Impacts**
Oil	Substantial increase in activity levels (mostly tertiary extraction from mature wells)	Roads and highway system, pipelines
Natural Gas	Substantial increase in activity levels (Barnett Shale, Eagle Ford Shale, and Haynesville Shale)	Roads and highway system (specifically lower functional road classes will be critically impacted), pipelines, and ports
Coal	Substantial increase in activity levels	Rail
Renewables (mostly wind)	Declining levels of activity	

9.5 Scenario 4—Renewable Future (Regulatory Driven)

Scenario 4 has the same outcome as Scenario 2, but unlike Scenario 2 where growth in the renewable energy industry is driven by market demands, technological breakthroughs, and additional incentives for renewable energy sources, the drivers for Scenario 4 are technological breakthroughs and increased mandates and legislation.

Texas's economy continues to grow at the past rate of about 2.4% as a result of a rapidly growing population (i.e., 2.7%). Energy demand increases, but higher overall energy costs temper the energy demand. Per capita energy consumption thus declines so that the demand for energy grows at the past rate of about 2.2%.

On a national level, legislative mandates are adopted to enhance domestic energy production and enhance energy security. The U.S. Congress mandates that 20% of all electricity is generated from renewable sources, with wind delivering the highest percentage of the electricity generated in Texas. However, biofuel production varies by region as a result of resource availability and costs. For example, high corn transportation costs into Texas for ethanol production limits the production share of ethanol.

Concerns over energy security and climate change also motivate the federal and state governments to adopt strict environmental regulations to reduce emissions. This results in the passing of GHG legislation and a number of mandates that require the implementation of enhanced energy efficiency measures. State leaders increase the Texas RPS to 25,000 MW. The federal government renews existing renewable electricity PTCs and ITCs, but no additional funding is allocated to support further development. Texas completes an adequate transmission network to service the CREZs. The state's wind energy industry continues to grow as wind energy developers invest in wind farm developments in West Texas, the Panhandle, and the coastal areas.

Concerns over global warming result in the closure of Texas's oldest coal-fired electricity generation plants, resulting in a loss of 5,000 MW. Stricter regulations and mandates result in major technology advancements and the installation of CCS in coal-fired electricity generation plants becomes the standard for any coal plant development. Texas also makes considerable investments in retro-fitting older coal energy plants with clean coal technologies and in constructing numerous Integrated Gasification Combined Cycle (IGCC) plants. The high cost of these technologies, however, impacts the growth of the industry.

In Scenario 4, increased mandates and legislation driven by environmental and energy security concerns result in a substantial increase in natural gas mining and renewable energy production. On the other hand, Texas sees a slowdown in the mining of oil in the Permian Basin, while investments in clean coal technologies result in sustained activity levels for the coal industry. Table 9.2 displayed the main changes in the drivers that could result in this scenario; Table 9.5 illustrates the additional transportation impacts associated with a Renewable Energy Future driven by increased regulations and mandates.

Table 9.6: Additional Transportation Impacts—Renewable Energy Future (Regulatory Driven)

Energy Sector	**Energy Impacts**	**Additional Transportation Impacts**
Oil	Slowdown in activity levels	
Natural Gas	Substantial increase in activity levels (Barnett Shale, Eagle Ford Shale, and Haynesville Shale)	Roads and highway system (specifically lower functional road classes will be critically impacted), pipelines, and ports
Coal	Sustained activity levels	
Renewables (mostly wind)	Substantial increase in activity (CREZs, but also some off-shore wind developments)	Roads and highway system, rail, and ports

9.6 Concluding Remarks

In addition to the drivers considered in the development of the above scenarios, the AEO 2010 report argued that the "recovery of the world's financial markets is especially important for the energy supply outlook, because the capital-intensive nature of most large energy projects makes access to financing a critical necessity" (EIA, 2010). An important additional driver that will therefore impact Texas's future energy sector is the state of the global financial markets.

Although thus not exhaustive, each of the future scenarios holds different implications for the state of Texas and its transportation system. Though some assumptions are more likely than others, it remains important to consider alternative outcomes. The upcoming decades will bring changes to the country's political environment, advancements in technologies, increasing concerns over GHG emissions, and fluctuating fuel prices. These changes will ultimately decide Texas's position in the energy realm. The developed scenarios can assist TxDOT to visualize preferred futures, identify opportunities, adjust current constraints to prevent future outcomes, and recognize early warnings to possible changes.

Chapter 10. Concluding Remarks

Texas has been known as an energy state ever since the Lucas Number 1 well blew mud, gas, and oil 200 feet into the air at Spindletop on January 10, 1901. Since then, the oil and gas industry has contributed greatly to the state's Gross Domestic Product (GDP). From the oil discoveries in North, East, and West Texas during the early 1900s to recent natural gas discoveries in the Barnett Shale region of Arlington and Fort Worth, the Haynesville Shale region of East Texas, and the Eagle Ford Shale of South Texas, the oil and natural gas industries have been a significant factor in Texas's economic success. At the same time, coal-generated power plants produce a significant share of the electricity in the state. More than half of the coal feedstock is low sulfur Wyoming coal that is brought to the state by Union Pacific (UP) and Burlington Northern Santa Fe (BNSF) on long, heavy unit trains. Texas is also the number one producer of wind energy in the U.S., with a rated capacity of approximately 10,000 MW installed in West Texas and the Texas Panhandle. Other renewable energy sources, such as biomass electricity generation, biofuel production, solar energy, and geothermal energy are also being promoted in different regions of the state. On the other hand, the energy sector has placed significant demands on Texas's transportation system. Both the provision/construction of the enabling infrastructure and the daily operations of the different energy industries impacts Texas's transportation infrastructure. It is thus imperative to understand the factors that impact Texas's energy sector, how Texas's transportation system serves the energy sector, how the sector impacts the transportation system, and the future transportation needs of the energy sector. The focus of this report was the development of four energy scenarios that reflect different assumptions and outcomes for Texas's future energy sector over a 20- to 30-year period.

10.1 Energy Drivers

Information for several factors, referred to as *drivers*, that may impact the energy sector in the future were identified and analyzed. The drivers included the following:

- current and historic trends in energy production in Texas,
- current and historic energy demand,
- enabling infrastructure,
- improvements in energy extraction technologies,
- current and historic energy price trends,
- socio-economic impacts of the energy sector,
- environmental regulations, and
- tax and other government incentives.

Information regarding each of these drivers was presented in this report before using these drivers in developing plausible future scenarios for Texas's energy sector. The salient findings are summarized here.

10.1.1 Energy Production

Energy production in Texas has been generally declining since the 1970s primarily due to aging energy infrastructure and the depletion of conventional resources. Since 2005, however, energy production has leveled off and experienced an increase due to upgrades to existing power plants, the installation of new capacity, higher crude oil prices, advances in EOR, and the mining of unconventional natural gas (i.e., Barnett Shale, Haynesville Shale, and Eagle Ford Shale). Approximately 21.3 and 30%, respectively, of total U.S. oil and natural gas production occurs in Texas. In addition, approximately 10% of electricity produced in Texas occurs at the state's two nuclear power plants: Comanche Peak Nuclear Power Plant and the South Texas Project. Most of the state's electricity power generation (i.e., more than 80%), however, comes from coal and natural gas. Finally, as of July 2010, Texas had 9,707 MW of installed wind energy generation capacity—i.e., more than any other U.S. state and more than three times the installed capacity in California (American Wind Energy Association, 2010).

10.1.2 Energy Demand

From 1960 to 2005, the total energy consumed in Texas grew at an approximate annual rate of 2.2%, with the demand for transportation fuel growing at approximately 2.7% (The Energy Report 2008, 2008). Texas's industrial and transportation sectors are the largest consumers of energy at 49% and 25% of the total energy consumed in Texas in 2008. Industries such as cement production, petroleum refining, forestry product processing, and aluminum and glass production are very high energy consumers in Texas. A trend analysis also showed that the energy consumed by all sectors (i.e., residential, commercial, industrial, and transportation) increased between 1960 and 2005. The energy consumed by the industrial sector—although increasing overall—has experienced more annual fluctuations partly due to variations in energy prices. In terms of electricity consumption, historic trends clearly demonstrate a correlation between electricity consumption and population growth. For example, between 1980 and 2004, Texas's population grew at an average rate of 2.45% while electricity consumption grew at a rate of 2.4%. Anticipated increases in Texas's population will thus potentially result in an increase in energy demand.

10.1.3 Energy Efficiency

While the population and energy consumption has been increasing in Texas, the total energy intensity, or energy use per dollar of Texas's Gross State Product, has been decreasing since 1960 (The Energy Report 2008, 2008). This suggests that an increase in energy efficiency could temper the overall growth in energy consumption in the future. Several barriers to increase energy efficiency, however, exist in the residential and commercial sectors. A major barrier is lack of information on energy efficient practices and products. Also, energy-efficient investments tend to require a large, up-front monetary investment that can take years to recover. Increased energy costs, greater environmental awareness, improved building codes, increased appliance efficiency standards, and improved state and local utility programs are thus required to improve energy efficiency in the residential and commercial sectors. In the transportation sector—specifically, passenger transportation—changes in consumer trends and technologies could increase fuel efficiency. Improvements to the spark ignition vehicle, diesel engines, and the introduction of hybrid vehicles could potentially have the largest impact on energy consumption in the passenger transportation sector. In the case of freight transportation, the AEF concluded that a 10 to 20% reduction in fuel consumption can be achieved by advances in engine technologies and a transition to rail transportation. On the other hand, the major barriers to enhancing fuel efficiency in the transportation sector include unstable oil prices, a lack of production capacity, and the desire for size and performance over fuel efficiency. In terms of the industrial sector, the AEF projected a substantial energy use reduction given cost-efficient investments in key industries, particularly the chemical, petroleum, and cement processing industries. For example, high temperature reactors, advanced system controls, corrosion resistant materials, and overall energy efficient practices in the chemical and petroleum processing industries could improve efficiency by 10–20%. The major barriers to implementing energy efficiency improvements, however, include the high initial costs of energy efficiency improvements, a lack of expertise and knowledge regarding energy efficiency measures and technologies, and high risks associated with the introduction of new technologies.

10.1.4 Enabling Infrastructure

Texas's electricity grid was designed and built decades ago, with the last major addition added in the 1980s (Lott, Seaman, Upshaw, & Haron, 2011). Since then, electricity demand has increased substantially and the grid's increasingly outdated technology has been deteriorating and struggling to supply the demand. ERCOT has acknowledged the issues concerning Texas's aging transmission infrastructure and has elected to invest in smart and high efficiency technologies as opposed to repairing and maintaining the current grid configuration. The main component of the new electricity transmission project is the implementation of smart grid technology and building a more efficient grid. As of 2009, over 1,300 circuit miles of transmission lines have been added or improved. An additional 2,800 circuit miles are anticipated to be improved or added by 2013 (Smitherman B. , ERCOT Energy Seminar 2009, 2009). However, further transmission line improvements will be needed to bring the grid completely up to date.

10.1.5 Technology Advancements

Technology advancements offer the potential to (a) increase the supply of natural gas production in Texas; (b) provide more robust information about reservoirs and increase the tertiary oil recovered in the Permian Basin; (c) remediate environmental concerns regarding the use of coal as an energy source; (d) increase wind turbine power ratings and improve wind energy storage; (e) decrease the cost and improve the efficiency of solar technologies; and (f) move the experimental production of cellulosic ethanol to viable commercial production.

In recent years, the use of innovative, unconventional technologies and the mining of unconventional natural gas fields have resulted in an increase in natural gas production. However, more advances are needed in terms of drilling technologies to ensure the financial feasibility of these mining operations over the long term. Improvements in technology and decreasing drilling and production costs will increase the productive capacity of wells and potentially the number of productive wells.

Advanced drilling and EOR technologies are also believed to have the highest potential for increasing oil production in Texas. The advanced drilling technologies currently available or under development are horizontal drilling, multilateral drilling, extended reach drilling, and complex path drilling. On the other hand, three types of EOR technologies—i.e., thermal recovery, gas injection, and chemical injection—have been used successfully to increase oil production from existing wells by 30 to 60%. It has been estimated that nearly 74 billion barrels of oil are remaining in mature reservoirs in East and Central Texas that could be accessed using CO_2-EOR. To enhance the efficiency of EOR methods, more accurate well mapping technologies are needed. Research to develop a mapping tool that would create a realistic representation of the oil reservoir is under way. More robust information about reservoirs will allow for more precise drilling, more accurate use of EOR technologies, and an increase in the oil recovered (Improving Oil Extraction With New Mapping Technology, 2009).

Abundant supplies and relatively inexpensive extraction costs have resulted in coal being a popular source for electricity generation. However, the burning of coal is a large contributor of GHG and other pollutants. Two new processing and pollution reduction technologies that aim to reduce the environmental impacts of coal usage have been under development: (a) coal gasification technologies and (b) carbon capture and storage. Regarding the former, instead of burning the coal directly, coal gasification requires that the coal first be converted into a gas and then cleaned of a majority of its impurities. The new gaseous fuel, referred to as Syngas, is then converted into electricity similarly to natural gas, resulting in increased efficiencies and significantly less GHG and particulate pollutants. The process also produces hydrogen gas, which could be used in the development of hydrogen fuel cells. Because approximately one-third of carbon emissions in the U.S. are released by fossil power plants (Carbon Capture R&D, 2011), research into the separation and storage of CO_2—e.g., carbon capture and storage (CSS)—has become important over the last several years. CCS involves the separation of CO_2 gas from the other emissions released by power plants and storing the CO_2 in underground geological formations. The high costs associated with the implementation of coal gasification power plants and CCS has, however, limited the adoption of these technologies. Technology advancements that reduce the costs of CSS and near-zero-emissions coal power plant technologies are thus required to ensure that coal remain a feasible energy source given increased environmental regulations.

In the field of wind energy technologies, one trend aims to increase the capacity—and therefore size—of wind turbines. The larger the diameter, the larger the individual components, and the more challenging the transportation of the individual components and the erection of these turbines become. Research has thus been conducted on alternative self-erection concepts to overcome some of the challenges in erecting and maintaining very large wind turbines (Thresher & Laxson, 2006). If the research proves the concept feasible, it will facilitate the erection of even larger wind turbines. On the other hand, the transportation challenges and structural capacity limitations of the tower foundations have also sparked an interest in the development of smaller, lighter wind turbine components. For example, researchers at the National Renewable Energy Laboratory (NREL) have built a full-scale prototype of a 1.5 MW generator with a diameter of only 4 meters, and they have a preliminary design of a generator with a diameter of 2 meters—a size reduction of 60 to 80% (Thresher & Laxson, 2006). Finally, the unpredictability of wind energy, surpassing the capacity of the grid at some points and almost completely ceasing production at others, has resulted in wind energy storage becoming another area of research. Currently, large-scale battery facilities, compressed air energy, and hydrogen storage are three key storage technologies that are under development.

Given Texas's very high potential for solar power generation, two types of solar power were of interest to this project: solar photovoltaic (PV) and concentrated solar power (CSP). Currently, market PV cells have an efficiency of 12 to 18% and future developments are striving for a higher efficiency at lower production costs. Some of the barriers to the more widespread use of this power source include the high initial cost to home owners (in the case of residential applications) and the large land area needed to make it financially feasible for utilities. CSP uses mirrors in an array of shapes and formations to focus the sun's heat energy on a single point to produce steam and electricity. The latter is a utility scale solar technology for regions with high solar flux. Design improvements in high temperature and optical materials, as well as energy storage technologies such as thermal energy storage (TES), will potentially improve the cost effectiveness of CSP (Kimbis, 2008). In addition to TES, battery storage, CAES, and hydrogen storage are also options for storing excess solar energy.

Because of the potential negative impacts on the food and feedstock markets resulting from bio-fuels derived from corn and soybeans, alternative feedstocks have become the focus of recent bio-fuels research. An alternative bio-fuel that holds great potential is cellulosic ethanol. Waste generated from agriculture, forestry, and urban areas can be converted into cellulosic ethanol without impacting the food and feedstock market. Texas has the potential to be a major producer of cellulosic ethanol. However, although the feedstock for cellulosic ethanol is abundant, the technology to convert the feedstock material into cellulosic ethanol is still largely experimental. As of 2008, the conversion process could only be achieved in the laboratory. Demonstration on a commercial scale will thus largely be the deciding factor as to whether cellulosic ethanol is a viable substitute for corn grain ethanol or conventional gasoline.

Finally, nuclear energy constitutes a clean source of electricity and unlike biomass and other forms of renewable energy, no major research and development needs to be conducted to deploy nuclear power. Several issues, however, surround the widespread use of nuclear. The two main issues are cost and public concern about radiation exposure. It is extremely expensive to build a nuclear power plant. Investments in future plants will be limited if cost overruns occur or if the electricity produced is not competitive in the market. Another major obstacle that nuclear energy faces is public concern about radiation exposure. Incidents such as Three Mile Island, Chernobyl, and Fukushima Daiichi have left a lasting impression on the public that nuclear energy are unsafe. Currently, no facilities exist for the long-term storage of nuclear wastes. Without a site for long term disposal of nuclear waste, the stockpiles of spent fuel continue to grow and fuel uncertainty about the future of nuclear power as an energy source.

10.1.6 Energy Prices

The trend analysis conducted in this research indicates that the price of petroleum and electricity increased substantially in the U.S. since 2002. The price of natural gas increased between 2002 and 2005 but declined in 2006 and 2007 before increasing again in 2008. The price of coal increased marginally between 2003 and 2008, while the price of nuclear power remained constant between 1989 and 2008. Energy prices are largely anticipated to continue to increase in the future given all four scenarios—i.e., high economic growth, low economic growth, high oil price, and low oil price—of the EIA's AEO. The exception is the average price of motor gasoline under the low oil price scenario.

10.1.7 Socio-Economic Impacts

Concurrent with the development of new forms of energy, primarily wind, Texas is currently experiencing a boom cycle in oil and gas drilling activity not seen since the early 1980s. In 2007, over 20,000 wells were drilled in Texas, which were the most holes drilled within a year since 1985 (Texas Renewable Portfolio Standard). The research team found that while new developments may bring about population changes such as those of a boomtown model (as experienced by communities in the Eagle Ford play), much of the current energy development is occurring in rural areas of previous energy development (and thus the human capital and physical infrastructure is in place) or within metropolitan areas with more diverse economies. In addition, drilling crews in these new developments may commute from other areas and remain in the local community only temporarily. Thus the impacts may not be as great (and have a more diffused impact) than those felt within a boomtown (Wynveen, 2011; Gramling & Brabant, 1986). The research team also found that wind farms are located primarily in areas in West Texas where oil and gas production is occurring. Relative to oil and gas drilling, the impacts of wind energy development, though important, are small. However, this industry is relatively young. As the industry develops, some areas in Texas have potential for specialization in this industry with broader impacts than those seen here.

10.1.8 Environmental Regulations

The regulatory playing field for energy production is expected to change substantially over the next 3 to 15 years. Over the past year and a half (2010–2011), a plethora of environmental rules regarding air quality, emissions, water quality, and waste management that apply to energy production facilities has been issued by the EPA. Some of these rules have been issued to comply with federal circuit court orders with some deadlines for compliance starting in 2012 and working till 2018. Specifically, the EPA has issued new rules under the Clean Air Act pertaining to stationary sources regarding Particulate Matter (PM), Hazardous Air Pollutants (HAPs), National Emission Standards for Hazardous Air Pollutants (NESHAPS), Maximum Achievable Control Technology (MACT), and National Air Attainment Quality Standards (NAAQS). These are expected to impact existing and new site development for power plants and other industries that utilize boilers and produce regulated and hazardous pollutants and GHGs. For example, during September 2009, the EPA announced a proposal that focused on large facilities that emitted over 25,000 tons of GHG annually. Facilities will be required to obtain permits to demonstrate they are using best practices/technologies to minimize GHG emissions (EPA, 2009). In April 2011 the EPA also proposed the Cooling Water Intake Rule for all existing power generating facilities and manufacturing industrial facilities (EPA (c) no date). This rule applies to all existing power-generating facilities (and manufacturing and industrial facilities) that withdraw more than two million gallons of water per day and use at least 25% of the water withdrawn exclusively for cooling purposes. For example, these facilities would be subject to an upper limit on how many fish can be killed by being pinned against intake screens or other parts of the facility.

The EPA is also currently developing permitting guidance for oil and gas hydraulic fracturing activities. This rule is being developed under the parameters of the Safe Drinking Water Act (SDWA) Underground Injection Control (UIC) Class II Regulations. Stakeholder meetings were held during spring 2011, including a series of webinars where the EPA worked with stakeholders to gather information to assist the permit writers. The draft guidance was expected to be developed during summer 2011 and the public comment period proposed for fall 2011.

10.1.9 Financial and Tax Incentives

It is often argued that the future of the U.S. and Texas's energy sector will be determined by technology advancements, <u>financial and tax incentives</u>, policy changes, and the rising costs of fossil fuels. For some energy industries—specifically the future of the wind and biomass industry—the continuance of federal and state incentive programs is critical to the industries' continued growth. For example, renewal or expiration of the Energy Policy Act (EPACT) of 2005 could have a major policy impact on the future of wind energy. Currently, EPACT authorizes loan guarantees for technologies that avoid emitting GHGs and provides subsidies for wind and other alternative energy producers. Specifically, $2.7 billion was allocated to extend the renewable electricity Production Tax Credit (PTC) (U.S. Department of Energy, 2010). The PTC provides a federal income tax credit for wind generation in the first 10 years of a wind facility's operation and, as of May 2010, the PTC was valued at about $0.022/kWh of wind energy. The PTC is set to expire in 2012. Similarly, the oil and gas industry will be impacted by the elimination of a number of financial incentives. For example, in President Obama's 2011 budget, he proposed eliminating nine different tax expenditures that primarily benefit the oil and gas industry. The latter include the deduction of certain types of intangible costs associated with the drilling and preparing of wells for the production of oil and gas; the subsidization of the costs for tertiary injectants used in EOR; the allowance of an independent oil company to deduct from its taxes about 15% of the revenue generated from a well (i.e., percentage depletion allowance); and the deduction of geological and geophysical expenditures associated with searching for oil over a 2-year period.

10.2 Energy Futures

Scenario development is a tool used in planning for the future, and was employed in this research to develop varying alternatives for Texas's "energy futures." The purpose of scenarios is not to precisely forecast future events and their implications, but rather to answer exploratory questions, such as these:

- How will the state's population change in the future? Will a growing Texas population require more energy?
- Will oil and natural gas resources be adequate to meet rising demands? If not, when will their reserves mature?
- What technological developments will be the gateway to feasible and economically attractive renewable energy implementation?
- With economic recovery, what changes will be realized in the energy industry?
- Will concerns over energy security and the climate motivate governments to draft legislation impacting the energy industries? If so, what policy changes will have the greatest ramifications?

Seeking answers to these questions, this research considered and analyzed a number of drivers in terms of their potential impact on each of Texas's energy industries. These results were then incorporated with those from the analysis of other industries to form a framework for a potential scenario. The framework was then evaluated and refined to produce a general scenario concept, which evolved into a future Texas scenario. Ultimately, four scenarios were developed that present different assumptions with regards to the future of oil, coal, natural gas, and renewables in Texas.

Scenario 1 (Fossil Fuels Future) is driven by growing energy demand and relatively high oil prices that result in increased oil and natural gas production in the Permian Basin, the coastal areas, and the shale regions (i.e., Barnett Shale, Eagle Ford Shale, and Haynesville Shale). Scenario 1 will result in a substantial increase in activity on Texas's highway system (specifically, the lower functional classes because of increased natural gas activity), Texas's ports and the access roads to Texas's ports, and the state's pipeline infrastructure. **Scenario 2 (Renewable Energy Future—Market Driven)** is driven by high economic growth, technology breakthroughs, and increased concern about the environment and energy security that result in increased incentives for the renewable energy sector. Scenario 2 will result in increased activity in Texas's natural gas regions and CREZs, impacting all modes of transportation. However, an increase in natural gas production and increased development of wind energy could substantially impact Texas's lower functional road classes. In **Scenario 3 (Carbon Future)**, Texas's oil and natural gas industry see record-setting levels of production given high oil prices. On the other hand, the ailing U.S. economy and low economic growth in Texas have a negative impact on the renewably energy sectors. The latter is largely because of the elimination of a number of financial incentives and tax credits. Finally, high natural gas prices and increased concerns over energy security given global conflicts result in a renewed emphasis on the construction of new coal-fired electricity plants. Scenario 3 will result in increased activity in Texas's natural gas regions and the Permian Basin, resulting in potentially dire impacts on the lower functional road classes in the natural gas regions. Also, in the Carbon Future, increased rail activity can be anticipated given an increased demand for out-of-state coal. In **Scenario 4 (Renewable Energy Future—Regulatory Driven)**, increased mandates and legislation driven by environmental and energy security concerns result in a substantial increase in natural gas mining and renewable energy production. Texas sees a slowdown in the mining of oil in the Permian Basin, while investments in clean coal technologies result in sustained activity levels for the coal industry. Scenario 4 will result in a substantial increase in activity on Texas's highway system (specifically, the lower functional classes because of increased natural gas activity), Texas's ports and the access roads to Texas's ports, and the state's pipeline infrastructure.

Although not exhaustive, each of the future scenarios holds different implications for the state of Texas and its transportation system. Though some assumptions are more likely than others, it remains important to consider alternative outcomes. The upcoming decades will bring changes to the country's political environment, advancements in technologies, increasing concerns over GHG emissions, and fluctuating fuel prices. These changes will ultimately decide Texas's position in the energy realm. The developed scenarios can assist TxDOT envisaging preferred futures, in identifying opportunities, adjusting current constraints to prevent future outcomes, and in recognizing early warnings to possible changes.

10.3 Energy Indicators

In developing Texas's energy scenarios, the research team identified a number of drivers or indicators that TxDOT can track in an effort to anticipate energy demand and therefore an associated increase in activity on Texas's transportation system. The following are thus key drivers by energy source that TxDOT can track:

- *Oil*—crude oil price, technology advancements, and lifting of the congressional moratorium that currently restricts offshore leasing and drilling of oil;
- *Coal*—economic growth (resulting in commercial expansion and increased industrial production with associated increases in electricity consumption), environmental regulations (including possible GHG regulations), and high natural gas prices;

- *Renewable energy*—legislation changes (specifically, renewal of the Energy Policy Act of 2005, The Energy Independence and Security Act, and the state's Renewable Portfolio Standard) and financial incentives and tax credits (e.g., loan guarantees, subsidies and tax credits, such as the PTC and the federal ITC) ; and
- *Natural gas*—economic growth (resulting in commercial expansion and increased industrial production with associated increases in electricity consumption), advanced drilling technologies and technology improvements, and environmental legislation pertaining to hydraulic fracturing.

Tracking these drivers will assist the agency in recognizing early warnings that an increase in activity on Texas's transportation system may be forthcoming. For example, oil drilling in the Permian Basin is highly dependent on the price of oil. This is because Texas is a relatively high cost producer of oil. Oil reclamation activity in Texas is thus largely a function of the oil price. High oil prices thus result in increased oil reclamation activity, necessitating the movement of equipment, water to the site, and brine water from the site. At the same time, activity decreases rapidly when oil prices fall. Tracking the price of a barrel of oil can thus provide an indication of the amount of drilling activity and hence the impact on Texas roads in the Permian Basin.

10.4 Concluding Remarks

Texas's thriving energy sector is the product of many decades of resource discoveries and innovative production practices, all supported by the state's transportation system. Whether importing out-of-state coal, using Farm-to-Market roads to access natural gas wells, or transporting wind turbine components along major Interstate Highway corridors, the transportation system plays a major role in supporting Texas's energy industry. With the assumption that Texas's energy sector—conventional and renewable—will experience substantial growth over the next couple of decades, it is crucial to the state's economic success that TxDOT consider a variety of energy outcomes and their impact on the transportation system.

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Appendix A: Regulations for Energy Production Facilities (2010–2011)

Over the past year and a half (2010–2011), a plethora of new environmental rules regarding air quality, emissions, water quality, and waste management that apply to energy production facilities have been issued by the U.S. Environmental Protection Agency (EPA). Some of these rules have been issued to comply with Court Orders from federal circuit courts. This appendix briefly describes the various rules and the informational and methodological changes the EPA proposed, issued, or discussed, as well as potential impacts that are expected. Finally, the appendix also summarizes the findings of reports issued by the North American Electric Reliability Corporation (NERC) entitled *Reliability Impacts of Climate Change Initiatives*[10] and *2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations,*[11] which looked at four rules under development vis-à-vis the potential impact on megawatt generation.

A.1 Review of Litigation surrounding Air Quality 2010

Litigation surrounding federal and state implementation plans (i.e., FIPs and SIPs) saw four main cases surrounding conformity with air quality and National Ambient Air Quality Standards (NAAQS).[12] New source review (NSR) and the prevention of significant deterioration (PSD) along with new source performance standards (NSPS) saw five main cases decided in 2010.[13] Hazardous air pollutants (HAPs) and National Emission Standards for Hazardous Air Pollutants (NESHAPs) saw three main cases decided during 2010.[14] Mixed in with this litigation were also cases surrounding mobile sources and fuels, and protection of stratospheric ozone, which also impact the FIP, SIP, and NAAQS determinations. For the purposes of many of the new rules, the HAP and NESHAP determinations will continue to play a role in how the EPA constructs new rules and standards surrounding stationary sources.

The complexity of how rules may be created, delisted, and then relisted by the EPA often has significant impacts for plant construction, reconstruction, alterations, and additions. For example, in *Sierra Club v. Sandy Creek Energy Assocs*., the Fifth Circuit reversed a district court's decision that had denied summary judgment to Sierra Club on its claim that Sandy Creek's ongoing construction of a coal-fired plant without a determination of emissions

[10] North American Electric Reliability Corporation. *Reliability Impacts of Climate Change Initiatives*. July 2010. Accessed from: http://www.nerc.com/files/RICCI_2010.pdf

[11] North American Electric Reliability Corporation. 2010 *Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations*. October 26, 2010. Accessed from: http://www.nerc.com/files/EPA_Scenario_Final.pdf

[12] *Natural Res. Def. Council v. S. Coast Air Quality Mgmt. Dist.*, 694 F. Supp. 2d 1092 (C.D. Cal. 2010); *Del. Dep't of Natural Res. & Envtl. Control v. U.S. Army Corps of Eng'rs,*, 681 F. Supp. 2d 546 (D. Del. 2010); *North Carolina v. Tenn. Valley Auth.*, 615 F.3d 291 (4th Cir. 2010; and *S. Coast Air Quality Mgmt. Dist. v. Fed. Energy Regulatory Comm'n* (FERC)., 621 F.3d 1085 (9th Cir. 2010).

[13] *United States v. Midwest Generation*, 694 F. Supp. 2d 999 (N.D. Ill. 2010); *Nat'l Parks Conservation Ass'n v. Tenn. Valley Auth,* No. 3:01-CV-71, 2010 WL 1291335 (E.D. Tenn. Mar. 31, 2010); *Sierra Club v. Otter Tail Power Co.*, 615 F.3d 1008 (8th Cir. 2010); *United States v. Cinergy Corp.*, 623 F.3d 455 (7th Cir. 2010); and *Pennsylvania v. Allegheny Energy*, No. 05-0885, 2010 WL 1541457 (W.D. Pa. Apr. 18, 2010).

[14] *Coal. of Battery Recyclers Ass'n v. EPA.*, 604 F.3d 613 (D.C. Cir. 2010); *Sierra Club v. Sandy Creek Energy Assocs.*, 627 F.3d 134 (5th Cir. 2010); *Wildearth Guardians v. Pub. Serv. Co. of Colo.*, 698 F. Supp. 2d 1259 (D. Colo. 2010).

limitations for mercury violated Section 112 of the Clean Air Act (CAA). Construction of this plant had occurred when the EPA had delisted coal and oil-fired electric generating units from the list of sources of HAPs subject to the maximum achievable control technology (MACT) under Section 112. The delisting of this rule was vacated by a D.C. circuit opinion in 2008[15]. The Fifth Circuit held that notwithstanding Sandy Creek's reasonable reliance on the delisting rule, the ongoing construction without a MACT determination by the state permitting authority violated Section 112.

The delisting rule was also considered in *Wildearth Guardians v. Pub. Sev. Co. of Colo.*, where a utility had been issued a final permit after the EPA promulgated a final rule removing coal and oil fired utility steam generating units from regulation under Section 112 (g) CAA in 2005. Construction had commenced in October 2005 and did not include the MACT determination. The complaint was filed by the plaintiff after the D.C. circuit had vacated the delisting rule. The Defendant's permit was amended in February 2010 to include a MACT determination. As this case raised federal questions under the CAA, it concluded it should abstain from further review and not interfere with the state's ongoing process for implementation and review of the air permit.

Citizen suits are also of interest for the purposes of transportation's interaction in a SIP and in air pollution. Five major citizen suits surrounding the SIP, emission standards, and permit issuance were also issued during 2010.[16]

Regulatory Developments: Air

From 2010 to June 2011, the EPA has issued a slew of new rules under its rule-making authority contained in the CAA 1990, pertaining to stationary sources and PM, HAP, NESHAPS, MACT, and NAAQS. The EPA also issued multiple notices regarding new measuring methods for various pollutants. All these developments will impact existing sites and new site development for power plants and other industries that utilize boilers and produce regulated pollutants, hazardous pollutants, and Greenhouse Gases (GHGs).[17] The rules, notices, and other items for air are listed through the months from January 2010 to June 2011 in Appendix B.

For our purposes, eight main sets of promulgated and proposed rules (where the EPA is requesting comment) will have direct impact on the energy production sector and the development of transportation improvement plans that have to conform and work with the SIP to ensure air quality compliance. Many of these are in response to court vacateur decisions, which have strict compliance dates. For many of the rules deadlines for compliance begin in 2012 and work through to 2018. Table A.1 shows the proposed costs for installation and maintaining controls under the various proposed and promulgated rules.

[15] *New Jersey v. EPA.*, 517 F.3d 574 (D.C. Cir. 2008).
[16] *Sierra Club v. Korleski.*, 716 F. Supp. 2d 699 (S.D. Ohio 2010); *McEvoy v. IEI Barge Servs., Inc.*, 622 F.3d 671 (7th Cir. 2010); *Sierra Club v. Jackson.*, 724 F. Supp. 2d 33 (D.D.C. July 20, 2010); *Concerned Citizens Around Murphy v. Murphy Oil USA, Inc.*, 686 F. Supp. 2d 663 (E.D. La. 2010); and *Sierra Club v. Dairyland Power Coop.*, No. 10-CV-303-bbc, 2010 WL 4294622 (W.D. Wis. Oct. 21, 2010).
[17] This appendix only includes rules that are general/national in nature and rules that are Texas-specific (or where Texas is one of a list of states that are impacted).

Table A.1: Proposed Rules and Estimated Costs per Year

Rule	Cost (per year)
Clean Air Transport Rule	$2.8 billion (2006 $)
Ozone Standards Under NAAQS	$7.6 to $8.8 billion annually in 2020 (achieve 0.075 ppm). 2010 rule requires 0.060–0.070 ppm).
Industrial Boiler Maximum Achievable Control Technology (MACT)	
Major source boilers	$1.4 billion
Area source boilers	$487 million
Commercial and industrial solid waste incineration units including solid waste and recycling in commercial and industrial solid waste incinerator units	$232 million
Portland Cement Kiln MACT	
Installing and operating	$350 million in 2013
Installing operating + indirect social costs	$926 million to $950 million by 2013
Utility Maximum Achievable Control Technology (MACT) (also known as the Toxics Rule)	$109 billion in 2015 ($2007 dollars) in annual incremental compliance cost
Coal Combustion Residuals (adding together Subtitle C – Special Waste + Subtitle D + Subtitle D – Prime)	$1,474 million (Special waste) $587 million (Subtitle D) $236 million (D Prime)
Cooling Water Intake Rule (the EPA analyzed only two hypothetical outcomes for site-specific BTA determinations under Option 1: (a) cost of closed cycle at the 76 largest fossil fuel plants withdrawing from tidal waters and (b) variant on this scenario involving 46 facilities assuming only base load and load following facilities would retrofit to closed-cycle cooling).	$762 million (76 largest fossil fuel plants) $480 million (variance of 46 plants)
Greenhouse Gas Tailoring Rule:	
Industrial Permit Costs	$46,400 per permit (new); $1,700 thousand for permit revision
State/Local/Tribal Permit Costs	$19,700 per permit (new); $9.8 thousand new commercial/residential; and $1,800 for permit revision

Clean Air Transport Rule

40 CFR Parts 51, 52, 72, 78 and 97 will limit the interstate transportation of NO_x and sulfur dioxide (SO_2). The EPA identified and limited emissions from 32 states in the eastern U.S. that affect the ability of downwind states to attain and maintain compliance with the 1997 and 2006 Particulate Matter ($PM_{2.5}$) NAAQS and the 1997 Ozone NAAQS. The EPA proposes to limit these emissions through Federal Implementation Plans (FIPs) that regulate electric generating units in the 32 identified states. Texas is one of these identified states for the 1997

Ozone NAAQS.[18] The rule will reduce interstate transportation of ozone and fine particulate. The Clean Air Transport Rule will replace the Clean Air Interstate Rule (CAIR) that was issued in 2005, about which the court ruled had some parts that were not authorized by law. The court left CAIR in place, but required the EPA to replace it.[19]

The EPA is proposing a preferred approach (method) to achieve the emission reductions. It requires each state to limit its emissions; allows air pollution emissions trading within a state, and limited between-state trading among power plants. In total, four trading programs are proposed–one for seasonal NOx, one for annual NOx, and two for SO_2. The EPA is proposing two alternative approaches.

1st Alternative	**2nd Alternative**
• Requires each state to limit its emissions • Allows only within-state trading	• Requires each state to limit its emissions • Limits the emission rate of each source (direct control) • Allows limited emissions averaging within each state.

The EPA prefers the limited trading approach because of the following factors:

- Most source-specific control requirements limit emissions rates, not total emissions.
- If sources cannot adjust their power output, electricity reliability is likely to suffer.
    - None of the EPA's alternatives within this proposal can ensure that there will be no emission increases at any facility.
        - Under the direct control alternative, the emissions rate for each facility is reduced, but each facility could emit more by increasing its power output.
        - Under the within-state trading option, state emissions are limited, but individual facilities within each state could increase their emissions as long as another facility in the state decreased theirs.
- Determining a separate cap for each source would be time-consuming and would likely lead to less-stringent control requirements.
- Limited trading helps keep control costs—and electricity prices—low.

Unlike other trading programs, the CATR limits total emissions from covered sources in each state:

- Sources CANNOT use existing CAA allowances to comply, which means sources cannot draw on the existing bank instead of reducing emissions.
- Strict penalties:
    - If a source fails to turn in enough allowances to cover its emissions, it must surrender additional allowances (beyond the number needed to cover its emissions) and is violating the CAA and must therefore pay a maximum discretionary penalty of $37,500 per ton/day (inflation adjusted).

[18] 75 Fed. Reg. 45,210 Accessed at http://www.gpo.gov/fdsys/pkg/FR-2010-08-02/pdf/2010-17007.pdf#page=1

[19] U.S. EPA. *EPA Transport Rule: What Does it Mean for Environmental Justice Communities.* September 2010 Webinar. Accessed at http://www.epa.gov/airtransport/pdfs/WebinarTransportRuleMaterials.pdf

- A source must also turn in additional allowances if it emits more than its share when the state limit is exceeded. If it fails to do that, it is subject to CAA penalties.

- States have additional tools (e.g., SIP requirements) that provide an additional "backstop."
- The EPA is also working on other efforts (e.g., tighter NAAQS and the implementation of air toxics standards) to protect every neighborhood from air pollution.[20]

By 2014, the proposed Transport Rule is estimated to increase national average retail electricity prices roughly 1.5%. The EPA cites the following as an example: if you spend $100.00 per month on your electric bill in 2014, your bill is estimated to increase to $101.50 as a result of the Transport Rule. The EPA estimates that the annual direct costs to the power sector to comply with the proposal (i.e., installing and operating advanced pollution control equipment or switching fuels) is $2.8 billion dollars per year (in 2006 dollars).[21]

<u>Ozone Standards under NAAQS</u>

In January 2010, the EPA proposed to strengthen the NAAQS for ground-level ozone. The proposal is to strengthen the 8-hour primary ozone standard, to a level within the range of 0.060–0.070 parts per million (ppm). The EPA also proposes to establish a distinct cumulative, seasonal "secondary" standard (to protect sensitive vegetation and ecosystems) within the range of 7–15 ppm-hours. This was a result of reconsideration of identical primary and secondary ozone standards that were set in 2008 at 0.075 ppm. The EPA's panel of scientific advisors (Clean Air Scientific Advisory Committee—CASAC)[22] commented that the 2008 standards were not consistent with their recommendations, so the EPA has opted to strengthen the primary standard by placing more weight on key scientific and technical information, including epidemiological studies showing effects in healthy adults at 0.060 ppm. The EPA did not reconsider the form of the primary standard, but did review and change the form of the proposed secondary standard as a cumulative peak-weighted index called W126. This is calculated by

- weighting each hourly ozone measurement occurring during the 12 daylight hours (8:00 a.m. to 8:00 p.m.) each day, with a higher weight given higher concentrations. This "peak weighting" emphasizes higher concentrations more than lower concentrations, because higher concentrations are disproportionately more damaging to sensitive trees and plants;

- adding these 12 weighted hourly ozone measurements for each day to get a cumulative daily value;

- summing the daily values for each month to get a cumulative monthly value;

[20] EPA *EPA Transport Rule: What Does it Mean for Environmental Justice Communities.* September 2010 Webinar. Accessed at: http://www.epa.gov/airtransport/pdfs/WebinarTransportRuleMaterials.pdf
[21] EPA. *Proposed Transport Rule Fact Sheet*. June 2010. Accessed at: http://www.epa.gov/airtransport/pdfs/FactsheetTR7-6-10.pdf
[22] EPA Ozone Standards. National Ambient Air Quality Standards Webpage. Accessed at: http://www.epa.gov/ttnnaaqs/standards/ozone/s_o3_index.html.

- identifying the three consecutive months during the ozone season with the highest index value, to get the cumulative seasonal index value; and
- averaging these maximum seasonal index values over 3 years.

An area would meet the proposed secondary standard if the 3-year average of the cumulative seasonal index values is less than or equal to the level of the standard (i.e., 7–15 ppm-hours).

The EPA proposed the final rule to be issued in August 2010 and the timeline for implementation was envisaged to be put onto an accelerated schedule so that by January 2011 states would make recommendations for designation of attainment/non-attainment areas. The EPA would make final area designations in July 2011, which would become effective on August 2011. By December 2013, SIPS would be due to the EPA and between 2014 and 2031 states would be required to meet the primary standard with deadlines depending on the severity of the problem. However, due to the level of comments, ongoing scientific rule, and the EPA's administrator's intention to ensure that the decision is grounded in the best science, the EPA intends to set a final standard in the range recommended by CASAC by the end of July 2011.[23]

The EPA also issued a separate rule in July 2009 to modify the ozone air quality monitoring network design requirements. These were concluded to better support the alternative ozone standards. During the 2010 rule issuance the EPA noted that approximately 270 new ozone monitors would be required to satisfy the new monitoring requirements.[24] The EPA estimates that the cost of implementing a standard of 0.075 ppm would range from a low of $7.6 billion to a high of $8.8 billion annually in 2020.[25]

<u>Industrial Boiler Maximum Achievable Control Technology (MACT)</u>

During May 2011, the EPA announced the next step in allowing time to seek and review additional public input on the final standards for boilers and certain waste incinerators that were issued in February 2011. This was in response to a D.C. Court of Appeals ruling that had vacated previous regulations affecting these sources issued in July 2007. The agency had listed in April 2010 draft rule proposals and received over 4,800 comments, including information that industry had not provided prior to the proposals. The EPA made extensive revisions to the proposed subcategories and to some of the proposed emission limits and requested additional time for review from the United States Court of Appeals for the District of Columbia Circuit. The Court only granted the EPA an additional 30 days, which led to the February 2011 issuance of rules.[26] The EPA is now reconsidering the standards, because the public did not have sufficient

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[23] EPA. Ground Level Ozone Regulatory Actions Webpage. Accessed at: http://www.epa.gov/glo/actions.html
[24] EPA. *Fact Sheet: Proposal to Revise the National Ambient Air Quality Standards for Ozone.* January 6, 2010. Accessed at: http://www.epa.gov/air/ozonepollution/pdfs/fs20100106std.pdf . See also Ground-level Ozone Regulatory Actions Page at http://www.epa.gov/air/ozonepollution/actions.html#jan10s
[25] EPA. Fact Sheet. *Final Revisions to the National Ambient Air Quality Standards for Ozon*e. March 2008. Accessed at: http://www.epa.gov/glo/pdfs/2008_03_factsheet.pdf
[26] EPA. Fact Sheet *EPA Next Step for the Reconsideration of the Final Air Toxics Standards for Industrial, Commercial, and Institutional Boilers and Process Heaters at Major Source Facilities and Commercial and Industrial Solid Waste Incineration Units*. May 16 2011. Accessed at: http://www.epa.gov/airquality/combustion/docs/20110516nextstepfs.pdf

Final rule establishes emission limits for

- mercury,
- dioxin,
- particulate matter (PM) (as a surrogate for non-mercury metals),
- hydrogen chloride (HCl) (as a surrogate for acid gases), and
- carbon monoxide (CO) (as a surrogate for non-dioxin organic air toxics)

opportunity to comment on the changes, and as a result, further public review and feedback is required to meet the legal obligations under CAA.[27]

The February 2011 finalized rules—released under court orders—will reduce emissions of air pollutants from existing and new boilers, commercial and industrial solid waste incinerators (CISWI), and sewage sludge incinerators (SSI). The specific actions are described in this section.

Area Source Facilities: This class covers boilers located at area source facilities that burn coal, oil, or biomass, or non-waste materials, but not boilers that burn only gaseous fuels or any solid waste. The source boilers are being regulated based on boiler design. Different rules are set for large and smaller boilers and are based on heat input capacity. Smaller boilers have a heat input capacity less than 10 million British Thermal Units per hour (Btu per hr) and larger boilers have a heat input capacity greater or equal to 10 million Btu. The rule establishes standards to address emissions of mercury, PM (as a surrogate for non-mercury metals), and carbon monoxide (as a surrogate for organic air toxics).

For new boilers, the rule requires that coal-fired boilers, with heat input equal or greater than 10 million Btu per hour, meet emission limits for mercury, PM, and CO; biomass and oil-fired boilers, with heat input equal or greater than 10 million Btu per hour, meet emission limits for PM, and boilers with heat input less than 10 million Btu per hour must perform a boiler tune-up every 2 years.

For existing boilers, the rule requires that coal-fired boilers, with heat input equal or greater than 10 million Btu per hour, meet emission limits for mercury and CO; and biomass boilers, oil-fired boilers, and small coal-fired boilers are not required to meet emission limits. They are required to meet a work practice standard or a management practice by performing a boiler tune-up every 2 years. By improving the combustion efficiency of the boiler, fuel usage can be reduced and losses from combustion imperfections can be minimized. Minimizing and optimizing fuel use will reduce emissions of mercury and all other air toxics. All area source facilities with large boilers are required to conduct an energy assessment to identify cost-effective energy conservation measures.

The EPA estimates the U.S. has approximately 187,000 existing area source boilers at 92,000 facilities and that approximately 2,400 new area source boilers will be installed over the next 3 years. Installing and maintaining controls for this rule is estimated to cost $487 million per year.[28]

Major Source Facilities: This class covers new and existing industrial, commercial, and institutional boilers and process heaters at major source facilities. A major source facility emits or has the potential to emit 10 or more tons per year (tpy) of any single air toxic or 25 tpy or more of any combination of air toxics.

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[27] EPA Emissions Standards for Boilers and Process Heaters and Commercial/Industrial Solid Waste Incinerators Webpage. Accessed at: http://www.epa.gov/airquality/combustion/actions.html

[28] EPA. Fact Sheet *Final Air Toxics Standards for Industrial, Commercial and Institutional Boilers at Area Source Facilities.* February 21, 2011. Accessed at: http://www.epa.gov/airquality/combustion/docs/20110221aboilersfs.pdf

For all new and existing natural gas- and refinery gas-fired units, the final rule establishes a work practice standard instead of numeric emission limits. The operator will be required to perform an annual tune-up for each unit. Units combusting other gases can qualify for work practice standards by demonstrating that they burn "clean fuel" with contaminant levels similar to natural gas. For all new and existing units with a heat input capacity less than 10 million British thermal units per hour (MMBtu/hr), the final rule establishes a work practice standard instead of numeric emission limits. The operator will be required to perform a tune-up for each unit once every 2 years.

The final rule establishes a work practice standard instead of numeric emission limits for all new and existing "limited use" boilers. The operator will be required to perform a tune-up for each unit once every 2 years. These units are operated less than 10% of the year as emergency/backup boilers to supplement process power needs. The final rule establishes numeric emission limits for all other existing and new boilers and process heaters located at major sources (including those that burn coal and biomass).

Monitoring is required to assure compliance with emission limits. The largest major source boilers must continuously monitor their particle emissions as a surrogate for metals such as lead and chromium. All units larger than 10 MMBtu/hr must monitor oxygen as a measure of good combustion. Existing major source facilities are also required to conduct a one-time energy assessment to identify cost-effective energy conservation measures.

The EPA estimates that the U.S. has approximately 13,840 boilers and process heaters at major sources. Approximately 47 new units would be installed over the next 3 years. Installation and maintaining controls for this rule is estimated to cost $1.4 billion per year.

Commercial and Industrial Solid Waste Incineration Units: The EPA issued finalized revisions of the December 2000 new source performance standards and emission guidelines for new and existing CISWI units. A CISWI is any device used to burn solid waste at a commercial or industrial facility. The final rule covers four CISWI sub-categories:

- Incinerators,
- Energy recovery units,
- Waste burning kilns, and
- Small incinerators in very remote locations.

Nine pollutants will have emissions limits: mercury, lead, cadmium, hydrogen chloride, particulate matter, carbon monoxide, dioxins/furans, nitrogen oxides, and sulfur dioxide. The final rules also requires stack testing, monitoring and additional monitoring for new sources, annual inspections of the emission control devices, annual visible emission tests of ash handling operations, and owner operators to follow procedures for test data submittal.

The EPA estimates the U.S. has approximately 88 operating CISWI units. Three units meet the proposed

The reduced nationwide emission from CISWI is expected to be

- 5,700 tons per year (tpy) of acid gases (i.e., hydrogen chloride and sulfur dioxide),
- 1,600 tpy of particulate matter,
- 23,000 tpy of carbon monoxide,
- 5,700 tpy of nitrogen oxides, and
- 5.5 tpy of metals (i.e., lead, cadmium, and mercury) and dioxins/furans

emission standards; the remaining 85 will need to comply no later than 3 years after the EPA approves a state plan for implementing the rule or by February 21, 2016. Installing and maintaining controls for this rule is estimated to cost $232 million per year.[29]

Solid Waste and Recycling in Commercial and Industrial Solid Waste Incinerator Units: The EPA issued four rules to provide for reductions in HAPs. They were developed together because of the interrelationship among them. Three rules were developed under the CAA (boiler rules above) and one under the Resource Conservation and Recovery Act (RCRA).[30] The RCRA rule identifies which non-hazardous secondary materials are, or are not, solid waste when burned in a combustion unit such that

- Non-hazardous secondary materials considered solid wastes under RCRA would be subject to Section 129 CAA requirements.
- Non-hazardous secondary materials not considered solid wastes under RCRA would be subject to Section 112 CAA requirements[31]

Under RCRA rule, traditional fuels (e.g., coal, oil, and natural gas) and alternative traditional fuels (e.g., cellulosic biomass) are not secondary materials and thus not solid waste. Non-hazardous secondary materials burned in combustion units are identified as solid waste unless

- The material is used as a fuel and remains within the control of the generator (whether at the site of generation or another site the generator has control over) and it meets the legitimacy criteria;
- The following materials have not been discarded in the first instance and meet the legitimacy criteria when used as a fuel (by the generator or outside the control of the generator): scrap tires removed from vehicles and managed under an established tire collection program and resinated wood residuals;
- The material is used as an ingredient in a manufacturing process (whether by the generator or outside the control of the generator) that meets the legitimacy criteria;
- The material has been sufficiently processed to produce a fuel or ingredient that meets the legitimacy criteria; or
- Through a case-by-case petition process, it has been determined that material handled outside the control of the generator has not been discarded and is indistinguishable in all relevant aspects from a fuel product.

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[29] EPA Fact Sheet. *Final Amendments to New Source Performance Standards and Emission Guidelines for Commercial and Industrial Solid Waste Incineration Units*. February, 21 2011. Accessed at: http://www.epa.gov/airquality/combustion/docs/20110221ciswifs.pdf

[30] EPA. Fact Sheet. *Identification of Non-Hazardous Secondary Materials that are Solid Wastes Final Rule.* February 2011. Accessed at: http://www.epa.gov/epawaste/nonhaz/define/pdfs/final-fs.pdf and http://www.epa.gov/epawaste/nonhaz/define/index.htm

[31] 76 Fed. Reg 15,456 (Mar. 21. 2011). Accessed at: http://www.gpo.gov/fdsys/pkg/FR-2011-03-21/pdf/2011-4492.pdf

The EPA estimates that the final rule under RCRA does not directly invoke any costs or benefits. This is because this rule is published as part of a four-rule package that includes the boiler MACT and CISWI Rules.

Portland Cement Kiln MACT

In November 2010, the EPA issued amendments to two rules to reduce emissions of mercury, air toxics, total hydrocarbons, hydrochloric acid, and particle forming pollutants from new and existing Portland Cement Kilns.[32] The rules also limit emissions of ozone and particle forming pollutants from new kilns along with reductions in nitrogen oxide and sulfur dioxide. The rules apply to large and small kilns that emit toxic air pollutants (HAPS); see Table A.2.

The EPA projects that 181 Portland cement kilns will operate at approximately 100 facilities in the U.S. by 2013. The amended air toxics will apply to 158 of those kilns. The remaining kilns are subject to a separate regulation for kilns that burn hazardous waste. Seven kilns will be subject to NSPS. The deadline will be in 2013.[33]

Table A.2: Emission Limits for Existing and New Kilns

Pollutant	**Existing Source Kilns**	**New Source Kilns**
Mercury	55 pounds per million tons of clinker averaged over 30 days	21 pounds per million tons of clinker averaged over 30 days
Total Hydrocarbons	24 parts per million by volume averaged over 30 days	24 parts per million by volume averaged over 30 days
PM (surrogate for toxic metals other than mercury)	0.04 pounds per ton clinker averaged over 30 days	0.01 pounds per ton of clinker averaged over 30 days
Hydrochloric acid	3 parts per million by volume averaged over 30 days	3 parts per million by volume averaged over 30 days

Source: EPA

The EPA classes a major source as a kiln that emits 10 or more tons a year of a single air toxic air pollutant, or 25 or more tons of a combination of air toxics. Area sources are those that emit lesser amounts. The EPA estimates the following annual emission reductions by 2013:

- Mercury: 16,600 pounds, a 92% reduction from projected 2013 emission levels;
- Total hydrocarbons: 10,600 tons, a reduction of 83%;
- Particulate matter: 11,500 tons, a 92% reduction;
- Acid gases (measured as hydrochloric acid): 5,800 tons, a 97% reduction;
- Sulfur dioxide (SO_2): 110,000 tons, a 78% reduction; and
- Nitrogen oxides (NOx): 6,600 tons, a reduction of 5%.

[32] 75. Fed. Reg. 54,970 (Nov. 8, 2010 issued Sep. 9, 2010)
[33] EPA. Rule and Implementation Information for Portland Cement Manufacturing Industry. Web page. Accessed at: http://www.epa.gov/ttnatw01/pcem/pcempg.html

Under the CAA, the EPA is required to set NSPS for industrial categories that cause or contribute significantly to air pollution. Cement kilns emit NOx and SO_2 so the NSPS will apply to kilns built after June 16, 2008. The emissions limits can be seen in Table A.3.[34]

Table A.3: Emission Limits for New Source Performance Standards

Pollutant	Emission Limit
NOx	1.5 lb/ton clinker averaged over 30 days
SO_2	0.4 lb/ton clinker averaged over 30 days
PM	0.01 lb/ton clinker averaged over 30 days

Source: EPA[35]

<u>Utility Maximum Achievable Control Technology (MACT)—The " Air Toxics Rule"</u>

In May 2011, the EPA proposed national emission standards for hazardous air pollutants (NESHAP) from coal- and oil fired electric utility steam generating units (EGUs) under CAA section 112(d) and proposing revised new source performance standards (NSPS) for fossil fuel-fired EGUs under CAA section 111(b).[36] This followed from the EPA's conclusion in 2000 that it was appropriate and necessary to regulate HAPs from EGUs under CAA section 112 to reduce the emissions of Hg and other HAP from coal- and oil fired EGUs. The EPA initially added these sources to the list of stationary sources subject to regulations governing the emissions of HAP. However, in a rulemaking effort completed in 2005, the EPA reversed its findings and instead adopted regulations under other provisions of the CAA. The DC Circuit Court vacated the resulting regulations, noting that the EPA had sidestepped important legal requirements in the CAA that govern the delisting of source categories[37]. The DC Circuit Court's action restored the EPA's December 2000 original determination.

In December 2008, several environmental and public health organizations also filed a complaint in district court alleging that the EPA had failed to perform a nondiscretionary duty under CAA Section 304 (a) (2) by failing to promulgate final section 112 (d) standards for HAP from coal and oil-fired EGUs by the statutory mandated deadline of December 20, 2002. The EPA settled this litigation and the consent decree that was signed required the EPA to sign a notice of proposed rulemaking by March 16, 2011, and a notice of final rule making by November 16, 2011.[38]

The promulgated rule issued in May 2011 requires that newly constructed facilities or reconstructed units or sources at existing facilities would be subject to 112(g) requirements if they have the potential to emit HAPs in "major" amounts (i.e., 10 tons or more of an individual

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[34] EPA *Rules and Implementation New Source Performance Standards for Portland Cement Plants*. Website page. Accessed at: http://www.epa.gov/ttn/atw/nsps/pcemnsps/pcemnspspg.html

[35] EPA. Fact Sheet. *Final Amendments to National Air Toxics Emission Standards and New Source Performance Standards for Portland Cement Manufacturing.* August 8, 2010. Accessed at: http://www.epa.gov/ttn/atw/pcem/pcem_fs_080910.pdf

[36] 76 Fed. Reg 24976 (May. 3, 2011). Accessed at http://www.gpo.gov/fdsys/pkg/FR-2011-05-03/pdf/2011-7237.pdf

[37] Those requirements provide that the EPA can delist a source category only if it can demonstrate that no source within the listed category poses a lifetime cancer risk above one in one million to the individual most exposed and that emissions from no source in the category exceed the level that is adequate to protect public health with an ample margin of safety and that no adverse environmental effects will result from the emissions of any source. CAA 112(c)(9)(B).

[38] 76 Fed. Reg. 24976 at page 24986.

pollutant or 25 tons or more of a combination of pollutants). Reconstruction is defined by the EPA as a change that costs 50% of the cost of constructing a new unit or source like the one being rebuilt.

Sources or facilities subject to 112(g) would be subject to stringent air pollution control requirements, referred to as new source MACT. Under CAA, new source MACT control is required to be no less stringent than the *best controlled similar source or facility*. Facilities will be required to install emission control equipment such as activated carbon injection, scrubbers or dry sorbent injections, and upgrades to particular controls. The standards will result in additional reductions of SO_2 as well as reducing metals, including mercury, arsenic, chromium, nickel, and acid gases, including hydrogen chloride and hydrogen fluoride and particulate matter. The EPA is also proposing NSPS for PM, SO_2, and NO_x.

The EPA's final rule provides an 18-month transition period for states that have a preconstruction review process already in place to make adjustments in their programs to comply with 112(g) requirements. For states that are unable to adopt these requirements within the designated timeframe, the EPA has provided two options for review and approval of case-by-case MACT determinations.

The EPA estimates that the annual incremental compliance cost of the proposed Toxics Rule is $10.9 billion in 2015 (2007 dollars). Table A.4 estimates the system costs of energy efficiency policies.

Table A.4: Effect of Energy Efficiency Policy on Generation System Costs

Total Costs (billion 2007$)—IPM + Total EE	**2015**	**2020**	**2030**
Base	144	155	200
Base + EE	142	150	190
Toxics Rule	155	165	210
Toxics Rule + EE	153	159	199
1. Increment (Base to Base + EE)	-2	-5	-11
2. Increment (Toxics Rule to Toxics Rule + EE)	-2	-6	-11
3. Increment (Base to Toxics Rule)	11	10	10
4. Increment (Base + EE to Toxics Rule + EE)	11	9	9
5. Increment (Base to Toxics Rule) to (Base + EE to Toxics Rule + EE)	0	-1	-1
6. Increment (Base to Toxics Rule + EE)	9	4	-1

According to the EPA,

> [i]n this analysis, the costs of the energy efficiency policies are treated as a component of the cost of generating electricity and are imbedded in the costs seen in Table 4. The modeling estimated that these energy efficiency policies would reduce the total cost of implementing the rule by billions of dollars. EPA looked at a case in which these energy efficiency policies were in place with and without the Toxics Rule. As Table [A.]4 shows, with or without the Toxics Rule, energy efficiency policies reduce the overall costs to generate electricity. The cost reductions increase over time. When comparing the Toxics Rule Case without energy efficiency to the Toxics Rule Case with energy efficiency, the analysis shows that these energy

> efficiency policies could reduce overall system costs by $2 billion in 2015, $6 billion in 2020, and $11 billion in 2030.[39]

Greenhouse Gas Rules

During September 2009, the EPA announced a proposal that focused on large facilities that emitted over 25,000 tons of greenhouse gases (GHG) a year. These facilities were required to obtain permits to demonstrate they were using best practices and technologies to minimize GHG emissions.[40] The rule proposed new thresholds for GHG emissions that define when the CAA permits under the New Source Review Title V operating permits would be required for new or existing facilities. Thresholds would tailor the permit program to limit which facilities would be required to obtain New Source Review Title V operating permit and would cover nearly 70% of the national GHG emissions that come from stationary sources including power plants and cement production facilities. The proposed rule covered emissions of six GHGs that could be controlled or limited:

1. Carbon dioxide (CO_2);
2. Methane (CH_4);
3. Nitrous oxide(N_2O);
4. Hydroflurocarbons (HFCs);
5. Perfluorocarbons (PFCs); and
6. Sulfur hexafluoride (SF_6).

Under the Prevention of Significant Deterioration (PSD) portion of NSR—which is a permit program designed to minimize emissions from new sources and existing sources making major modifications—the EPA is proposing these levels:

- Major stationary source threshold of 25,000 tpy CO_2e. This threshold level would be used to determine if a new facility or a major modification at an existing facility would trigger PSD permitting requirements.
- Significance level between 10,000 and 25,000 tpy CO_2e. Existing major sources making modifications that result in an increase of emissions above the significance level would be required to obtain a PSD permit. The EPA is requesting comment on a range of values in this proposal, with the intent of selecting a single value for the GHG significance level.

Under the proposed emissions thresholds, the EPA estimates that 400 new sources and modifications would be subject to PSD review each year for GHG emissions. Less than 100 of these would be newly subject to PSD. **In total, approximately 14,000 large sources would need to obtain operating permits for GHG emissions under the operating permits program. About 3,000 of these sources would be newly subject to CAA operating permit**

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[39] From page 25074 of 76 Fed Reg 24976 (May. 3 2011)

[40] EPA. Fact Sheet – Proposed Rule: Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule. September 30, 2009. Accessed at: http://www.epa.gov/NSR/fs20090930action.html

requirements as a result of this action. The majority of these sources are expected to be municipal solid waste landfills.[41]

During December 2010 the EPA issued a series of rules to set the regulatory framework in place to ensure that industrial facilities can get CAA permits covering their GHG emissions, and facilities emitting GHGs at levels below those established in the Tailoring Rule do not need to obtain CAA permits. This followed on from April 2010's Tailoring Rule to ensure that only the target sources of GHGs—those responsible for 70% of the GHG pollution from stationary sources—would require air permits.[42] The EPA worked with state agencies to ensure that permitting agencies have authority to permit GHG (or are on the path) with the EPA able to serve as an interim permitting authority, and ensure that only sources identified in the Tailoring rule—largest emitters—are required to obtain permits. The GHG Tailoring Rule requires Title V permits for major sources with GHG emissions of 100,000 tons per year (tpy) or more of carbon dioxide equivalents (CO_2e). Many state and local programs generally require Title V permitting at major source thresholds as low as 100 tpy for any air pollutant. The phased-in approach, established in the Tailoring Rule, provides time for large industrial facilities and state governments to develop the capacity to implement permitting requirements for GHGs.

- Starting in January 2011, large industrial facilities that must already obtain CAA permits for non-GHGs must also include GHG requirements in these permits if they are newly constructed and have the potential to emit 75,000 tons per year of carbon dioxide equivalent (CO_2e) or more or if they make changes at the facility that increase GHG emissions by that amount.
- Starting in July 2011, in addition to facilities described above, all new facilities emitting GHGs in excess of 100,000 tons of per year of CO_2e and facilities making changes that would increase GHG emissions by at least 75,000 tpy of CO_2e, and that also exceed 100/250 tons per year of GHGs on a mass basis, will be required to obtain permits that address GHG emissions.
- Operating permits will be needed by all sources that emit at least 100,000 tons of GHGs per year on a CO_2e basis beginning in July 2011.
- Sources less than 50,000 tons of GHGs per year on a CO_2e basis will not be required to obtain permits for GHGs before 2016.

The review also led to the SIP call issued in December 2010 that found 13 states not meeting CAA requirements (Texas included) and required them to revise their programs.

According to the EPA, the final rule uses a phased-in approach for requiring sources of GHG emissions to comply with Title V operating permit and PSD statutory requirements, which shifts the burden for the phase-in period for a large number of smaller sources of GHGs. Thus, this rule provides regulatory relief rather than regulatory requirements for these smaller GHG sources. For larger sources of GHGs that will be required to obtain Title V permits and/or comply with PSD requirements, the EPA notes that this final rule results in no direct economic burdens or costs, because these requirements are not imposed as a result of this rulemaking.

[41] 75 Fed. Reg 31514 (Jun. 3, 2010). Accessed at: http://www.gpo.gov/fdsys/pkg/FR-2010-06-03/pdf/2010-11974.pdf#page=1

[42] EPA. Fact Sheet. Clean Air Act Permitting for Greenhouse Gas Emissions – Final Rules. December 23, 2010. Accessed at: http://www.epa.gov/nsr/ghgdocs/20101223factsheet.pdf

Statutory requirements to obtain a Title V operating permit or to adhere to PSD requirements are already mandated by the CAA and by existing rules, not by this rule.

The EPA did, however, estimate costs for the Tailoring Rule for the permit costs to sources. The EPA estimated that for the PSD permit an industrial source would incur costs of $46,350 to prepare the application and receive the permit. A commercial or residential source would incur costs of $19,688 for a PSD permit.

R**egulatory Developments: Waste**

Coal Combustion Residuals

In June 2010, the EPA co-proposed two options for regulating the disposal of coal combustion residuals (CCRs), commonly known as coal ash-generated from the combustion of coal at electric utilities and independent power producers. Under the first proposal, the EPA would reverse its August 1993 and May 2000 Bevill Regulatory Determinations regarding CCRs and list these residuals as special wastes subject to regulation under subtitle C of the Resource Conservation and Recovery Act (RCRA), when they are destined for disposal in landfills and surface impoundments. Under the second proposal, the EPA would leave the Bevill Regulatory Determinations in place and regulate the disposal of such materials under subtitle D of RCRA by issuing national minimum criteria. Under both alternatives, the EPA proposed not to change the May 2000 Regulatory Determination for beneficially used CCRs, which are currently exempt from the hazardous waste regulations under Section 3001(b)(3)(A) of RCRA.[43] However, the EPA in this clarifying determination sought comment on potential refinements for certain beneficial uses. The EPA is also not proposing to address the placement of CCRs in mines, or non-mine fill uses of CCRs at coal mine sites in this action.[44]

In August 2010, the EPA issued a technical corrections notice, which had five main actions[45]:

1. Extension of the public comment period from September 20 to November 19, 2010. This 60-day extension was in response to numerous requests to extend the comment period.
2. Technical corrections to the proposed rule. The proposed rule as published in the Federal Register on June 21, 2010, had several inadvertent administrative errors, which could cause confusion if not corrected.
3. Notice that additional support documents have been placed in the rulemaking docket for public inspection. This includes documents referenced in the proposed rule, but previously found on the EPA's Coal Combustion Residuals Partnership website. The docket provides the date on which documents have been added, making the new materials easy to identify.
4. Two additional Public Hearings. Given the significant public interest in the proposal and to further public participation opportunities, on August 6, 2010, the EPA announced on

[43] 75 Fed. Reg. 35,128 (Jun. 21, 2010)
[44] EPA. Coal Combustion Residuals Webpage. Accessed at http://www.epa.gov/osw/nonhaz/industrial/special/fossil/ccr-rule/index.htm
[45] EPA. Coal Combustion Residuals Webpage. Accessed at: http://www.epa.gov/osw/nonhaz/industrial/special/fossil/ccr-rule/index.htm

its website that it would hold hearings in Pittsburgh, PA on September 21, 2010, and in Louisville, KY, on September 28, 2010 in addition to five public hearings already scheduled.

5. One additional webinar.

In October 2010, the EPA issued a notice of data availability on CCR surface impoundments. The EPA was also seeking comment on how, if at all, this additional information should affect the Agency's decision as it develops a final rule.[46]

In assessing the environmental justice impacts of this rule, the EPA noted that of the 495 electric utility plants, 383 of the plants (77%) operate CCR disposal units onsite (i.e., onsite landfills or onsite surface impoundments), 84 electric utility plants solely transport CCRs to offsite disposal units operated by other companies (e.g., commercial waste management companies), and 28 of the electric utility plants generate CCRs that are solely beneficially used rather than disposed.[47]

The EPA estimated the regulatory compliance costs, the monetized benefits for each regulatory option and computed comparison indicators: net benefits (i.e., benefits minus cost) and the benefit/cost ratio. Table A.5 shows the breakdown comparison of the Regulatory Benefits to Costs Ranging over all three beneficial use scenarios.

Table A.5: Comparison of Regulatory Benefits to Costs Ranging—Three Beneficial Use Scenarios

	Subtitle C "Special Waste"	**Subtitle D**	**Subtitle "D Prime"**
A Present Values 1. Regulatory Costs 2. Regulatory Benefits 3. Net Benefits 2-1 4. Benefit/Cost Ratio (2/1)	$20,349 87,221to 102,191 ($251,166) to $81,842 (11.343) to 5.022	$8,095 $34,964 to $41,761 ($6,927) to $33,666 0.144 to 5.159	$3,259 $14,111 to $17,501 ($2,666) to $14,242 0.182 to 5.370
B Average Annualized Equivalent Values 1. Regulatory Costs 2. Regulatory Benefits 3. Net Benefits 2-1 4. Benefit/Cost Ratio (2/1)	$1,474 $6,320 to $7,405 ($18,199) to $5,930 (11.347) to 5.022	$587 2,533$ to $3,026 ($502) to $ 2,439 0.145 to 5.159	$236 $1,023 to $1,286 ($193) to $1,032 0.182 to 5.370
$ Millions @2009 prices and @ 7% discount rate over 50-year period of analysis 2012–2061			

Source: EPA Final Rule

[46] 75 Fed. Reg. 64,974 (Oct. 21, 2010).
[47] 75 Fed. Reg. 35,128 (Jun, 21, 2010) at page 35229. Accessed at: http://www.gpo.gov/fdsys/pkg/FR-2010-06-21/pdf/2010-12286.pdf

Regulatory Developments: Water

Rules that will impact energy production facilities vis-à-vis water are found in two main areas: the Clean Water Act itself in terms of ecosystem protection and the Safe Water Drinking Act for effluent and discharge that may come from energy production facilities. Again, very often these rules have been enacted as a consequence of court cases.

The most significant of the rules for our purposes is the Cooling Water Intake Rule. The Cooling Water Intake Rule (CWA 316 (b)) was suspended for existing large power plants, in response to the second circuit court of appeals decision in *Riverkeeper, Inc. v. EPA.*[48]

Two further court cases followed. The EPA promulgated new rules and is requesting comment on requirements under section 316 CWA for all existing power generating facilities and manufacturing industrial facilities. The comment period closed July 19, 2011.[49]

In April 2011, the EPA proposed a new rule to establish requirements under Clean Water Act (CWA) Section 316(b) for all existing power generating facilities (and manufacturing and industrial facilities) that withdraw more than two million gallons of water per day and use at least 25% of the water withdrawn exclusively for cooling purposes. The proposed national requirements, which would be implemented through National Pollutant Discharge Elimination System (NPDES) permits, would establish national requirements applicable to the location, design, construction, and capacity of cooling water intake structures at these facilities by setting requirements that reflect the best available technology (BAT) to minimize adverse environmental impact. In other words, the facilities would be subject to an upper limit on how many fish can be killed by being pinned against intake screens or other parts of the facility.

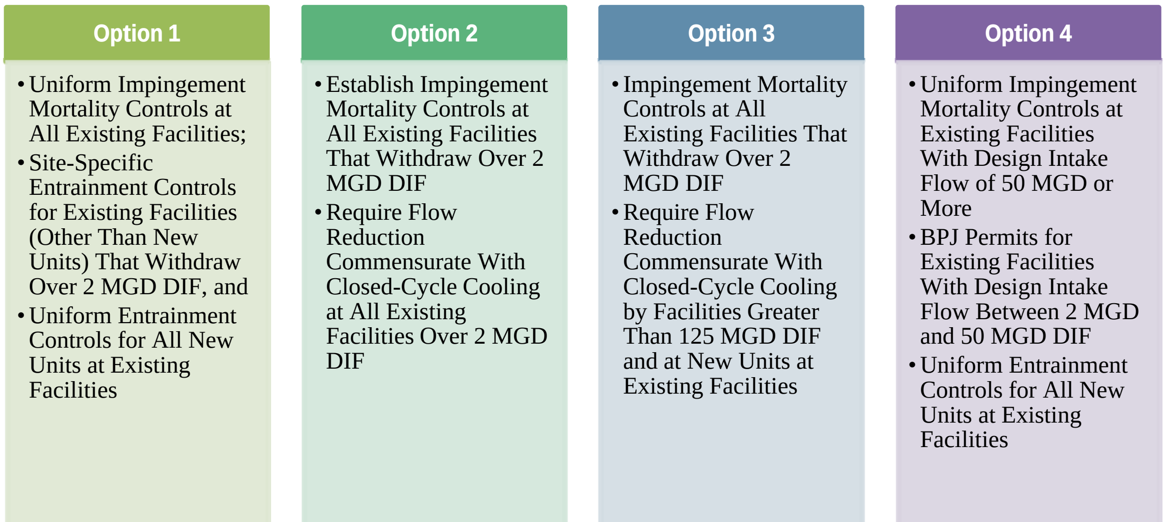
Existing facilities that withdraw very large amounts of water—at least 125 million gallons per day—would be required to conduct studies to help their permitting authority determine whether and what site-specific controls, if any, would be required to reduce the number of aquatic organisms sucked into cooling water systems (entrainment). This decision process would include public input. New units that add electrical generation capacity at an existing facility would be required to add technology that is equivalent to closed-cycle cooling (continually recycles and cools the water so that minimal water needs to be withdrawn from an adjacent water body). This can be done by incorporating a closed-cycle system into the design of the new unit, or by making other design changes equivalent to the reductions associated with closed-cycle cooling. Closed-cycle cooling systems—often referred to as *cooling towers* or *wet cooling*—are the most effective at reducing entrainment.

The proposed rule constitutes the EPA's response to the court's remand of the Phase II existing facility rule and the court's remand of the existing facilities portion of the Phase III rule. In addition, the EPA is also responding to the decision in *Riverkeeper I* and proposing to remove from the Phase I new facility rule the restoration-based compliance alternative and the associated monitoring and demonstration requirements. The EPA expects this proposed regulation would minimize adverse environmental impacts, including substantially reducing the harmful effects of impingement and entrainment. As a result, the Agency anticipates this proposed rule would help protect ecosystems affected by cooling water intake structures and preserve aquatic organisms

[48] Riverkeeper, Inc. v. U.S. EPA 358 F.3d 174, 181 (2d Cir.2004).
[49] EPA. Accessed at: http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/index.cfm

and the ecosystems they inhabit in waters used by cooling water intake structures at existing facilities.[50]

The technology basis for the proposed regulation center around four primary options (Figure A.1). These are also based on reviews of BAT. Three of the options would require strict impingement mortality standards, but would vary the approach to entrainment mortality controls. The fourth option would allow both impingement and entrainment mortality controls to be established on a site specific best practice basis for facilities with a DIF of less than 50 million gallons a day.



Source: EPA

Figure A.1: Description of Four Primary BAT Options

In assessing costs for the proposed rule, the EPA reviewed potential facility closures, downtime for retrofits for facilities, social costs, compliance costs, and the impact on consumer electricity prices in the various NERC Regions. The potential electricity price effects were assessed by the EPA in two ways:

1. An assessment of the potential annual increase in household electricity costs; and
2. An assessment of the potential annual increase in electricity costs per MWh of total electricity sales. These analyses assume that all compliance costs will be passed through on a pre-tax basis as increased electricity prices as opposed to the treatment in the facility- and firm-level analyses discussed in Section VII.D.b.1, which assume that none of the compliance costs will be passed to consumers through electricity rate increases

According to the EPA, in the discussion of social cost of the four regulatory options,

> at a 3 percent discount rate, EPA estimates annualized costs of compliance of $384 million under Option 1, $4,463 million under Option 2, $4,631 million under Option 3, and $327 million under Option 4. At a 7 percent discount rate, these costs are $459

[50] 76 Fed. Reg. 22,174 (Apr. 20, 2011). Accessed at: http://www.gpo.gov/fdsys/pkg/FR-2011-04-20/pdf/2011-8033.pdf

million, \$4,699 million, \$4,862 million, and \$383 million, respectively. The largest component of social cost is the pre-tax cost of regulatory compliance incurred by complying facilities. These costs include one-time technology costs of complying with the rule, one-time costs of installation downtime, annual fixed and variable operating and maintenance (O&M) costs, the value of electricity requirements for operating compliance technology, and permitting costs (initial permit costs, annual monitoring costs, and permit reissuance costs). In addition, all Electric Generators are expected to become subject to I&E mortality requirements at the 125 MGD threshold under Option 2. Social cost also includes implementation costs incurred by Federal and State governments. EPA's social cost estimates exclude the cost to facilities estimated to be baseline closures.[51]

Cost to residential households was estimated for the various NERC regions and utilized 2015 electricity sales projected from the Department of Energy's AEO 2009 (Table A.6).

Table A.6 Average Annual Cost per Residential Household by Energy Region

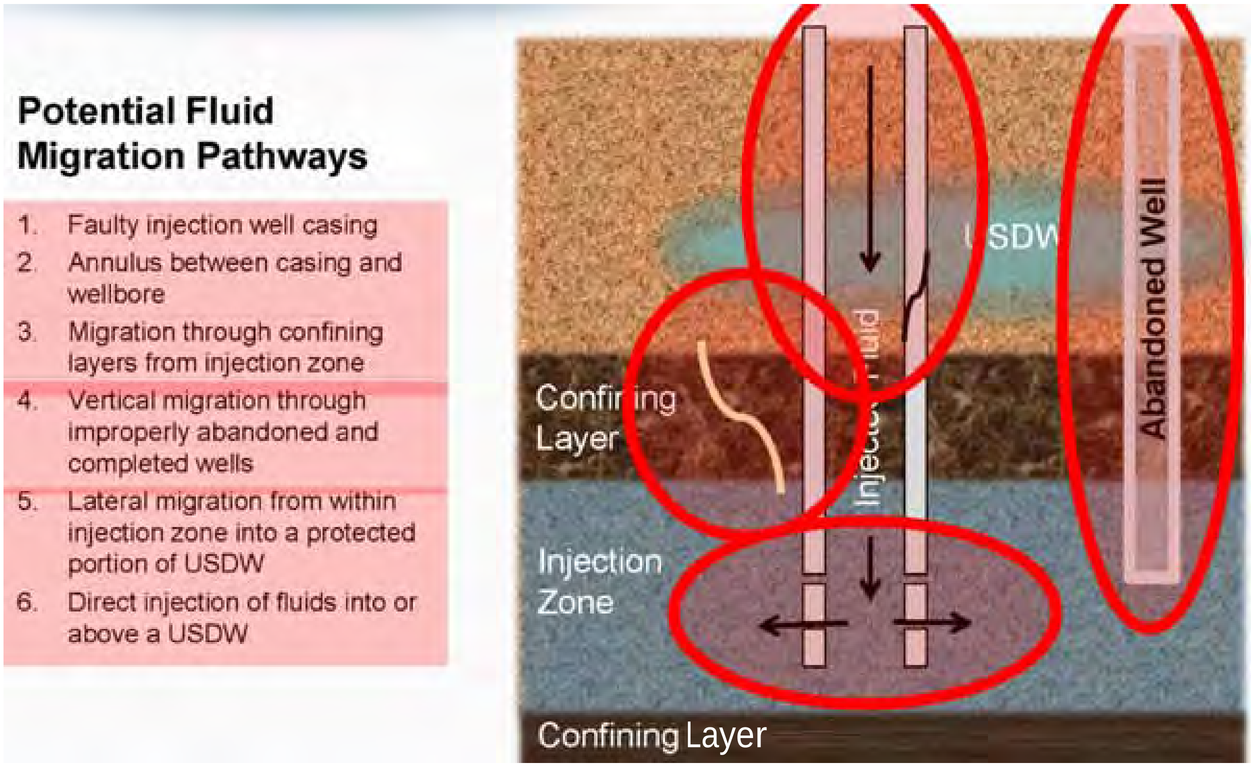
NERC Region	**Option 1**	**Option 2**	**Option 3**	**Option 4**
ASCC	0.00	0.00	0.00	0.00
ECAR	1.23	20.00	20.47	1.22
ERCOT	1.76	26.52	26.52	1.74
FRCC	2.37	17.89	18.21	2.37
HICC	3.16	23.82	23.82	3.16
MAAC	2.11	18.97	19.31	1.95
MAIN	1.46	19.18	20.18	1.41
MAPP	1.79	16.00	17.04	1.74
NPCC	1.38	19.89	21.13	1.37
SERC	1.64	27.11	27.88	1.61
SPP	3.93	21.56	21.56	3.86
WECC	0.05	0.09	0.11	0.01
US	1.41	17.09	17.60	1.37

Source: EPA

The EPA is also currently developing permitting guidance for oil and gas hydraulic fracturing activities. This rule is being developed under the parameters of the Safe Drinking Water Act (SDWA) Underground Injection Control (UIC) Class II Regulations (40 CFR 144.12(a)). Stakeholder meetings were held during spring 2011, including a series of webinars where the EPA worked with stakeholders to gather information to assist the permit writers. The draft guidance is expected to be developed during summer 2011 and public comment period is proposed to be held during fall 2011.

Potential fluid migration pathways can be seen in Figure A.2.

[51] Page 22218 of 76 Fed. Reg 22174 (Apr. 20, 2011).



Source: EPA Diesel Guidance Webinar 6-15-2011

Figure A.2: Potential Fluid Migration Pathways

The requirements will vary according to well class but may include:

- Limits on injection pressure to prevent
  - Initiation of new fractures or propagating existing fractures in the injection zone or confining zone;
  - Causation of movement of injection or formation fluids into underground sources of drinking water; and
  - Generation of significant seismic activity (earthquakes) that would endanger underground sources of drinking water.
- Continuous pressure monitoring.
- Automatic shut-off devices to stop injection at established limits, or to prevent flow from injection zone.

Monitoring and operation may also include

- Injectate monitoring;
- Ground water monitoring; and
- Mechanical integrity tests.

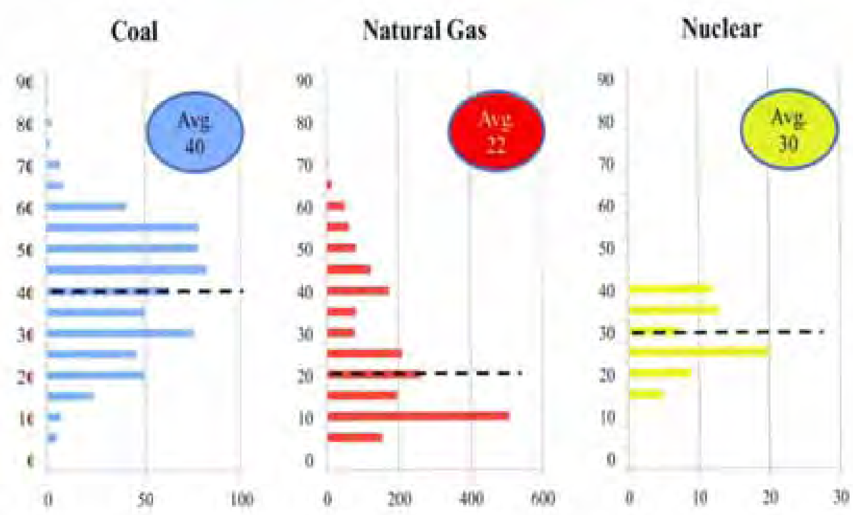
The area of review surrounding the injection well that may be affected by the injection activity is still being determined. The EPA noted in its June 15, 2011, webinar that this could be determined by a fixed radius or mathematical modeling to determine the zone of endangering influence.

Commentary: Air, Energy, and Waste

Much commentary has issued from many sources regarding the new rules issued by the EPA over the past year and a half. The *Wall Street Journal*, for example, led on March 4 with the headline "An EPA Regulatory Spree Unprecedented in U.S. History."[52]

NERC issued two reports in 2010 that looked at reliability scenario assessments and impacts for climate change, and the reliability impacts of four of the new environmental regulations. They estimated that just four of the EPA rules could force the retirement of up to 77 Gigawatts (GW) of electric generating capacity by 2015. The Edison Electric Institute (EEI) also reviewed the potential impacts of GHG regulation on the generating fleet. Concluding that the impending regulations of HAPS, MACT, and GHG will cause a number of coal plants to retire. Depending on a variety of scenarios modeled there will be between 33–75 GW of unplanned coal retirements by 2015 growing to between 36–96 GW by 2020. [53]

As Table A.1 showed, the compliance costs are also extremely onerous, with some rules coming in the range of $100 billion in compliance costs. Some groups have argued that the combination of the rules in air, waste, and water will cause plants to close and impact generating margin rules, resulting in fines. This issue is also compounded by the blend of fuels used to generate electricity in the U.S. and the age of generating facilities. Figure A.3 shows NERC's assessment of the average ages of coal, natural gas, and nuclear power generating plants in the U.S. Figure A.4 shows the blend of fuels used by different regions around the country.



Source: NERC, July 2010.

Figure A.3: Age Profile of U.S. Fossil and Nuclear Generation Fleet

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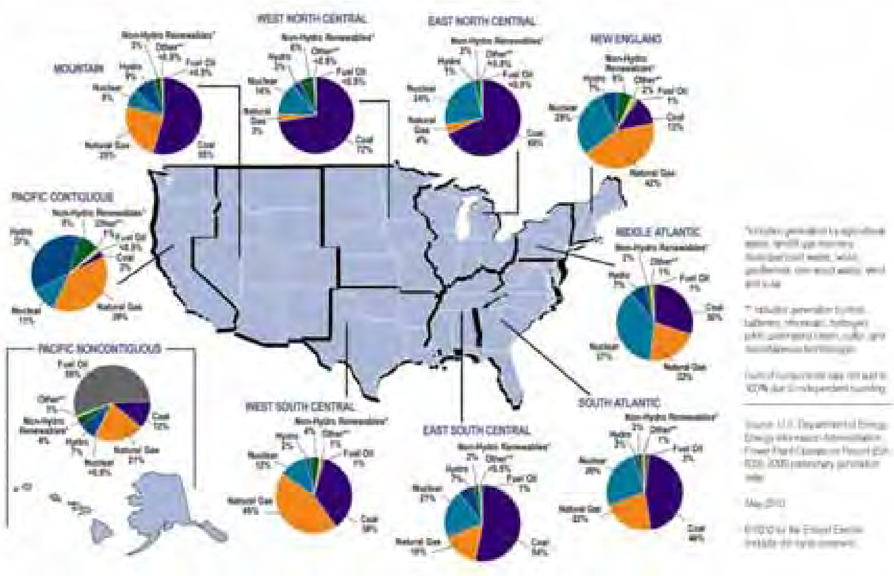
[52] Wall Street Journal. *An EPA Regulatory Spree Unprecedented in U.S. History.* March, 4, 2011.

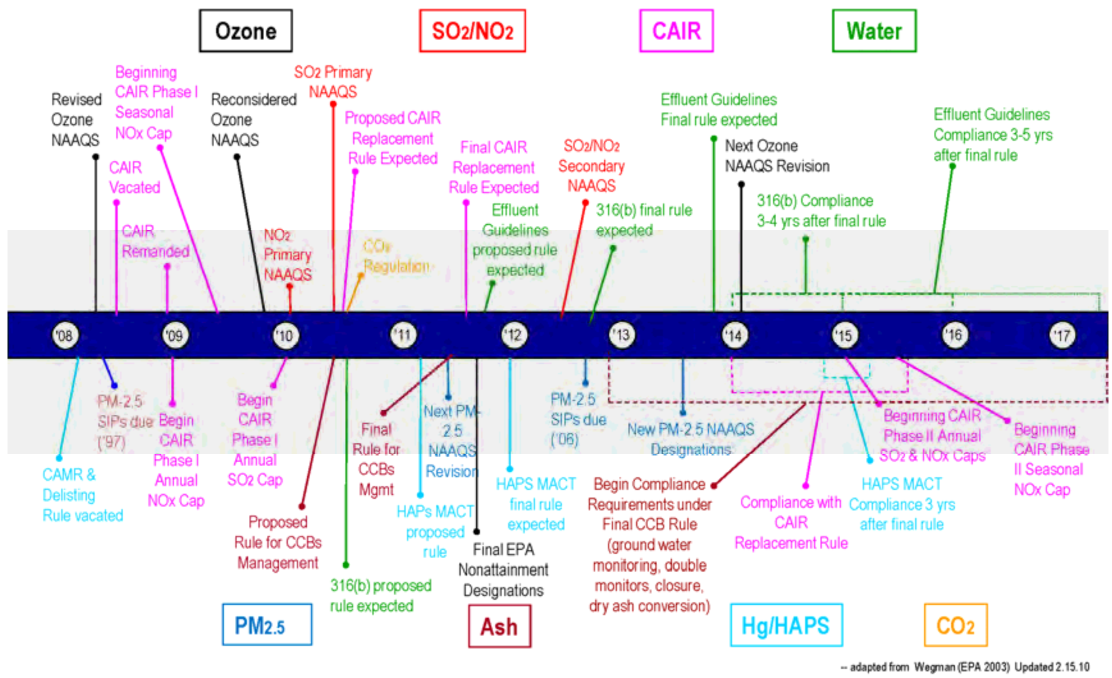
[53] Edison Electric Institute. Analysis prepared by ICF International. *Potential Impacts of the Environmental Regulation on the U.S. Generation Fleet.* January 2011. Accessed at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/EEIModelingReportFinal-28January2011.pdf at Page 11.



Source: Shea, 2010

Figure A.4: Regional Fuel Mixes to Generate Electricity

EEI testimony to the Congressional Caucus on Coal during 2010 showcased the timeline (some might say aggressive timeline) for the implementation of the various rules for energy utility generators (Figure A.5).

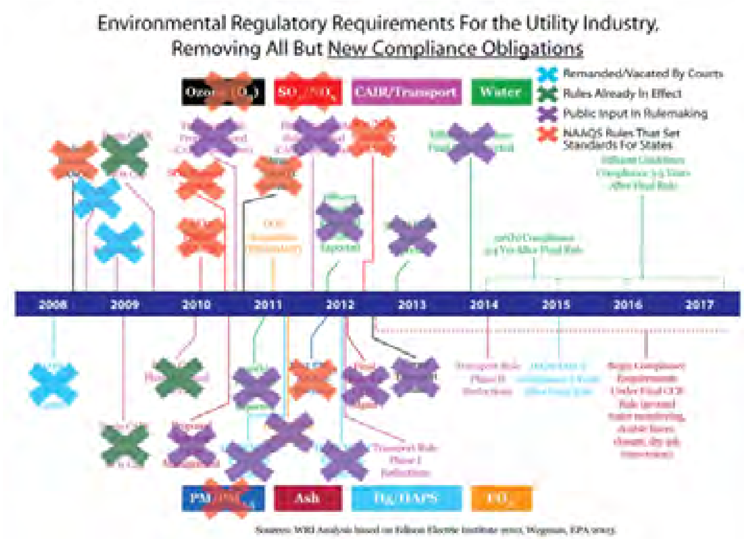


Source: Shea, 2010[54]

Figure A.5: Possible Timeline for Environmental Regulatory Requirements for Utilities

However, this was countered by the World Resources Institute (WRI), who issued a rebuttal to this timeline, noting that the EPA is pursuing a realistic timeline over the next decade to bring the electric industry into compliance with the law. In most cases, they argue, the electric power sector has been on notice for several years (in some cases decades) that these pollutants would be regulated. Figure A.6 shows their amended timeline.

[54] Quinlan Shea. *Economic Impacts of Coal*. Statement of Edison Electric Institute Submitted to Congressional Caucus on Coal. May 24, 2010. Accessed at: http://www.eei.org/whatwedo/PublicPolicyAdvocacy/TFB%20Documents/100525SheaCongressCoalImpacts.pdf



Source: WRI, 2010[55]

Figure A.6: Environmental Regulatory Requirements for Utility Industry—Removing All but New Compliance Obligations

The depiction of a "more accurate timeline" created by WRI can be seen in Figure A.7.

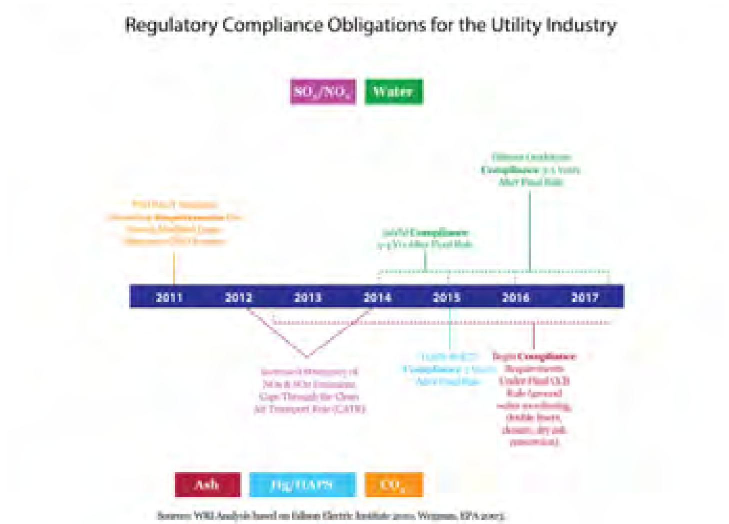


Figure A.7: Regulatory Compliance Obligations for the Utility Industry

NERC's 2010 special reliability report was designed to evaluate the potential impacts on Planning Reserve Margins (PRM), assuming that there would be no industry actions in the near term to address compliance issues or market response, and identify the need for additional resources that may arise in light of industry responses to each of these environmental regulations individually and in aggregate. NERC looked at four rules vis-à-vis impact on MW generation:

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[55]Larsen, J. *Response to EEI's Timeline of Environmental Regulations for the Utility Industry*. December, 3 2010. World Resources Institute Accessed at: http://www.wri.org/stories/2010/12/response-eeis-timeline-environmental-regulations-utility-industry.

1. Cooling Water Intake Structures;
2. National Emission Standards for HAP (NESHAP) MACT Standard;
3. Clean Air Transport Rule (CATR), and
4. Coal Combustion Residuals (CCR) Disposal Regulations.[56]

Their major findings are summarized in Figure A.8.

Proposed regulations may have significant impact on forecast PRM	• Without additonal power production or demand-side resources beyond current regional plans, combined effects of four rules will significantly affect PRM. In most regions, more resources will be required to maintain reference margin levels. • Up to 78 GW reduction of coal and gas-fired capacity is identified for retirement in 10-year period of scenario.
Rule implementation timeline should consider reliability impacts	• Combined scenario impacts a large number of units, affecting some regions more than others. • Based on assessment assumptions, greatest risk to PRM occus by 2015 in the combined scenario, requiring addtional resources in a short timeframe.
Individually, Cooling Water Intake Structures Rule has greatest potential impact on PRM	• Implementation of this rule will apply to 252 GW (1,201 units) of coal, oil steam, and gas steam across the U.S., as well as to 60 GW of nuclear capacity (approximately one-third of all U.S. resources).
The MACT, CATR, and CCR rules also contribute to reductions in capacity	• MACT alone could drive PRM of 8 regions below NERC reference margin levels and trigger retirement of 2–15 GW of coal capacity by 2015. • CATR could have signfiicant impacts by 2015 if no offset trading is allowed, potentially 3–7 GW of retirements and retrofit of 28–576 plants by 2015. • CCR Rule will have least impact, triggering retirement of up to 12 coal units (388 MW). Cost sensitivity reveals retirements could reach 2 GW (53 units).
EPA actions create need for prompt industry response and action	• Report identifies number of tools the industry has for mitigating potential reliability impacts.

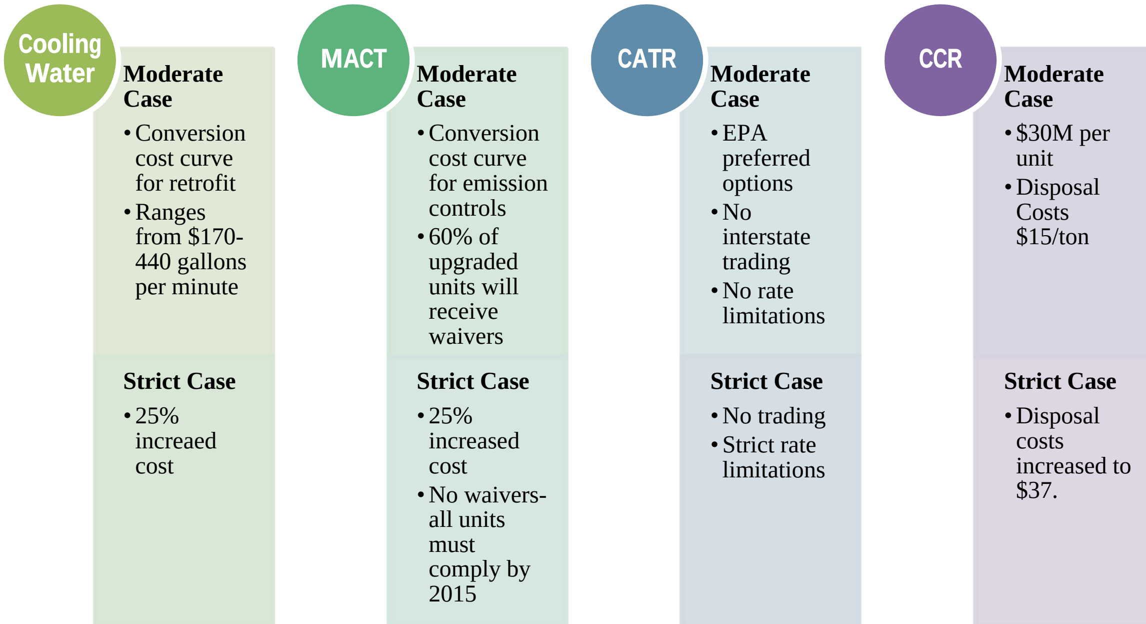
Source: NERC, 2010 (pages IV and V)

Figure A.8: Major Findings

Two scenario cases in their EPA regulation(s) analysis (Moderate and Strict Case) were used to provide a range of sensitivities, with the Strict Case incorporating more stringent rule assumptions and higher compliance costs. The reliability assessment designed used a plant-by-

[56] North American Electric Reliability Corporation. 2010 *Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations*. October 26, 2010. Accessed from: http://www.nerc.com/files/EPA_Scenario_Final.pdf

plant assessment; cost factors for each unit were generic, based on size and location, and did not include engineering-level cost factors. Potential retirements and PRM were assessed for the two cases; see Figure A.9.



Source: NERC, 2010 (page 5)

Figure A.9: Differences in Scenario Case Assumptions

The assessment did not examine the possibility that the industry may be unable to meet tight proposed compliance deadlines. Following were the assessment objectives:

- identify potential future outcomes of the EPA's active rule making for each of the Cooling Water Intake Rule, CCR, CATR and MACT, and other air toxics individually and in aggregate (combined EPA regulation scenario);
- quantify and project impacts on PRM for two sensitivity cases for each regulation, as well as combined impacts for years 2013, 2015, and 2018;
- examine impacts of potential unit retirement on regional reliability, and the PRM to measure relative impacts to resource adequacy across NERC regions and sub-regions; and
- provide results to stakeholders, industry, policymakers, regulators, and the public.

Scenario results from the 2010 Special Reliability Assessment found that the EPA rules may have significant economic impacts on generating units as measured by declines in PRMs. Based on the design of the assessment, overall total compliance cost would place between 40 and 69 GW of existing capacity (441–761 units) as *economically vulnerable* for accelerated retirement due to more cost efficient compliance alternatives by 2018.[57] On-site station loads for equipment operation rate the net generating capacity of the retrofitted units by 6.7–7.4 GW.

[57] NERC, 2010 page 13.

Overall affect would be a total of 46–76 GW of capacity reductions significantly affecting PRMs if no additional resources are built beyond plans that were issued in NERC's 2009 reliability assessment. The potential retirement and deratings affect resource portfolios in all eight NEC regions, but especially in the ERCOT (Texas), MRO, SERC, and NPCC regions. The most significant impacts are due to the Cooling Water Intake Rule, followed by MACT, CATR, and then CCR.[58] NERC also broke down the scenario results by rule. Impacts to ERCOT and SPP (regional entities serving Texas) are included in Tables A.7 through A.11 to show the predicted impacts.

Table A.7: Cooling Water Intake Structures Rule Impacts

- Moderate Case Scenario would increase unit production costs above replacement power costs at 347 stations, retiring 33 GW in current generating capacity.
- Spread across rule implementation period 2014–2018.
- Majority of economically vulnerable units are older oil/gas steam units: 253 units with 30 GW capacity.
- 94 additional coal steam units (2.5 GW) are also economically vulnerable.
- Remaining 688 would incur a 5GW capacity derating to suport increased station loads.
- ERCOT, SERC-Delta, RFC, and WECC-CAA account for 65% of unit retirements.

ERCOT Predicted Impacts 2015 (MW)					
Moderate			**Strict**		
Derated	Retired	Total	Derated	Retired	Total
187	556	743	187	752	939
SPP Predicted Impacts 2015					
Moderate			**Strict**		
Derated	Retired	Total	Derated	Retired	Total
113	501	614	113	531	644
ERCOT Predicted Impacts 2018					
Moderate			**Strict**		
Derated	Retired	Total	Derated	Retired	Total
322	5055	5377	316	5295	5611
SPP Predicted Impacts 2018					
Moderate			**Strict**		
Derated	Retired	Total	Derated	Retired	Total
143	933	1076	141	994	1135

[58] NERC, 2010 page 13

Table A.8: Maximum Achievable Control Technology Rule (Toxics Rule)

- Moderate Case Scenario varies for MACT emission rate limitations by coal type.
- Assessment asumes the EPA deadline of January 1, 2015. In Moderate Case only 40% of units that will retire will do so by the January 2015 deadline.
- Moderate Case assumes no forced retirements by 2013. 20% of units retire by 2014, reaching 40% by January 2015 with 20% following each subsequent year until all designated units are retired by January 2018 deadline.
- In 2015, the impact of Moderate Case is roughly 2.1 GW of existing coal-fired capacity; 59 units are economically vulnerable for retirement, although another 0.8 GW may be derated.
- Figure triples to 6.6 GW by 2018 for coal capacity retirements, and 1.8GW derated for total impact of 8.4 GW.
- Strict Case assumes no waivers are granted, and all units must be in compliance by January 2015. Waivers assumed to be difficult to obtain as the EPA has only granted one sector-wide exemption in the past. Assumes all retirements occur in 2 years leading up to deadline (2013–2014). Increases compliance costs by 25%.
- Two above assumptions are significant changes, which leads to 14.9 GW of coal-fired capacity made economically vulnerable for retirement by 2015, and 2.8 GW derated—for total of 17.6GW.
- MACT depicts greatest variation between two cases of all the EPA regulations. There is a 12 GW difference in capacity loss between Moderate and Strict Cases by 2015, and a 9 GW difference by 2018.

ERCOT Predicted Impacts 2015 (MW)					
Moderate			**Strict**		
Derated	Retired	Total	Derated	Retired	Total
73	0	73	73	0	73
SPP Predicted Impacts 2015					
Moderate			**Strict**		
Derated	Retired	Total	Derated	Retired	Total
127	0	127	130	52	181
ERCOT Predicted Impacts 2018					
Moderate			**Strict**		
Derated	Retired	Total	Derated	Retired	Total
73	0	73	73	0	73
SPP Predicted Impacts 2018					
Moderate			**Strict**		
Derated	Retired	Total	Derated	Retired	Total
130	52	181	130	52	181

Table A.9: Clean Air Transport Rule

- Aplies to fossil fuel units with greater than 25 MW capacity. The EPA preferred selection used was for Moderate Case.
- Rule has greatest impact on utilities that relied heavily upon purchased allowances for the Acid Rain program compliance. Limiting out-of-state purchases/banked allowances after 2013 would force some utilities to retrofit FGD and SCR emission controls on larger units or retire them.
- Extension of retirements triggered by CATR is linked to flexibility provided to affected sources, and final budget state cap. The EPA-preferred option would result in retirement of five coal-fired units (538 MW) by 2013 and 18 coal-fired units (2,740 MW) by 2015.
- If the EPA pursued emission rate limitations on coal fired units, they provide no ability to trade and forced retrofits. Coupled with NAAQS Strict Case assumes the EPA will adopt stricter limits on all coal-fired capacity.
- Capital cost would increase by 25%.
- 86 units (5,221 MW) would have operating costs pushed above new replacement capacity and force retirement.
- Impacts past 2015 not expected to materialize.

ERCOT Predicted Impacts 2013 (MW)					
Moderate			**Strict**		
Derated	Retired	Total	Derated	Retired	Total
0	0	0	64	0	64
SPP Predicted Impacts 2013					
Moderate			**Strict**		
Derated	Retired	Total	Derated	Retired	Total
0	0	0	110	26	136
ERCOT Predicted Impacts 2015					
Moderate			**Strict**		
Derated	Retired	Total	Derated	Retired	Total
0	0	0	91	0	91
SPP Predicted Impacts 2015					
Moderate			**Strict**		
Derated	Retired	Total	Derated	Retired	Total
0	0	0	202	115	317

Table A.10: Coal Combustion Residuals Rule

- Additional capital and annual operating cost increases under both scenarios.
- Economically vulnerable coal-fire capacity located in only four NERC regions (not Texas).
- Large number affected in Strict Case; Moderate Case affects only plants using ponds for ash disposal. Strict Case assumes all coal plants will be required to store coal combustion byproducts in landfill.

ERCOT Predicted Impacts 2018 (MW)					
Moderate			**Strict**		
Derated	Retired	Total	Derated	Retired	Total
0	0	0	0	0	0
SPP Prdicted Impacts 2018 (MW)					
Moderate			**Strict**		
Derated	Retired	Total	Derated	Retired	Total
0	0	0	0	0	0

NERC also computed a combined cumulative effect of the impact of the four rules.

Table A.11: Combined Case of Four Rules
(Cooling Water Intake, CATR, MACT, and CCR)

- Cumulative effect assessed for 3 years. In 2015 anywhere from 31–70 GW of existing fossil fuel capacity (351–678 units), beyond the 28 GW of retirements already announced, are economically vulnerable for retirements
- Additionally 273–700 units of continuing operation will be derated by a toal of 2.4–7.3 GW from the increased parasitic loads from control operations.
- Projected retirements are lower in 2013 and significantly higher for Moderate Case in 2018.

ERCOT Predicted Impacts 2013 (MW)					
Moderate			**Strict**		
Derated	Retired	Total	Derated	Retired	Total
0	0	0	91	0	91
SPP Predicted Impacts 2013 (MW)					
Moderate			**Strict**		
Derated	Retired	Total	Derated	Retired	Total
0	0	0	58	89	147
ERCOT Predicted Impacts 2015 (MW)					
Moderate			**Strict**		
Derated	Retired	Total	Derated	Retired	Total
246	5055	5301	480	5295	5775
SPP Predicted Impacts 2015 (MW)					
Moderate			**Strict**		
Derated	Retired	Total	Derated	Retired	Total
198	831	1029	428	2149	2577
ERCOT Predicted Impacts 2018 (MW)					
Moderate			**Strict**		
Derated	Retired	Total	Derated	Retired	Total
366	5055	5421	480	5295	5775
SPP Predicted Impacts 2018 (MW)					
Moderate			**Strict**		
Derated	Retired	Total	Derated	Retired	Total
271	972	1243	428	2149	2577

Other critics of the electric industry claims have also argued that the potential for alternative resources has also not been taken into account in the “doomsday” type claims for MW disruption.[59] Tierney and Cicchetti, in May 2011, concluded that the EEI report entitled *Potential Impacts of Environmental Regulation on the U.S. Generation Fleet*[60] was based on

[59] Yeh, S. National Resources Defense Council Staff Blog. *Peer Review Discredits Electric Industry Claims while PJM Demonstrates Potential for Alternative Resources*. June 13, 2011. Accessed at: http://switchboard.nrdc.org/blogs/syeh/peer_review_discredits_electri.html
[60] Edison Electric Institute. Analysis prepared by ICF International. *Potential Impacts of the Environmental Regulation on the U.S. Generation Fleet.* January 2011. Accessed at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/EEIModelingReportFinal-28January2011.pdf

worst-case assumptions that have not materialized and upon climate change legislation never enacted into law. They found that the report *"does not adequately distinguish between the non-environmental drivers of changes in the electricity industry and the various EPA rulemakings."*[61] Tierney et al.'s analysis evaluated the report findings in light of the proposed Utility Air Toxics and Cooling Water Intake Regulations issued in March 2011. Key findings are included in Table A.12.

[61] Tierney, S. F. and Cicchetti, C. *The Results in Context: A Peer Review of EEI's "Potential Impacts of Environmental Regulation in the U.S. Generation Fleet."* May 2011. Analysis Group Inc. Accessed at: http://www.analysisgroup.com/uploadedFiles/News_and_Events/News/EEI_PeerReview_Tierney_Cicchetti%20_May2011.pdf

Table A.12: Key Findings of Tierney and Cicchetti's Rebuttal

1. Key assumptions are excessively conservative.	Each of the EEI's 9 scenarios contained at least one assumption unreasonable at the time EEI conducted analysis. Unrealistic key assumptions for each scenario describe the worst possible cases and give little credence to EEI's analysis. For example, in six of nine scenario runs, the EEI assumed the Waxman-Markey bill would be in effect by 2016 (price on carbon starting at $26/ton), even though the legislation failed to pass the Senate one year before the analysis. The EEI's assumptions also failed to recognize the substantial portion of units with already installed environmental control equipment, and eight of nine scenarios failed to consider less costly methods of controlling air emissions. They noted that Midwest Generation (one of the largest merchant coal generators in the U.S.) announced that less costly technologies could be deployed, thus preventing retirements.
2. Market fundamentals are responsible for half of the predicted retirements.	Only 21–24 GW of the 70–80 GW of coal plant retirements that EEI predicts can be attributed to the EPA regulations. They found that low natural gas prices are independently responsible for 22–25 GW of total retirements.
3. Even EEI's most plausible scenario overstates the number of retirements.	The EEI's third run, titled "Scenario 1 + Alt Air," contains the most plausible assumptions but still overstates retirements. This scenario run assumes a Cooling Water Intake Rule that requires all plants to install cooling towers, which was not the standard in the EPA's actual rule proposed. They recommend this scenario should be rejected as either unreasonable or put into the upper end of the bracket—not lowest as the report suggested.
4. Incremental retirements driven by EPA regulations are manageable.	The 24 GW of estimated retirements driven by EPA regulations represents less than 8% of the total national coal capacity. They also point out that, between 2003 and 2005, the electric generating industry constructed 160 GW of new combined cycle generation—over six times the amount of retirements predicted by EEI's most plausible scenario. This also does not consider current electricity demand forecasts, which show lower demand between 2015–2020 of 2.5% relative to the 2010 forecast used by EEI. PJM, grid operator in parts of the Mid Atlantic/Midwest regions, recently released new forecasts showing that, because of economic factors including cost-effective energy efficiency and demand response programs, demand for electricity will be substantially lower than previously forecasted.

Commentary: Greenhouse Gas Rules

In July 2010, NERC also conducted a report that reviewed the reliability impacts of climate change initiatives (RICCI report). They found that meeting the carbon reduction goals of climate change initiatives may lead to unprecedented changes in a nearly one million megawatt resource mix in North America (U.S. and Canada). To form a basis for this report, the task force that produced the report reviewed current and ongoing climate change initiatives, which included the Waxman-Market initiative that proposed emission reductions below the 2005 base year by 3% by 2012, 17% by 2020, 42% by 2030, and 83% by 2050. They also reviewed Canada and the U.S. commitment under the Copenhagen Accords to meet a 17% reduction from a 2005 base year by 2020. As binding emission targets and mechanisms for carbon were not known at the time of the report, no attempt was made to complete detailed simulations addressing the magnitude of resource change and technology deployment.

The report reviewed recent regulation, legislation, and proposed standards, e.g., renewable portfolio standards, that may make up the timeframe and mechanisms for GHG emission reductions. Items reviewed included the following:

- Clean Air Act (Existing);
- Energy Independence and Security Act of 2007 (Existing);
- American Recovery and Reinvestment Act of 2009 (Existing);
- American Clean Energy and Security Bill 2009 (Proposed);[62]
- Federal Renewable Portfolio Standards (Proposed);
- Additional Federal Emission Trading Programs (Existing);
- Kyoto Protocol (Canada has ratified, U.S. has not; it sets commitment to reduce GHG 6% below country’s 1990 levels between 2008–2012);
- Regional GHG Initiatives e.g., RGGI, Northeast Regional NOx Budget Trading Program;
- State Renewable Portfolio Standards;
- Canadian Renewable Portfolio Standards by province;
- Joint Canadian U.S. Initiatives e.g., Western Climate Initiative; and
- Copenhagen Accords. [63]

The report assumed the Waxman-Market Bill and the Copenhagen Accords reduction would form the basis for its conclusions. Three horizon planning timelines were developed to assess GHG impacts between 2010 and 2050 (Horizon 1: 1–10 years, Horizon 2: 10–20 years, and Horizon 3: 20+ years) as a way to systematically evaluate future pathways and/or scenarios. NERC envisaged each scenario would have unique challenges, but Horizon 1, for example, was projected to have a large number of coal unit retirements, which would challenge reliability in the Midwest. Horizon 3 was assumed to have multiple changes in the North American fuel mix, which would offset the retirements of fossil-fired units that are not fitted with carbon capture and

[62] This is the Waxman-Markey Bill, which includes cap and trade system for newly created markets. It sets new combined efficiency and RPS standards of 20% by 2020 and emission reduction standards of 17% by 2020, 42% by 2030, and 83% by 2050.
[63] Copenhagen Accords is a non-legally binding commitment to achieve 17% reduction below base year of 2005 by 2020.

sequestration components (CCS).[64] To meet carbon reduction targets, natural gas units without CCS may not be viable, which will increase the need for non-emitting resources. Both Horizons II and III envisage the introduction of an array of new and existing technology, large energy storage units, transmission line development, demand response and variable renewable generation and electric vehicles. Key observations are described in Figure A.10.

Timing of carbon reduction targets will require unprecedented shift in resource mix

- Capacity of current resource mix is close to 1M MW.
- Meeting CO_2 and GHG reduction targets will require significant change in resource mix.
- Climate change initiatives must consider timing of emission targets, giving industry time to adapt and gain experience with new technology behavior.
- Reliability considerations depend on construction of new low carbon generation, transmission upgrades, demand side management, and integration of multiple resources.

Regional solutions are needed to respond to climate change initiatives, driven by unique characteristics and existing infrastructure

- Impacts will be regional, even though targets are common to all jurisdictions.
- Significant differences in generation, transmission, and distribution characteristics across North America, so some regions presently emit more GHG than others.
- Resource portfolios for some regions will have to dramatically change, and resource availability agreement will have to be renegotiated.

Additon of new resources increases need for transmission and energy storage/balancing resources

- Location-constrained large-scale solar, wind geothermal, nuclear and coal-fired units fitted with CCS resources are projected.
- Successful integration of these resoures will require new/upgraded tramsission to slot into bulk power system.
- Additional system operational strategy flexibility will be needed to deploy technologies such as demand response, energy storage, power electronics, and variable plant diversity.

Carbon reduction from increasing demand-side management must be balanced against reliability impacts

- Climate change initiatives at state/local level combined with consumer led efforts at reduction of energy consumption will broaden size and scope of DSM programs.
- Depending on DSM for long-term capacity, energy reductions will require experience to provide certainty of DSM role in maintaining reliability.

Climate change efforts that increasingly depend on distribution system options can, in aggregate, impact bulk power system reliability

- As amount/type of generation or generation-like resources on the distribution system increase, it will function in similar manner as bulk transmission.
- Options not yet defined could include bidirectional power flow, use of distributed variable generation resources.
- Smart grid deployments must be completed in a secure fashion with defined preventative actions to ensure reliability of bulk power system.

Source: NERC, RICCI 2010 (pages IIII and IV)

Figure A.10: Major Findings

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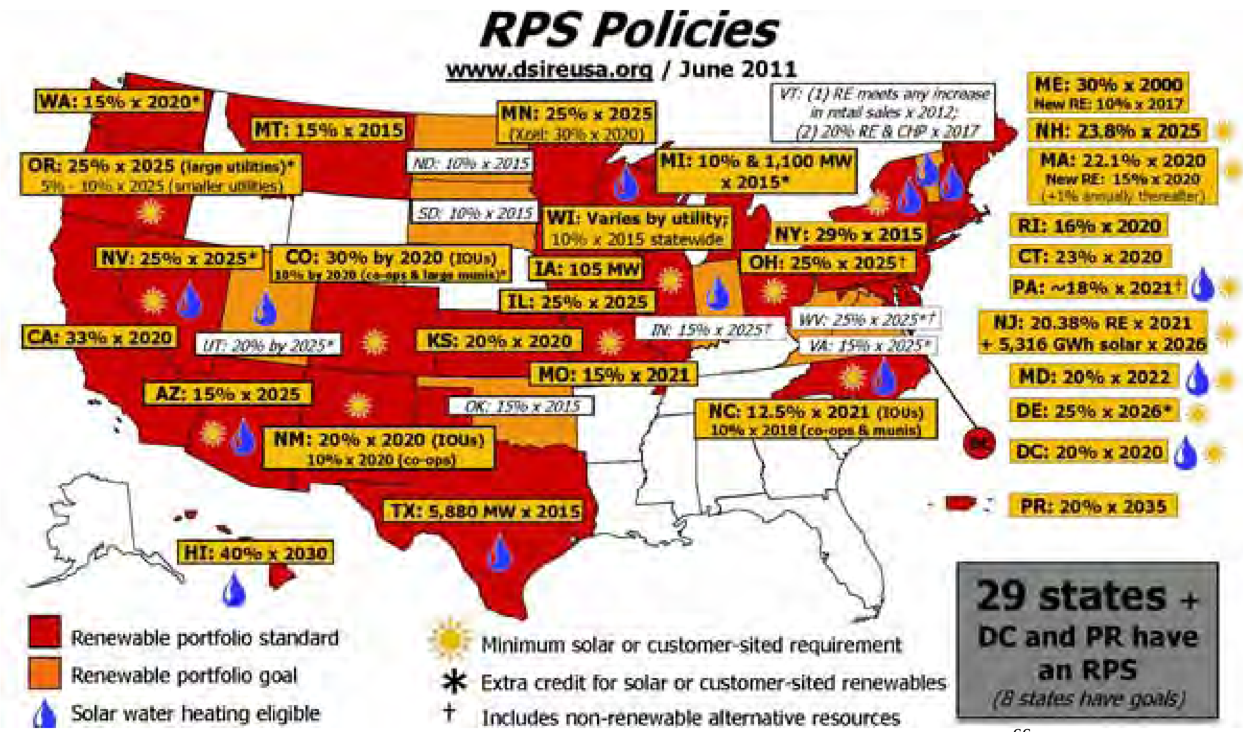
[64] NERC, RICCI 2010 page 10-11.

As part of this study a series of published scenarios, models, and reports from various organizations were also reviewed. For example, ERCOT's 2009 study on the effects of proposed climate change legislation on electricity prices in the ERCOT market was assessed.[65]

A framework was then developed to structure the future reliability assessment by reviewing existing scenarios and models developed by government and industry. The high level structure for these scenarios provided a relative comparison of RPS requirement and GHG mandates, and served as a guide for scenario development that NERC could utilize in the future.

The initial observation was that there were two prevalent legislative themes: GHG reduction mandates, which also includes energy efficiency and demand response, and RPS standards. RPS Policies are in effect in 29 states (see Figure A.11).



Source: Database of State Incentives for Renewables & Efficiency.[66]

Figure A.11: RPS Standards

The second theme included market dimensions of supply and demand, technology introduction, and capital costs. Based off these themes, four distinct scenarios were identified based on scenario analysis performed by government agencies. Some slight overlap of key outcomes and variables occurs, but the structure is in place to provide insights. NERC considered that by identifying a limited set of key drivers, future vision and assessment of the bulk power outcomes could be made. The four scenarios are discussed below were included in the report and Figure A.12 shows the scenarios and models that the report reviewed fit in the matrix.

Business as usual. This scenario represents incremental changes from the status quo. In this scenario, less stringent GHG mandates are enforced as there is an abundance of carbon

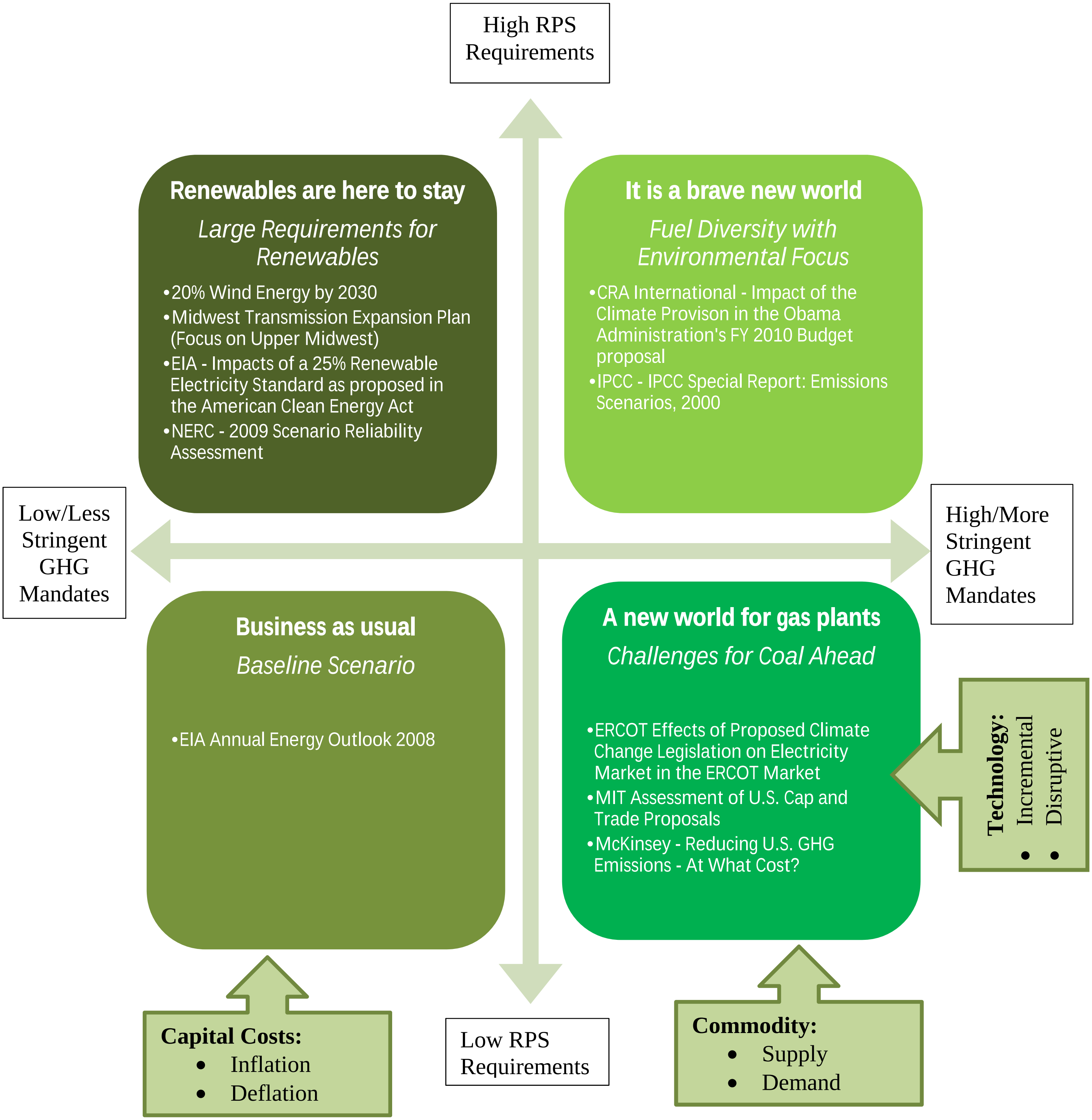
[65] ERCOT Analysis of Potential Impacts of CO2 Emission Limits on Electric Power Costs in the ERCOT Region. May 12, 2009. Accessed at: http://www.ercot.com/content/news/presentations/2009/Carbon_Study_Report.pdf
[66] Accessed at: http://www.dsireusa.org/summarymaps/index.cfm?ee=1&RE=1

credits under a cap-and-trade regime or small carbon tax. Mandates for GHG reductions are long-term, because most of the stringent goals are set a long time into the future—2030 and beyond. In addition to weak GHG mandates, RPS requirements are low (15% or less) and are regionally dictated. Rules on generation of Renewable Energy Credits (REC) are broad, and can be easily generated and used to achieve mandated goals. This scenario represents a continuation of industry trends, including issues with the reliability of the bulk power system, and consists of replacing aging infrastructure and old equipment with "smart" technology. Operational reliability considerations include short-term integration issues with existing and new renewable resources.

A new world for gas plants. In this scenario, a shift occurs in generation from coal to natural gas. Strong legislation with aggressive GHG reduction mandates are in place. The amount of carbon credits and/or carbon tax is very limited. The mandated GHG reduction targets are strong in the short and long term and may be federally mandated. Carbon credits/taxes are allocated or charged to stationary carbon sources. In this scenario, RPS requirements are also low at 15% or less. RECs are easily generated and mandates are easily achieved. This scenario represents a shift from industry's history (where power was mostly coal based). Nuclear and natural gas slowly gain a more relevant role in the base load over the short term and dominate the base load generation in the long term. Reliability issues in this scenario are centered on the ability of the system to transition from coal to natural gas. This is also coupled with the integration of renewable resources into the transmission grid and control of their dispatch.

Renewables are here to stay. In this scenario renewable generation has achieved large-scale penetration. There is less stringent legislation (similar to the business as usual scenario) with low GHG mandates and an abundance of carbon credits under a cap-and-trade regime or a lower carbon tax. Mandates for GHG reduction are long term, because most of the stringent goals are set in the future at 2030 and beyond. Instead of aggressive carbon pricing, enacted legislation would achieve emissions reductions through aggressive RPS requirements and renewable targets of more than 20%. Rules for generating RECs are stringent and targets must be met by construction of new renewable generation facilities. Under this scenario, energy efficiency (EE) and demand response (DR) programs are widespread, so load growth is flat in the short term and declines over the longer term. Reliability issues under this scenario include integration of large amounts of interruptible and dispatchable generation and supply assets into the power system and their effects on other generation assets, which are mostly not designed to cycle.

It is a brave new world. This scenario includes a significant mix of changes relative to the current industry source mix. This scenario is characterized by approved legislation that contains strong GHG reduction mandates in the short and long term. The strong RPS mandated targets exceed 20%. There is strong penetration of EE and DR programs that flattens load growth in the short term and reduces it over the long term. Reliability issues include all elements of the three previous scenarios and present the greatest challenges to maintaining reliability of the power system.



Source: NERC, RICCI 2010, page 26

Figure A.12: Proposed Scenario Matrix

One extremely important factor in determining penetration of new renewable generation sources is the transmission network. NERC predicted a need for entities to more than double the average number of transmission miles constructed over any 5-year period since 1990 to meet planned levels of development over the next 10 years. Beyond transmission, NERC also noted the need to strengthen the transmission system with a number of technologies to handle varying reliability considerations, to improve flexibility, and increase capacity of the operation. Smart transmission technologies and strategically placed energy storage will be needed to make more efficient and reliable use of the system.

Commentary: Water

Industry and environmental groups have also waged a “war of words” regarding the impacts of the proposed Cooling Water Intake rule. The EPA has found itself in the cross-fire with groups accusing it of passing the buck. According to NERC, the rule is expected to impact 252 GW of coal, oil, steam, and gas steam generation and 60 GW of nuclear power.[67] This assessment found that the Cooling Water Intake rule would have the widest impact and could significantly drive down planning reserve margins in about half the electricity regions monitored by the reliability watchdog.[68]

The EEI reviewed the energy and price consequences of the rule. In a PowerPoint to the American Legislative Exchange Council in 2010, they reported capacity reductions due to efficiency losses at approximately 2–4%. This included extended outages with some companies reporting 40+ months for retrofit. Resource margin adequacy, reliability difficulties, and load balancing concerns were also paramount. For example, the New York ISO forecast 20% of generation resources may retire. Concerns were also raised that insufficient compliance time may not allow for development of replacement capacity. Price increases were discussed. For example, California is expected to see a 9% price increase.[69]

The proposed rule is also subject to congressional oversight. Late last year, Representative Fred Upton (R-MI)—Chairman of the powerful House Energy and Commerce Committee—called on EPA Administrator Lisa Jackson to provide greater transparency as the Agency considers rules for Cooling Water Intake structures at existing electric generation and manufacturing facilities. Upton noted the following:

> Given that this rulemaking has the potential to affect more than 400 power plants throughout the country and could impact energy supply and reliability, I am concerned about the direction of the proposal and its timing. The potential retrofit costs could be substantial ($200–300 million per unit for coal and $700 million to $1 billion for nuclear power plants) and some coal steam generators may not have the space necessary for the installation of cooling towers and other associated equipment. This could result in the retirement of some of these generators.

[67] NERC, 2010 *Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations*. October 26, 2010. Accessed from: http://www.nerc.com/files/EPA_Scenario_Final.pdf

[68] Cash, C. *US EPA Postpones Release of Cooling /Water Rule Proposal*. Platts. March 14, 2011. Accessed at: http://www.platts.com/RSSFeedDetailedNews/RSSFeed/ElectricPower/6906197

[69] Edison Electric Institute. Cooling Water Intake Structures Rule. Presentation to American Legislative Exchange Council. Washington DC. December 2, 2010. Accessed at: http://www.alec.org/AM/PDF/Energy/SNPS%202010%20Presentations/Asti.pdf

Upton called on the EPA to allow 180 days at minimum for the public to digest and prepare comments for a rule of this magnitude.[70]

The Natural Resources Defense Council (NRDC) and Riverkeeper (which led to the issuance of the new proposed rule) issued a release in March 2011:

> The proposed rule, released this evening (March 28), was supposed to modernize the way power plants take in and release water used for cooling. Instead, EPA will leave it up to state agencies to figure out requirements for plants, but decades of experience have shown that states lack the resources and expertise to make these decisions on a case-by-case basis and have complained to EPA of the extreme burden of having to do so.[71]

Riverkeeper's Executive Director, Paul Gallay, noted:

> We expected more out of the EPA to protect the country's waterways from power plants' destructive impacts. A case-by-case approach will simply not work. Instead, it will continue an endless cycle of paperwork and litigation that will leave water bodies across the country unprotected and countless species at risk.[72]

Gallay went on to comment:

> [W]ith nearly 500 U.S. power plants still relying on the antiquated and destructive, once-through cooling system, each plant can withdraw at least 50 million (and often, more than a billion) gallons of cooling water. This water goes through a condenser where it absorbs heat from the boiler steam, and then is discharged back into the water at higher temperatures. Not only does this super-heated water kill marine life but billions of fish are sucked in with the water and killed with this system. Environmental groups want all power and manufacturing plants, new or old, to use closed-cycle cooling systems. This would generally reduce that amount of water taken in by 95 percent when compared with once-through cooling, leaving trillions of gallons of water untouched every year and fish out of cooling systems. Some plants have voluntarily moved to this system but others still refuse to make the move.

The regulatory role around safe drinking water is also taking a new turn with the proposed EPA rules on hydraulic fracturing. The Securities and Exchange Commission (SEC) has also jumped into the fray and is asking drillers for specific information, including chemicals used in this process. News analysis during August 2011 discussed why the SEC was asking questions. Commentators noted that if the process of drilling pollutes drinking water, cleaning up the mess would be expensive. If the company is publically traded, some argue, it should warn investors of such financial risk ahead of time.[73]

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[70] MI Rep. *Upton Selected Chairman of Energy & Commerce*. ENews USA. December 7, 2010. Accessed at http://enewsusa.blogspot.com/2010/12/mi-rep-upton-selected-chairman-of.html

[71] Natural Resources Defense Council. *Dead Fish, Fouled Water, EPA Misses Opportunity to Fix Power Plant Damage*. Press Release. March, 28, 2011. Accessed at: http://www.nrdc.org/media/2011/110328.asp?utm_source=feedburner&utm_medium=feed&utm_campaign=Feed%3A+NRDCPressReleases+%28NRDC+Press+Releases%29&utm_content=Google+Reader

[72] Riverkeeper. *Dead Fish, Fouled Water, EPA Misses Opportunity to Fix Power Plant Damage*. Press Release. March, 28, 2011. Accessed at: http://www.riverkeeper.org/news-events/news/preserve-river-ecology/dead-fish-fouled-water-epa-misses-opportunity-to-fix-power-plant-damage/

[73] Block, M. *SEC Jumps Into Fight over Fracking.* National Public Radio, August 25, 2011. Accessed at: http://www.npr.org/2011/08/25/139952857/sec-jumps-into-fight-over-fracking. See also Lammik, Glenn. G. *E In*

A.2 Conclusions

The regulatory playing field for energy production will continue to change over the next 3 to 15 years. The EPA's rulemaking approach to permitting guidance for oil and gas hydraulic fracturing activities will also change the landscape for the nascent fracturing industry. This will also be challenged, no doubt, by some of the states who are starting to implement moratoriums on fracturing activities based on citizen concern. For example, New Jersey's Governor Chris Christie, in August 2011, imposed a 1-year conditional veto to institute a 1-year moratorium on fracturing on S-2576, which had recommended changes to increase fracturing. This was to allow federal and state agencies to review the issue comprehensively.[74]

Chuck D. Barlow, Associate General Counsel for Entergy Services Inc., during February 2011 succinctly summed up the landscape of forthcoming environmental regulatory hurdles for energy production:

> Minds that are knowledgeable on the debate regarding the country's energy future disagree on the magnitude of the impact that these air and water regulations will have on the availability and stability of our electric generation and delivery systems. The perception of whether the cost of compliance will be justified by the sometimes debated environmental benefits varies greatly depending on the viewer. But there is no doubt that the impacts will be significant and costly; and that the implementation of EPA's anticipated rules should proceed in a coordinated manner that considers the sequencing and timing of the various rules and the probability that, waiting somewhere in the wings, is the wild card of greenhouse gas regulation.[75]

SEC Doesn't Stand for Environment – Why is it Probing Fracking? August 25, 2011. Forbes. Accessed at: http://www.forbes.com/sites/docket/2011/08/25/e-in-sec-doesnt-stand-for-environment-why-is-it-probing-fracking/

[74] State of New Jersey: Governor Chris Christie. *Governor Chris Christie Stands up for Sound Policymaking by Issuing One-Year Moratorium on Fracking.* August 25, 2011. Press Release. Accessed at: http://www.state.nj.us/governor/news/news/552011/approved/20110825c.html

[75] Barlow, C.D. *Environmental Regulatory Hurdles for Future Energy Production*. Presented by International Practice and Law and Toxic Tort and Environmental Law Sections at the Federation of Defense and Corporate Counsel Winter Meeting. Indian Wess, CA. February 26–March 5, 2011. Accessed at: http://www.thefederation.org/documents/19.Environmental%20Regulatory%20Hurdles.pdf

Appendix B: Air Quality Rules since 2010

Title I: Federal Implementation Plans (FIPS) and State Implementation Plans (SIPS), Conformity, Federal Facilities

January 2010:

- Office of Air Quality Planning and Standards issued two draft assessment documents related to review of the NAAQs for Particulate Matter (PM) available for comment.[76]

February 2010:

- Draft document, "*Policy Assessment for the Review of the Particulate Matter National Ambient Air Quality Standards—First External Review Draft,*" made available for public comment.
- The EPA promulgated a final rule effective April 12, 2010 revising primary NAAQS for Nitrogen Dioxide (NO). This supplemented the existing annual standard for NO_2 by establishing a new one-hour standard at 100 parts-per billion (ppb), based on the 3-year average of the 98th percentile of the yearly distribution of 1-hour daily maximum concentrations. The EPA also established requirements for a NO_2 monitoring network.[77]

March 2010:

- Proposed rule that provided notice that in accordance with 40 CFR Part 53, a new equivalent method for measuring concentrations of lead in total suspended particulate matter (TPS) was designated. None as EQL-0310-189—Procedure for Determination of Lead in Ambient Air TSP by Hot Plate Acid Extraction and ICP-MS Analysis.[78]
- Release for public comment draft documents pertaining to the qualitative analysis being conducted in a review of NAAQS for carbon monoxide.[79]
- Release of preliminary draft report, *Policy Assessment for the Review of the Secondary National Ambient Air Quality Standards for Oxides of Nitrogen and Oxides of Sulfur: First External Review Draft.*[80]
- Proposed rule that would revise Section 112(j) of the CAA to clarify and streamline the process for establishing case-by-case emission limits for major sources of HAPs.[81]

April 2010:

- Final rule revising the General Conformity Regulations, promulgated in 1993. The final rule is designed to assist state, tribal, and local agencies in developing SIP revisions to address revised ozone NAAQS and the 2007 fine particulate matter standard.[82]
- Issued amendments to the Transportation Conformity Rule to make it consistent with the CAA and to implement provisions ensuring conformity with SIPs regarding particulate matter (PM2.5 and PM10) and carbon dioxide (CO_2) areas.[83]

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[76] 75 Fed. Reg 4067 (Jan 26 2010).
[77] 75 Fed. Reg. 6474 (Feb. 9, 2010) (40 C.F.R. pts. 50 & 58).
[78] 75 Fed. Reg. 9894 (Mar. 4, 2010).
[79] 75 Fed. Reg. 10,252 (Mar. 5, 2010).
[80] 75 Fed. Reg. 11,877 (Mar. 12, 2010).
[81] 75 Fed. Reg. 15,655 (proposed Mar. 30, 2010).
[82] 75 Fed. Reg. 17,254 (Apr. 5, 2010).

- Issued notice that in accordance with 40 CFR Part 53, Agency had designated a new equivalent method for measuring concentrations of ozone (O_3) in the ambient air that utilizes a method based on ultraviolet absorption photometry. [84]

May 2010:

- Notice of designation of new equivalent method for measuring lead concentrations in total suspended PM in the ambient air. Designated as EQL–0510–191, Determination of Lead Concentration in TSP by Inductively Coupled Plasma Mass Spectrometry (ICP/MS) with Heated Ultrasonic Nitric and Hydrochloric Acid Filter Extraction. [85]

June 2010:

- Made available a final document entitled *Quantitative Risk and Exposure Assessment for Carbon Monoxide*, which discusses the quantitative analyses conducted to characterize health risks associated with exposure to ambient carbon monoxide (CO)[86].
- Finding of failure of 29 states/territories to submit completed SIPs to satisfy interstate transportation requirements under §110(a) CAA for the 2006 24-hour NAAQS for fine PM.[87]
- Proposed amendments for Protocol Gas Verification Program (PGVP) due to recent gas audits revealing that some gas cylinders used to calibrate continuous emission monitoring systems on stationary sources did not meet the Agency's performance specifications. The EPA amended its PGVP and the minimum competency requirements for air emission testing bodies, which had become effective on January 1, 2009. The EPA also proposed amendments to the Acid Rain Program continuous emission monitoring system regulations.[88]
- Revision to primary sulfur dioxide (SO_2) NAAQS—specifically established a new one-hour SO_2 standard at a level of 75 ppb, based on the 3-year average of the annual 90th percentile of 1-hour daily maximum concentrations. With the issuance of this rule, the EPA revoked the existing 24-hour and annual primary SO_2 standards.[89]

July 2010:

- Availability of two final documents pertaining to the quantitative analyses that have been conducted as part of the review of the NAAQS for PM. These documents are titled *Quantitative Health Risk Assessment for Particulate Matter* and *Particulate Matter Urban-Focused Visibility Assessment.*[90]
- Availability of draft document *Policy Assessment for the Review of the Particulate Matter National Ambient Air Quality Standards—Second External Review Draft*, which discusses the EPA's review of the primary and secondary PM NAAQS.[91]

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[83] 75 Fed. Reg. 14,260 (Mar. 24, 2010).
[84] 75 Fed. Reg. 22,126 (Apr. 27, 2010).
[85] 75 Fed. Reg. 30,022 (May 28, 2010).
[86] 75 Fed. Reg. 32,179 (June 7, 2010).
[87] 75 Fed. Reg. 32,673 (June 9, 2010).
[88] 75 Fed. Reg. 35,520 (June 22, 2010).
[89] 75 Fed. Reg. 35,520 (June 22, 2010).
[90] 75 Fed. Reg. 39,252 (July 8, 2010).
[91] 75 Fed. Reg. 39,253 (July 8, 2010).

August 2010:

- Provided notice that in accordance with 40 CFR Part 53, it designated a new equivalent method for measuring concentrations of lead in TSP, EQL–0710–192, Heated Nitric Acid Hot Block Digestion and ICP/MS Analysis for Lead on TSP High-Volume Filters.[92]
- Proposed FIPs to identify and limit interstate transportation of emissions of NOx and SO_2 from electric generating units within 32 states in the eastern U.S. that potentially prevent downwind states from achieving compliance with the 1997 and 2006 fine PM NAAQS as well as the 1997 ozone NAAQS (Texas is included in this list). This will work in conjunction with other federal and state actions to ensure most areas in the eastern part of the U.S. will be in compliance with the PM and ozone NAAQs by 2014 if not sooner (known as the Air Transport Rule).[93]
- Notice of designation, in accordance with the provisions of 40 CFR Part 53, of two new equivalent methods to measure concentration of PM_{10} and SO_2 in the ambient air. The method designated for PM_{10} measurement is an automated monitoring method that utilizes a measurement principle based on sample collection by filtration and analysis by beta-ray attenuation. The method designated for the measurement of SO_2 is an automated method that utilizes ultraviolet fluorescence.[94]
- Issued proposed rule to clarify obligation to retain 1-hour nonattainment NSR program requirements for certain areas designated in nonattainment for the 1997 8-hour ozone NAAQS.[95]
- Proposed to revise the rule for implementing 1997 8-hour ozone NAAQS to address how NSR requirements that applied to the areas 1-hour ozone NAAQS classification should apply under anti-backsliding provisions in the 1997 8-hour implementation rule. This rule was also proposed in response to the ruling by the U.S. Court of Appeals for the D.C. Circuit in *South Coast Air Quality Management District v. EPA.*[96]

September 2010:

- Notice of data availability pertaining to this Proposed Transport Rule; it made available to the public an updated version of the power modeling platform that the Agency proposes to use to support the final rule.[97]
- Issued corrections to minor technical errors in original Transport Rule and corrected an erroneous statement that proposed trading program do not allow units to opt-in.[98]
- Amendments to both the NESHAPs as pertaining to the Portland Cement Manufacturing Industry and the NSPS for Portland Cement Plants. Regarding the NESHAP amendments, the EPA added and revised emission limits for mercury, total hydrocarbons, and PM from new and existing kilns located at both major and area sources, as well as hydrochloric acid from new and existing kilns located at major sources only. For the NSPS amendments, the EPA added or revised emission limits for Opacity, PM, NOx, and SO_2 for facilities constructed or modified after June 16, 2008. Additional testing and

[92] 75 Fed. Reg. 45,627 (Aug. 3, 2010).
[93] 75 Fed. Reg. 45,210 (proposed Aug, 2, 2010).
[94] 75 Fed Reg. 51, 039 (Aug. 18, 2010).
[95] 75 Fed. Reg. 51,960 (proposed Aug. 24, 2010).
[96] 472 F.3d 882 (D.C. Cir. 2006).
[97] 75 Fed. Reg. 53,613 (Sept. 1, 2010).
[98] 75 Fed. Reg. 55,711 (proposed Sept. 14, 2010).

monitoring requirements for affected sources were also incorporated into the amended rule [99]

- Preliminary draft report entitled "*Policy Assessment for the Review of the Secondary National Ambient Air Quality Standards for Oxides of Nitrogen and Oxides of Sulfur: Second External Review Draft*" released for public comment and review and to seek early consultation with the Clean Air Scientific Advisory Committee.[100]

October 2010:

- Release of additional materials pertaining to the draft report issued in September "*Policy Assessment for the Review of the Secondary National Ambient Air Quality Standards for Oxides of Nitrogen and Oxides of Sulfur: Second External Review Draft.*"[101]
- Notice of data availability supporting federal implementation plans to reduce interstate transportation of fine PM and ozone. Also included revisions to emission inventories.[102]

November 2010:

- Availability of final document *Policy Assessment for the Review of the Carbon Monoxide National Ambient Air Quality Standards*.[103]
- Promulgated a rule establishing air quality designations for certain areas in the U.S. for the 2008 lead NAAQS. The EPA determined in this final rule areas that had not met the 2008 lead NAAQS and also areas that contribute to lead air pollution in a nearby area that does not meet lead NAAQS. Areas determined to be in nonattainment are required to take planning and pollution control activities to achieve standard attainment status.[104]

December 2010:

- Finalized determination that Dallas/Fort Worth moderate 8-hour ozone non-attainment area failed to attain the 1997 8-hour ozone NAAQS. Issued new attainment date of no later than June 15, 2013, and required Texas to submit revisions to its SIP no later than January 19, 2012.[105]
- Issued final rule establishing methods for measurement of certain filterable and condensable PM from stationary sources.[106]
- The EPA proposed to revise its interpretation of the Reasonable Further Progress (RFP) Rule such that states would not be able to take credit for emission reductions from outside the attainment area to meet the area's FRP obligations.[107]
- Issued revised lead ambient air monitoring requirements pertaining to when state and local monitoring agencies are required to undertake this monitoring.[108]

January 2011:

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[99] 75 Fed. Reg. 54,970 (Sept. 9, 2010).
[100] 75 Fed. Reg. 57,463 (Sept. 21, 2010).
[101] 75 Fed. Reg. 61,486 (Oct. 5, 2010).
[102] 75 Fed. Reg. 66,055 (Oct. 27, 2010).
[103] 75 Fed. Reg. 67,361 (Nov. 2, 2010).
[104]75 Fed Reg. 71,033 (Nov. 22, 2010).
[105]75 Fed. Reg. 79,302 (Dec. 20, 2010).
[106]75 Fed. Reg. 80,118 (Dec. 21, 2010).
[107]75 Fed. Reg. 80,420 (proposed Dec. 22, 2010)
[108]75 Fed. Reg. 81,126 (Dec. 27, 2010).

- Notice of data availability for FIPs and alternative allowance programs to reduce interstate transportation of PM and ozone. As part of this request for comment on alternative actions, calculation of assurance provisions allowance surrender requirements, new-unit allocations in Indian Country, and allocation by states.[109]

Title 1: New Source Review (NSR), Prevention of Significant Deterioration (PSD), and New Source Performance Standards (NSPS).

February 2010:

- Proposed rule that would repeal the grandfathering provision for PM less than 2.5 micrometers ($PM_{2.5}$) contained in the federal PSD requirements. Additionally, the EPA proposed to end early the PM_{10} Surrogate Policy applicable in states that have an approved PSD program in their SIP.[110]

March 2010:

- Extended for 18 months an existing "stay" on the Fugitive Emission Rule (published December 19, 2008). This revised agency requirements in the federal PSD program and required fugitive emissions to be included in the determination on whether a physical or operational change resulted in a major modification for sources designated under §302(j) CAA.[111]

April 2010:

- Reconsideration of NSR Aggregation Amendments Rule (issued January 15, 2009), which established that sources and permitting authorities should aggregate emission only when nominally-separate changes at a major stationary source are related. After a petition was received from the Natural Resources Defense Council that raised various legal and policy issues in January 2009, the EPA proposed to revoke the rule and extend the stay of the rule's effective date for 6 additional months.[112]

May 2010:

- Extended the NSR Aggregation Amendments Rule effective date until further review is completed.[113]

June 2010:

- Issued proposed rule defining commercial and industrial waste established under the NSPS and emission guidelines for commercial and industrial waste incineration units.[114] This was in response to the vacateur by the court of a previous 2005 definition in *Natural Resources Defense Council v. EPA.*[115] The proposed rule includes a 5-year technology

[109] 76 Fed. Reg. 1109 (Jan. 7, 2011).
[110] 75 Fed. Reg. 6827 (proposed Feb. 11, 2010).
[111] 75 Fed. Reg. 16,012 (Mar. 31, 2010).
[112] 75 Fed. Reg. 19,567 (proposed Apr. 15, 2010).
[113] 75 Fed. Reg. 27,643 (May 18, 2010).
[114] Which can be utilized to generate electricity.
[115] 489 F.3d 1250 (D.C. Cir. 2007).

rule of NSPS, emission guidelines, and other amendments that are pertinent to these incineration units.[116]

- Issued proposed revisions to NSPS for new stationary compression ignition (CI) internal combustion engines (ICE). The EPA proposed the following amendments: (1) stricter standards for certain non-emergency new CI stationary ICEs; (2) owners and operators are now able to develop their own operation and maintenance plans as opposed to the previous requirement to follow procedures set by engine manufacturers; (3) temporary engines (engines in one location for less than 1 year) generally considered to be mobile non-road engines, so NSPS and other regulations applicable to stationary engines are not applicable to these engines; (4) less stringent NOx standards for stationary CI ICE with a displacement of > or equal to 30 l/cly in areas where low sulfur fuel is not required; (5) addition of a reconstruct definition that is specific for stationary CI ICE; and (6) other minor corrections and revisions to the initial rule. The EPA estimates this will significantly reduce annual releases of NOx, PM, and hydrocarbons.[117]

October 2010:

- Final amendments issued to PSD requirements for $PM_{2.5}$. This established increments and implemented two screening tools: (i) Significant Impact Levels (SILs) and (ii) Significant Monitoring Concentration. The SILs were added to two other NSR rules that regulate the major stationary sources located in attainment or unclassifiable areas where emissions may violate NAAQS.[118]

January 2011:

- The EPA announces plan to <u>defer for 3 years</u> GHG permitting requirements for CO_2 emissions from biomass-fired and other biogenic sources. This was in response to over 7,000 comments that had been received in a July 2010 call for information on accounting for biogenic GHG emissions under the PSD program.

March 2011:

- The EPA issued interim rule to "stay" a December 2008 rule known as the "Fugitive Emission Rule," which established new provisions for how fugitive emissions (those that do not pass through a stack, chimney, vent, or other similar opening) should be treated for NSR permitting. This replaced the "stay" the EPA issued on March 2010 that was effective through October 3, 2011.[119]

April 2011:

- Proposed deferral for CO_2 emission from bioenergy and other biogenic sources under the PSD and Title V programs and Guidance for Determining Best Available Control Technology for reducing CO_2 emissions from bioenergy production. Defers for 3 years GHG permitting requirements for CO_2 emissions from biomass-fired and other biogenic sources. [120] The EPA also made available a guidance document, *Determining Best Available Control Technology for Reducing Carbon Dioxide Emissions from Bioenergy*

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[116] 75 Fed. Reg. 31,938 (proposed June 4, 2010).
[117] 75 Fed. Reg. 32,612 (proposed June 8, 2010).
[118] 75 Fed. Reg. 64,854 (Oct. 20, 2010).
[119] 76 Fed. Reg. 17,548 (Mar. 30, 2011).
[120] 76 Fed. Reg. 15,249 (Mar. 21, 2011).

Production, to assist facilities and permitting authorities with permitting decisions until the Proposed Rule is finalized.[121]

- Final Rule Covering Greenhouse Gas Permitting in Texas. Related to FIP Plan regarding Texas's PSD program. According to the EPA, this will ensure businesses in Texas will be able to seek and obtain air permits needed for new or expanding projects that increase GHG emissions. [122]

May 2011:

- Final rule that repealed the "grandfather" provision for PM less than 2.5 micrometers under the PSD program. This provision had allowed certain facilities under certain circumstances to satisfy the PSD permit requirements for $PM_{2.5}$ by meeting the requirements for controlling particulate matter less than 10 micrometers and analyzing impacts on PM_{10} air quality as a surrogate approach. Entities that are affected include those proposed new and modified major stationary sources subject to the PSD program that submitted a complete application for a PSD permit before July 15, 2008—effective date of the final $PM_{2.5}$ NSR Implementation Rule—but have not yet received a final and effective permit authorizing commencement of construction. The EPA estimates that fewer than 30 proposed new major sources/modifications will be affected by this repeal.[123]

Title III: National Emission Standards for Hazardous Air Pollutants (NESHAPs)[124]

June 2010:

- Proposed NESHAPs for the following two area source categories: (1) industrial boilers and (2) commercial and institutional boilers. Rule applies to all owners and operators of boilers that combust coal, biomass, or oil, located at an area source, as well as owners and operators of boilers that combust natural gas at an area source, which then converts to combusting coal, biomass, or oil, after the date of this proposal. The emission standards set forth in this proposed rule are based on the MACT emission limits for mercury and CO, and on the generally available control technology standards for PM.[125]
- Proposed rule requires that all industrial, commercial, and institutional boilers and process heaters comply with the NESHAP based on MACT standards. The rule sets emission limits for the affected sources. The EPA also proposed that all existing major source facilities with an affected boiler are required to have a one-time energy assessment of the boiler system performed to identify potential energy conservation measures.[126]

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[121] EPA Office of Air and Radiation. *Guidance for Determining Best Available Control Technology for Reducing Carbon Dioxide Emissions from Bioenergy Production*. March 2011. Accessed at: http://www.epa.gov/nsr/ghgdocs/bioenergyguidance.pdf

[122] EPA. Final Rule. Accessed at: http://www.epa.gov/nsr/ghgdocs/20110422TexasPSD.pdf . Also at 76. Fed. Reg. 25,178 (May, 3, 2011).

[123] EPA. Final Rule. Accessed at http://www.epa.gov/nsr/documents/20110512grandfather.pdf

[124] Note that Title II rules relate to mobile sources of emissions and is not included in this report, which covers stationary sources.

[125] 75 Fed. Reg. 31,896 (proposed June 4, 2010).

[126] 75 Fed. Reg. 32,006 (proposed June 4, 2010).

March 2011:

- On September 13, 2004, under authority of Section 112 of the CAA, EPA promulgated national emission standards for HAPs for new and existing industrial/commercial/ institutional boilers and process heaters. On June 19, 2007, the United States Court of Appeals for the District of Columbia Circuit vacated and remanded the standards. In response to the Court's vacateur and remand, the EPA in this rule established emission standards that will require industrial/commercial/institutional boilers and process heaters located at major sources to meet HAP standards reflecting the application of the MACT. These final emission standards for control of mercury and polycyclic organic matter emission from coal fired area source boilers are based on MACT. The final emission standards for control of HAP emissions from biomass-fired and oil-fired area source boilers are based on the EPA's determination as to what constitutes the generally available control technology or management practice. This rule protects air quality and promotes public health by reducing emissions of HAP listed in Section 112(b) (1) CAA.[127]
- Promulgates the EPA's final response to the 2001 voluntary remand of the December 1, 2000, new source performance standards and emission guidelines for commercial and industrial solid waste incineration units and the vacateur and remand of several definitions by the District of Columbia Circuit Court of Appeals in 2007. In addition, this action includes the 5-year technology review of the new source performance standards and emissions guidelines required under Section 129 CAA. This action also promulgates other amendments that the EPA believes are necessary to address air emissions from commercial and industrial solid waste incineration units.[128]

May 2011

- The EPA is delaying the effective dates for the final rules titled "*National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters*" and "*Standards of Performance for New Sources and Emission Guidelines for Existing Sources: Commercial and Industrial Solid Waste Incineration Units*" under the authority of the Administrative Procedure Act (APA) until the proceedings for judicial review of these rules are completed or the EPA completes its reconsideration of the rules, whichever is earlier.[129]
- Proposing NESHAP from coal- and oil-fired electric utility steam generating units (EGUs) under CAA Section 112(d) and proposing revised new source performance standards (NSPS) for fossil fuel-fired EGUs under CAA section 111(b). The proposed NESHAP would protect air quality and promote public health by reducing emissions of the hazardous air pollutants (HAP) listed in CAA Section 112(b). In addition, these proposed amendments to the NSPS are in response to a voluntary remand of a final rule. The EPA is also proposing several minor amendments, technical clarifications, and corrections to existing NSPS provisions for fossil fuel-fired EGUs and large and small industrial commercial institutional steam generating units.[130]

[127] 76 Fed. Reg. 15,554 (Mar. 21, 2011).
[128] 76 Fed. Reg. 15,704 (proposed Mar. 21, 20110 – effective May. 20, 2011).
[129] 76 Fed. Reg. 28,662 (proposed Mar 21, 2011)
[130] 76 Fed. Reg. 54976 (May 3, 2011).

Title V: Permits—Greenhouse Gas Emissions

During September 2009, the EPA announced a proposal that focused on large facilities that emitted over 25,000 tons of GHG a year. These facilities were required to obtain permits to demonstrate they were using best practices and technologies to minimize GHG emissions.[131] The rule proposed new thresholds for GHG emissions that define when the CAA permits under the New Source Review and Title V operating permits would be required for new or existing facilities. Thresholds would tailor the permit program to limit which facilities would be required to obtain New Source Review Title V operating permits, and would cover nearly 70% of the national GHG emissions that come from stationary sources, including power plants and cement production facilities. The proposed rule covered emissions from six GHGs that could be controlled or limited:

1. Carbon dioxide (CO_2);
2. Methane (CH_4);
3. Nitrous oxide(N_2O);
4. Hydroflurocarbons (HFCs);
5. Perfluorocarbons (PFCs); and
6. Sulfur hexafluoride (SF_6).

Under the Prevention of Significant Deterioration (PSD) portion of NSR—which is a permit program designed to minimize emissions from new sources and existing sources making major modifications—the EPA is proposing these levels:

- major stationary source threshold of 25,000 tpy CO_2 equivalent. This threshold level would be used to determine if a new facility or a major modification at an existing facility would trigger PSD permitting requirements.
- significance level between 10,000 and 25,000 tpy CO_2 equivalent. Existing major sources making modifications that result in an increase of emissions above the significance level would be required to obtain a PSD permit. The EPA is requesting comment on a range of values in this proposal, with the intent of selecting a single value for the GHG significance level.

Under the proposed emissions thresholds, the EPA estimates that 400 new sources and modifications would be subject to PSD review each year for GHG emissions. Less than 100 of these would be newly subject to PSD. In total, approximately 14,000 large sources would need to obtain operating permits for GHG emissions under the operating permits program. About 3,000 of these sources would be newly subject to CAA operating permit requirements as a result of this action. The majority of these sources are expected to be municipal solid waste landfills.

January 2010:

- Published rule for NAAQS ozone and established different primary and secondary standards than were proposed in the originating promulgation of March 2008. To protect public health and welfare and children and other at risk populations, the EPA decreased the primary standard for O_3 from 0.075 ppm in the 2008 rule to 0.060–0.070 ppm. The

[131] EPA. Fact Sheet – Proposed Rule: Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule. September 30, 2009. Accessed at: http://www.epa.gov/NSR/fs20090930action.html

EPA proposed to provide additional protections against adverse impacts of ozone on vegetation and forested ecosystems.[132]

March 2010:

- Provided notice of availability of Draft Inventory of U.S. Greenhouse Gas Emissions and Sink: 1990–2008. This provides annual emissions from 1990 through 2008 and this inventory also provides emissions estimates for the six GHGs that the Tailoring rule covered. [133]
- Issued proposed rule and direct final rule amending the Mandatory GHG Reporting Rule (MRR) promulgated on October 2009. The 2009 rule is not changed by these amendments; they'd rather make revisions to the format of several sections in the general provisions.[134] Several revisions and supplements were also issued in April 2010.

April 2010:

- Revisions and supplements to the proposed rule amending the MRR.
    - Rule amendment that would require reporters to submit information not previously mandated. For example, information about their U.S. parent company, primary and other applicable North American Industry Classification System (NAICS) code(s), and whether their reported emissions are from a cogeneration unit.
    - Amendment revising initial rule by requiring fluorinated GHG emissions from certain source categories, such as electronics manufacturing, fluorinated gas production, and use of electrical transmission and distribution equipment, to be reported. Proposed that those who manufacture and refurbish electrical equipment and who import/export pre-charged equipment and closed cell foams are obligated to report.
    - Issued a proposed rule that would require reporting for CO_2 injection and geologic sequestration in the MRR.
    - Proposed another supplement to the MRR by requiring reporting of GHG emissions from various petroleum and natural gas system industries, such as onshore petroleum and natural gas production, offshore petroleum and natural gas production, natural gas processing, natural gas transmission compressor stations, underground natural gas storage, and liquefied natural gas storage, import and export terminals, and distribution.
- Final rule on MRR was withdrawn April 30, due to receiving potentially adverse comments on the rule.[135]
- Issued final action on reconsideration of existing interpretation of the federal PSD program from 2008 memorandum known as the *Johnson Memorandum*.[136] Confirmed the EPA's intention to continue its interpretation of the regulation with one exception. Specifically, EPA refined its interpretation by establishing "that the PSD permitting requirements will not apply to a newly regulated pollutant until a regulatory requirement

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[132] 75 Fed. Reg. 2938 (proposed Jan. 19, 2010).
[133] 75 Fed. Reg. 12,232 (Mar. 15, 2010).
[134] 75 Fed. Reg. 12,489 (proposed Mar. 16, 2010); 75 Fed. Reg. 12,451 (Mar. 16, 2010).
[135] 75 Fed. Reg. 22,699 (Apr. 30, 2010).
[136] 75 Fed. Reg. 17,004 (Apr. 2, 2010).

to control emissions of that pollutant takes effect." The EPA also determined that PSD and Title V permitting requirements will not be applied to GHGs until at least January 2, 2011.

June 2010:

- Final rule tailoring applicability criteria that determine which stationary sources and modification projects become subject to permitting requirements for GHG emissions under the PSD and Title V programs of CAA. This was designed to avoid a substantial increase in the number of required permits by phasing in the applicability of these programs to GHG sources. It will start with the largest GHG emitters. The rule excludes certain smaller sources from PSD and Title V permitting for GHG emissions until at least April 30, 2016.[137]
- Published various amendments to the specific provisions of the MRR to correct technical and editorial errors that had been identified through public comment.[138]

July 2010:

- Issued a proposed amendment to the MRR whereby the confidentiality status of data required to be reported under the MRR would be determined (October 2009 rule required the EPA to collect data from facilities that directly emit GHGs from their processes or sources).[139] The EPA further supplemented this proposal in late July to address the confidentiality of new and revised data elements addressed in the proposed rule published on August 11, 2010.[140]
- Final rule that requires monitoring and reporting of GHG emissions from four source categories, including underground coal mines.[141]

August 2010:

- Issued proposed rule to amend MRR to clarify some provisions, correct technical/editorial errors, and address some issues and questions that had arisen since promulgation.[142]
- Denied petitions to reconsider the Endangerment and Cause or Contribute Findings for GHGs under §202(a) CAA.

September 2010:

- Proposed a FIP to apply to any state that was unable to submit, by its deadline, a corrected SIP to ensure state has authority to issue permits under CAA's NSR PDS program for GHGs.[143] This was a companion making rulemaking to *Action to Ensure Authority to Issue Permits Under the Prevention of Significant Deterioration Program to Sources of Greenhouse Gas Emissions: Finding of Substantial Inadequacy and SIP Call.* Where the EPA had proposed to make findings of substantial inadequacy and issue a SIP call for 13 states (Texas was one of these) on grounds their SIPs do not appear to apply

[137] 75 Fed. Reg. 31,514 (June 3, 2010).
[138] 75 Fed. Reg. 33,950 (proposed June 15, 2010).
[139] 75 Fed. Reg. 39,094 (proposed July 7, 2010).
[140] 75 Fed. Reg. 43,889 (July 27, 2010).
[141] 75 Fed. Reg. 39,736 (July 12, 2010).
[142] 75 Fed. Reg. 48,744 (Aug. 11, 2010).
[143] 75 Fed. Reg. 53,892 (proposed Sept. 2, 2010).

the PSD program to GHG-emitting sources.[144] Texas's new SIP was due for submission December 1, 2010.

> EPA proposed to issue a SIP call in accordance with CAA section 110(k) (5). EPA explained that the reference in CAA section 110(k)(5) to ''any requirement of [the CAA]'' includes the PSD requirements and that SIPs are therefore required to include PSD programs that apply to sources that emit pollutants subject to regulation. As a result, EPA proposed the 13 states' SIPs merit a finding of substantial inadequacy because they fail to apply the PSD program to GHG-emitting sources on and after January 2, 2011. EPA further proposed that because the SIPs merit a finding of substantial inadequacy, EPA is authorized to issue a SIP call and thereby require a corrective SIP revision.

- Additional amendments to the MRR—mostly editorial errors and a new requirement that *reporters* supply name and address, percentage ownership of U.S. parent company, primary NAICS codes, and if reported emissions come from a cogeneration unit.[145]

October 2010:
- Finalized amendments of June 2010 MRR corrections.[146]

December 2010:
- Finalized finding of substantial inadequacy in SIP regarding the PSD program and GHG emitting sources and <u>issued the SIP call for 13 states, including Texas</u>. Deadlines for these SIPs ranged from December 2010 to December 1, 2011.[147]
- Interim final rule, deferring until August 31, 2011, the reporting deadline for year 2010 data elements that are inputs to emission equations under the MRR. Also issued a proposed rule that would defer until March 31, 2014, the requirement to report inputs to emission equations for calendar years through 2012. The deferred deadlines are intended to allow time for the EPA to consider comments and other information concerning these data elements before the EPA issues final confidentiality determinations and before these data are reported to the EPA, when they may become publicly available.[148]
- Issued rule requiring monitoring and reporting (but not control) of GHGs from facilities that conduct geologic sequestration of CO_2 and all other facilities that conduct injection of CO_2.[149]
- Issued FIP to apply to seven states that have not submitted a corrected SIP by the deadline for their PSD program to sources of GHGs.
- The EPA narrowed its previous approval of state Title V operating permit programs so that only sources that equal or exceed the GHG thresholds established in the final GHG Tailoring Rule would be covered as major sources by the federally approved programs in the affected states.[150]

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[144] 75 Fed. Reg. 53,883 (proposed Sept. 2, 2010).
[145] 75 Fed. Reg. 57,669 (Sept. 22, 2010).
[146] 75 Fed. Reg. 66,434 (Oct. 28, 2010).
[147] 75 Fed. Reg. 77,698 (Dec. 13, 2010).
[148] 75 Fed. Reg. 81,338 (Dec. 27, 2010); 75 Fed. Reg. 81,350 (Dec. 27, 2010).
[149] 75 Fed. Reg. 75,060 (Dec. 1, 2010).
[150] 75 Fed. Reg. 82,254 (Dec. 30, 2010).

- The EPA narrowed approval of certain states' SIPs to eliminate the PSD obligations under federal law for sources below the GHG Tailoring Rule thresholds. The target states (Texas is not in this list) were those with approved SIPs that do not incorporate the Tailoring Rule [151]

[151] 75 Fed. Reg. 82,536 (Dec. 30, 2010).

Appendix C: Federal and State Incentives for Eligible Technologies

Table C.1: Federal and State Incentives for Eligible Technologies

(Not including local incentives/utility rebate programs or personal exemptions)

				Eligible Technologies																	
Authority	**Name**	**Summary**	**Incentive Type**	**Solar**	**Geothermal**	**Biomass**	**Wind**	**Elec/ Efficiency**	**Natural Gas**	**Biodiesel**	**Ethanol**	**Other**	**Amount**	**Maximum**	**Enacted-Effective**	**End Date**	**Statute/Funding**				
Federal	Business Energy Investment Tax Credit (ITC)	11	Corporate Tax Credit	X	X	X	X	X				X	Varies based on energy source (see summary)		2008	12/31/2016	26 USC Section 48	IRS Instruction	IRS Form 3468		
Federal	Renewable Electricity Production Tax Credit (PTC)	13	Corporate Tax Credit		X	X	X					X	Varies based on energy source (see summary)		1992	Varies by technology	26 USC Section 45				
Federal	U.S. Department of Treasury - Renewable Energy Grants	14	Federal Grant Program	X	X	X	X					X	30% of property that is part of qualified fuel cell, solar or wind property; 10% of all other property	$1,500 per 0.5 kW for qualified fuel cell. $200 per kW for qualified microturbine	1/1/2009-12/17/2010	2011	HR 4853	HR 1: Div. B, Sec. 1104 &1603	US Dep of Treasury : Grant Program		
Federal	USDA - Rural Energy for America Program (REAP) Grants	16	Federal Grant Program	X	X	X	X					X	Varies	25% of Project Cost	2003	N/A	7 USC Section 8106	USDA			
Federal	Clean Renewable Energy bonds (CREBs)	17	Federal Loan Program	X	X	X	X					X	Varies	N/A	8/8/2005	11/1/2010	26 USC Section 54	26 USC Section 54A	26 USC Section 54C	IRS Notice 2009-33	IRS Announcement 2010-54
Federal	Qualified energy Conservation Bonds (QECBs)	19	Federal Loan Program	X		X	X					X	Varies	N/A	2/17/2009		26 USC Section 54A	26 USC Section 54D	IRS Notice 2009-29	26 USC Section 6431	IRS Notice 2010-35
Federal	U.S. Department of Energy - Loan Guarantee Program	20	Federal Loan Program	X	X	X	X					X	Varies ($25 million+ Projects)	N/A	2005	Periodically Offered	42 USC Section 16511	10 CFR 609	DOE		
Federal	USDA - Rural Energy for America Program (REAP) Loan Guarentees	21	Federal Loan Program	X	X	X	X					X	Varies	$25 million	2003	Periodically Offered	7 USC Section 8106				

				Eligible Technologies																	
Authority	**Name**	**Summary**	**Incentive Type**	**Solar**	**Geothermal**	**Biomass**	**Wind**	**Elec/ Efficiency**	**Natural Gas**	**Biodiesel**	**Ethanol**	**Other**	**Amount**	**Maximum**	**Enacted-Effective**	**End Date**	**Statute/Funding**				
Federal	Qualifiying Advanced Energy Manufacturing Investment Tax Credit	23	Industry Recruitment/Support	X	X		X	X				X	30% of Qualified Investment	$2.3 Billion	2/17/2009	Expired (01/2010)	26 USCS Section 48C	DOE			
Federal	Renewable Energy Production Incentive (REPI)	24	Performance-Based Incentive	X	X	X	X					X	2.2 cents /kWh	Ends after 10 years in service.	10/24/1992	10/1/2016	42 USC Section 13317	10 CFR 451			
State	Solar and Wind Energy Device Franchise Tax Deduction	1	Corporate Deduction	X			X						10% of Amortized Cost from Income or Full Cost from Capital	None	1981-1982	N/A	Texas Tax Code Section 171.107				
State	Solar and Wind Energy Business Franchise Tax Exemption	2	Industry Recruitment/Support	X			X						Exemption from franchise tax	N/A	1981-1982	N/A	Texas Tax Code Section 171.056				
State	Renewable Energy Systems Property Tax Exemption	3	Property Tax Incentive	X		X	X						Exemption of energy device value from property tax	N/A	1981-1981	N/A	Texas Tax Code Section 11.27				
State	Memorial Day Weekend Sales Tax Holiday	4	Sales Tax Incentive									X	100% of Sales and Use Tax	Limit on Cost of Product	2007	N/A	Texas Tax Code Section 151.333				
State	Department of Rural Affairs - Renwable Energy Demonstration Pilot Program	5	State Grant Program	X	X	X	X					X	Varies (Project Budget of $681,000 in 2011)	N/A	2010	N/A	Federal Community Development Block Grant Funding				
State	LoanSTAR Revolving Loan Program	6	State Loan Program	X	X		X						Varies (Project Budget of $126 Million)	$5 Million	1989	N/A	Petroleum Violation Escrow Funds; ARRA				

				Eligible Technologies																	
Authority	**Name**	**Summary**	**Incentive Type**	**Solar**	**Geothermal**	**Biomass**	**Wind**	**Elec/ Efficiency**	**Natural Gas**	**Biodiesel**	**Ethanol**	**Other**	**Amount**	**Maximum**	**Enacted-Effective**	**End Date**	**Statute/Funding**				
State	Oncor Electric Delivery - City and School Matching Grant Program	7	Utility Grant Program					X				X	Cities: Up to $50,000 matching grant; Schools: up to $25,000	N/A		N/A	Take a Load off Texas				
Federal	Energy Efficient Commercial Building Tax Deduction	8	Corporate Deduction					X				X	$0.30-$1.80 per square foot	$1.80/Sq. Ft	8/8/2005-1/1/2006	12/31/2013	26 USC Section 179D				
Federal	Modified Accelerated Cost Recovery System (MACRS) + Bonus	9	Corporate Depreciation	X	X	X	X	X				X	50% Bonus Depreciation in 2012		1986	2012	26 USC Section 168	26 USC Section 48	H.R. 4853	IRS Rev. Proc. 2011-26	
Federal	Residential Energy Conservation Subsidy Exclusion	10	Corporate Exemption	X									100% of Subsidy		1992-2003		26 USC Section 136				
Federal	Energy Efficient New Homes Tax Credit for Home Builders	12	Corporate Tax Credit									X	$1,000-$2,000	$2,000	8/8/2005-1/1/2006	12/31/2011	HR 4853	26 USC Section 45L			
Federal	USDA - High Energy Cost Grant Program	15	Federal Grant Program	X		X	X	X				X	$75,000-$5,000,000	$5 Million	2000	N/A	USDA				
Federal	Energy Efficient Mortgages	18	Federal Loan Program	X				X						N/A			Energy Star Program				
Federal	Energy Efficient Appliance Manufacturing Tax Credit	22	Industry Recruitment/Support					X					Varies (See Summary)	$25 million per manufacturer	1/1/2007	12/31/2011	26 USC Section 45M	HR 4853	IRS Website		
State	Clean Vehicle and Infrastructure Grants	25	State Grant Program						X	X	X	X				Periodically Offered	Texas Commision on Environmental Quality				
State	Alternative Fuel and Advanced Vehicle Grants	26	State Grant Program						X	X	X	X				Periodically Offered	Texas Commision on Environmental Quality				

								Eligible Technologies													
Authority	**Name**	**Summary**	**Incentive Type**	**Solar**	**Geothermal**	**Biomass**	**Wind**	**Elec/ Efficiency**	**Natural Gas**	**Biodiesel**	**Ethanol**	**Other**	**Amount**	**Maximum**	**Enacted-Effective**	**End Date**	**Statute/Funding**				
State	Clean Fleet Grants	27	State Grant Program						X			X				Periodically Offered	Texas Commision on Environmental Quality				
Federal	Alternative Fuel Infrastructure Tax Credit	28	Tax Credit						X	X	X		Varies (See Summary)	Varies (See Summary)		12/31/2011	IRS Form 8911 and/or IRS Form 3800				
Federal	Alternative Fuel Excise Tax Credit	29	Tax Credit						X				$0.50 per gallon			12/31/2011	IRS Publication 510, IRS Forms 637, 720, 4136 and 8849				
Federal	Alternative Fuel Mixture Excise Tax Credit	30	Tax Credit						X				$0.50 per gallon			12/31/2011	IRS Publication 510, IRS Forms 637, 720, 4136 and 8849				
Federal	Alternative Fuel Tax Exemption	31	Tax Exemption						X								IRS Publication 510				
Federal	Improved Energy Technology Loans	32	Loan Guarantee Program						X								Loan Guarantee Program				
State	Alternative Fueling Infrastructure Grants	33	State Grant Program						X				50% of eligible costs	$500,000		8/31/2018	Texas Commision on Environmental Quality				
State	Natural Gas Vehicle (NGV) and Fueling Infrastructure Grants	34	State Grant Program						X				Varies (See Summary)	Varies (See Summary)		8/31/2017	Texas Commision on Environmental Quality				
State	Heavy-Duty Natural Gas Vehicle (NGV) Grants	35	State Grant Program						X							8/31/2012	Texas General Land Office				
State	Natural Gas Fuel Rates and Alternative Fuel Promotion	36	State Grant Program						X								Texas General Land Office				

				Eligible Technologies																	
Authority	Name	Summary	Incentive Type	Solar	Geothermal	Biomass	Wind	Elec/ Efficiency	Natural Gas	Biodiesel	Ethanol	Other	Amount	Maximum	Enacted-Effective	End Date	Statute/Funding				
State	Natural Gas Fuel Rate Reduction and Infrastructure Maintenance - Clean Energy	37	Utility Grant Program						X												
State	Natural Gas Vehicle (NGV) and Fueling Infrastructure Rebates - Texas Gas Service	38	Utility Grant Program						X				Varies (See Summary)	Varies (See Summary)							
State	Natural Gas Infrastructure Technical Assistance - Atmos Energy	39	Utility Grant Program						X												
State	Natural Gas Infrastructure Technical Assistance - CenterPoint Energy	40	Utility Grant Program						X												
Federal	Biodiesel Mixture Excise Tax Credit	41	IRS Tax Credit							X			$1.00/gallon			12/31/2011	IRS Publication 510 and IRS Forms 637, 720, 4136, 8849, and 8864				
Federal	Biodiesel Income Tax Credit	42	Income Tax Credit							X			$1.00/gallon			12/31/2011	IRS Publication 510 and IRS Forms 637 and 8864				
Federal	Small Agri-Biodiesel Producer Tax Credit	43	IRS Tax Incentive							X			$0.10/gallon			12/31/2011	IRS Publication 510 and IRS Forms 637 and 8864				
Federal	Advanced Energy Research Project Grants	44	Advanced Research Projects Agency - Energy							X	X										
Federal	Improved Energy Technology Loans	45	Loan Guarantee Program							X	X		100% of the loan amount				See Summary				

				Eligible Technologies																	
Authority	**Name**	**Summary**	**Incentive Type**	**Solar**	**Geothermal**	**Biomass**	**Wind**	**Elec/ Efficiency**	**Natural Gas**	**Biodiesel**	**Ethanol**	**Other**	**Amount**	**Maximum**	**Enacted-Effective**	**End Date**	**Statute/Funding**				
Federal	Advanced Biofuel Production Grants and Loan Guarantees	46	Biorefinery Assistance Program							X	X			$250,000,000			See Summary				
Federal	Advanced Biofuel Production Payments	47	Bioenergy Program for Advanced Biofuels							X	X						See Summary				
Federal	Biodiesel Education Grants	48	Biodiesel Fuel Education Program							X	X						See Summary				
Federal	Biomass Research and Development Initiative	49	National Institute of Food and Agriculture							X	X						See Summary				
Federal	Value-Added Producer Grants (VAPG)	50	Office of Rural Development, US Department of Agriculture							X	X						See Summary				
Federal	Biobased Transportation Research Funding	51	Surface Transportation Research, Development, and Deployment							X	X						See Summary				
Federal	Cellulosic Biofuel Producer Tax Credit	52	IRS Tax Incentive							X	X		Varies (See Summary)	$1.01/gallon		12/31/2012	IRS Publication 510 and IRS Forms 637 and 6478				
State	Renewable Fuel Production Grants	53	State Grant Program							X	X		$0.20/gallon				See Summary				
State	Diesel Fuel Blend Tax Exemption	54	State Grant Program							X	X		Exemption from Diesel Fuel Tax				See Summary				
Federal	Volumetric Ethanol Excise Tax Credit (VEETC)	55	IRS Tax Incentive								X		$0.45/gallon of pure ethanol			12/31/2011	IRS Publication 510 and IRS Forms 637, 720, 4136, 6478, and 8849				
Federal	Small Ethanol Producer Tax Credit	56	IRS Tax Incentive								X		$0.10/gallon of ethanol			12/31/2011	IRS Publication 510 and IRS Forms 637 and 6478				

				Eligible Technologies																	
Authority	**Name**	**Summary**	**Incentive Type**	**Solar**	**Geothermal**	**Biomass**	**Wind**	**Elec/ Efficiency**	**Natural Gas**	**Biodiesel**	**Ethanol**	**Other**	**Amount**	**Maximum**	**Enacted-Effective**	**End Date**	**Statute/Funding**				
Federal	Ethanol Infrastructure Grants and Loan Guarantees	57	Rural Energy for America Program								X		See Summary	See Summary			Office of Rural Development, US Department of Agriculture				

Appendix D: Explanation of the Incentives

Incentive	Summary
1	Texas allows a corporation or other entity subject the state franchise tax to deduct the cost of a solar energy device from the franchise tax. Entities are permitted to deduct 10% of the amortized cost of the system from their apportioned margin. The franchise tax is Texas's equivalent to a corporate tax. For the purposes of this deduction, a solar energy device means "a system or series of mechanisms designed primarily to provide heating or cooling or to produce electrical or mechanical power by collecting and transferring solar-generated energy. The term includes a mechanical or chemical device that has the ability to store solar-generated energy for use in heating or cooling or in the production of power." Under this definition wind energy is also included as an eligible technology. Texas also offers a franchise tax exemption for manufacturers, seller, or installers of solar energy systems which also includes wind energy as an eligible technology.
2	Companies in Texas engaged solely in the business of manufacturing, selling, or installing solar energy devices are exempted from the franchise tax. The franchise tax is Texas’s equivalent to a corporate tax; their primary elements are the same. There is no ceiling on this exemption, so it is a substantial incentive for solar manufacturers. For the purposes of this exemption, a solar energy device means "a system or series of mechanisms designed primarily to provide heating or cooling or to produce electrical or mechanical power by collecting and transferring solar-generated energy. The term includes a mechanical or chemical device that has the ability to store solar-generated energy for use in heating or cooling or in the production of power." Under this definition wind energy is also listed as an eligible technology. Texas also offers a franchise tax deduction for solar energy devices which also includes wind energy as an eligible technology.
3	The Texas property tax code allows an exemption of the amount of the appraised property value that arises from the installation or construction of a solar or wind-powered energy device that is primarily for the production and distribution of thermal, mechanical, or electrical energy for on-site use, or devices used to store that energy. "Solar" is broadly defined and includes a range of biomass technologies.
4	Purchases of certain energy-efficient products during Memorial Day weekend are exempt from the state sales and use tax.* This amounts to a three-day tax holiday beginning on the Saturday preceding the last Monday in May (Memorial Day) and ending on that same Monday. The state sales and use tax rate is presently 6.25%; some local jurisdictions add an additional levy of up to 2%. The state exemption applies to both the state and local portion (if one exists) of the tax. Although the eligibility of some products is limited according to their sale price, there are no limitations on the total value or number of products exempt from sales tax. This incentive is available only for the following types of products that meet federal Energy Star requirements: Air conditioners with a sales price of less than $6,000 Refrigerators with a sales price of less than $2,000 Clothes washers

Incentive	Summary
	Dishwashers Dehumidifiers Ceiling fans Incandescent or fluorescent light bulbs Programmable thermostats**
5	The Texas Department of Rural Affairs (TDRA) offers the Renewable Energy Demonstration Pilot Program (REDPP), which provides grants to local, non-entitlement local governments for the installation of renewable energy projects. The REDPP is part of the larger federal Community Development Block Grant Program (CDBG). The primary objectives of the CDGB program are: to primarily benefit persons of low and moderate income; to aid in the elimination of slums and blight; and to meet other community development needs of a particular urgency that pose a serious and immediate threat to the health and safety of the public. The CDBG program separates local governments into two major categories: entitlement communities and non-entitlement communities. Entitlement governments, defined as cities with more than 50,000 residents and qualifying counties with more than 200,000 residents, receive an automatic allocation of CDBG funds. The REDPP portion administered by the TDRA is offered only to those local governments that do not receive an automatic allocation. There are a total of approximately 1260 non-entitlement cities and counties in Texas. In order to qualify for funding under the REDPP, activities must use "a naturally occurring, theoretically inexhaustible source of energy such as biomass, solar, wind, tidal, wave, or hydroelectric". Beyond this requirement, eligible activities are determined according to the broader terms of the CDBG program. The program guidebook contains a detailed list of eligible and ineligible activities for CDGB funds. Grants will be awarded on a competitive basis according to an evaluation structure which considers: Type of project (e.g., does the project provide public facilities that serve basic human needs) Use of innovative technologies and/or methods Prospects for wider application or duplication in other rural areas Long-term cost/benefits and relationship to state renewable energy goals (e.g., expected energy savings) Partnerships and collaborations with other entities focusing on promoting renewables Leveraging of other funding sources (i.e., level of matching funds) Location in rural areas
6	Through the State Energy Conservation Office, the LoanSTAR Program offers low-interest loans to all public entities, including state, public school, colleges, university, and non-profit hospital facilities for Energy Cost Reduction Measures (ECRMs). Such measures include, but are not limited to: HVAC, lighting, and insulation. Funds can be used for retrofitting existing equipment or, in the case of new construction, to finance the difference between standard and high efficiency equipment. The evaluation of on-site renewable energy options (e.g., solar water heating, photovoltaic panels, small wind turbines) is encouraged in the analysis of potential projects. The LoanSTAR Program funds “Design, Bid, Built” or “Design, Built” projects. All projects are approved based on the Detailed Energy Assessment Report, which must be prepared according to LoanSTAR Technical Guidelines or the Performance Contracting Guidelines. SECO performs design specification review and on-site construction monitoring at the very minimum when the project is 100% complete. Repayment of the loans does not begin until after construction is 100% completed.

Incentive	Summary
	During Fiscal year 2010 (September 1, 2009 to Aug 31, 2010) LoanSTAR made four loans totaling over $7 million. During fiscal year 2009, LoanSTAR made 5 loans totaling over $22 million. Applications are available on the program website. The technical guidelines for the LoanSTAR program can be found on the program web site.
7	The Texas City and School Matching Grant Programs help public facilities reduce their energy spending. All cities and schools with an Oncor electric meter can apply for matching grant dollars for implementing energy efficiency projects. The grants match up to $25,000 for schools and $50,000 for cities to improve HVAC, lighting, and custom efficiency projects. Applicants are required to certify funding and complete projects within a year of approval.
8	The federal Energy Policy Act of 2005 established a tax deduction for energy-efficient commercial buildings applicable to qualifying systems and buildings placed in service from January 1, 2006, through December 31, 2007. This deduction was subsequently extended through 2008, and then again through 2013 by Section 303 of the federal Energy Improvement and Extension Act of 2008 (H.R. 1424, Division B), enacted in October 2008. A tax deduction of $1.80 per square foot is available to owners of new or existing buildings who install (1) interior lighting; (2) building envelope, or (3) heating, cooling, ventilation, or hot water systems that reduce the building's total energy and power cost by 50% or more in comparison to a building meeting minimum requirements set by ASHRAE Standard 90.1-2001. Energy savings must be calculated using qualified computer software approved by the IRS. Click here for the list of approved software. Deductions of $0.60 per square foot are available to owners of buildings in which individual lighting, building envelope, or heating and cooling systems meet target levels that would reasonably contribute to an overall building savings of 50% if additional systems were installed. The deductions are available primarily to building owners, although tenants may be eligible if they make construction expenditures. In the case of energy efficient systems installed on or in government property, tax deductions will be awarded to the person primarily responsible for the system's design. Deductions are taken in the year when construction is completed. The IRS released interim guidance (IRS Notice 2006-52) in June 2006 to establish a process to allow taxpayers to obtain a certification that the property satisfies the energy efficiency requirements contained in the statute. IRS Notice 2008-40 was issued in March of 2008 to further clarify the rules. NREL published a report (NREL/TP-550-40228) in February 2007 which provides guidelines for the modeling and inspection of energy savings required by the statute, and the US Department of Energy has compiled a list of qualified computer software for calculating commercial building energy and power cost savings.
9	Under the federal Modified Accelerated Cost-Recovery System (MACRS), businesses may recover investments in certain property through depreciation deductions. The MACRS establishes a set of class lives for various types of property, ranging from three to 50 years, over which the property may be depreciated. A number of renewable energy technologies are classified as five-year property (26 USC § 168(e)(3)(B)(vi)) under the MACRS, which refers to 26 USC § 48(a)(3)(A), often known as the energy investment tax credit or ITC to define eligible property. Such property currently includes: a variety of solar-electric and solar-thermal technologies, fuel cells and microturbines, geothermal electric, direct-use geothermal and geothermal heat pumps, small wind (100 kW or less), combined heat and power (CHP).

Incentive	Summary
	The provision which defines ITC technologies as eligible also adds the general term "wind" as an eligible technology, extending the five-year schedule to large wind facilities as well. In addition, for certain other biomass property, the MACRS property class life is seven years. Eligible biomass property generally includes assets used in the conversion of biomass to heat or to a solid, liquid or gaseous fuel, and to equipment and structures used to receive, handle, collect and process biomass in a waterwall, combustion system, or refuse-derived fuel system to create hot water, gas, steam and electricity. The 5-year schedule for most types of solar, geothermal, and wind property has been in place since 1986. The federal Energy Policy Act of 2005 (EPAct 2005) classified fuel cells, microturbines and solar hybrid lighting technologies as five-year property as well by adding them to § 48(a)(3)(A). This section was further expanded in October 2008 by the addition of geothermal heat pumps, combined heat and power, and small wind under The Energy Improvement and Extension Act of 2008. The federal Economic Stimulus Act of 2008, enacted in February 2008, included a 50% first-year bonus depreciation (26 USC § 168(k)) provision for eligible renewable-energy systems acquired and placed in service in 2008. This provision was extended (retroactively for the entire 2009 tax year) under the same terms by The American Recovery and Reinvestment Act of 2009, enacted in February 2009. Bonus depreciation was renewed again in September 2010 (retroactively for the entire 2010 tax year) by the Small Business Jobs Act of 2010 (H.R. 5297). In December 2010 the provision for bonus depreciation was amended and extended yet again by The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (H.R. 4853). Under these amendments, eligible property placed in service after September 8, 2010 and before January 1, 2012 qualifies for 100% first-year bonus depreciation. For 2012, bonus depreciation is still available, but the allowable deduction reverts from 100% to 50% of the eligible basis. To qualify for bonus depreciation, a project must satisfy these criteria: the property must have a recovery period of 20 years or less under normal federal tax depreciation rules; the original use of the property must commence with the taxpayer claiming the deduction; the property generally must have been acquired during the period from 2008 - 2012; and the property must have been placed in service during the period from 2008 - 2012. If property meets these requirements, the owner is entitled to deduct a significant portion of the adjusted basis of the property during the tax year the property is first placed in service. As noted above, for property acquired and placed in service after September 8, 2010 and before January 1, 2012, the allowable first year deduction is 100% of the adjusted basis. For property placed in service from 2008 - 2012, for which the placed in service date does not fall within this window, the allowable first-year deduction is 50% of the adjusted basis. In the case of a 50% first year deduction, the remaining 50% of the adjusted basis of the property is depreciated over the ordinary MACRS depreciation schedule. The bonus depreciation rules do not override the depreciation limit applicable to projects qualifying for the federal business energy tax credit. Before calculating depreciation for such a project, including any bonus depreciation, the adjusted basis of the project must be reduced by one-half of the amount of the energy credit for which the project qualifies. For more information on the federal MACRS, see IRS Publication 946, IRS Form 4562: Depreciation and Amortization, and Instructions for Form 4562. The IRS web site provides a search mechanism for forms and publications. Enter the relevant form, publication name or number, and click

Incentive	Summary
	"GO" to receive the requested form or publication. For guidance on bonus depreciation, including information relating to the election to claim either 50% or 100% bonus depreciation, retroactive elections to claim 50% bonus depreciation for property placed in service during 2010, and eligible property, please see IRS Rev. Proc. 2011-26.
10	According to Section 136 of the U.S. Code, energy conservation subsidies provided to customers by public utilities,* either directly or indirectly, are non-taxable. This exclusion does not apply to electricity-generating systems registered as "qualifying facilities" under the Public Utility Regulatory Policies Act of 1978. If a taxpayer claims federal tax credits or deductions for the energy conservation property, the investment basis for the purpose of claiming the deduction or tax credit must be reduced by the value of the energy conservation subsidy (i.e., a taxpayer may not claim a tax credit for an expense that the taxpayer ultimately did not pay). The term "energy conservation measure" includes installations or modifications primarily designed to reduce consumption of electricity or natural gas, or to improve the management of energy demand. Eligible dwelling units include houses, apartments, condominiums, mobile homes, boats and similar properties. If a building or structure contains both dwelling units and other units, any subsidy must be properly allocated. The definition of "energy conservation measure" implies that utility rebates for residential solar-thermal projects and solar-electric systems may be non-taxable. However, the IRS has not ruled definitively on this issue. Taxpayers considering using this provision for a renewable energy system should discuss the details of the project with a tax professional. Other types of utility subsidies that may come in the form of credits or reduced rates might also be non-taxable, according to IRS Publication 525. This publication states: "If you are a customer of an electric utility company and you participate in the utility's energy conservation program, you may receive on your monthly electric bill either: a reduction in the purchase price of electricity furnished to you (rate reduction), or a nonrefundable credit against the purchase price of the electricity. The amount of the rate reduction or nonrefundable credit is not included in your income."
11	Note: The American Recovery and Reinvestment Act of 2009 allows taxpayers eligible for the federal renewable electricity production tax credit (PTC)** to take the federal business energy investment tax credit (ITC) or to receive a grant from the U.S. Treasury Department instead of taking the PTC for new installations. The new law also allows taxpayers eligible for the business ITC to receive a grant from the U.S. Treasury Department instead of taking the business ITC for new installations. The grant is only available to systems where construction begins prior to December 31, 2011. The Treasury Department issued Notice 2009-52 in June 2009, giving limited guidance on how to take the federal business ITC instead of the federal renewable electricity production tax credit. The federal business energy investment tax credit available under 26 USC § 48 was expanded significantly by the Energy Improvement and Extension Act of 2008 (H.R. 1424), enacted in October 2008. This law extended the duration -- by eight years -- of the existing credits for solar energy, fuel cells and microturbines; increased the credit amount for fuel cells; established new credits for small wind-energy systems, geothermal heat pumps, and combined heat and power (CHP) systems; allowed utilities to use the credits; and allowed taxpayers to take the credit against the alternative minimum tax (AMT), subject to certain limitations. The credit was further expanded by The American Recovery and Reinvestment Act of 2009, enacted in February 2009. In general, credits are available for eligible systems placed in service on or before December 31, 2016: Solar. The credit is equal to 30% of expenditures, with no maximum credit. Eligible solar energy property includes equipment that uses solar energy

Incentive	Summary
	to generate electricity, to heat or cool (or provide hot water for use in) a structure, or to provide solar process heat. Hybrid solar lighting systems, which use solar energy to illuminate the inside of a structure using fiber-optic distributed sunlight, are eligible. Passive solar systems and solar pool-heating systems are not eligible. Fuel Cells. The credit is equal to 30% of expenditures, with no maximum credit. However, the credit for fuel cells is capped at $1,500 per 0.5 kilowatt (kW) of capacity. Eligible property includes fuel cells with a minimum capacity of 0.5 kW that have an electricity-only generation efficiency of 30% or higher. (Note that the credit for property placed in service before October 4, 2008, is capped at $500 per 0.5 kW.) Small Wind Turbines.* The credit is equal to 30% of expenditures, with no maximum credit for small wind turbines placed in service after December 31, 2008. Eligible small wind property includes wind turbines up to 100 kW in capacity. (In general, the maximum credit is $4,000 for eligible property placed in service after October 3, 2008, and before January 1, 2009. The American Recovery and Reinvestment Act of 2009 removed the $4,000 maximum credit limit for small wind turbines.) Geothermal Systems.* The credit is equal to 10% of expenditures, with no maximum credit limit stated. Eligible geothermal energy property includes geothermal heat pumps and equipment used to produce, distribute or use energy derived from a geothermal deposit. For electricity produced by geothermal power, equipment qualifies only up to, but not including, the electric transmission stage. For geothermal heat pumps, this credit applies to eligible property placed in service after October 3, 2008. Note that the credit for geothermal property, with the exception of geothermal heat pumps, has no stated expiration date. Microturbines. The credit is equal to 10% of expenditures, with no maximum credit limit stated (explicitly). The credit for microturbines is capped at $200 per kW of capacity. Eligible property includes microturbines up to two megawatts (MW) in capacity that have an electricity-only generation efficiency of 26% or higher. Combined Heat and Power (CHP).* The credit is equal to 10% of expenditures, with no maximum limit stated. Eligible CHP property generally includes systems up to 50 MW in capacity that exceed 60% energy efficiency, subject to certain limitations and reductions for large systems. The efficiency requirement does not apply to CHP systems that use biomass for at least 90% of the system's energy source, but the credit may be reduced for less-efficient systems. This credit applies to eligible property placed in service after October 3, 2008. In general, the original use of the equipment must begin with the taxpayer, or the system must be constructed by the taxpayer. The equipment must also meet any performance and quality standards in effect at the time the equipment is acquired. The energy property must be operational in the year in which the credit is first taken. Significantly, The American Recovery and Reinvestment Act of 2009 repealed a previous restriction on the use of the credit for eligible projects also supported by "subsidized energy financing." For projects placed in service after December 31, 2008, this limitation no longer applies. Businesses that receive other incentives are advised to consult with a tax professional regarding how to calculate this federal tax credit.
12	This credit was originally made available by the Energy Policy Act of 2005 for homes constructed in 2006 and 2007. It was renewed two more times for homes constructed in 2008 and 2009, but expired and was unavailable for homes constructed in 2010. The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 reinstated this credit retroactively for homes acquired after December 31, 2009 and before January 1, 2012. The federal Energy Policy Act of 2005 established tax credits of up to $2,000 for builders of all new energy-efficient homes, including manufactured homes constructed in accordance with the Federal Manufactured Homes Construction and Safety Standards. Initially scheduled to expire at the end of 2007, the tax credit was extended through 2008 by Section 205 of the Tax Relief and Health Care Act of 2006 (H.R. 6111), and then extended again through December 31, 2009 by Section 304 of The Energy Improvement and Extension Act of 2008 (H.R. 1424).

Incentive	Summary
	The home qualifies for the credit if: It is located in the United States; Its construction is substantially completed after August 8, 2005; It meets the energy saving requirements outlined in the statute; and It is acquired from the eligible contractor after December 31, 2005, and before January 1, 2010, for use as a residence. Energy Saving Requirements Site-built homes qualify for a $2,000 credit if they are certified to reduce heating and cooling energy consumption by 50% relative to the International Energy Conservation Code standard and meet minimum efficiency standards established by the Department of Energy. Building envelope component improvements must account for at least one-fifth of the reduction in energy consumption. Manufactured homes qualify for a $2,000 credit if they conform to Federal Manufactured Home Construction and Safety Standards and meet the energy savings requirements of site-built homes described above. Manufactured homes qualify for a $1,000 credit if they conform to Federal Manufactured Home Construction and Safety Standards and reduce energy consumption by 30% relative to the International Energy Conservation Code standard. In this case, building envelope component improvements must account for at least one-third of the reduction in energy consumption. Alternatively, manufactured homes qualify if they meet Energy Star Labeled Home requirements.
13	Note: The American Recovery and Reinvestment Act of 2009 (H.R. 1) allows taxpayers eligible for the federal renewable electricity production tax credit (PTC) to take the federal business energy investment tax credit (ITC) or to receive a grant from the U.S. Treasury Department instead of taking the PTC for new installations. The grant is only available to systems where construction began prior to December 31, 2011. The new law also allows taxpayers eligible for the business ITC to receive a grant from the U.S. Treasury Department instead of taking the business ITC for new installations. The Treasury Department issued Notice 2009-52 in June 2009, giving limited guidance on how to take the federal business energy investment tax credit instead of the federal renewable electricity production tax credit. The federal renewable electricity production tax credit (PTC) is a per-kilowatt-hour tax credit for electricity generated by qualified energy resources and sold by the taxpayer to an unrelated person during the taxable year. Originally enacted in 1992, the PTC has been renewed and expanded numerous times, most recently by H.R. 1424 (Div. B, Sec. 101 & 102) in October 2008 and again by H.R. 1 (Div. B, Section 1101 & 1102) in February 2009. The October 2008 legislation extended the in-service deadlines for all qualifying renewable technologies; expanded the list of qualifying resources to include marine and hydrokinetic resources, such as wave, tidal, current and ocean thermal; and made changes to the definitions of several qualifying resources and facilities. The effective dates of these changes vary. Marine and hydrokinetic energy production is eligible as of the date the legislation was enacted (October 3, 2008), as is the incremental energy production associated with expansions of biomass facilities. A change in the definition of "trash facility" no longer requires that such facilities burn trash, and is also effective immediately. One further provision redefining the term "non-hydroelectric dam," took effect December 31, 2008. The February 2009 legislation revised the credit by: (1) extending the in-service deadline for most eligible technologies by three years (two years for

Incentive	Summary
	marine and hydrokinetic resources); and (2) allowing facilities that qualify for the PTC to opt instead to take the federal business energy investment credit (ITC) or an equivalent cash grant from the U.S. Department of Treasury. The ITC or grant for PTC-eligible technologies is generally equal to 30% of eligible costs.* The tax credit amount is 1.5¢/kWh in 1993 dollars (indexed for inflation) for some technologies, and half of that amount for others. The rules governing the PTC vary by resource and facility type. The table below outlines two of the most important characteristics of the tax credit -- in-service deadline and credit amount -- as they apply to different facilities. The table includes changes made by H.R. 1, in February 2009, and the inflation-adjusted credit amounts are current for the 2011 calendar year. (See the history section below for information on prior rules.) Resource Type In-Service Deadline Credit Amount Wind December 31, 2012 2.2¢/kWh Closed-Loop Biomass December 31, 2013 2.2¢/kWh Open-Loop Biomass December 31, 2013 1.1¢/kWh Geothermal Energy December 31, 2013 2.2¢/kWh Landfill Gas December 31, 2013 1.1¢/kWh Municipal Solid Waste December 31, 2013 1.1¢/kWh Qualified Hydroelectric December 31, 2013 1.1¢/kWh Marine and Hydrokinetic (150 kW or larger)** December 31, 2013 1.1¢/kWh The duration of the credit is generally 10 years after the date the facility is placed in service, but there are two exceptions: Open-loop biomass, geothermal, small irrigation hydro, landfill gas and municipal solid waste combustion facilities placed into service after October 22, 2004, and before enactment of the Energy Policy Act of 2005, on August 8, 2005, are only eligible for the credit for a five-year period. Open-loop biomass facilities placed in service before October 22, 2004, are eligible for a five-year period beginning January 1, 2005. In addition, the tax credit is reduced for projects that receive other federal tax credits, grants, tax-exempt financing, or subsidized energy financing. The credit is claimed by completing Form 8835, "Renewable Electricity Production Credit," and Form 3800, "General Business Credit." For more information, contact IRS Telephone Assistance for Businesses at 1-800-829-4933. History As originally enacted by the Energy Policy Act of 1992, the PTC expired in July 1999, and was subsequently extended through the end of 2001 by the Ticket to Work and Work Incentives Improvement Act of 1999 in December 1999. The PTC expired again at the end of 2001, but was then extended again in March 2002 as part of the Job Creation and Worker Assistance Act of 2002 (H.R. 3090). The PTC then expired yet again at the end of 2003 and was not renewed until October 2004, as part of H.R. 1308, the Working Families Tax Relief Act of 2004, which extended the credit through December 31, 2005. The Energy Policy Act of 2005 (H.R. 6) modified the credit and extended it through December 31, 2007. In December 2006, the PTC was extended for yet another year -- through December 31, 2008 -- by the Tax Relief and Health Care Act of 2006 (H.R. 6111). The American Jobs Creation Act of 2004 (H.R. 4520), expanded the PTC to include additional eligible resources -- geothermal energy, open-loop biomass, solar energy, small irrigation power, landfill gas and municipal solid waste combustion -- in addition to the formerly eligible wind energy,

Incentive	Summary
	closed-loop biomass, and poultry-waste energy resources. The Energy Policy Act of 2005 (EPAct 2005) further expanded the credit to certain hydropower facilities. As a result of EPAct 2005, solar facilities placed into service after December 31, 2005, are no longer eligible for this incentive. Solar facilities placed in-service during the roughly one-year window in which solar was eligible are permitted to take the full credit for five years. *Prior to H.R. 1, geothermal facilities were already eligible for a 10% tax credit under the energy ITC (26 USC § 48). However, the new legislation permits all PTC-eligible technologies, including geothermal electric facilities, to take a 30% tax credit (or grant) in lieu of the PTC. Recent guidance from the IRS regarding the Treasury grants in lieu of tax credits indicates that geothermal facilities that qualify for the PTC are eligible for either the 30% investment tax credit or the 10% tax credit, but not both. The window for the 30% tax credit runs through 2013, the in-service deadline for the PTC, while the 10% tax credit under the section 48 ITC does not have an expiration date. **H.R. 1424 added marine and hydrokinetic energy as eligible resources and removed "small irrigation power" as an eligible resource effective October 3, 2008. However, the definition of marine and hydrokinetic energy encompasses the resources that would have formerly been defined as small irrigation power facilities. Thus H.R. 1424 effectively extended the in-service deadline for small irrigation power facilities by 3 years, from the end of 2008 until the end of 2011 (since extended again through 2013).
14	Note: The American Recovery and Reinvestment Act of 2009 (H.R. 1) allows taxpayers eligible for the federal business energy investment tax credit (ITC) to take this credit or to receive a grant from the U.S. Treasury Department instead of taking the business ITC for new installations. The new law also allows taxpayers eligible for the renewable electricity production tax credit (PTC) to receive a grant from the U.S. Treasury Department instead of taking the PTC for new installations. (It does not allow taxpayers eligible for the residential renewable energy tax credit to receive a grant instead of taking this credit.) Taxpayers may not use more than one of these incentives. Tax credits allowed under the ITC with respect to progress expenditures on eligible energy property will be recaptured if the project receives a grant. The grant is not included in the gross income of the taxpayer. This grant cannot be taken for systems where construction began after December 31, 2011. The American Recovery and Reinvestment Act of 2009 (H.R. 1), enacted in February 2009, created a renewable energy grant program that is administered by the U.S. Department of Treasury. This cash grant may be taken in lieu of the federal business energy investment tax credit (ITC). In July 2009 the Department of Treasury issued documents detailing guidelines for the grants, terms and conditions and a sample application. There is an online application process, and applications are currently being accepted. See the US Department of Treasury program web site for more information, including answers to frequently asked questions and program guidance. The Treasury also maintains a list of award recipients on the website. The Department of Treasury has also filed a sample form that recipients of the grant must fill out each year to avoid recapture. Grants are available to eligible property* placed in service in 2009, 2010 or 2011 or placed in service by the specified credit termination date,** if construction began in 2009, 2010 or 2011. Originally, this program was only available to systems placed in service in 2009 or 2010 or where construction began in 2009 or 2010, but Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (H.R. 4853), signed in December 2010, extended the program through 2011. The guidelines include a "safe harbor" provision that sets the beginning of construction at the point where the applicant has incurred or paid at least 5% of the total cost of the property, excluding land and certain preliminary planning activities. Generally, construction begins when "physical work of a significant nature" begins. Below is a list of important program details as they apply to each different eligible technology.

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	Solar. The grant is equal to 30% of the basis of the property for solar energy. Eligible solar-energy property includes equipment that uses solar energy to generate electricity, to heat or cool (or provide hot water for use in) a structure, or to provide solar process heat. Passive solar systems and solar pool-heating systems are not eligible. Hybrid solar-lighting systems, which use solar energy to illuminate the inside of a structure using fiber-optic distributed sunlight, are eligible. **Fuel Cells.** The grant is equal to 30% of the basis of the property for fuel cells. The grant for fuel cells is capped at $1,500 per 0.5 kilowatt (kW) in capacity. Eligible property includes fuel cells with a minimum capacity of 0.5 kW that have an electricity-only generation efficiency of 30% or higher. **Small Wind Turbines**. The grant is equal to 30% of the basis of the property for small wind turbines. Eligible small wind property includes wind turbines up to 100 kW in capacity. Qualified Facilities. The grant is equal to 30% of the basis of the property for qualified facilities that produce electricity. Qualified facilities include wind energy facilities, closed-loop biomass facilities, open-loop **biomass facilities,** geothermal energy facilities, landfill gas facilities, trash facilities, qualified hydropower facilities, and marine and hydrokinetic renewable energy facilities. **Geothermal Heat Pumps.** The grant is equal to 10% of the basis of the property for geothermal heat pumps. **Microturbines.** The grant is equal to 10% of the basis of the property for microturbines. The grant for microturbines is capped at $200 per kW of capacity. Eligible property includes microturbines up to two megawatts (MW) in capacity that have an electricity-only generation efficiency of 26% or higher. Combined Heat and Power (CHP). The grant is equal to 10% of the basis of the property for CHP. Eligible CHP property generally includes systems up to 50 MW in capacity that exceed 60% energy efficiency, subject to certain limitations and reductions for large systems. The efficiency requirement does not apply to CHP systems that use biomass for at least 90% of the system's energy source, but the grant may be reduced for less-efficient systems. It is important to note that only tax-paying entities are eligible for this grant. Federal, state and local government bodies, non-profits, qualified energy tax credit bond lenders, and cooperative electric companies are not eligible to receive this grant. Partnerships or pass-thru entities for the organizations described above are also not eligible to receive this grant, except in cases where the ineligible party only owns an indirect interest in the applicant through a taxable C corporation. Grant applications must be submitted by October 1, 2012. The U.S. Treasury Department will make payment of the grant within 60 days of the grant application date or the date the property is placed in service, whichever is later.
15	NOTE: The most recent solicitation for this program closed September 8, 2010. Check the program website for information on future solicitations. The U.S. Department of Agriculture (USDA) offers an ongoing grant program for the improvement of energy generation, transmission, and distribution facilities in rural communities. This program began in 2000. Eligibility is limited to projects in communities that have energy costs at least 275% above the national average. Individuals, non-profits, commercial entities, state and local governments, and tribal governments are eligible for this grant. Individuals must work on a project that will benefit the community in order to qualify. Grants ranging from $75,000 to $5 million are available for a variety of activities, including: Electric generation, transmission, and distribution facilities; Natural gas or petroleum storage or distribution facilities; Renewable energy facilities used for on-grid or off-grid electric power generation, water or space heating, or process heating and power; Backup up or emergency power generation or energy storage equipment; and Weatherization of residential and community property, or other energy efficiency or conservation programs. This grant program is not limited to renewable energy or energy conservation and efficiency measures, but these measures are eligible for this grant

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	program.
16	Note: The U.S. Department of Agriculture's Rural Development issues periodic Notices of Solicitation of Applications for the Rural Energy for America Program (REAP). The deadline to apply for grants and loan guarantees under the most recent solicitation is June 15, 2011. Grants and loan guarantees will be awarded for investments in renewable energy systems, energy efficiency improvements and renewable energy feasibility studies. The Food, Conservation, and Energy Act of 2008 (H.R. 2419), enacted by Congress in May 2008, converted the federal Renewable Energy Systems and Energy Efficiency Improvements Program,* into the Rural Energy for America Program (REAP). Similar to its predecessor, the REAP promotes energy efficiency and renewable energy for agricultural producers and rural small businesses through the use of (1) grants and loan guarantees for energy efficiency improvements and renewable energy systems, and (2) grants for energy audits and renewable energy development assistance. Congress has allocated funding for the new program in the following amounts: $55 million for FY 2009, $60 million for FY 2010, $70 million for FY 2011, and $70 million for FY 2012. REAP is administered by the U.S. Department of Agriculture (USDA). In addition to these mandatory funding levels, there may also be discretionary funding issued each year. Of the total REAP funding available, approximately 88% is dedicated to competitive grants and loan guarantees for energy efficiency improvements and renewable energy systems. These incentives are available to agricultural producers and rural small businesses to purchase renewable energy systems (including systems that may be used to produce and sell electricity) and to make energy efficiency improvements. Funding is also available to conduct relevant feasibility studies, with approximately 2% of total funding being available for feasibility studies. Eligible renewable energy projects include wind, solar, biomass and geothermal; and hydrogen derived from biomass or water using wind, solar or geothermal energy sources. These grants are limited to 25% of a proposed project's cost, and a loan guarantee may not exceed $25 million. The combined amount of a grant and loan guarantee may not exceed 75% of the project’s cost. In general, a minimum of 20% of the funds available for these incentives will be dedicated to grants of $20,000 or less. The USDA likely will announce the availability of funding for this component of REAP through a Notice of Funds Availability (NOFA). The USDA will also make competitive grants to eligible entities to provide assistance to agricultural producers and rural small businesses “to become more energy efficient” and “to use renewable energy technologies and resources.” These grants are generally available to state government entities, local governments, tribal governments, land-grant colleges and universities**, rural electric cooperatives and public power entities, and other entities, as determined by the USDA. These grants may be used for conducting and promoting energy audits; and for providing recommendations and information related to energy efficiency and renewable energy. Of the total REAP funding available, approximately 9% is dedicated to competitive grants for energy technical assistance.
17	Note: The IRS is not currently accepting applications for New CREB bond volume. The deadline for New CREB applications from electric cooperatives under IRS Announcement 2010-54 expired November 1, 2010. Bond volume for other eligible sectors (government entities and public power providers) was fully allocated in October 2009. Readers should also note that the terms "New" and "Old" CREBs are used in the following summary to distinguish between prior CREB allocations and the New CREB authorizations made by the U.S. Congress in 2008 and 2009. The use of the term "New CREBs" has legal significance in that New CREBs authorized under 26 USC § 54A and 54C have substantially different rules than prior CREB allocations authorized under 26 USC § 54. Clean renewable energy bonds (CREBs) may be used by certain entities -- primarily in the public sector -- to finance renewable energy projects. The

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	list of qualifying technologies is generally the same as that used for the federal renewable energy production tax credit (PTC). CREBs may be issued by electric cooperatives, government entities (states, cities, counties, territories, Indian tribal governments or any political subdivision thereof), and by certain lenders. CREBs are issued -- theoretically -- with a 0% interest rate.* The borrower pays back only the principal of the bond, and the bondholder receives federal tax credits in lieu of the traditional bond interest.** The Energy Improvement and Extension Act of 2008 (Div. A, Sec. 107) allocated $800 million for new Clean Renewable Energy Bonds (CREBs). In February 2009, the American Recovery and Reinvestment Act of 2009 (Div. B, Sec. 1111) allocated an additional $1.6 billion for New CREBs, for a total New CREB allocation of $2.4 billion. The Energy Improvement and Extension Act of 2008 also extended the deadline for previously reserved allocations ("Old CREBs") until December 31, 2009, and addressed several provisions in the existing law that previously limited the usefulness of the program for some projects. A separate section of the law extended CREBs eligibility to marine energy and hydrokinetic power projects. Participation in the program is limited by the volume of bonds allocated by Congress for the program. Participants must first apply to the Internal Revenue Service (IRS) for a CREBs allocation, and then issue the bonds within a specified time period. The New CREBs allocation totaling $2.4 billion does not have a defined expiration date under the law; however, the recent IRS solicitations for new applications require the bonds to be issued within 3 years after the applicant receives notification of an approved allocation (see History section below for information on previous allocations). Public power providers, governmental bodies, and electric cooperatives are each reserved an equal share (33.3%) of the New CREBs allocation. The tax credit rate is set daily by the U.S. Treasury Department. Under past allocations, the credit could be taken quarterly on a dollar-for-dollar basis to offset the tax liability of the bondholder. However, under the new CREBs allocation, the credit has been reduced to 70% of what it would have been otherwise. Other important changes are described in IRS Notice 2009-33. CREBs differ from traditional tax-exempt bonds in that the tax credits issued through CREBs are treated as taxable income for the bondholder. The tax credit may be taken each year the bondholder has a tax liability as long as the credit amount does not exceed the limits established by the federal Energy Policy Act of 2005. Treasury rates for prior CREB allocations, or "Old" CREBs are available here, while rates for New CREBs and other qualified tax credit bonds are available here. In April 2009, the IRS issued Notice 2009-33, which solicited applications for the New CREB allocation and provided interim guidance on certain program rules and changes from prior CREB allocations. The expiration date for New CREB applications under this solicitation was August 4, 2009. Further guidance on CREBs is available in IRS Notices 2006-7 and 2007-26 to the extent that the program rules were not modified by 2008 and 2009 legislation. In October 2009, the Department of Treasury announced the allocation of $2.2 billion in new CREBs for 805 projects across the country. A new solicitation (IRS Announcement 2010-54) was issued in September 2010 for roughly $191 million in unallocated New CREB bond volume available only to electric cooperatives. The November 1, 2010 deadline under IRS Announcement 2010-54 has now expired. It remains to be seen if the IRS will issue new funding announcements for Old CREB allocations which are not issued by the December 31, 2009 deadline. History The federal Energy Policy Act of 2005 (EPAct 2005) established Clean Energy Renewable Bonds (CREBs) as a financing mechanism for public sector renewable energy projects. This legislation originally allocated $800 million of tax credit bonds to be issued between January 1, 2006, and December 31, 2007. Following the enactment of the federal Tax Relief and Health Care Act of 2006, the IRS made an additional $400 million in

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	CREBs financing available for 2008 through Notice 2007-26. In November 2006, the IRS announced that the original $800 million allocation had been reserved for a total of 610 projects. The additional $400 million (plus surrendered volume from the previous allocation) was allocated to 312 projects in February 2008. Of the $1.2 billion total of tax-credit bond volume cap allocated to fund renewable-energy projects, state and local government borrowers were limited to $750 million of the volume cap, with the rest reserved for qualified municipal or cooperative electric companies. For further information on CREBs, contact Zoran Stojanovic or Timothy Jones of the IRS Office of Associate Chief Counsel at (202) 622-3980. Questions on recent IRS Notice 2009-33 can be directed to Janae Lemley at (636) 255-1202.
18	Homeowners can take advantage of energy efficient mortgages (EEM) to either finance energy efficiency improvements to existing homes, including renewable energy technologies, or to increase their home buying power with the purchase of a new energy efficient home. The U.S. federal government supports these loans by insuring them through Federal Housing Authority (FHA) or Veterans Affairs (VA) programs. This allows borrowers who might otherwise be denied loans to pursue energy efficiency, and it secures lenders against loan default. The federal Energy Star program has a partnership program for lenders whereby lenders who provide EEMs to borrowers may become Energy Star lender partners. These EEMs may or may not be used to purchase an Energy Star qualified home. Becoming a partner allows lenders to utilize the Energy Star brand to promote themselves as Energy Star partners offering EEMs. To become a lender, partner lenders must first provide proof that they know how to write EEMs. To maintain their partnership benefits, lenders must write a certain number of EEMs per year. Energy Star does not have a lender certification program or process. Click here for more information about Energy Star's lender partnership program. As of July 2010, the federal Energy Star program lists 23 lenders who offer EEMs and/or ENERGY STAR mortgages to applicants buying homes that have earned the Energy Star label. Energy Star requires that its lender partners provide EEMs to qualified borrowers regardless of whether it is an FHA EEM, Fannie Mae EEM, or VA EEM. FHA Energy Efficient Mortgages The FHA allows lenders to add up to 100% of energy efficiency improvements to an existing mortgage loan with certain restrictions. FHA mortgage limits vary by county, state and the number of units in a dwelling. See website for more details. These mortgages were previously limited to $8,000. In June 2009, HUD issued Mortgagee Letter 2009-18 which announced the removal of the dollar cap. The maximum amount of the portion of an energy efficient mortgage allowed for energy improvements is now the lesser of 5% of: The value of the property, 115% of the median area price of a single-family dwelling, or 150% of the Freddie Mac conforming loan limit Loan amounts may not exceed the projected savings of the energy efficiency improvements. These loans may be combined with FHA 203 (h) mortgages available to victims of presidentially-declared disasters and with financing offered through the FHA 203 (k) rehabilitation program. FHA loan limits do not apply to the EEM. Homebuyers must submit a Home Energy Rating (HER), contractor bids, and a FHA B Worksheet. This process may become streamlined in 2009 as a result of the Housing and Economic Recovery Act of 2008, which requires HUD to report to congress with ways to remove the administrative barriers and increase consumer participation and awareness of these financing options. Presently, up to $200 of the cost of the HER may be included in the mortgage, and borrowers may include closing costs and the up-front mortgage

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	insurance premium in the total cost of the loan. The loan is available to anyone who meets the income requirements for FHA's Section 203 (b), provided the applicant can meet the monthly mortgage payments. New and existing owner-occupied homes of up to two units qualify for this loan. Cooperative units are not eligible. Homebuyers should submit applications to their local HUD Field Office through an FHA-approved lending institution. Department of Veterans Affairs (VA) Energy Efficient Mortgages The VA insures EEMs to be used in conjunction with VA loans either for the purchase of existing homes or for refinancing loans secured by the dwelling. Homebuyers may borrow up to $3,000 if only documentation of improvement costs or contractor bids is submitted, or up to $6,000 if the projected energy savings are greater than the increase in mortgage payments. Loans may exceed this amount at the discretion of the VA. Applicants may not include the cost of their own labor in the total amount. No additional home appraisal is needed, but applicants must submit a HER, contractor bids and certain other documentation. The VA insures 50% of the loan if taken by itself, but it may insure less if the total value of the mortgage exceeds a certain amount. This mortgage is available to qualified military personnel, reservists and veterans. (See www.homeloans.va.gov/elig2.htm for more details). Applicants should secure a certificate of eligibility from their local lending office and submit it to a VA-approved private lender. If the loan is approved, the VA guarantees the loan when it is closed. Conventional EEMs Conventional mortgages are not backed by a federal agency. Private lenders sell loans to Fannie Mae and Freddie Mac, which in turn allows homebuyers to borrow up to 15% of an existing home's appraised value for improvements documented by a HER. Fannie Mae also lends up to 5% for Energy Star new homes. Fannie Mae EEMs are available to single-family, owner-occupied units, and Fannie Mae provides EEMs to those whose income might otherwise disqualify them from receiving the loans by allowing approved lenders to adjust borrowers' debt-to-income ratio by 2%. The value of the improvements is immediately added to the total appraised value of the home. Freddie Mac offers EEMs for one- to four-unit dwellings and also helps raise the effective income of the borrower to qualifying levels by allowing lenders to increase the borrower's income by a dollar amount equal to the estimated energy savings. Any energy efficiency improvements can qualify, and these mortgages can be combined with both fixed-rate and adjustable-rate mortgages. Borrowers should apply directly to the lender. See www.natresnet.org/resources/lender/default.htm for more details. Energy Star Mortgage Pilot Program The U.S. EPA and the U.S. DOE, through their Energy Star program, have collaborated with the Energy Programs Consortium, state energy and housing agencies, and the Ford and Surdna Foundations to provide an Energy Star Mortgage Pilot Program. Currently, there are lenders participating in the program in Colorado, Maine, and Virginia, and plans are being developed to bring the pilot program to Massachusetts, New York, New Jersey, Pennsylvania, and the District of Columbia. Through the program, the home being financed must either be an Energy Star qualified home or a home being retrofitted to reduce its energy use by at least 20% under a Home Performance with Energy Star program or a Weatherization Assistance Program. Participating lenders must provide borrowers a financial benefit such as a closing cost or interest rate discount, or a loan fee reduction. Click here for more information.

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19	The Energy Improvement and Extension Act of 2008, enacted in October 2008, authorized the issuance of Qualified Energy Conservation Bonds (QECBs) that may be used by state, local and tribal governments to finance certain types of energy projects. QECBs are qualified tax credit bonds, and in this respect are similar to new Clean Renewable Energy Bonds or CREBs. The October 2008 enabling legislation set a limit of $800 million on the volume of energy conservation tax credit bonds that may be issued by state and local governments. The American Recovery and Reinvestment Act of 2009, enacted in February 2009, expanded the allowable bond volume to $3.2 billion. In April 2009, the IRS issued Notice 2009-29 providing interim guidance on how the program will operate and how the bond volume will be allocated. Subsequently, H.R. 2847 enacted in March 2010 introduced an option allowing issuers of QECBs and New CREBs to recoup part of the interest they pay on a qualified bond through a direct subsidy from the Department of Treasury. Guidance from the IRS on this option was issued in April 2010 under Notice 2010-35. With tax credit bonds, generally the borrower who issues the bond pays back only the principal of the bond, and the bondholder receives federal tax credits in lieu of the traditional bond interest. The tax credit may be taken quarterly to offset the tax liability of the bondholder. The tax credit rate is set daily by the U.S. Treasury Department; however, energy conservation bondholders will receive only 70% of the full rate set by the Treasury Department under 26 USC § 54A. QECB rates are available here. Credits exceeding a bondholder's tax liability may be carried forward to the succeeding tax year, but cannot be refunded. Energy conservation bonds differ from traditional tax-exempt bonds in that the tax credits issued through the program are treated as taxable income for the bondholder. For QECBs issued after March 18, 2010, the bond issuer may make an irrevocable election to receive a direct payment from the Department of Treasury equivalent to the amount of the non-refundable tax credit described above, which would otherwise accrue to the bondholder. The direct payment comes in the form of a refundable tax credit to the issuer in lieu of a tax credit to the bondholder. This option was formerly limited to Build America Bonds (see 26 USC § 6431, H.R. 2847 and IRS Notice 2010-35 for details). The advantage of either option is that it creates a lower effective interest rate for the issuer because the federal government subsidizes a portion of the interest costs. In contrast to CREBs, QECBs are not subject to a U.S. Department of Treasury application and approval process. Bond volume is instead allocated to each state based on the state's percentage of the U.S. population as of July 1, 2008. Each state is then required to allocate a portion of its allocation to "large local governments" within the state based on the local government's percentage of the state's population. Large local governments are defined as municipalities and counties with populations of 100,000 or more. Large local governments may reallocate their designated portion back to the state if they choose to do so. IRS Notice 2009-29 contains a list of the QECB allocations for each state and U.S. territory. Interested individuals should contact their State Energy Office for information on how the program will be administered in their state.
20	There are no solicitations under this program currently accepting application. See the website above for more information. Title XVII of the federal Energy Policy Act of 2005 (EPAct 2005) authorized the U.S. Department of Energy (DOE) to issue loan guarantees for projects that "avoid, reduce or sequester air pollutants or anthropogenic emissions of greenhouse gases; and employ new or significantly improved technologies as compared to commercial technologies in service in the United States at the time the guarantee is issued." The loan guarantee program has been authorized to offer more than $10 billion in loan guarantees for energy efficiency, renewable energy and advanced transmission and distribution projects. The DOE actively promotes projects in three categories: (1) manufacturing projects, (2) stand-alone projects, and (3) large-scale integration projects that may combine multiple eligible renewable energy, energy efficiency and transmission technologies in accordance with a staged development

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	scheme. Under the original authorization, loan guarantees were intended to encourage early commercial use of new or significantly improved technologies in energy projects. The loan guarantee program generally does not support research and development projects. In July 2009, the DOE issued a solicitation for projects that employ innovative energy efficiency, renewable energy, and advanced transmission and distribution technologies. Proposed projects must fit within the criteria for "New or Significantly Improved Technologies" as defined in 10 CFR 609. The solicitation provides for a total of $8.5 billion in funding. The due date for Part I applications was August 24, 2010. The Part II application deadline was December 31, 2010. The DOE periodically makes new solicitations available. Information about current and past solicitations can be found at the website above.
21	Note: The U.S. Department of Agriculture's Rural Development issues periodic Notices of Solicitation of Applications for the Rural Energy for America Program (REAP). The deadline to apply for grants and loan guarantees under the most recent solicitation was June 15, 2011. Grants and loan guarantees will be awarded for investments in renewable energy systems, energy efficiency improvements and renewable energy feasibility studies. The Food, Conservation, and Energy Act of 2008 (H.R. 2419), enacted by Congress in May 2008, converted the federal Renewable Energy Systems and Energy Efficiency Improvements Program,* into the Rural Energy for America Program (REAP). Similar to its predecessor, the REAP promotes energy efficiency and renewable energy for agricultural producers and rural small businesses through the use of (1) grants and loan guarantees for energy efficiency improvements and renewable energy systems, and (2) grants for energy audits and renewable energy development assistance. Congress has allocated funding for the new program in the following amounts: $55 million for FY 2009, $60 million for FY 2010, $70 million for FY 2011, and $70 million for FY 2012. REAP is administered by the U.S. Department of Agriculture (USDA). In addition to these mandatory funding levels, there may also be discretionary funding issued each year. Of the total REAP funding available, approximately 88% is dedicated to competitive grants and loan guarantees for energy efficiency improvements and renewable energy systems. These incentives are available to agricultural producers and rural small businesses to purchase renewable energy systems (including systems that may be used to produce and sell electricity) and to make energy efficiency improvements. Funding is also available to conduct relevant feasibility studies, with approximately 2% of total funding being available for feasibility studies. Eligible renewable energy projects include wind, solar, biomass and geothermal; and hydrogen derived from biomass or water using wind, solar or geothermal energy sources. These grants are limited to 25% of a proposed project's cost, and a loan guarantee may not exceed $25 million. The combined amount of a grant and loan guarantee may not exceed 75% of the project’s cost. In general, a minimum of 20% of the funds available for these incentives will be dedicated to grants of $20,000 or less. The USDA likely will announce the availability of funding for this component of REAP through a Notice of Funds Availability (NOFA). The USDA will also make competitive grants to eligible entities to provide assistance to agricultural producers and rural small businesses “to become more energy efficient” and “to use renewable energy technologies and resources.” These grants are generally available to state government entities, local governments, tribal governments, land-grant colleges and universities, rural electric cooperatives and public power entities, and other entities, as determined by the USDA. These grants may be used for conducting and promoting energy audits; and for providing recommendations and information related to energy efficiency and renewable energy. Of the total REAP funding available, approximately 9% is dedicated to competitive grants for energy technical assistance.

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22	The federal Energy Policy Act of 2005 established tax credits for manufacturers of high-efficiency residential clothes washers, refrigerators, and dishwashers produced in calendar years 2006 and 2007. The Energy Improvement and Extension Act of 2008 (H.R. 1424, Division B) extended these credits, depending on the efficiency rating of the manufactured appliance. Manufacturers may only receive these credits for the increase in production of qualifying appliances over a two-year rolling baseline, and only appliances produced in the United States are eligible. Dishwashers $45 for models manufactured in calendar year 2008 or 2009 which use no more than 324 kilowatt hours (kWh) per year and 5.8 gallons per cycle. $75 for models manufactured in calendar year 2008, 2009, or 2010 which use no more than 307 kWh per year and 5.5 gallons per cycle. $25 for models manufactured in calendar year 2011 which use no more than 307 kWh per year and 5.0 gallons per cycle (5.5 gallons per cycle for dishwashers designed for greater than 12 place settings). $50 for models manufactured in calendar year 2011 which use no more than 295 kWh per year and 4.25 gallons per cycle (4.75 gallons per cycle for dishwashers designed for greater than 12 place settings). $75 for models manufactured in calendar year 2011 which use no more than 280 kWh per year and 4 gallons per cycle (4.5 gallons per cycle for dishwashers designed for greater than 12 place settings). Clothes washers $75 for residential top-loading models manufactured in 2008 which meet or exceed a 1.72 modified energy factor (MEF) and do not exceed an 8.0 water consumption factor (WCF). $125 for residential top-loading models manufactured in 2008 or 2009 which meet or exceed a 1.8 MEF and do not exceed a 7.5 WCF. $150 for residential or commercial models manufactured in 2008, 2009, or 2010 which meet or exceed a 2.0 MEF and does not exceed a 6.0 WCF. $250 for residential or commercial models manufactured in 2008, 2009, or 2010 which meet or exceed a 2.2 MEF and do not exceed a 4.5 WCF. $175 for top-loading models manufactured in calendar year 2011 which meet or exceed a 2.2 modified energy factor and do not exceed a 4.5 WCF. $225 for top-loading models manufactured in calendar year 2011 which meet or exceed a 2.4 modified energy factor and do not exceed a 4.2 WCF.* $225 for front-loading models manufactured in calendar year 2011 which meet or exceed a 2.8 modified energy factor and do not exceed a 3.5 WCF.* Refrigerators $50 for models manufactured in 2008 which are between 20% and 22.9% more efficient than the 2001 energy conservation standards. $75 for models manufactured in calendar year 2008 or 2009 which are between 23% and 24.9% more efficient than the 2001 energy conservation standards. $100 for models manufactured in calendar year2008, 2009, or 2010 which are between 25% and 29.9% more efficient than the 2001 energy conservation standards. $200 for models manufactured in calendar year2008, 2009, or 2010 which are at least 30% more efficient than the 2001 energy conservation standards. $150 in the case of a refrigerator manufactured in calendar year 2011 which consumes at least 30 percent less energy than the 2001 energy conservation standards. $200 in the case of a refrigerator manufactured in calendar year 2011 which consumes at least 35 percent less energy than the 2001 energy conservation standards.* **Each manufacturer is limited to a total of $25 million in 2011 for all credits under this provision. See note below for exceptions to this rule.**
23	Note: This incentive is no longer available; an act of Congress is required to renew this tax incentive. As of February 2011, this has not yet occurred.

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	The U.S. Treasury Department, in consultation with the U.S. Department of Energy (DOE), is no longer accepting applications for this tax credit. See a list of approved projects (announced in January 2010). The American Recovery and Reinvestment Act of 2009 (H.R. 1), enacted in February 2009, established a new investment tax credit to encourage the development of a U.S.-based renewable energy manufacturing sector. In any taxable year, the investment tax credit is equal to 30% of the qualified investment required for an advanced energy project that establishes, re-equips or expands a manufacturing facility that produces any of the following: Equipment and/or technologies used to produced energy from the sun, wind, geothermal or "other" renewable resources Fuel cells, microturbines or energy-storage systems for use with electric or hybrid-electric motor vehicles Equipment used to refine or blend renewable fuels Equipment and/or technologies to produce energy-conservation technologies (including energy-conserving lighting technologies and smart grid technologies)* Qualified investments generally include personal tangible property that is depreciable and required for the production process. Other tangible property may be considered a qualified investment only if it is an essential part of the facility, excluding buildings and structural components. The U.S. Treasury Department will issue certifications for qualified investments eligible for credits to qualifying advanced energy project sponsors. In total, $2.3 billion worth of credits may be allocated under the program. After certification is granted, the taxpayer has one year to provide additional evidence that the requirements of the certification have been met and three years to put the project in service. There are provisions for credit recapture for non-compliance. In determining which projects to certify, the U.S. Treasury Department must consider those which most likely will be commercially viable, provide the greatest domestic job creation, provide the greatest net reduction of air pollution and/or greenhouse gases, have great potential for technological innovation and commercial deployment, have the lowest levelized cost of generated (or stored) energy or the lowest levelized cost of reduction in energy consumption or greenhouse gas emissions, and have the shortest project time. Any taxpayer receiving this credit may not also receive the federal business energy investment tax credit. See the U.S. DOE's Advanced Energy Manufacturing Tax Credit (48C) web site for more information.
24	Established by the federal Energy Policy Act of 1992, the federal Renewable Energy Production Incentive (REPI) provides incentive payments for electricity generated and sold by new qualifying renewable energy facilities. Qualifying systems are eligible for annual incentive payments of 1.5¢ per kilowatt-hour (kWh) in 1993 dollars (indexed for inflation) for the first 10-year period of their operation, subject to the availability of annual appropriations in each federal fiscal year of operation. REPI was designed to complement the federal renewable energy production tax credit (PTC), which is available only to businesses that pay federal corporate taxes. Qualifying systems must generate electricity using solar, wind, geothermal (with certain restrictions), biomass (excluding municipal solid waste), landfill gas, livestock methane, or ocean resources (including tidal, wave, current and thermal). The production payment applies only to the electricity sold to another entity. Eligible electric production facilities include not-for-profit electrical cooperatives, public utilities, state governments and political subdivisions thereof, commonwealths, territories and possessions of the United States, the District of Columbia, Indian

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	tribal governments or political subdivisions thereof, and Native Corporations. Payments may be made only for electricity generated from an eligible facility first used before October 1, 2016. Appropriations have been authorized for fiscal years 2006 through fiscal year 2026; however, program funding is determined each year as part of the U.S. Department of Energy budget process. If there are insufficient appropriations to make full payments for electricity production from all qualified systems for a federal fiscal year, 60% of the appropriated funds for the fiscal year will be assigned to facilities that use solar, wind, ocean, geothermal or closed-loop biomass technologies; and 40% of the appropriated funds for the fiscal year will be assigned to other eligible projects. Funds will be awarded on a pro rata basis, if necessary. In past years this has meant that actual incentive payments have corresponded to only a small fraction of the theoretical inflation adjusted incentive level of ~2 cents/kWh.
25	The Texas Commission on Environmental Quality administers the Emissions Reduction Incentive Grants (ERIG) Program, part of the Texas Emissions Reduction Plan, which provides grants for various types of clean air projects to improve air quality in the state's nonattainment areas. Eligible projects include those that involve heavy-duty vehicle replacement, retrofit, or repower; alternative fuel dispensing infrastructure; idle reduction and electrification infrastructure; and alternative fuel use. (Reference Texas Statutes, Health and Safety Code 386)
26	The Texas Council on Environmental Quality administers the New Technology Research and Development (NTRD) Program, part of the Texas Emissions Reduction Plan, which provides grants for alternative fuel and advanced technology demonstration and infrastructure projects to encourage and support research, development, and commercialization of technologies that reduce pollution. (Reference Texas Statutes, Health and Safety Code 387)
27	The Texas Commission on Environmental Quality (TCEQ) administers the Texas Clean Fleet Program, part of the Texas Emissions Reduction Plan, which encourages owners of fleets containing diesel vehicles to permanently remove the vehicles from the road and replace them with alternative fuel vehicles (AFVs) or hybrid electric vehicles (HEVs). Grants are available to fleets to offset the incremental cost of such replacement projects. An entity that operates a fleet of at least 100 vehicles and places 25 or more qualifying vehicles in service for use entirely in Texas during a given calendar year may be eligible for grant. Qualifying AFV or HEV replacements must reduce emissions of nitrogen oxides or other pollutants by at least 25% as compared to baseline levels and must replace vehicles that meet operational and fuel usage requirements. Neighborhood electric vehicles do not qualify. This program ends August 31, 2017. (Reference Texas Statutes, Health and Safety Code 391)
28	A tax credit is available for the cost of alternative fueling equipment placed into service after December 31, 2005. Qualified alternative fuels are natural gas, liquefied petroleum gas, hydrogen, electricity, E85, or diesel fuel blends containing a minimum of 20% biodiesel. The credit amount is up to 30% of the cost, not to exceed $30,000 for equipment placed into service in 2011. Equipment placed into service in 2009 and 2010 may receive a credit in the amount of 50% of eligible costs not to exceed $50,000. Fueling station owners who install qualified equipment at multiple sites are allowed to use the credit towards each location. Consumers who purchase qualified residential fueling equipment may receive a tax credit of up to $1,000. The maximum credit amount for hydrogen fueling equipment placed into service before January 1, 2015, is $200,000. Under current law, the credit expires December 31, 2011, for all other eligible fuel types. Unused credits that qualify as general business tax credits, as defined by the Internal Revenue Service (IRS), may be carried backward one year and carried forward 20 years. For more information, see IRS Form 8911 and/or Form 3800, which are available via the IRS website. (Reference H.R. 4853, 2010, Section 711; and 26 U.S. Code 30C and 38B)
29	A tax incentive is available for alternative fuel that is sold for use or used as a fuel to operate a motor vehicle. A tax credit in the amount of $0.50 per gallon is available for the following alternative fuels: compressed natural gas (based on 121 cubic feet), liquefied natural gas, liquefied petroleum gas, P-Series fuel, liquid fuel derived from coal through the Fischer-Tropsch process, and compressed or liquefied gas derived from biomass. For an

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	entity to be eligible to claim the credit they must be liable for reporting and paying the federal excise tax on the sale or use of the fuel in a motor vehicle. Tax exempt entities such as state and local governments that dispense qualified fuel from an on-site fueling station for use in vehicles qualify for the incentive. Eligible entities must be registered with the Internal Revenue Service (IRS). The incentive must first be taken as a credit against the entity's alternative fuel tax liability; any excess over this fuel tax liability may be claimed as a direct payment from the IRS. The tax credit is not allowed if an incentive for the same alternative fuel is also determined under the rules for the ethanol or biodiesel tax credits. For more information, see IRS Publication 510 and IRS Forms 637, 720, 4136, and 8849, which are available via the IRS website. Under current law, this incentive expires December 31, 2011. The U.S. Internal Revenue Service (IRS) has issued special guidance to allow a 180-day period for the submission of a one-time claim for 2010 credits. Please refer to IRS Notice 2011-10PDF for additional information.
30	An alternative fuel blender that is registered with the Internal Revenue Service (IRS) may be eligible for a tax incentive on the sale or use of the alternative fuel blend (mixture) for use as a fuel in the blender's trade or business. The credit is in the amount of $0.50 per gallon of alternative fuel used to produce a mixture containing at least 0.1% gasoline, diesel, or kerosene. Qualified alternative fuels are: compressed natural gas (based on 121 cubic feet), liquefied natural gas, liquefied petroleum gas, P-Series fuel, liquid fuel derived from coal through the Fischer-Tropsch process, and compressed or liquefied gas derived from biomass. The incentive must first be taken as a credit against the blender's alternative fuel tax liability; any excess over this fuel tax liability may be claimed as a direct payment from the IRS. The tax credit is not allowed if an incentive for the same alternative fuel is also determined under the rules for the ethanol or biodiesel tax credits. For more information, see IRS Publication 510 and IRS Forms 637, 720, 4136, and 8849, which are available via the IRS website. Under current law, this incentive expires December 31, 2011. The U.S. Internal Revenue Service (IRS) has issued special guidance to allow a 180-day period for the submission of a one-time claim for 2010 credits. Please refer to IRS Notice 2011-10PDF for additional information.
31	Alternative fuels used in a manner that the Internal Revenue Service (IRS) deems as nontaxable are exempt from federal fuel taxes. Common nontaxable uses in a motor vehicle are: on a farm for farming purposes; in certain intercity and local buses; in a school bus; exclusive use by a nonprofit educational organization; and exclusive use by a state, political subdivision of a state, or the District of Columbia. This exemption is not available to tax exempt entities that are not liable for excise taxes on transportation fuel. For more information, see IRS Publication 510, which is available via the IRS website.
32	The U.S. Department of Energy (DOE) provides loan guarantees through the Loan Guarantee Program (Program) to eligible projects that reduce air pollution and greenhouse gases, and support early commercial use of advanced technologies, including biofuels and alternative fuel vehicles. The Program is not intended for research and development projects. DOE may issue loan guarantees for up to 100% of the amount of the loan for an eligible project. For loan guarantees of over 80%, the loan must be issued and funded by the Treasury Department's Federal Financing Bank. For additional Program guidelines and solicitation announcements, please visit the Loan Guarantee Program website. (Reference 42 U.S. Code 16513)
33	Effective September 1, 2011, the Texas Commission on Environmental Quality will establish and administer the Alternative Fueling Facilities Program, part of the Texas Emissions Reduction Plan, which provides grants for 50% of eligible costs, up to $500,000, to construct, reconstruct, or acquire a facility to store, compress, or dispense alternative fuels in Texas air quality nonattainment areas. Qualified alternative fuels include electricity, natural gas, hydrogen, propane, and fuel mixtures containing at least 85% methanol (M85). The entity receiving the grant must agree to make the fueling station available to people and organizations not associated with the grantee during certain times. Additional terms and conditions apply. This program ends August 31, 2018. (Reference Senate Bill 20, 2011, and Texas Statutes, Health and Safety Code 394)
34	Effective September 1, 2011, the Texas Commission on Environmental Quality (CEQ) will establish and administer the NGV Grant Program, part of the Texas Emissions Reduction Plan, which provides grants to replace existing medium- and heavy-duty vehicles with new, converted, or repowered

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	NGVs. Qualifying vehicles must be on-road vehicles with a gross vehicle weight rating of more than 8,500 pounds and certified to current federal emissions standards. Grant funds may cover only the incremental costs. Additional terms and conditions apply. To ensure that NGVs have access to natural gas fueling infrastructure, CEQ may also award grants to support the development of a network of natural gas fueling stations along the interstate highways connecting Houston, San Antonio, Dallas, and Forth Worth. Through a competitive process, CEQ may not award more than three station grants to any one entity, or more than one grant for each station. Grant amounts may not exceed $100,000 for a compressed natural gas station, $250,000 for a liquefied natural gas station, or $400,000 for a station providing both forms of natural gas. Funded stations must be accessible to the public and located within three miles of an interstate highway system. Additional terms and conditions apply. This program ends August 31, 2017. (Reference Senate Bill 20, 2011, and Texas Statutes, Health and Safety Code 393)
35	The Texas General Land Office administers the NGV Initiative Grant Program to encourage public-sector fleets in certain counties to increase their use of heavy-duty NGVs. Private fleets also may be eligible particularly those that operate directly under contract for government work or do other government business. The program is funded with a Texas Emissions Reduction Plan grant through the Texas Commission on Environmental Quality. A variety of vehicles, including street sweepers, forklifts, buses, and garbage trucks, are eligible for grants to help cover the cost of replacing diesel vehicles with NGVs. The program ends August 31, 2012. As of July 2011, funding is not available.
36	Through its natural gas program, the Texas General Land Office (GLO) makes competitively-priced natural gas available to school districts and other state and local public entities for use in natural gas vehicles. The GLO has also established an alternative fuels program to aggressively promote the use of alternative energy sources, especially for those fuels abundant in Texas. The GLO alternative fuels program serves as a liaison between government and industry.
37	Clean Energy Fuels offers services to the natural gas vehicle industry that include compressed natural gas fueling station equipment maintenance and competitive fuel pricing for larger fleet customers, as well as alternative fuel vehicle financing.
38	The Texas Gas Service Conservation Program offers a $2,000 rebate for the purchase of a qualified NGV or $3,000 for the conversion of a gasoline powered vehicle to operate on natural gas. The rebate is available for up to five vehicles per customer, and only centers certified by the Railroad Commission of Texas may perform conversions. A $1,000 rebate is also available for the purchase of a natural gas forklift. Additionally, qualified residential and commercial NGV fueling infrastructure may be eligible for a $2,000 rebate. These incentives are available to commercial and residential customers within the city limits of Austin, Sunset Valley, Rollingwood, West Lake Hills, Cedar Park, and Kyle with specific gas rate codes.
39	Atmos Energy offers preliminary feasibility studies for compressed natural gas fueling stations and may assist with vendor selection on a case-by-case basis.
40	CenterPoint Energy offers preliminary feasibility studies for compressed natural gas fueling stations and may assist with vendor selection on a case-by-case basis within the CenterPoint Energy service area.
41	A biodiesel blender that is registered with the Internal Revenue Service (IRS) may be eligible for a tax incentive in the amount of $1.00 per gallon of pure biodiesel, agri-biodiesel, or renewable diesel blended with petroleum diesel to produce a mixture containing at least 0.1% diesel fuel. Only blenders that have produced and sold or used the qualified biodiesel mixture as a fuel in their trade or business are eligible for the tax credit. The incentive must first be taken as a credit against the blender's fuel tax liability; any excess over this tax liability may be claimed as a direct payment from the IRS. Claims must include a copy of the certificate from the registered biodiesel producer or importer that: identifies the product; specifies the product's biodiesel, agri-biodiesel, and/or renewable diesel content; confirms that the product is properly registered as a fuel with the U.S. Environmental Protection Agency; and confirms that the product meets the requirements of ASTM specification D6751. Renewable diesel is defined

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	as liquid fuel derived from biomass that meets EPA's fuel registration requirements and ASTM specifications D975 or D396; the definition of renewable diesel does not include any fuel derived from co-processing biomass with a feedstock that is not biomass. For more information, see IRS Publication 510 and IRS Forms 637, 720, 4136, 8849, and 8864, which are available via the IRS website. Under current law, this incentive expires December 31, 2011. The U.S. Internal Revenue Service (IRS) has issued special guidance to allow a 180-day period for the submission of a one-time claim for 2010 credits. Please refer to IRS Notice 2011-10PDF for additional information. (Reference H.R. 4853, 2010, Section 701; and 26 U.S. Code 6426)
42	A taxpayer that delivers pure, unblended biodiesel (B100) into the tank of a vehicle or uses B100 as an on-road fuel in their trade or business may be eligible for an incentive in the amount of $1.00 per gallon of biodiesel, agri-biodiesel, or renewable diesel. If the biodiesel was sold at retail, only the person that sold the fuel and placed it into the tank of the vehicle is eligible for the tax credit. The incentive is allowed as a credit against the taxpayer's income tax liability. Claims must include a copy of the certificate from the registered biodiesel producer or importer that: identifies the product; specifies the product's biodiesel, agri-biodiesel, and/or renewable diesel content; confirms that the product is properly registered as a fuel with the U.S. Environmental Protection Agency (EPA); and confirms that the product meets the requirements of ASTM specification D6751. Renewable diesel is defined as liquid fuel derived from biomass that meets EPA's fuel registration requirements and ASTM specifications D975 or D396; the definition of renewable diesel does not include any fuel derived from co-processing biomass with a feedstock that is not biomass. Under current law, this incentive expires December 31, 2011. For more information, see IRS Publication 510 and IRS Forms 637 and 8864, which are available via the IRS website. (Reference H.R. 4853, 2010, Section 701; and 26 U.S. Code 40A)
43	A small agri-biodiesel producer that is registered with the Internal Revenue Service (IRS) may be eligible for a tax incentive in the amount of $0.10 per gallon of agri-biodiesel that is: sold and used by the purchaser in the purchaser's trade or business to produce an agri-biodiesel and diesel fuel mixture; sold and used by the purchaser as a fuel in a trade or business; sold at retail for use as a motor vehicle fuel; used by the producer in a trade or business to produce an agri-biodiesel and diesel fuel mixture; or used by the producer as a fuel in a trade or business. A small producer is one that has, at all times during the tax year, not more than 60 million gallons of productive capacity of any type of agri-biodiesel. Agri-biodiesel is defined as diesel fuel derived solely from virgin oils, including esters derived from corn, soybeans, sunflower seeds, cottonseeds, canola, crambe, rapeseeds, safflowers, flaxseeds, rice bran, mustard seeds, and camelina, and from animal fats; renewable diesel does not qualify for the credit. The incentive applies only to the first 15 million gallons of agri-biodiesel produced in a tax year is allowed as a credit against the producer's income tax liability. Under current law, this incentive expires December 31, 2011. For more information, see IRS Publication 510 and IRS Forms 637 and 8864, which are available via the IRS website. (Reference H.R. 4853, 2010, Section 701; and 26 U.S. Code 40A)
44	The Advanced Research Projects Agency - Energy (ARPA-E) was established within the U.S. Department of Energy with the mission to fund projects that will develop transformational technologies that reduce the nation's dependence on foreign energy imports; reduce U.S. energy related emissions, including greenhouse gases; improve energy efficiency across all sectors of the economy; and ensure that the U.S. maintains its leadership in developing and deploying advanced energy technologies. The ARPA-E focuses on various concepts in multiple program areas including, but not limited to, vehicle technologies, biomass energy, and energy storage. For more information, visit the ARPA-E website.
45	The U.S. Department of Energy (DOE) provides loan guarantees through the Loan Guarantee Program (Program) to eligible projects that reduce air pollution and greenhouse gases, and support early commercial use of advanced technologies, including biofuels and alternative fuel vehicles. The Program is not intended for research and development projects. DOE may issue loan guarantees for up to 100% of the amount of the loan for an eligible project. For loan guarantees of over 80%, the loan must be issued and funded by the Treasury Department's Federal Financing Bank. For additional Program guidelines and solicitation announcements, please visit the Loan Guarantee Program website. (Reference 42 U.S. Code 16513)

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46	The Biorefinery Assistance Program (Section 9003) provides loan guarantees for the development, construction, and retrofitting of commercial-scale biorefineries that produce advanced biofuels. Grants for demonstration scale biorefineries are also available. Advanced biofuel is defined as fuel derived from renewable biomass other than corn kernel starch. Eligible applicants include, but are not limited to, individuals, state or local governments, farm cooperatives, national laboratories, institutions of higher education, and rural electric cooperatives. The maximum loan guarantee is $250 million and the maximum grant funding is 50% of project costs. For more information, see the Biorefinery Assistance Program website. (Reference 7 U.S. Code 8103)
47	Through the Bioenergy Program for Advanced Biofuels (Section 9005), eligible producers of advanced biofuels, or fuels derived from renewable biomass other than corn kernel starch, may receive payments to support expanded production of advanced biofuels. Payment amounts will depend on the quantity and duration of production by the eligible producer; the net nonrenewable energy content of the advanced biofuel, if sufficient data is available; the number of producers participating in the program; and the amount of funds available. No more than 5% of the funds will be made available to eligible producers with an annual refining capacity of more than 150,000,000 gallons of advanced biofuel. For more information, see the Bioenergy Program for Advanced Biofuels website and contact the appropriate State Rural Development Office. (Reference 7 U.S. Code 8105)
48	Competitive grants are available through the Biodiesel Fuel Education Program (Section 9006) to educate governmental and private entities that operate vehicle fleets, the public, and other interested entities about the benefits of biodiesel fuel use. Eligible applicants are nonprofit organizations or institutes of higher education that have demonstrated knowledge of biodiesel fuel production, use, or distribution; and have demonstrated the ability to conduct educational and technical support programs. (Reference 7 U.S. Code 8106)
49	The U.S. Department of Agriculture's National Institute of Food and Agriculture, in conjunction with U.S. Department of Energy Office of Biomass Programs, provides grant funding for projects addressing research, development, and demonstration of biofuels and biobased projects and the methods, practices, and technologies for their production, under the Section 9008 Biomass Research and Development Initiative. The competitive award process focuses on three main technical areas: feedstock development; biofuels and biobased products development; and biofuels development analysis. Eligible applicants are institutions of higher learning, national laboratories, federal research agencies, private sector entities, and nonprofit organizations. The non-federal share of the total project cost must be at least 20%. For more information, see the Biomass Research & Development website. (Reference 7 U.S. Code 8108)
50	Value-Added Producer Grants (VAPG) are available to help independent agricultural producers enter into or expand value-added activities, including innovative uses of agricultural projects, such as biofuels production. Eligible applicants include independent producers, farmer and rancher cooperatives, agricultural producer groups, and majority-controlled producer-based business ventures. Participants may apply for either a planning grant or a working capital grant, but not both. In addition, no more than 10% of program funds may be awarded to majority-controlled producer-based business ventures. Grants are awarded to projects determined to be economically viable and sustainable. For more information about grant eligibility, see the VAPG website and contact the appropriate State Rural Development Office. (Reference 7 U.S. Code 1632a)
51	The Surface Transportation Research, Development, and Deployment (STRDD) program funds activities to promote innovation in transportation infrastructure, services, and operations. A portion of the funding made available to the STRDD program is set aside for the Biobased Transportation Research program to carry out biobased research of national importance at research centers and through the National Biodiesel Board. For more information, see the STRDD Program fact sheet. (Reference 23 U.S. Code 502 and 7 U.S. Code 8109)
52	A cellulosic biofuel producer that is registered with the Internal Revenue Service (IRS) may be eligible for a tax incentive in the amount of up to $1.01 per gallon of cellulosic biofuel that is: sold and used by the purchaser in the purchaser's trade or business to produce a cellulosic biofuel mixture; sold and used by the purchaser as a fuel in a trade or business; sold at retail for use as a motor vehicle fuel; used by the producer in a trade

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	or business to produce a cellulosic biofuel mixture; or used by the producer as a fuel in a trade or business. If the cellulosic biofuel also qualifies for alcohol fuel tax credits, the credit amount is reduced to $0.46 per gallon for biofuel that is ethanol and $0.41 per gallon if the biofuel is not ethanol. Cellulosic biofuel is defined as liquid fuel produced from any lignocellulosic or hemicellulosic matter that is available on a renewable basis, and meets U.S. Environmental Protection Agency fuel and fuel additive registration requirements. Alcohol with a proof of less than 150, fuel with a water or sediment content of more than 4%, and fuel with an ash content of more than 1% are not considered cellulosic biofuels. The incentive is allowed as a credit against the producer's income tax liability. Under current law, only qualified fuel produced in the U.S. between January 1, 2009, and December 31, 2012, for use in the U.S. may be eligible. For more information, see IRS Publication 510 and IRS Forms 637 and 6478, which are available via the IRS website. (Reference Public Law 111-152, Section 1408; Public Law 110-234, Section 15321; and 26 U.S. Code 40)
53	Qualified producers may be eligible for grants of $0.20 for each gallon of ethanol, biodiesel, or renewable diesel, or $0.20 for each MMBtu of renewable methane, produced from renewable resources. The grant is available to registered producers for up to 18 million gallons or MMBtu per fiscal year at any one production facility. (Reference Senate Bill 1303, 2011, and Texas Statutes, Agriculture Code 16.001, 16.002, and 16.006)
54	The biodiesel or ethanol portion of blended fuel containing taxable diesel is exempt from the diesel fuel tax. The biodiesel or ethanol fuel blend must be clearly identified on the retail pump, storage tank, and sales invoice in order to be eligible for the exemption. (Reference Texas Statutes, Tax Code 162.204)
55	An ethanol blender that is registered with the Internal Revenue Service (IRS) may be eligible for a tax incentive in the amount of $0.45 per gallon of pure ethanol (minimum 190 proof) blended with gasoline. Only entitles that have produced and sold or used the qualified mixture as a fuel in their trade or business are eligible for the tax credit. The incentive must first be taken as a credit against the blender's fuel tax liability; any excess over this tax liability may be claimed as a direct payment from the IRS. Under current law, this incentive expires December 31, 2011. For more information, see IRS Publication 510 and IRS Forms 637, 720, 4136, 6478, and 8849, which are available via the IRS website. (Reference H.R. 4853, 2010, Section 708; and 26 U.S. Code 6426)
56	A small ethanol producer that is registered with the Internal Revenue Service (IRS) may be eligible for a tax incentive in the amount of $0.10 per gallon of ethanol that is: sold and used by the purchaser in the purchaser's trade or business to produce an ethanol fuel mixture; sold and used by the purchaser as a fuel in a trade or business; sold at retail for use as a motor vehicle fuel; used by the producer in a trade or business to produce an ethanol fuel mixture; or used by the producer as a fuel in a trade or business. A small producer is one that has, at all times during the tax year, not more than 60 million gallons of productive capacity of any type of alcohol. The incentive applies only to the first 15 million gallons of ethanol produced in a tax year and is allowed as a credit against the producer's income tax liability. Under current law, this incentive expires December 31, 2011. For more information, see IRS Publication 510 and IRS Forms 637 and 6478, which are available via the IRS website. (Reference H.R. 4853, 2010, Section 708; and 26 U.S. Code 40)
57	The Rural Energy for America Program (REAP) provides loan guarantees and grants to agricultural producers and rural small businesses to purchase renewable energy systems or make energy efficiency improvements. Eligible renewable energy systems include flexible fuel pumps, or blender pumps, that dispense intermediate ethanol blends. The maximum loan guarantee is $25 million and the maximum grant funding is 25% of project costs. At least 20% of the grant funds awarded must be for grants of $20,000 or less. (Reference 7 U.S. Code 8107)