Synapse
Energy Economics, Inc.

The Hidden Costs of Electricity:

Comparing the Hidden Costs of Power Generation Fuels

Prepared for the Civil Society Institute

September 19, 2012

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Foreword

This is the fourth report commissioned by the Civil Society Institute in an effort to advance a realistic and sustainable energy policy for the U.S. electricity sector. CSI, with the expertise of Synapse Energy Economics, seeks to examine and make accessible to policy makers and the public the shortcomings of the prevailing, business-as-usual approach advanced by both political parties. We do not have the financial resources, the water and air resources or the time to waste in our national search for practical and actionable steps toward a safe and sustainable energy future.

By summarizing and comparing the full costs (beyond those included in utility bills) of all the major power generation resources, we hope to highlight the costs of the “business as usual” energy path in terms of human health and the safety and integrity of our environment. The findings, thus far, are conclusive: there are no technological or economic barriers to a sustainable electric grid based primarily on efficiency, renewable and distributed resources. Political will is the sole barrier to realizing the economic, public health and environmental benefits of a sustainable energy policy. The public, as demonstrated by over 28 national and state public opinion surveys commissioned by CSI since 2004 (as well as surveys by numerous others), has consistently logged its readiness and support for accelerating energy efficiency and the deployment of clean, renewable energy sources.

The lack of political will is made worse by intense lobbying from the coal, nuclear, natural gas and utility sectors, who feel threatened by the fundamental shift in investment patterns required for true sustainability.

The American public supports precaution and concerted action over politics.

The main impetus behind the “Hidden Costs of Power” report is the Clean Energy Standard (CES) concept supported by both political parties. This inside-the-beltway discussion surrounding the CES is supplanting the Renewable Electricity Standard as a principal public policy vehicle for addressing the electric generation mix in the US.

The CES is a politically driven, “all-in” approach that does not address the simultaneous public needs identified by CSI: affordability, reliability, adequate water availability and water quality, enhanced public health, improved environmental protection, and mitigation of climate change. Under the guise of regional differences, the CES seeks to appease entrenched coal, nuclear and natural gas interests by anointing these resources as “clean” in federal statute. In this case, “clean” means resources that ostensibly reduce carbon dioxide emissions or meet CO_2 emissions thresholds at the point of electric generation. What is ignored are the costs incurred by the public as a result of the entire fuel cycle of these resources, including the myriad emissions, discharges, wastes and health effects generated by the power sector beyond CO_2.

During the course of its exploration into energy policy, CSI has engaged numerous organizations around the country that are dealing with the public health and environmental impacts of mining and fracking operations and costly and polluting power plants. These discussions also led CSI to think more critically about the range of impacts associated with the various energy technologies. For example, applying the term “clean” to natural gas seems less appropriate when taking into account the methods of extraction and emissions from the national pipeline system. Similarly, organizations in the Southeast brought CSI’s attention to unsustainable trends in biomass harvest (e.g., pelletizing whole trees for export) that raise questions about a large-scale shift to biomass for power generation.

The “Hidden Costs of Electricity” report challenges the underlying notion of the CES: that “clean” can be measured by a single emission rate, ignoring land and water impacts and ignoring a technology’s full lifecycle. What the public requires is an honest account of the true costs of electric generation technologies in as accurate a form as possible. CSI hopes that this comparison of lifecycle costs will inform the public dialogue about the direction our energy policy should take. We are firmly convinced that, whatever the resource, it must be deployed in a sustainable manner. Whatever the resource, it must meet the public requirements of affordability, reliability, adequate water availability, enhanced public health, improved environmental protection, and mitigation of climate change.

CSI wishes to thank the staff at Synapse Energy Economics for its expertise and tireless work in researching energy issues. This report would not have been possible without Synapse’s dedicated staff and the expertise they bring to these difficult issues.

CSI also wishes to thank the grassroots organizations across the country that have contributed greatly to our perspective and knowledge and that continue to fight for social and environmental justice on behalf of themselves and future generations.

Grant Smith, Senior Energy Analyst, with CSI has provided critical leadership and intellectual guidance in the development of this report along with colleagues from Synapse. This report would not be possible without him.

Pam Solo
President
Civil Society Institute

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1. Introduction

In the U.S. electric power sector, government policy at the federal, state, and even local level plays an important role in determining what generating resources are built and used to serve load. This role is enacted through state-level resource planning proceedings, and through various kinds of government subsidies and support for different kinds of power projects. The overall goal is to minimize cost while serving all customer needs, complying with environmental laws, and meeting other policy objectives.

Too often left out of this equation are a number of important “hidden” costs, also called “indirect” or “externalized” costs, associated with each generation technology. These include costs to society such as depletion of resources, air and water pollution, detrimental impacts on human health and the environment, and contributions to global climate change. While direct costs (the monetary cost to build and operate a generating plant) are important to consumers, so too are these indirect costs, whether or not they can be easily expressed in monetary terms.

Because of the large and costly role of government in the power sector, it is reasonable to ask whether we as a society are making the best investments to promote our long-term welfare. Figure 1 presents U.S. Department of Energy (DOE) research and development spending for 2012 and 2013.

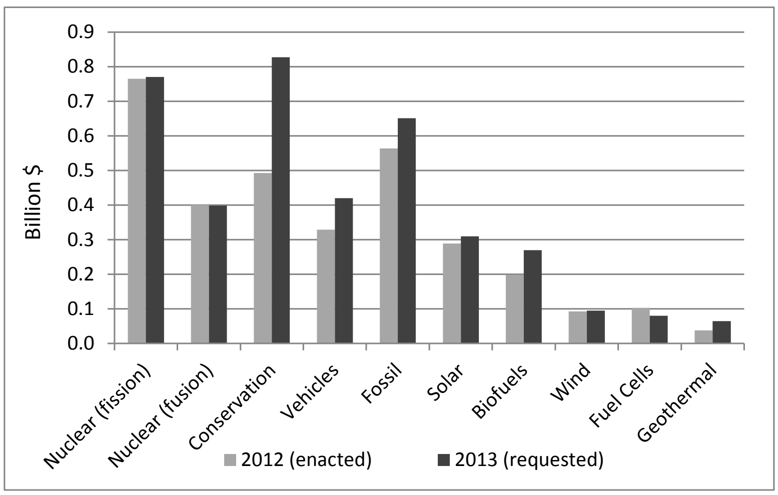

Figure 1. U.S. Department of Energy R&D spending by energy technology (DOE 2012)

This allocation of R&D resources carries an implicit preference for certain resource types over others: nuclear power, energy conservation, and fossil fuels are given strong support, while other power generation fuels receive much less. In this study, we compare many types of government support for these technologies, including both subsidies and externalities (i.e., costs that private industry is allowed to impose on the public without compensation).

The fuels considered here are biomass, coal, nuclear, natural gas, solar (photovoltaic and concentrating solar power), and wind (both onshore and offshore). Although many emerging technologies hold promise, we focus only on currently commercial technologies. Additionally, hydro and geothermal power have been excluded from this study. There is little interest in developing new, large-scale hydro projects, and the expansion of geothermal is also resource-limited (although there may be opportunities for expansion as deep drilling technology improves).

Wherever possible we have relied on cross-cutting work that applies consistent methods and assumptions to different generating fuels and technologies. The National Renewable Energy Laboratory's (NREL) work harmonizing lifecycle greenhouse gas (GHG) estimates is very valuable in this respect. The lifecycle analyses performed under the Environmental Product Declaration® (EPD) are another example. However, in many areas – air pollutants other than GHGs, water and land impacts – little of the existing work is consistent across fuels and technologies, and in some areas, there are few estimates of any kind.

Thus, this report summarizes our first efforts to bring together large and often inconsistent bodies of work. There is more work to be done to refine and harmonize this information. Throughout the paper we indicate where additional primary research is needed and where further analysis of existing work is needed.

2. Summary of Findings

Tables 1 through 7 below compare the hidden costs of the six electricity fuels analyzed in this study. We divide hidden costs into the following categories for comparison:

- Planning and cost risk,
- Subsidies and tax incentives,
- Climate change impacts,
- Air pollution impacts,
- Water impacts,
- Land impacts, and
- Other impacts.

In each table we summarize our conclusions about the relative level of the impacts across technologies by color coding the cells in these tables. Red indicates that the sum of the hidden costs in that category is high. Yellow indicates moderate costs, and green indicates low costs. These judgments are inevitably subjective, as different kinds of impacts must be weighed against each other. We believe that a more robust debate over these valuations is long overdue.

Table 1. Planning and Cost Risk

Biomass	Coal	Nuclear	Natural Gas	Solar	Wind
Typically 3 to 4-year lead time for new units. Up-front costs are in the range of $650 per kW, putting significant money at risk in the event of project cancellation.[1] Many biomass projects are developed by non-utility companies, reducing ratepayer risk. Fuel cost risk is usually significant; this risk is sometimes shifted to customers via a fuel adjustment mechanism.	Typically 5 to 8-year lead time, increasing planning risk relative to plants that can be developed more rapidly. Cost overruns of 50% to 100% have been common in recent years. Up-front costs are moderate – $430 to $530 per kW.[1] Coal-fired plants are usually built by utilities, and cost overruns are often passed on to ratepayers. Also, utilities are often allowed to begin charging customers for new units before the units are completed.	Though none has been completed in the U.S., it appears that new nuclear units will have 6 to 10+ year lead times, creating very high planning risk. Up-front costs are in the range of $960 per kW, leading to significant losses in the event of project cancellation.[1] Cost overruns of 200% to 300% were common in the 1970s and 80s. Cost estimates are escalating again for the projects under development now. Nuclear units are usually built by utilities. Cost overruns are often passed on to ratepayers, and utilities are allowed to begin charging customers for new units before the units are completed.	Typically 3 to 4-year lead time for new units results in low planning risk. Up-front costs are very low – roughly $160 per kW.[1] Many gas projects are developed by non-utility companies, reducing ratepayer risk. The primary risk of gas-fired units is the risk of rising gas prices. Gas prices have been volatile and extremely high during some recent periods.	Distributed PV projects have very short lead times, well under a year for residential projects. The largest projects – several hundred MWs – take 3 to 4 years to complete. Small PV project sizes allow decision makers to respond rapidly to revised load forecasts. CSP projects are larger and more expensive than PV, increasing risk. Solar projects impose no fuel cost risk. Estimated up-front costs for PV range from $470 for large projects to $650 for small. Costs for CSP are $610 per kW.[1] The large land area needed for ground-mounted PV increases the risks of environmental and archeological permitting delays and costs. Most solar projects are being developed by non-utility companies, reducing ratepayer risk.	Typically 3 to 4-year lead time for large onshore projects; smaller projects can be developed more rapidly. Current lead times for offshore projects are long – 5 to 10 years – although lead times are likely to fall as the U.S. industry matures. Up-front costs of onshore projects are very low – roughly $140 per kW – reducing losses in the event of a cancelled project.[1] Up-front costs for offshore projects are high, due to the costs of working at sea. Wind projects impose no fuel cost risk. Most onshore and offshore projects are developed by non-utility companies, reducing ratepayer risk.

[1]As a proxy for "up-front" costs, we compare "owner's costs" estimated by EIA (2010b). These costs include: development costs; preliminary feasibility and engineering studies; environmental studies and permitting; legal fees; project management; interconnection costs; owner's contingency; and insurance and taxes during construction. Many of these costs, though not all of them, are incurred early in project development, and thus are likely to be lost in the event of project cancellation.

Table 2. Subsidies and Tax Incentives

Biomass	Coal	Nuclear	Natural Gas	Solar	Wind
Production Tax Credit: 1.1 – 2.2 ¢/kWh. Accelerated depreciation. Tax credit for Clean Renewable Energy Bonds. Some states have Renewable Portfolio Standards that support biomass plants. DOE R&D funding ($270 million in 2012 for all biomass, including transportation biofuels). Eligible for §1703 and §1705 loan guarantees.	20% Investment Tax Credit for clean coal projects. Tax credit for non-conventional fuels. Accounting treatment of coal royalty payments and certain mining costs. Percentage depletion allowance for mining companies. DOE R&D funding ($368 million in 2012). Eligible for §1703 loan guarantees. $6.5 billion taxpayer bailout of the Abandoned Mine Lands Reclamation Fund. $42 million appropriation to Pennsylvania for Centralia mine fire. Estimated subsidy of $29 billion in below-market coal leases on federal land. Local taxpayers pay for road damage caused by heavy equipment used in mining.	Production Tax Credit: 1.8 ¢/kWh for the first 6 GWs of new nuclear capacity built. Accelerated depreciation. Percentage depletion allowance and no royalty payments for uranium mined on public lands. DOE R&D funding ($1.6 billion in 2012). Eligible for §1703 loan guarantees. Current utility payments for long-term waste storage are not likely to be adequate. The U.S. Government is legally obligated to store waste. Taxpayers are bearing significant costs associated with uranium mining and enrichment. Utility accident liability is capped; taxpayer liability from a major accident could be considerable. Plants pose a unique security risk, and taxpayers have subsidized security.	Foreign royalty payments are often characterized as taxes paid, reducing U.S. tax liability. Tax credit for non-conventional fuels. Percentage depletion allowance for drilling companies. Tax deductions and credits for natural gas vehicles and refueling property. Certain pipelines are eligible for accelerated depreciation. DOE R&D funding ($15 million in 2012). Gas deposits on federal lands are often leased at below market value. Taxpayers have covered some costs of gas field reclamation. Local taxpayers pay for road damage caused by heavy equipment used in drilling.	30% Investment tax Credit for solar projects. Accelerated depreciation. Tax credit for Clean Renewable Energy Bonds. Some states have tax credit and grant programs. Some states have Renewable Portfolio Standards. DOE R&D funding ($289 million in 2012 for all solar programs). Eligible for §1703 and §1705 loan guarantees.	Production Tax Credit: 2.2 ¢/kWh. Accelerated depreciation. Tax credit for Clean Renewable Energy Bonds. Some states have Renewable Portfolio Standards. DOE R&D funding ($93 million in 2012). Eligible for §1703 and §1705 loan guarantees.

Table 3. Climate Change Impacts

Biomass	Coal	Nuclear	Natural Gas	Solar	Wind
Direct CO_2 emissions (from plant operation) are in the range of 1,350 g/kWh. There are additional carbon emissions from fuel harvesting and transportation. Emissions are offset (re-sequestered) by growing biomass; however, recent studies show that this occurs over a long time frame. These studies estimate that it takes between 15 and 40 years for biomass carbon emissions to be equivalent to coal-fired emissions, depending on the biomass fuel type. It takes longer to reach carbon payback relative to gas-fired generation.	**Direct** emissions from existing (subcritical) coal plants are in the range of 1,000 g CO_2-eq/kWh, depending on coal type and plant efficiency. An NREL re-analysis of many studies found **lifecycle** emissions estimates for existing (subcritical) units to range from 880 to 1,270 g CO_2-eq/kWh, with a mean of 1,010 g CO_2-eq/kWh. For new (supercritical) units, the NREL study found **lifecycle** estimates to fall between 730 and 1,010 g CO_2-eq/kWh, with a mean of 790 g CO_2-eq/kWh. This analysis suggests that upstream GHG emissions from coal-fired plants are very small relative to emissions from the plant. However, this analysis if lifecycle emissions did not include the loss of CO_2 sequestered in vegetation removed during mining.	**Direct** emissions (from plant operation) are very low. Major sources of lifecycle emissions are: uranium mining, enrichment and transportation, plant construction and decommissioning. NREL's re-analysis found that estimates of **lifecycle** GHGs range from 3.7 to 110 g CO_2-eq/kWh, with a mean of 18 g CO_2-eq/kWh.	**Direct** emissions from CCCTs typically fall between 350 and 400 g/kWh, depending on the efficiency of the unit. There are additional GHG emissions (methane) from gas drilling, processing and pipeline leakage. Recent studies have found that unconventional drilling ("fracking") releases far more methane than conventional techniques. EPA rules are expected to reduce these emissions considerably by 2015. Estimates of methane losses in processing range from 0 to 0.2%. Estimates of pipeline losses range from 0.4% to 2.4%; however, utilities have measured gas "unaccounted for" at up to 5%. More work is needed to characterize **lifecycle** GHG emissions.	**Direct** emissions from plant operation are negligible. Major sources of lifecycle emissions are: extracting and refining resources; and manufacturing PV panels and "balance of system" components. For PV, NREL's re-analysis found estimates of **lifecycle** GHGs from crystalline silicon panels between 26 and 183 g CO_2-eq/MWh, with a mean of 52 g CO_2-eq/kWh. Estimates for thin film systems ranged from 14 to 38 g CO_2-eq/MWh, with a mean of 23 g CO_2-eq/kWh, but only five studies were reviewed. For lifecycle emissions from tower and trough CSP systems, NREL found a range of 9 to 55 g CO_2-eq/kWh, with a mean of 23 g CO_2-eq/kWh.	**Direct** emissions from plant operation are negligible. Major sources of lifecycle emissions are: extracting and refining resources; production of steel, concrete and composites; construction of supply factories. For both onshore and offshore projects, NREL's re-analysis of **lifecycle** GHG emissions found a range of 3.0 to 45 g CO_2-eq/kWh, with a mean of 15 g CO_2-eq/kWh. The estimates are very similar for onshore and offshore projects. The mean for onshore is 15 g CO_2-eq/kWh, and the mean for offshore is 12.

Table 4. Air Pollution Impacts

Biomass	Coal	Nuclear	Natural Gas	Solar	Wind
Biomass power plants emit significant quantities of NO_X, CO, PM, VOCs, and air toxics. Plants burning waste fuels, often categorized as biomass, can have higher emissions of sulfur and air toxics. This study focuses on plants burning woody biomass only. There are additional emissions from fuel harvest and transport. These emissions, primarily from diesel engines, have not been well characterized per unit of biomass fuel or electricity generated. More work is needed here. Currently, federal air regulations are less stringent for biomass plants than for coal-fired plants, and state emission standards for biomass vary widely.	Coal-fired plants have been the largest U.S. source of SO_2, mercury, arsenic, and acid gases, and one of the largest sources of NO_X, PM and other toxics. **Direct** emission rates (g/kWh) are in the range of: • SO_2: 0.5 – 14 • NO_X: 0.3 – 3.0 • PM: 0.1 – 3.0 • Mercury: 1.5×10^{-6} – 3.0×10^{-5} • HCl: 0.2 • HF: 0.03 Estimates of annual damages from the U.S. coal fleet – not including climate change – range from roughly \$70 to \$190 billion (2010\$). New regulations will reduce these emissions significantly, but coal plants will remain one of the largest sources of air pollution. There are also NOx, PM and toxic emissions from coal mining and transportation. Studies have linked proximity to mining with serious health problems. More work is needed to understand these associations.	**Direct** emissions are very low. Major sources of lifecycle emissions are: uranium mining, enrichment and transportation, plant construction and decommissioning. Based on three analyses of European units, **lifecycle** emission rates (g/kWh) are in the range of: • SO_2: 0.03 – 0.04 • NO_X: 0.03 • PM: 0.02 • VOCs: 5.1×10^{-4} to 5.6×10^{-4} • HCl: 1.7×10^{-4} to 1.8×10^{-4} • HF: 4.8×10^{-5} to 5.2×10^{-5} Low-level emissions of other air pollutants are also reported.	Gas-fired CCCTs emit significant amounts of NO_X and PM, and smaller amounts of CO, VOCs and toxic gases. There are additional emissions from drilling (fugitive emissions from wells and exhaust from diesel equipment) and emissions from gas processing and pipeline operation. Upstream emissions have not been quantified well enough to estimate lifecycle emissions from gas-fired generation. In some regions, gas-field emissions of NO_X and VOCs have been identified as a major source of ozone pollution (smog). New EPA rules are expected to reduce these emissions by 2015.	**Direct** emissions are very low. More work is needed to characterize lifecycle air pollution from both PV and CSP systems. Based on three studies, **lifecycle** air emissions from PV are (in g/kWh): • SO_2: 0.05 – 0.2 • NO_X: 0.1 – 0.4 • $PM_{2.5}$: 0.01 – 0.02 • VOCs: 0.05 – 0.08 Based on one study, lifecycle air emissions from CSP are (in g/kWh): • SO_2: 0.04 – 0.05 • NO_X: 0.05 – 0.16 • PM_{10}: 0.02 – 0.03 • $PM_{2.5}$: 0.02 – 0.03 • VOCs: 0.01 – 0.05 One study of lifecycle cadmium emissions from CdTe PV systems estimates lifetime cadmium emissions at 0.3 g/GWh.	**Direct** emissions are very low. Major sources of lifecycle emissions are: production of steel, concrete and composites; construction of supply factories. An analysis of multiple projects in Europe, including both onshore and offshore projects, produced the following **lifecycle** emission rates (g/kWh): • SO_2: 0.03 • NO_X: 0.03 • PM: 0.02 • VOCs: 1.8×10^{-3} • HCl: 4.5×10^{-4} • HF: 2.9×10^{-4}

Table 5. Water Impacts

Biomass	Coal	Nuclear	Natural Gas	Solar	Wind
Most biomass plants use closed-loop cooling systems with wet towers. These plants typically withdraw 500 to 600 gal/MWh and lose most of this to evaporation. With dry cooling, withdrawals can be less than 100 gal/MWh, however most new biomass plants seek permits for wet cooling towers. For dedicated energy crops, water use for irrigation can be considerable. One study estimates water use for most crops between 40,000 and 100,000 gal/MWh, with some crops exceeding this range. Forest biomass does not require irrigation, but its harvest can affect stream water quality. Many states are drafting new harvesting guidelines to address potential impacts.	Roughly 61% of U.S. coal plants have closed-loop systems, and 39% have open loop. Units with open-loop cooling systems withdraw between 20,000 and 50,000 gal/MWh and lose roughly 300 gal/MWh of this via evaporation. Units with closed-loop systems withdraw between 500 and 600 gal/MWh and lose most of this. Coal mining degrades surface water quality in many ways; acid mine drainage is the largest source of water pollution in some regions. Air emissions from coal plants contribute to the eutrophication of lakes and bays. Liquid effluent from power plants degrades river water quality. Coal waste impoundments pose risks to ground and surface water, and large-scale accidents pose safety and environmental risks.	Roughly 62% of U.S. nuclear plants have closed-loop cooling systems, and 38% have open-loop. Units with open-loop cooling systems withdraw between 20,000 and 60,000 gal/MWh and lose roughly 400 gal/MWh of this via evaporation. Units with closed-loop systems withdraw between 700 and 1,100 gal/MWh and lose most of this to evaporation. Estimates of **lifecycle** water use for three European units range from 2,600 to 6,900 gal/MWh, *not including cooling water use*. Wastewater production ranges from 6.3 to 7.4 gal/MWh. The major lifecycle water impacts are from uranium mining; groundwater contamination has been documented at a number of old uranium mines, and current mining techniques can leave elevated levels of contaminants in ground water.	About 60% of U.S. CCCTs have dry cooling systems, and about 31% have wet cooling towers. Units with dry cooling withdraw water at under 100 gal/MWh and lose 50 to 70 gal/MWh via evaporation. Plants with wet towers withdraw water at a rate of roughly 230 gal/MWh and lose about 180 gal/MWh. Water impacts in the gas fuel cycle are significant but difficult to quantify. Fracking requires between 2 and 10 million gallons of water per well, and has contaminated ground and surface water in a number of documented cases. Gas drilling is not subject to federal water regulation, but EPA recently began investi-gating whether federal regulation is needed. Coalbed methane recovery depletes ground water: one estimate puts total groundwater removed between 1997 and 2006 at 172 billion gallons.	The water impacts of PV plant operation are negligible. One study estimates **lifecycle** water withdrawals for PV to be between 225 and 520 ga/MWh, with thin film at the low end and crystalline silicon at the high end. Cooling water use at CSP plants can be very high. CSP plants with wet cooling systems consume roughly 800 gal/MWh for cooling. Plants with dry cooling use around 80 gal/MWh. One study of **lifecycle** water use at a parabolic trough CSP plant estimates 1,240 gal/MWh with wet cooling and 290 gal/MWh with dry cooling.	The water impacts of plant operation are negligible. Estimates of the **lifecycle** water withdrawals from wind projects, including both onshore and offshore projects, range from 55 to 85 gal/MWh. Construction of offshore wind projects adversely affects marine life; however the majority of these impacts cease with the end of construction. Effects of offshore turbine noise (post-construction) on marine life are being studied. Several studies have found offshore projects to create micro-ecosystems based on the mussels, seaweed and other life that grows on towers and foundations.

Table 6. Land Impacts

Biomass	Coal	Nuclear	Natural Gas	Solar	Wind
NO_X emissions from biomass combustion contribute to soil acidification. While biomass has been responsible for a small portion of total NO_X emissions, this portion could grow. Increased harvest of woody biomass could affect soil quality. Some states are drafting new harvesting guidelines to address potential impacts. Large-scale conversion of U.S. croplands to biomass fuel would likely lead to deforestation outside the U.S. to compensate for the lost cropland. Biomass combustion produces large amounts of ash. Some ash can be used as a soil amendment; other ash must be landfilled.	Emissions of SO_2 and NO_X from coal plants are a major source of soil acidification in the Eastern U.S. Impacts from underground mining include land subsidence, underground fires and safety risks at abandoned mines. Strip mining in the East (mountaintop mining) destroys mature forests, strips topsoil and rock, and fills valleys with debris. Historically, reclamation has involved grass and herb planting. Hundreds of thousands of acres have also been stripped in the Western U.S., and reclamation efforts have only been approved on a small fraction of them.	Based on analyses of three European plants, the lifecycle of a typical nuclear unit would produce between 4.4×10^{-8} and 7.9×10^{-8} m^3/kWh of radioactive waste, not including spent fuel. Lifecycle spent fuel production would be in the range of 5.0×10^{-3} g/kWh for units not reprocessing fuel. Lifecycle production of hazardous waste would be 0.07 to 0.10 g/kWh, and other solid waste would be around 43 g/kWh. Uranium mining has left a legacy of abandoned open-pit mines and contaminated tailings across the West. EPA maintains a database of over 15,000 sites. Long-term remediation is also ongoing at uranium enrichment sites. High-level waste must be stored securely for thousands of years. Land use and property values will likely be affected around long-term waste storage sites.	NO_X emissions from natural gas combustion contribute to soil acidification. Land cleared for drilling reduces and fragments wildlife habitat. Up to 5 acres (20,000 m^2) are cleared per well pad, and waste ponds and roads add to occupied land. Drilling adversely impacts other land uses such as farming, ranching, horse breeding and hunting. In some cases domesticated animals have been killed by exposure to toxins.	Rooftop and building-integrated PV occupies no land. One source estimates land occupied by ground-mounted projects at 24 to 40 m^2/kW, or 0.3 to 1.0 m^2/MWh (lifetime), depending on capacity factor. A different study estimates **lifecycle** PV land use to range from 0.4 m^2/MWh for roof integrated to 5.5 m^2/MWh for ground mounted. Two studies estimate land occupied by trough CSP plants at 0.3 to 0.4 m^2/MWh (lifetime). One of these studies puts that figure for a tower CSP plant at 0.6 m^2/MWh (lifetime). There is concern about impacts on some threatened species' habitat due to large desert solar projects. Developers have been required to relocate animals. Some PV panels include heavy metals. Recycling is required in Europe, but regulations are needed in the U.S.	Wind projects encompass large areas, but most of the land can continue to be used for its prior purpose, typically farming, ranching or wilderness. One study estimates that wind power results in the on-site development of 0.002 m^2/MWh.[2] Most studies of wildlife impacts focus on avian mortality. A 2007 study estimated annual bird mortality from turbines at 100,000 per year, compared to total anthropogenic bird deaths of 100 million to 1 billion annually. Estimates from two other studies put average bird mortality between 0.2 and 2 deaths per GWh. There is more uncertainty around bat mortality, and there is concern about population-level impacts in some regions. At remote sites, roads and towers could affect species sensitive to habitat disruption.

[2] This study counts as "developed" land that becomes a new road, turbine foundation, structure or graded gravel area.

Table 7. Other Impacts

Biomass	Coal	Nuclear	Natural Gas	Solar	Wind
Noise and visual impacts are commonly cited as problems by groups opposing new units. More work is needed to quantify these impacts and compare them across all power plant types. Truck delivery of biomass fuel impacts the surrounding community and may affect property values near a plant.	Noise and visual impacts are commonly cited as problems by groups opposing new units. More work is needed to quantify these impacts and compare them across all power plant types. Coal trains up to two miles long disrupt traffic and deposit coal dust in the communities through which they pass.	Noise and visual impacts are commonly cited as problems by groups opposing new units. More work is needed to quantify these impacts and compare them across all power plant types. Production of enriched uranium presents nuclear weapons proliferation risk. There is evidence of adverse health effects from depleted uranium used in conventional munitions.	Noise and visual impacts are commonly cited as problems by groups opposing new units. More work is needed to quantify these impacts and compare them across all power plant types. Unconventional drilling increases heavy truck traffic significantly. EPA estimates that water deliveries alone can account for over 1,500 truck trips per well.	PV plants are not often opposed on the basis of noise or visual impacts. CSP plants are typically located in remote areas, and thus are rarely opposed on the basis of visual or noise impacts.	Noise and visual impacts are commonly cited as problems by groups opposing new units. More work is needed to quantify these impacts and compare them across all power plant types. Visual impacts are likely to be more significant for wind projects than for other plant types, because turbines are tall, usually spread over a large area and cannot often be hidden behind trees.

3. Biomass

Currently, biomass energy accounts for less than 2% of U.S. power generation; however, policies to promote renewable energy could result in dramatic increases in biomass power generation. The U.S. DOE lists 1,040 MW of biomass generating capacity in various stages of development, and industry databases list well over 100 proposed biomass projects. Notably, the vast majority of these projects are power-only steam plants with energy conversion efficiencies in the range of 25%. In modeling the Clean Energy Standard proposed in the U.S. Senate, EIA estimates that biomass generation would increase by a factor of 16 – from 11 to 176 million MWhs – with nearly all of the growth coming from the co-firing of biomass and coal (EIA 2012).[1]

In addition, another source of biomass demand – the wood pellet industry – has been expanding rapidly in recent years. While wood pellets were once sold primarily in bags for use in wood stoves, bulk sales for large boilers are expanding in response to rising energy costs in the U.S. and renewable energy targets in Europe. One forest products trade group projects demand for wood pellets to exceed 30 million tons per year by 2030 (Berg and Levaglio 2012).

The major hidden costs of biomass power generation are near-term carbon emissions and potential adverse impacts in the areas where biomass is harvested. Cooling water requirements at biomass plants are also an important consideration, although water use is arguably not a hidden cost. Finally, under the current regulatory framework, emissions of certain other air pollutants would be a concern in a high biomass growth scenario, although this concern could be addressed with more stringent air regulations.[2]

While to date, biomass combustion has generally been considered carbon neutral, direct greenhouse gas emissions (emissions from the plant) are roughly 50% higher than from coal combustion. Recent research demonstrates that it takes many years for these emissions to be offset, and in many cases, they are not likely to be offset fully. Given the importance of near-term emission reductions to reduce atmospheric carbon levels, this carbon emission profile raises serious concerns.

Increased harvest rates of forest residues – historically the primary fuel for biomass power plants – pose some risk to water quality, soil and wildlife habitat in forests. However, more troubling questions revolve around what biomass will be harvested once the limited supply of forest residues is under contract. A high biomass growth scenario would entail more extensive harvest of whole trees and the diversion of some timber from pulp markets to energy markets. These dynamics would have environmental and economic implications both within and outside the U.S.

[1] The numbers cited here are for woody biomass burned at large power plants. EIA also predicts robust growth in corn-based power generation, using byproducts of the ethanol production process. The growth in corn-based generation is roughly the same in EIA's "business as usual" case and under the Clean Energy Standard.

[2] More stringent air regulations would internalize air pollution costs that are currently externalized, so consumers would bear these costs directly rather than indirectly.

3.1 Cost and Planning Risks of Biomass Power Plants

Direct-fired biomass generation is a mature technology, using a boiler and steam turbine similar to that in a coal-fired plant. Technologies are also under development for the gasification of biomass, but power plants burning “syngas” have not yet been deployed on a large scale. Biomass power plants tend to be smaller than coal plants and much smaller than nuclear plants, so construction lead times are shorter and the overall investment is smaller. Adding capacity in smaller increments allows a utility or market to track load growth more closely, reducing the risk of load forecasting errors.

In addition, many biomass projects are being developed today by non-utility companies. These companies recover costs through contracts with utilities or sales into competitive power markets; therefore they cannot charge customers for “construction work in progress” or pass construction cost overruns to captive ratepayers. As discussed in the coal and nuclear sections, such cost recovery has been highly controversial recently.

However, fuel cost risk is a critical consideration for biomass projects. Fuel costs are highly region specific, and the addition of one large biomass consumer in a given region can affect prices significantly. In the case of non-utility projects, lenders prefer to see long-term fuel contracts with little room for price increases, and absent such contracts, financing costs are higher. Utilities are often able to pass fuel cost risk to ratepayers via a fuel adjustment mechanism. This brings the cost of capital down, benefitting customers, but it leaves customers with the risk of fuel price increases.

3.2 Subsidies to Biomass Power

In this section we address subsidies – intentional uses of taxpayer dollars to support a private industry. Subsidies take the form of tax breaks and direct payments such as grants. Externalities are addressed in the subsections below. Externalities are costs unintentionally imposed; that is, the government has not explicitly approved the shifting of these costs from industry to consumers. Both subsidies and externalities are hidden costs in that they are not typically included in the cost of electricity from a power plant.

The Environmental Law Institute has published a review of U.S. tax policies that benefit different energy industries (ELI 2009). This study cites three policies that benefit the biomass industry:

- the Production Tax Credit for renewable energy (IRC Section 45);
- Five Year Modified Accelerated Cost Recovery (IRC Section 168(e)(3)(B)); and
- the Tax Credit for Clean Renewable Energy Bonds (IRC Section 54).

In addition to these tax benefits, some states have also established renewable portfolio standards (RPSs) to incentivize the development of renewable energy. These programs require that electricity suppliers obtain a certain percentage of their electricity from eligible renewable resources. The eligible resources differ from one state to another, but biomass energy is eligible for many RPSs.

New biomass power technologies receive federal R&D funding and are eligible for federal loan guarantees. The DOE’s 2012 R&D budget included nearly $200 million for “biomass and biorefinery fuel systems." The 2013 budget request included $270 million (DOE 2012). Biomass projects using emerging technology are eligible for loan guarantees under the Section 1703 program, which supports "innovative clean energy technologies." However no biomass companies or projects have closed federally backed loans to date.

3.3 Climate Change Impacts of Biomass Power

There is a great deal of uncertainty around the overall greenhouse gas impact of bioenergy. The direct emissions per MWh from a biomass-fired power plant are greater than those from a coal-fired plant, because biomass is less energy dense than coal and because biomass-fired plants are less efficient than coal-fired plants. Most electricity-only biomass plants have efficiencies in the range of 25%, while most coal-fired plants are in the range of 30% to 35%, and many gas-fired plants are close to 50% efficient. Manomet (2010) estimates that existing biomass plants emit approximately 1.5 tons of CO_2 per MWh compared to about 1.0 ton of CO_2 per MWh for coal.

However, many carbon reduction policies to date have assumed that burning biomass for energy is carbon neutral. The assumption is either that the carbon would have been released anyway, as the biomass decomposed, or that new plant growth will offset carbon emissions released at the power plant. These rationales ignore two important issues: the timeframe over which emissions occur and potential land use changes induced by the additional biomass demand.

When biomass is harvested and burned, the carbon stored in it is released, resulting in a carbon "debt." The key questions are: is the debt fully repaid, and if so, how long does it take? The answer to these questions depends on the type of biomass harvested, the type of new biomass grown, and potential land use changes resulting from the harvest. Harvesting old growth forests and whole trees results in a larger debt, whereas diverting managed timber to energy production and taking logging remnants or other woody material results in a smaller debt.[3] Regarding land use, if managed forests or land growing food crops are diverted to energy production on a large scale, it creates pressure to bring other land under management to compensate for the lost timber or food supply. The additional land is likely to be cultivated outside the U.S., as there is little land in the U.S. today that is not managed or protected.

A number of recent studies have estimated carbon pay-back periods, based on analysis of these dynamics. Manomet (2010) finds that carbon debts would take more than 40 years to repay relative to coal-fired electricity, when whole trees are burned. This means that a biomass plant would have to operate for more than 40 years before its overall net emissions were equal to a scenario in which the same electricity had been generated using coal. McKechnie et al. (2011) find that carbon debts from burning forest residues are paid back relative to coal after 16 years, while whole tree harvesting requires 38 years to reach a payback. Colnes et al. (2012) estimate that the pay-back period relative to various fossil fuels ranges from 35 to 50 years.

Other recent work has focused on induced changes in land use. Abt et al. (2010) estimate that a biomass co-firing rate of 10% across all coal units in the Southeastern U.S. would result in 20%

[3] A number of different woody fuels are burned in biomass plants. Whole trees are harvested from energy plantations and from forest thinning operations. Logging residues (tops and branches) are another common fuel. Downed wood is also extracted from forests for other reasons, including fire management, recreational use and wildlife habitat.

increases in both pulpwood demand and price in many regions. These changes would add pressure to increase forest rotation rates and divert land into the production of woody biomass. Fargione et al. (2008), Searchinger et al. (2008), Reilly and Paltsev (2007), Elbehri et al. (2008), Lewis (2007) and others explore these issues relating to agricultural land, and many of these papers raise concerns about the effect of biomass energy use in the U.S. on land use abroad. While many of these studies focus on the impact of diverting U.S. corn crops to energy markets, increased demand for woody biomass would create similar dynamics. For example, aggressive renewable energy targets in Europe have recently resulted in the export of U.S. biomass across the Atlantic.

Studies like the ones cited above are beginning to influence policy. In September 2011, EPA released a draft carbon accounting framework to support carbon regulations for stationary sources burning biomass (EPA 2011a). However, EPA's Science Advisory Board found the framework to be too narrowly defined and recommended accounting for impacts across a broader range of carbon sources and sinks. It is not clear how or when EPA will revise this draft framework.

In April of 2012, the State of Massachusetts revised its RPS requirements for biomass power plants (MA DOER 2012). To be eligible for the RPS, the revised rules assign different carbon emission profiles to "thinnings and residues" and require that facility net lifecycle carbon emissions over 20 years are no more than 50% the emissions of a new natural gas facility. This carbon payback requirement, along with plant efficiency provisions, will effectively restrict RPS compliance to combined heat and power plants.[4] The rules also establish a certification program for eligible biomass fuel and annual reporting requirements for power plants.

Many states are also revising forestry management guidelines in response to increasing demand for woody biomass. This is discussed further below.

3.4 Air Impacts of Biomass Power

When thinking about the air emissions from biomass-fired power plants, it is important to define the fuel type clearly. In various U.S. databases and regulations, a range of different fuels are defined as biomass, including waste products such as tires, municipal solid waste (MSW), construction and demolition (C&D) waste and landfill gas. In some cases, plants are permitted to burn both plant matter and waste fuels, and a number of state Renewable Portfolio Standards (RPSs) provide credit to biomass with no specific qualifications for the feedstock source. The costs and benefits of waste incinerators are different from those of plants burning only wood or agricultural residues. Air emissions are more difficult to control from waste incineration, and hazardous emissions can result from the combustion of paints, glues and plastics. Consequently, waste incinerators are subject to more rigorous emission standards than biomass plants. However, waste incineration does reduce the amount of waste going into landfills. It is important for policy makers to consider these issues carefully when deciding whether to incentivize biomass and/or waste incineration. In this review, we focus on power generation using wood or agricultural residues only.

[4] The efficiency provisions grant one-half of a renewable energy credit per MWh to plants operating at 50% efficiency and a full credit at 60% efficiency. Plants operating at an efficiency rate below 50% get no credit.

The primary pollutants of concern with biomass combustion are: particulate matter (PM), nitrogen oxides (NOx), carbon monoxide (CO), and volatile organic compounds (VOCs). Plants burning only wood tend to have relatively low sulfur emissions. Biomass combustion can also emit toxic air pollutants such as hydrochloric acid (HCl), formaldehyde, dioxins/furans, mercury, and arsenic. Plants burning waste fuels can produce different pollutants than those discussed here and/or different levels of the pollutants discussed here, and the growing number of plants seeking to burn C&D and other waste wood have increased concerns about emissions of air toxics.

At plants burning only biomass, emission rates can vary widely due to different fuel sources, boiler types, attention to combustion conditions and the presence and efficacy of emission controls. Generally, emissions limits for PM, NO_X and CO are similar to, or higher than, rates at coal-fired boilers, while SO_2 limits tend to be lower than at coal plants. Larger boilers of all types are subject to federal air regulations, however EPA applies different size thresholds to biomass and coal plants. Biomass boilers with the potential to emit 250 tons per year of a criteria pollutant must meet federal standards, while for coal boilers the limit is 100 tons per year. Thus, many biomass projects do not undergo federal air review. Emission limits for boilers not triggering federal review are set by state air regulators, and the stringency of the resulting permit limits varies widely from state to state, driven by differing state air quality levels and state policy priorities.

In addition to stack emissions of these pollutants, there are air emissions associated with biomass harvest, transport and processing (drying and chipping). Most of this work is done with diesel equipment, and these emissions could be significant. However, we have not seen a detailed analysis of energy use or air emissions associated with the biomass fuel cycle. Pehnt (2006) estimates lifecycle emissions from a number of renewable technologies, including several types of biomass plant; however, he provides little detail on assumptions like the biomass harvesting method or distance to the plant. Weisser (2006) estimates GHG emissions from the biomass fuel cycle but again does not discuss key assumptions. More work is needed to characterize the net energy balance of biomass power generation and the emissions associated with the fuel cycle.

3.5 Water Impacts of Biomass Power

Water Consumption and Withdrawal

As described in the Overview on page 16, all thermal plants require cooling, which is provided by an open- or closed-loop cooling system. Most biomass power plants have closed-loop cooling systems with a wet cooling tower. In these systems, water is lost via evaporation as steam exiting the turbine is cooled and condensed. The Electric Power Research Institute estimates cooling water *consumption* at biomass power plants at 480 gallons per MWh for plants with wet cooling towers (EPRI 2002). This would be an average of 183 million gallons per year for a 50-MW plant operating at an 87% capacity factor. Total *withdrawal* rates (as opposed to water consumption only) would be higher than this: one draft operating permit we reviewed (for a 50 MW plant) included average withdrawal limits of 662 thousand gallons per day and 242 million gallons per year (MA DEP 2008). Ten such plants added in a region would withdraw 2.42 billion gallons of water per year and lose most of this via evaporation. With competition for limited water resources increasing, this is an important aspect of biomass power generation to consider.

Overview: Cooling Water for Power Plants

Thermal power plants require water for cooling. These water cooling systems are either open loop or closed loop. Open-loop systems withdraw water for cooling from a nearby water body and return it at a higher temperature. Closed-loop systems recirculate cooling water through a cooling reservoir or tower. Less water is withdrawn by closed-loop systems than open loop-systems, but more water is consumed (via evaporation).

Open- and closed-loop systems impact water resources in different ways. Open-loop systems impact the waterways from which they withdraw water in several ways. First, fish and other aquatic life are injured and killed at water intake structures. Second, water is returned at a higher temperature, affecting oxygen levels and other important aspects of the ecosystem. While conversion to closed-loop cooling reduces these impacts dramatically, much more water is lost via evaporation in a closed-loop system. In areas of the country where water availability is a concern, conversion to closed-loop cooling will exacerbate the problem.

Air cooling (also known as dry cooling) offers an alternative to water cooling for new plants. While effective in reducing water use, air cooling lowers plant efficiency and requires larger cooling towers, increasing capital costs. The table below shows the breakdown of cooling system types for existing power plants in the U.S.

Prevalence of Cooling Systems at U.S. Power Plants from DOE/NETL (2010)

	Open-Loop	Closed-Loop (reservoir)	Closed-Loop (wet)	Closed-Loop (dry)
Nuclear	38%	18%	44%	0%
Coal	39%	13%	48%	0%
CCCT	9%	2%	31%	59%

To address mounting concerns about the impacts of open-loop cooling systems on aquatic life, EPA initiated a rulemaking under section 316(b) of the Clean Water Act. While not finalized, the rule would require steam plants that use open-loop cooling to reduce adverse impacts, either through enhanced protection at intake structures or by conversion to closed-loop cooling.

Water impacts from the biomass fuel cycle vary significantly based on the fuel. Biomass harvested from forests is irrigated by natural rainfall, and therefore cannot be considered to withdraw water from surface or ground water resources. Some dedicated crops, however, require irrigation using surface or ground water, especially in the Southwestern U.S., where average rainfall levels are lower. Wilson et al. (2012) estimate the water requirements of common energy crops.

Other Water Impacts

While forest biomass does not require irrigation, its harvest can affect water runoff and soil erosion. This in turn impacts river and stream water quality. The effects of logging on soil erosion and water quality have been well documented, and regulations for logging on state and federal lands are designed to minimize adverse impacts.[5] In the case of whole tree harvesting, the concerns and applicable regulations are the same, regardless of whether the trees are sold for lumber or fuel. However the harvest of logging residues or other woody biomass may not be subject to logging guidelines, or the applicability may be ambiguous. Therefore, some states, provinces and European countries are drafting or revising guidelines to address harvest operations other than traditional logging. Most of the new guidelines focus primarily on protecting soil quality and wildlife habitat, but some include measures to protect surface water (Evans 2008; Evans 2010).

3.6 Land Impacts of Biomass Power

As discussed above, the use of biomass for electricity and transportation fuel is likely to grow significantly under current energy policy, while the wood pellet industry also expands rapidly. Other policies under consideration, such as a Clean Energy Standard, could multiply these projected demand levels. This scenario would likely result in significant biomass price increases, more aggressive harvesting of managed land in the U.S., and potentially new harvests from old growth forests outside the U.S.[6] Similarly, shifting U.S. agricultural land to short-rotation fuel crops would create demand for additional agricultural land globally.

Increased harvest of woody biomass could have detrimental effects on soil quality. Harvesting biomass removes nutrients which would otherwise return to the soil through decomposition, and it can also increase nutrient loss through runoff into streams. Over time, soil can become depleted of nutrients like potassium and calcium, reducing plant diversity and lowering timber growth rates. An important factor in nutrient depletion rates is the type of bedrock underlying the forest, as this bedrock can be a significant source of minerals (Farve and Napper 2009). As noted, many states, provinces and countries are responding to increased demand for woody biomass with new guidelines to protect soil quality. These guidelines typically focus on the amount of residue (dead wood) removed; many recommend leaving between 10% and 30% of total residue (dead wood) as well as some large logs for wildlife habitat (Evans 2010).

The revised Massachusetts RPS rules also include limits on the amount of forest residue that can be harvested. On soils classified as “good,” only 75% of residue can be taken, and on soils classified as “poor,” no residues can be taken. It is important to note, however, that these regulations apply only to fuel used by RPS compliant biomass plants.

Ash from biomass impacts land use, because much of it is landfilled – although some ash is used as a soil amendment. Ash from plants burning C&D waste often contains significant levels of contaminants, and even ash from plants burning only biomass can have high levels of metals or other contaminants. Ash from waste incineration is classified as hazardous waste. Booth (2012) reviewed permit information from several plants between 35 and 40 MW in size and found average reported ash production to be in the range of 1 to 2 tons per hour. More work is needed to

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[5] For information on logging impacts and current best practices and regulations, see the U.S. Forest Service website (www.fs.fed.us) and the various state forestry department sites.

[6] Most studies agree that growth in biomass demand will easily outstrip available supplies of forest residues; as it is, many proposed biomass projects plan to use whole trees. Abt, Galik, and Henderson (2010) estimate that, with 10% co-firing of biomass (in coal plants) across the Southeastern U.S., roughly half the biomass fuel could come from forest residues and the other half would come from whole tree harvesting.

better characterize biomass ash production at different plant types, but it appears that a large increase in biomass power generation could easily result in millions of additional tons of ash going to landfills annually.

One promising land use concept is the growth of biomass on abandoned mine land. As discussed in Section 4, there are tens of thousands of acres of abandoned mine land in the U.S.[7] Much of this land has very poor remaining topsoil and is heavily depleted of nutrients, but researchers are experimenting with different soil amendments to determine whether biomass could be grown there cost effectively (Torres 2009). Estimates of potential crop yields from abandoned mine lands appear in Milbrandt (2005).

Increased biomass demand is not likely to have a significant effect overall on wildlife; the mix and distribution of species in the U.S. has been changing in response to logging for many years. Like logging, the removal of downed wood between trees disadvantages some species and benefits others. However, if aggregate demand for biomass increased to the extent that U.S. logging practices became more aggressive, or if protected land were opened for logging, this could affect some species significantly. Still, the major risk biomass generation poses to wildlife is near-term carbon emissions. If the scale of biomass combustion in the U.S. expands at even a fraction of some recent predictions, the near-term carbon emissions will be considerable.

[7] See: http://www.abandonedmines.gov/.

4. Coal

Coal-fired generation currently represents about 30% of the nation's installed capacity, and generates 36% of total electricity in the U.S. However, the rate of coal plant development has slowed over the past two decades. In the 1990s, the emergence of gas-fired, combined-cycle technology – low cost, comparatively clean burning and quick to build – reduced interest in new coal. In the 2000s, development of gas plants continued, environmental concerns intensified, and the cost of new coal plants increased, driven by rising costs for steel and other materials. Most coal-fired units operating today are over 30 years old, and many are over 40. Facing new air and water regulations, owners will have to decide whether to retire or retrofit aging plants.

Still, some new coal-fired projects have been completed in recent years, and several are currently under construction. Moreover, the federal government's current energy strategy is putting millions each year into R&D focused on carbon capture and sequestration (CCS) from coal-fired plants.

4.1 Cost and Planning Risks of Coal Plants

The cost risks of coal projects are significant given the large amounts of capital needed and long lead times. The construction phase takes roughly 4 years – if everything goes smoothly – and pre-construction project development can add several years or more. Further, the "up-front" costs of coal-fired projects (e.g., feasibility, engineering and environmental studies; permitting and legal fees; project management costs) are significant. When projects are cancelled, much of this investment is lost. When projects are delayed, interest on construction loans continues to accrue, as do costs such as insurance and taxes. The U.S. EIA estimates "owner's costs" at $343 million ($530 per kW) for a single 650 MW unit, and $564 million ($430 per kW) for twin units totaling 1,300 MW (EIA 2010b).[8]

Because new coal projects are so expensive and time consuming to build, most are taken on by utilities with regulated ratepayers. As with nuclear plants, utilities are often allowed to begin charging customers for coal plants before the plants are completed and online. Charging customers for "construction work in progress," or "CWIP," has become an increasingly controversial aspect of ratemaking, because it shifts to customers the risk of project delays or cancellation. In contrast, CWIP is rarely an issue for gas, biomass, wind, and solar projects. One reason for this is that a much higher percentage of these projects are developed by independent power companies. These companies recover costs via contracts with utilities or competitive power markets, so they are not able to charge consumers for plants that are under construction or recover cost overruns from consumers.[9] Another reason is that gas, biomass, wind and solar projects are much smaller and more modular, so delays and cost overruns are less common and less costly.

The following recent coal-fired projects illustrate the issues discussed above.

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[8] EIA defines owner's costs as: development costs; preliminary feasibility and engineering studies; environmental studies and permitting; legal fees; project management; interconnection costs; owner's contingency; and insurance and taxes during construction.

[9] Increasingly, utilities are seeking to treat costs such as CWIP with "trackers," such as a fuel adjustment clause, that allow cost recovery to be adjusted outside of rate cases. Trackers can reduce the cost of capital to utilities, but they also shift risk to ratepayers and can reduce the opportunity for external review that comes in rate cases.

- The Prairie State Energy Campus is expected to come online in late 2012 consisting of two 800-MW units. The project took over 10 years to complete, and the final price tag of $4.4 billion was more than twice the original estimate (Hawthorne 2010). Public outrage over the cost escalation finally caused project developers to absorb some of the overrun, capping costs to consumers at $4 billion (PSGC 2010). One of the municipalities with an ownership stake in the plant projected 30% rate increases due to investments in this project and another smaller coal-fired project in Kentucky (Hawthorne 2010).
- Kansas City Power & Light (KCP&L) began developing the Iatan 2 project in 2001. In 2004, the first detailed estimates put total costs at $1.28 billion. The project came online in 2010 at a cost of nearly $2 billion (Drabinski 2010). In 2011 the Kansas Corporation Commission granted KCP&L its fourth rate increase since 2005, for a total rate increase of approximately 30% over this period. If the Commission had granted KCP&L the full rate increase requested, rates would have risen 50% over this period (Everly 2010). The rate increase covered the cost of other smaller projects as well as Iatan 2, but the coal plant was by far the most costly project.
- Duke Energy is currently developing a 618-MW, Integrated Gasification Combined-Cycle (IGCC) plant in Edwardsport, Indiana. The company has highlighted the possibility of adding carbon capture and sequestration equipment to the plant at a later date, and received DOE grant funds to explore this option. When first announced in 2006, the project was projected to cost roughly $2 billion (Bayley and James 2011) and to be online in 2011. In October of 2011 the estimate was revised to $3.3 billion with an online date of late 2012; however, Duke has agreed to cap the costs charged to customers at $2.6 billion. The company estimates that the project will result in a 15% rate increase, which would have been a 22% increase absent the cap (Duke 2012).[10]

The companies that developed these projects are quick to point out that the cost of all baseload power plants increased between 2005 and 2010, driven by increases in the cost of key commodities like steel. While this is true, it also underscores the risks posed by projects that take 6 to 8 years to complete. For example, the 2005 to 2010 time period also included a global financial collapse and recession that reduced electricity demand growth significantly.

4.2 Subsidies to Coal Power

In this section we address subsidies – intentional uses of taxpayer dollars to support a private industry. Subsidies take the form of tax breaks and direct payments such as grants and appropriations from Congress. Externalities are addressed in the subsections below. These are costs unintentionally imposed; that is, the government has not explicitly approved the shifting of these costs from industry to consumers. Both subsidies and externalities are hidden costs in that they are not typically included in the cost of electricity from a power plant.

[10] The Chair of the Indiana Utility Regulatory Commission and a Commission lawyer were fired due to ethics violations occurring in the review of the Edwardsport plant, and several Duke executives were also fired or resigned.

4.2.1 Tax expenditures and foregone revenues

The Environmental Law Institute has published a review of U.S. tax policies that benefit different energy industries (ELI 2009). This study cites the following policies that benefit the coal industry:

- Tax credit for production of nonconventional fuels (IRC Section 45K) – applicable to coal-based synthetic fuels;
- Coal royalty payments can be treated as capital gains rather than ordinary income (IRC Section 631(c));
- Benefit payments to disabled miners are not taxed (30 U.S.C. 922(c));
- Certain alternative fuels are excluded from excise tax (IRC Section 6426(d)) – applicable to liquid coal fuels;
- Fuel excess of percentage over cost depletion (IRC Section 613) – companies can deduct 10% of gross income from coal production;
- 20% investment tax credit for clean coal investments (IRC Section 48A and 48B);
- Special rules for mining reclamation reserves (IRC Section 468) – deductions for early payments into reserve trusts;
- Certain mine safety equipment can be expensed rather than amortized (Section 179E); and
- Extended amortization period for coal pollution control assets (IRC Section 169(d)(5)).

The largest of these subsidies is the tax credit for nonconventional fuels, estimated by ELI (2009) at roughly $2 billion per year between 2002 and 2008. The credit applies to a range of fuels, but the authors note that it primarily benefits coal producers.

A considerable amount of the coal mined from federal lands has been sold by the government at prices below the market value. The leasing policy of the Bureau of Land Management (BLM), the agency responsible for leasing most Western coal tracts, is to estimate the fair market value of the coal and set bidding floors at that value. In 1982, the BLM issued leases for 1.6 billion tons of coal at roughly half of the value recommended by the analysis they had commissioned (Sanzillo 2011). A GAO review and two separate Congressional investigations all concluded that the coal was leased at below-market value – the GAO estimated $100 million below market (GAO 1983). These investigations also stressed the need for more transparency and better oversight of the coal leasing process; however, these changes have not been made (Sanzillo 2011).

4.2.2 Grants and other direct payments

As shown in Figure 1, DOE spending on fossil fuel R&D was in the range of $600 million in 2012 and 2013 (requested). Historically well over half of the fossil energy budget has gone to coal programs, but this percentage has been falling in recent years. For 2012, DOE planned to spend $368 million of the fossil R&D budget on coal programs (DOE 2012).

Two federal programs have also been established to address the environmental and human health effects of the coal industry: the Abandoned Mine Land Reclamation Fund and the Black Lung Disability Trust Fund. These programs are funded by taxes on coal sales. Funds collected for the abandoned mine fund have been sufficient to cover expenditures; however, funding of the black lung fund has been inadequate. By 2008 that fund had borrowed nearly $13 billion including interest. In the Emergency Economic Stabilization Act of 2008, Congress refinanced a portion of this debt with interest-free loans and paid off the remaining $6.5 billion with a one-time appropriation (ELI 2009). Both the foregone interest and the $6.5 billion “bailout” constitute subsidies.

Congress has also made one-time appropriations for coal-industry environmental remediation. The most notable example is a special appropriation to the State of Pennsylvania in response to an underground mine fire that has been burning under the borough of Centralia since 1962. The State has exercised eminent domain over all properties in the borough, and in 1983, Congress contributed $42 million to buy-out and relocate residents (Kiely 1983). Then Governor Thornburgh specifically asked Congress not to use funds from the State’s Abandoned Mine Land Reclamation Fund, arguing that that would bring to a halt other critical remediation work.

Finally, certain coal-fired projects are eligible for §1703 federal loan guarantees. Such guarantees are only a subsidy if there is a default and the government must repay the loan.

4.3 Climate Change Impacts of Coal Power

Coal-fired generation is one of the largest sources of CO_2 in the U.S., emitting approximately 2 billion tons nationwide in 2010 (EPA 2010a). Coal-fired plants emit CO_2 at a rate between 795 and 1,040 g/kWh (1,750 and 2,300 lb/MWh), depending on the type of coal burned and the plant efficiency. While the U.S. has no binding CO_2 regulations, several bills calling for reductions have been proposed in recent years. These bills contemplate economy-wide carbon reductions in the range of 80% from current levels, and the Obama Administration’s initiatives also target 80% emission reductions. Given the cost and difficulty of reducing carbon emissions in areas like transportation and space heating, many analysts believe that the electric power industry will need to achieve reductions *greater* than the economy-wide average reduction. To achieve this, the power industry would either have to phase out coal-fired generation completely or reduce it dramatically and capture and sequester carbon from most of the remaining plants.

Carbon capture and sequestration (CCS) is the focus of considerable R&D work worldwide. Although there are 4 projects operating globally that inject CO_2 into oil and gas fields, CO_2 capture from a power plant has not yet been demonstrated at scale, and questions remain about the cost, safety, and security of long-term geologic storage. Cost estimates for new coal-fired plants with CCS range from about 150% to 200% of a new coal-fired plant without CCS (IEA 2011; IPCC 2005). Operating costs would increase as well, as CCS would reduce overall plant efficiency: estimates of increased coal consumption per unit of energy produced range from 25% to 40% (IEA 2011; Epstein et al. 2011).[11] Retrofits of existing plants are expected to entail higher costs per MW and larger reductions in efficiency (IPCC 2005).

Safety and environmental concerns about long-term geologic storage focus on potential acidification of groundwater, increased underground pressure levels, and leaks of concentrated

[11] IEA (2011) estimates an efficiency reduction of “10 percentage points.” Assuming a 35% efficiency for a plant without CCS, this is a 28% reduction in efficiency.

CO_2 (IPCC 2005). A 2008 study by the GAO cited significant barriers to CCS, including "underdeveloped and costly CO_2 capture technology," regulatory and legal uncertainties (particularly liability from potential CO_2 leakage), and issues relating to current federal air, waste, and other regulations (GAO 2008). An interagency task force established by the Obama Administration also focused on regulatory barriers to CCS, and it laid out a plan to address these barriers, including support for technology development; legal and regulatory clarity and support; and public outreach (ITFCCS 2010).

4.3.1 Lifecycle GHG Emissions from Coal

Coal mining emits GHGs via the release of methane in coal deposits, the release of carbon sequestered in plant matter, and exhaust from the many engines used. After mining, coal is transported to power plants primarily by diesel powered rail.

There are three types of coal mining in the U.S.

- **Underground mining** is the oldest method of coal mining, practiced primarily in the Eastern half of the country. While underground mining continues on a large scale, its share of total U.S. production has been steadily shrinking.
- **Area surface mining** (also known as strip mining) removes coal from shallow deposits. Topsoil and rock are removed with bulldozers and explosives so that enormous excavators can access coal directly. In surface mining, large machinery and fuel reduces labor requirements, reducing costs relative to underground mining. It is the primary method used in the Powder River Basin of Wyoming and Montana, which accounted for 40% of U.S. production in 2007 (NAS 2010a).
- **Mountaintop mining with valley fills** (MTM/VF), also called "mountaintop removal" mining, is a method of surface mining developed in the 1970s in mountainous areas of Kentucky, West Virginia and Virginia.[12] In MTM/VF mining, high elevation forests in Appalachia are clear cut and soil and rock are removed to access coal seams. The soil and rock removed, called mining "spoil," is deposited in adjacent valleys. This type of mining has increasingly come under fire for its considerable environmental impacts.

In all three types of mining, methane is released from coal deposits during extraction, and these emissions have considerable global warming effects, as methane is roughly 25 times more effective at trapping heat in the atmosphere than CO_2 over a 100-year period.

Loss of carbon sequestered in vegetation is greatest at MTM/VF sites, where hundreds of acres of mature deciduous forest are removed. Reclamation efforts typically involve replacement of some soil and grass and herb planting. In a review of the scientific literature, Palmer et al. (2010) report that "many reclaimed areas show little or no regrowth of woody vegetation and minimal carbon sequestration even after 15 years" (p. 149). They further find that after 60 years, carbon sequestration on reclaimed land is still well below that in unmined areas of the same region. In recent years there have been efforts to improve reclamation efforts; for example the Appalachian Regional Reforestation Initiative is advocating a five-step "Forestry Reclamation Approach." However regulations still do not require reforestation efforts.

[12] Many MTM/VF sites encompass both mountain top mining and contour mining in the steep surrounding terrain.

Fox and Campbell (2010) estimate the carbon lost from the removal of vegetation at MTM/VF sites to be between 6 and 6.9 million tons each year. Additional carbon is emitted from disturbed soils and from coal fragments in the mining spoil, although there is more uncertainty around these emissions. Fox and Campbell estimate emissions from soil and spoil to be between 2.6 and 27.5 million tons annually.

Less sequestration capacity is lost when Powder River Basin coal is mined, because the region is more arid and less densely vegetated than Appalachia. However the sheer magnitude of recoverable coal in this region – an estimated 50 billion tons – makes the GHG implications of this mining considerable. Hoping to increase shipments to China, coal companies have been working to establish new export terminals and rail capacity in the Northwest. Given China's appetite for coal, expanded exports could release millions of tons per year of additional carbon, offsetting much hard work to reduce emissions in the U.S.

Finally, surface mining is done with massive, diesel powered trucks, dozers and excavators, all of which emit CO_2 and "black carbon," a type of particulate matter that traps heat in the atmosphere by absorbing heat while airborne and decreasing the reflectivity of snow and ice when it settles on these surfaces. The transportation of coal from mine to boiler is extremely energy intensive and also fueled largely by diesel engines. Coal was moved an estimated 730 billion ton-miles in 2006, a 47% increase from 1996; approximately 71% of these shipments were made via rail, 11% by truck and 10% by barge, mainly on inland waterways (NAS 2010a).

A number of studies have attempted to quantify GHGs from lifecycle of a coal-fired plant, and the scope of these studies (system boundaries), input assumptions and results all vary significantly. Recently, a collaborative effort to review and "harmonize" the results of these studies was published (Whitaker et al. 2012). As part of this research effort, analysts at NREL and other organizations reviewed the lifecycle GHG literature for all of the major power generation technologies.[13] The goal of the work was to identify the assumptions that drive divergent results and normalize those assumptions to reduce the spread across results. As part of the research on coal-fired plants, the authors compared and harmonized 163 different estimates of lifecycle "CO_2 equivalent" (CO_2-eq) emissions. Figure 2 summarizes the results of this analysis for different types of power plant. The vast majority of existing coal plants in the U.S. are subcritical, and most new plants being built are supercritical.

[13] See: http://www.nrel.gov/analysis/sustain_lcah.html

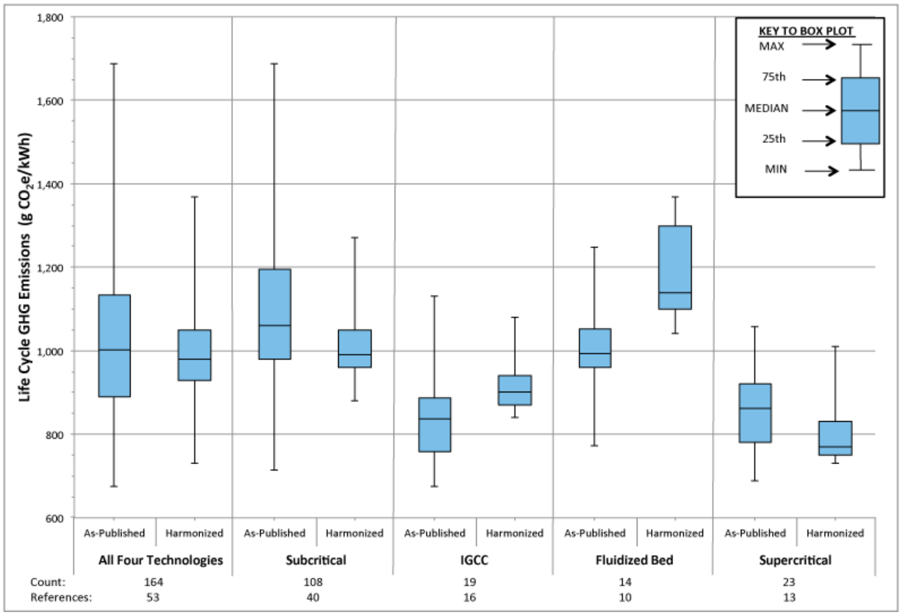


Figure 2. Summary of Lifecycle GHG Emissions from Coal Power Plants from Whitaker et al. (2012)

Based on this analysis, CO_2 emissions from the power plant make up the vast majority of lifecycle GHG emissions from coal-fired generation. The harmonized estimates for subcritical plants fall between 880 to 1,270 g/kWh, with a mean of 1,010 g/kWh. However, it is also important to note that Whitaker et al. do not address the loss of sequestered carbon when vegetation is removed during mining. As discussed above, these losses are likely to be significant in MTM/VF mining. More work is needed to translate estimates of sequestration losses into g CO_2 per ton of coal mined and to include these emissions in lifecycle analyses. This analysis will be complicated by the fact that loss of sequestered carbon is likely to vary significantly based on the mine type and location.

4.4 Air Impacts of Coal Power

Despite significant emission reductions over the past two decades, coal-fired power plants remain one of the largest sources of air pollution in the country.

- Coal-fired plants are the largest source of SO_2, emitting over 5 million tons in 2010, over half of U.S. emissions in that year (EPA 2010a).
- They are also one of the largest sources of NO_X, emitting nearly 2 million tons in 2010 (EPA 2010a).
- They are the largest source of mercury and arsenic emissions in the country, accounting for about 50% and 60% of total emissions, respectively (EPA 2012d).
- They are the largest source of acid gas emissions (such as hydrogen fluoride and hydrogen chloride), accounting for over 70% of total emissions (EPA 2012d).
- They are also a significant source of fine particulate matter ($PM_{2.5}$), the air pollutant with the greatest human health effects.

Overview: Air Pollution from Power Plants

The main air pollutants emitted by power plants are sulfur dioxide (SO_2), nitrogen oxides (NO_X), volatile organic compounds (VOCs), and particulate matter. In addition, plants emit toxic substances (also known as Hazardous Air Pollutants or "HAPs") including mercury and other heavy metals and acid gases. There is a broad body of literature documenting the environmental and human health effects of these pollutants. Much of this literature has been summarized in EPA rulemakings and regulatory impact analyses over the past decade.

SO_2 *is a primary contributor to industrial smog and acid deposition. Smog (or ground-level ozone) can aggravate asthma and existing cardiovascular disease and result in premature mortality in vulnerable populations (Levy et al., 2005; Bell, et al., 2006). Smog also reduces visibility and degrades buildings and other structures. Acid deposition has been found to accelerate the leaching of Long-term studies at the Hubbard Brook experimental forest in New Hampshire have documented significant declines in available calcium and magnesium over the past several decades (Driscoll et al. 2001). Acid deposition also mobilizes soil bound aluminum into groundwater where it is toxic to plants and aquatic life. SO2 is also a source of airborne sulfate particles, fine particles linked to very serious health effects (see below).*

NO_X and VOCs *combine with sunlight to form smog. NO_X is also transformed into fine particulate matter called nitrates which has serious human health impacts. Nitrogen deposited from the air contributes to soil acidification and is the primary source of eutrophication in U.S. lakes and estuaries. Symptoms of eutrophication include dense blooms of phytoplankton and sharply reduced oxygen levels, reducing populations of fish and other aquatic life.*

Coal, gas and biomass power plants emit ***particulate matter*** *in a range of sizes. Large particulate matter reduces visibility and soils cars and buildings near the source power plant. Fine particulate (PM2.5) matter travels much farther and contributes to reduced visibility in scenic areas across the country. However, with PM2.5 the major concern is human health impacts. Fine particulates – smaller than 2.5 microns in diameter – are small enough to bypass our bodies' respiratory filters and embed deep in lung tissue. They have been associated with mortality from both short-term (Daniels et al., 2000) and long-term exposure (Dockery et al., 1993) and various other impacts ranging in severity (Zanobetti et al., 2005). The literature on PM2.5 effects is summarized well by Pope and Dockery (2006). Importantly, this literature shows no threshold below which health effects from PM2.5 are not observed.*

Air toxics *are substances that EPA has determined are reasonably expected to harm human health, the environment or both. They are emitted in much smaller quantities than SO_2 and NO_X; however they have adverse health effects at much lower exposure thresholds. The list of air toxics includes: mercury, lead, arsenic and other metals; acid gases such as hydrogen fluoride and hydrogen chloride; benzene toluene and other compounds; dioxins, furans and formaldehyde; polycyclic aromatic hydrocarbons (PAHs); and radioactive materials like radium and uranium. Many of these substances are known carcinogens. EPA's website provides links to more information (see: http://www.epa.gov/ttn/atw/).*

Table 8 shows ranges that include the emission rates of most U.S. coal plants. The low end of the ranges represents a newer plant with emission controls, and the high end, an older plant without controls. This information is based on 2011 data from EPA's Air Markets Program and AP42 compilation of emission factors.

Table 8. Range of Emission Rates from Coal-Fired Power Plants

	g/kWh
SO_2	0.5 - 14
NO_X	0.3 – 3.0
PM	0.1 – 3.0
Mercury	1.5 $\times 10^{-6}$ – 3.0 $\times 10^{-5}$
HCl	0.2
HF	0.03

As noted in the Overview on page 26, these pollutants contribute to a range of human health problems. Three recent studies have estimated the cost of air pollution from coal-fired power plants. A 2009 study by the National Academy of Sciences (NAS 2010a) estimated the one-year damages from the U.S. coal fleet in 2005 to be $62 billion (in 2007 dollars). The study assessed the damages from criteria pollutant emissions on human health, agriculture, visibility and several other sectors, but did not include potential costs of climate change. Epstein et al. (2012) use much of the same data as NAS (2010a), however they use a different concentration-response curve for $PM_{2.5}$ and estimate the same one-year costs at $187.5 billion (in 2010 dollars). In both of these studies the vast majority of the damages are premature mortality from $PM_{2.5}$. A Clean Air Task Force study estimated the 2010 cost of $PM_{2.5}$ from coal-fired plants at $100 billion (CATF 2010).

Three major regulations recently promulgated or under development will likely reduce current levels of air pollution from coal-fired plants. The Clean Air Visibility Rule is requiring a number of plants that affect visibility in national parks and other natural areas to reduce SO_2 and NO_X. This rule is currently in force, and is impacting plants across the Western U.S. (EPA 2012f). The Cross State Air Pollution Rule (CSAPR) would cap NO_X and SO_2 emissions in 2012 across the eastern half of the country, excluding New England. The rule was written to begin capping emissions in 2012, however it was stayed by the D.C. Circuit Court pending a decision on challenges filed by 45 petitioners, including companies and states. The rule could be upheld, struck down or remanded to EPA for revision. A decision is expected by fall 2012 (EPA 2012g).

The proposed Mercury and Air Toxics Standards rule (MATS) is designed to reduce toxic air emissions from coal- and oil-fired power plants. It would reduce mercury emissions from coal-fired plants by 90% and achieve smaller but still significant reductions in other air toxics. Reductions in SO_2 would also accrue from the controls installed (EPA 2012h). As written, compliance on a large scale would occur around 2015, however this rule too has been challenged in court, with a decision expected in late 2012 or 2013.

It is difficult to predict the health and environmental impacts of power plant air pollution after the current regulatory and legal proceedings processes play out. If MATS is implemented as written, environmental mercury levels and human exposure will fall significantly over time. Health benefits would also accrue from reductions in SO_2 and $PM_{2.5}$. Implementation of CSAPR would provide additional benefits in the form of reduced ozone and $PM_{2.5}$ levels and reduced acid and nitrogen deposition across the Eastern U.S. The effects of the residual emissions would depend on the dose-response relationship of each pollutant and end point. Two facts will make $PM_{2.5}$ a continuing focus of research. First, the health effects of this pollutant make up the vast majority of damages in assessments of current air pollution costs, and second, no lower threshold of health effects – no safe level of exposure – has yet been identified.

4.4.1 Lifecycle Air Pollution from Coal

Air pollution from the coal fuel cycle comes from the engines driving mining equipment, from excavation and blasting, and from the transportation of coal. As discussed, surface mining relies heavily on large diesel engines, which emit NO_X, CO, VOCs, and $PM_{2.5}$. See the Overview on page 26 for a discussion of these pollutants. Excavation and blasting generate coal dust and other particulate matter, and the impacts of these particulates on underground miners' health have been understood for many years. As noted, Congress has established a trust fund to help pay for respiratory disease in miners. There is ongoing debate about whether miners' wages today, along with this fund, adequately compensate them for the health risks they face.

In addition to miners, however, people living near mines also have above-average rates of mortality and disease. Epidemiological studies have associated residential proximity to coal mining with increased rates of cardiac, pulmonary and kidney disease (Hendryx and Ahern 2008; Hendryx and Zullig 2009); birth defects (Ahern et al. 2011); and increased mortality from these same diseases (Hendryx 2009a; Hendryx 2009b). All of these studies control for other factors such as smoking, weight, income, and the availability of health care. The researchers see plausible links between these health effects and particulate matter from mining or toxins released during mining and coal processing. Other research has documented elevated levels of dust containing hazardous substances around surface mining operations (Palmer et al. 2010) and health risks associated with surface impoundments of coal processing and combustion waste (EPA 2007b). More work is needed to identify and address the causes of the observed association between mining and these public health problems.

As noted, transporting coal from mines to power plants produces air emissions, most notably $PM_{2.5}$ from diesel engines. In addition, coal dust coming off open rail cars poses health and safety risks to the communities through which trains pass. While the health effects of occupational exposure to coal dust have been studied extensively, the impacts of exposure to lower levels are less well understood. Given the rate at which coal dust accumulates both indoors and outdoors near rail lines, exposure levels in these areas are clearly not negligible.

4.5 Water Impacts of Coal Power

The coal fuel cycle affects ground and surface water in many ways, posing risks to aquatic life and human health. Power plants use considerable amounts of water for cooling, and they discharge wastewater containing contaminants. Coal mining and coal wastes also impact water in a number of ways.

4.5.1 Water Withdrawal and Consumption

Coal-fired power plants use vast quantities of water for cooling; only nuclear plants use more. Table 9 shows cooling water withdrawal and consumption rates for open- and closed-loop cooling systems at coal-fired power plants. See the Overview on page 16 for a discussion of cooling water use at power plants. The table also shows estimated annual and lifetime water use. About half of U.S. coal plants have open-loop systems and half have closed loop.

Table 9. Cooling Water Use Rates at Coal-Fired Plants from Stillwell et al. (2009)

System Type	Withdrawals (gal/MWh)	Consumption (gal/MWh)
Open Loop	20,000 – 50,000	300
Closed Loop	500 – 600	480

To address mounting concerns about the impacts of open-loop cooling systems on aquatic life, EPA initiated a rulemaking under section 316(b) of the Clean Water Act. While not finalized, the rule would require steam plants that use open-loop cooling to reduce adverse impacts, either through enhanced protection at intake structures or by conversion to closed-loop cooling. Conversion to closed-loop cooling is the most protective of aquatic ecosystems; however conversion is more costly than enhanced intake protection and it typically increases evaporative losses. In the Western U.S., this additional water loss would exacerbate already serious water supply constraints. (Water constraints in the West cause some power plants to use groundwater for cooling.)

Upstream water use – during coal mining, processing and transporting coal – is less well understood than cooling water use. Fthenakis and Kim (2010) cite several older estimates of water use in some upstream processes, but data are not reported for other processes. More work is needed to update these estimates. Wilson et al. (2012) present lifecycle water use estimates for coal-fired generation, with upstream estimates based on Fthenakis and Kim (2010).

4.5.2 Ground and Surface Water Impacts

Coal-fired power generation and the coal fuel cycle affect surface and ground water in four main ways:

- Mining via MTM/VF has significant impacts on watersheds;
- Acid leakage from all types of coal mines – both active and abandoned – is a major source of water pollution;
- Coal-fired plants release wastewater from various processes; and
- Coal processing and combustion waste has contaminated ground and surface water in a number of cases, including several large-scale accidents.

Water impacts of Surface mining

Studies of hydrology and water quality at MTM/VF sites have identified significant adverse impacts. There are obvious impacts when streams are covered with mining spoil, but there are also less obvious impacts on remaining streams and groundwater. The meta-study by Palmer et al. (2010) identifies: a decrease in soil infiltration by rainwater; increased frequency and magnitude of flooding; increased levels of total dissolved solids, sulfates and a range of minerals in stream water; and reduced stream biodiversity. Increased sulfate levels in streams have been linked to decreases in multiple measures of biological health. The authors note that “recovery of biodiversity in mining-waste impacted streams has not been documented, and [sulfate] pollution is known to persist long after mining ceases” (p. 148).

The environmental impacts of Appalachian mining are increased by the importance of these forests as remaining sites of biodiversity. A multi-agency Federal Programmatic Environmental Impact Statement (FPEIS), focused on the potential impacts of MTM/VF mining in Appalachia, notes that “[h]eadwater streams are generally important ecologically because they contain not only diverse invertebrate assemblages, but some unique aquatic species. Headwater streams also provide organic energy that is critical to fish and other aquatic species throughout an entire river” (EPA 2005, p. 3). Consistent with other work, the FPEIS found streams that had been completely covered and found greater flows and higher levels of minerals and sulfates in remaining streams near mining. Epstein et al. (2011) write: “[t]oday’s Appalachian coal mining is undeniably resulting in loss of aquatic species, many of which will never be known” (p. 84).

In addition to streams, effects of mining on groundwater have also been documented. A report by the USGS National Water Quality Assessment Program found water in wells near Appalachian mining sites to have “significantly greater” levels of sulfate, iron, manganese, aluminum, hardness, calcium, magnesium, turbidity and specific conductance[14] than wells in unmined areas (McAuley and Kozar 2006). Hendryx and colleagues note these elevated levels as a possible contributor to the observed human health impacts near coal mining (see Section 4.4.1).

Surface mining in the Northern plains and the West affects ground water significantly, and aquifers in this arid region can take decades to recharge. One measure of the difficulty of restoring ground water is the slow rate of successful reclamation at western mining sites. Reclamation at surface mines is governed by the Surface Mining Control and Reclamation Act of 1977 (SMCRA). This law created the Office of Surface Mining (OSM) within the Department of the Interior, and charged OSM with regulating mining on federal lands, developing minimum standards for state regulating of mining on private and state land and overseeing the implementation of state regulation. In states without approved programs, OSM regulates all mining activity. In an effort to ensure reclamation of mined land and its water resources, regulations in all states require companies to post bonds for sums equal to the estimated cost of reclamation.

Funds held in reclamation bonds are released in three phases. Phase I bond release comes after companies have backfilled and graded sites and replaced topsoil. Phase II release comes after erosion protection measures have been taken and the site has been reseeded. To attain full (Phase III) bond release, companies must meet revegetation standards, restore the productivity of the land to pre-mining levels and restore surface and groundwater quality and quantity (Epstein et al. 2007).

The intent of SMCRA, and of OSM’s regulations, is that mined lands should be reclaimed “contemporaneously,” that is, as new acreage is opened for mining, states should be approving reclamation on a similar amount of mined acreage. However, at surface mining sites in the Western U.S., reclamation has proceeded far slower than this. Between 1995 and 2005, roughly 400,000 acres were disturbed by surface mining in the five major mining states of the Northern plains and West, while Phase III reclamation was approved on only 22,900 acres (Epstein et al. 2007).[15] Thus, over 17 times more land was mined during this period than was reclaimed. This rate of reclamation may be an indication that the true cost of restoring ground water resources

[14] Electrical conductivity relates to the concentration of ions in a water sample. EPA uses conductivity as a measure of stream health and has published guidelines for maximum levels (see: Epstein et al. 2011, p. 84).
[15] The five major mining states in the Western U.S. are Colorado, Montana, New Mexico, North Dakota and Wyoming. The most mining by far is taking place in Wyoming.

may be much higher than the cost estimated for bonding, and mining companies are effectively writing off bonds rather than restoring the resources.

Acid mine drainage

Acid drainage occurs where ore or coal mining exposes sulfur-containing rock to rain or ground water. It can occur at all types of mines, at locations including waste rock piles, tailings, open pits, underground tunnels and leach pads. It can also occur at other large excavation sites, such as highway cuts. The acidic drainage itself impacts water quality, and it can also dissolve heavy metals from rock and carry them into ground and surface water. Impacts on streams can range from moderate loss of biodiversity to completely dead streams, running bright yellow in color (EPA 2012b).

Acid mine drainage is the largest source of water pollution in the heavily mined mid-Atlantic region: EPA estimates that 4,785 stream miles in this region with low pH have been impacted by mining (EPA 2012b). The Office of Surface Mining has estimated that at least $3.8 billion would be needed to remediate all known sites in this region (EPA 2012b).

Wastewater from power plants

Coal-fired power plants release waste water into rivers or settling ponds. This wastewater is the product of various processes, most notably flue-gas desulfurization (FGD), in which water and chemicals are sprayed into flue gas to reduce sulfur emissions. Such systems have been installed on nearly half the nation's coal-fired generating capacity in response to Clean Air Act requirements. However, these systems increase considerably the amount of wastewater produced by a plant; some large plants with FGD systems legally discharge tens of thousands of gallons each day into rivers (Duhigg 2009). The slurry produced by an FGD system includes high levels of many contaminants, including arsenic, barium, aluminum, chromium manganese and nickel. The solid portion of slurry is taken off and deposited in holding ponds (see below), and the remaining water is treated before it is released. Thus, the levels of these contaminants in the wastewater released depend on the plant's treatment system. It is likely that the effectiveness of treatment systems varies widely across power plants.

In response to the widespread adoption of FGD technology (and lawsuits from environmental groups), EPA is planning to draft new rules for power plant wastewater releases. In announcing the rulemaking, EPA stated that it had reviewed "wastewater discharges from power plants and the treatment technologies available" and that this review "demonstrated the need to update the current effluent guidelines" (EPA 2012a). EPA intends to issue a formal notice of rulemaking in November 2012 and take final action by April 2014 (EPA 2012a).

Impacts of coal processing and combustion waste

Most eastern coal is washed, using chemicals and considerable amounts of water, to remove impurities before it is shipped to power plants. This process produces a contaminated slurry that is stored in large impoundments ("slurry ponds") or pumped into old mine shafts. The main contaminants in slurry are heavy metals like arsenic, barium, cadmium and lead. Surface impoundments of coal processing slurry exist at many mining and coal processing sites in the Eastern U.S.

In addition, coal-fired plants produce fly ash, bottom ash, and boiler slag. Along with the solid portion of FGD waste, these byproducts are known as coal combustion residuals (CCR). An estimated 131 million tons of CCR were produced in 2007, of which about 56 million tons were reused for things like cement manufacture, structural fills and embankments (NAS 2010a).[16] CCR that is not recycled remains in a surface impoundment near the plant, or it is dried and landfilled. Typically CCR contains a number of contaminants, including heavy metals and radioactive material (NAS 2010a; USGS 1997). However, to date CCR has been exempted from federal regulation under the Resource Conservation and Recovery Act (RCRA) and has been regulated at the state level.

Over 670 coal processing waste and CCR sites have been identified by EPA, including both surface impoundments and landfills. Of these, 46 have been identified as "high hazard" sites (EPA 2012c). Some of these sites – the most recently constructed – are lined with composite materials, but most of them are either lined with clay or are unlined. During the past several decades, there have been several documented cases of ground or surface water contamination from coal processing or CCR impoundments (EPA 2007b). Further, in 2007 a draft risk assessment for EPA found significant human health risks at clay lined and unlined sites, from contaminants including arsenic, boron, cadmium, lead and thallium. The risk pathways identified include "groundwater to drinking water" and "groundwater to surface water to fish consumption" (EPA 2007b).

In addition to water contamination due to leaching, three major disasters have occurred at surface impoundments.

- In 1972 an impoundment failed at a mine in Logan County, West Virginia. Approximately 132 million gallons of slurry were released, wiping out a number of small mining towns and contaminated waterways.[17] Known today as the Buffalo Creek Flood, the accident killed 125 people, injured 1,100 and left over 4,000 homeless.
- In October of 2000, a slurry impoundment at a mine near Inez, Kentucky failed, releasing over 300 million gallons of coal sludge into nearby rivers, yards and croplands. There were no fatalities, however lawsuits over property damage are ongoing today.
- In December of 2008, an ash impoundment failed at a Tennessee Valley Authority's Kingston power plant in Roane County, Tennessee, releasing over a billion gallons of ash slurry. The slurry flowed into the Clinch and Emory Rivers and covered an estimated 300 acres with up to six feet of sludge.

Researchers from Duke University took periodic surface water and sediment samples over 18 months following the Kingston spill and measured levels of five contaminants. In the months after the cleanup, they found levels of four of the five contaminants to be generally below EPA's "maximum containment level" where there was ample water flow, but higher in areas of restricted

[16] Data companies reported to EIA provides another estimate of annual CCR production. Coal plant operators reported generating from 60 to 260 pounds of waste for each MWh produced (10th and 90th percentile, respectively) in 2008, with an average rate of 135 lbs per MWh. For the same year they reported producing between 11 to 170 lbs of ash waste per MWh from FGD units, with an average rate of 73 lbs per MWh. Applying these average figures to typical U.S. coal-fired generation (1,850 TWhs per year) yields an estimated 114 million metric tons per year of coal ash and 61 million metric tons per year of FGD waste.

[17] For reference, during the Exxon Valdez oil spill, between 11 and 32 million gallons of oil were released.

flow. Most troubling, however, were elevated levels of a potent form of arsenic (arsenite or As^{3+}) throughout the study area, which persisted during the 18-month study period (Ruhl et al. 2010).

EPA is now drafting rules that would regulate CCR under RCRA. The Agency has released two options for public comment, one in which CCR would be regulated as hazardous waste and another in which it would not. The latter approach would likely require impoundments to be retrofitted with composite liners and leachate collection systems. Classifying CCR as hazardous waste would entail additional safety precautions. Not surprisingly, the rulemaking has been delayed for more than a year amid considerable lobbying. A bill designed to preempt EPA by granting states clear authority over CCR passed the Senate in 2011 but did not pass the House.

4.6 Land Impacts of Coal Power

The coal fuel cycle affects land and land use via air emissions and solid waste from both power plants and mining operations.

4.6.1 Land impacts of coal waste

Coal processing slurry and combustion residuals (CCR) are discussed in Section 4.5.2, along with their impacts on ground and surface water. These waste products also affect soil and vegetation. Impoundments and landfills of these waste products cover thousands of acres nationwide, and many of them are not lined, as is required for large municipal landfills. The soil beneath these impoundments is heavily contaminated with heavy metals and radioactive material, and it would require extensive remediation before it could be used for another purpose. Further, the accidental releases of coal waste have contaminated large areas of land around impoundments. The Kingston spill covered roughly 300 acres of land with sludge that was in places six feet deep. Cleanup efforts entail removing the sludge and a portion of the contaminated topsoil and bringing in new topsoil where necessary. At some spills farmers have asserted that the soil brought in was much less fertile than the soil lost.

Finally, the value of property covered in a coal waste spill is likely to remain reduced even after the sludge is removed and structures are repaired.

4.6.2 Effects of Air Pollution on Land

The primary impact of power plant air pollution on land is acidification from the deposition of sulfur and nitrogen. Soil acidification leads to the loss of minerals and nutrients on which plants depend, it mobilizes aluminum and other soil-bound metals that are toxic to plants and aquatic life, and it increases the accumulation of sulfur and nitrogen in the soil. These impacts are discussed further in the Overview on page 26.

4.6.3 Effects of Mining on Land

In 2008 there were more than 1,600 coal mining operations in the U.S. that produced more than 1.18 billion tons of coal (NAS 2010a). Each type of mining affects land and its various inhabitants differently.

Underground Mining

Relative to surface mining, underground mining has the advantage of disturbing less soil and vegetation. However other land impacts are significant, including accident and fire risks and soil contamination.

Several people are killed each year from falls into mine works, underscoring the various safety hazards these sites pose. Tailings and other waste at abandoned mines contaminate soil and water and limit site reuse. The AML Portal, a federal, state and local collaboration, maintains information about the location and hazards of abandoned mines. They note that "[a]bandoned mines generally include a range of mining impacts or features that may pose a threat to water quality, public safety, and/or the environment." (AML 2012)

Land subsidence can occur when sections of underground mines cave in. The result is a sinkhole or trough, which can damage above ground structures and pose various hazards. Several states maintain websites with information on how to report incidents and seek damages.[18]

Fires at underground mines can be very difficult to extinguish. The most notable example is a fire that has burned in a mine below the borough of Centralia, Pennsylvania since 1962, causing the state to, among other actions, exercise eminent domain over all properties in the borough. In addition, Congress allocated over $42 million to buy out and relocate residents (Kiely 1983).

Finally, there are significant occupational hazards associated with structural failures and explosions at underground mines. While underground mining has become safer over time, as a result of evolving regulations and more strict enforcement, higher incidence of respiratory disease and traumatic accidents still make this a high risk occupation. Seventeen U.S. miners died in several different incidents in January 2006, and 29 died at one mine in April 2010. As noted, there is debate about whether miners' wages (and any damages paid to their families) fully compensate them for these risks or whether the risks represent externalized costs.

Area Surface Mining in the West

The large surface mines in the Western U.S. displace other land users for long periods of time. When state and federal land is mined, ranchers who had been grazing cattle on the land must transport the herd to other land or reduce the size of their operations. Hunters are also displaced, increasing crowding on other hunting land. In many cases, land is not reclaimed on a timely basis, and the displacement can last for decades.

Western mining also fragments wildlife habitat and reduces total acreage, and this can have significant impacts on sensitive species. For example, there is concern over the impacts of mining and drilling on the sage grouse. A study commissioned by BLM recommended "accelerated reclamation practices and habitat enhancement" to support the viability of the remaining grouse populations (BLM 2012).

All five of the major mining states in the Northern plains and West (Colorado, Montana, New Mexico, North Dakota and Wyoming) regulate mining at the state level, overseen by the OSM and subject to OSM regulations. However a 2007 review of this regulation, and the rate of land

[18] For example, see the Pennsylvania Department of Environmental Protection's website, at: http://www.dep.state.pa.us/MSI/WhatIsMS.html, accessed May 18, 2012.

reclamation in these states, found ample evidence that regulatory efforts are falling short of the Congressional intent laid out in the SMCRA of 1977 (Epstein et al. 2007). This study found that:

- data released by states and OSM are incomplete and often inconsistent;
- states and OSM are not inspecting mines with the frequency required by law;
- state and OSM budgets have been falling, resulting in reduced staffing levels; and
- land reclamation is not occurring “contemporaneously,” as intended by Congress.

As noted above, for every acre of land reclaimed between 1995 and 2005, more than 17 acres were stripped for mining. This rate of reclamation raises serious questions about the ability of the current bonding requirements to ensure reclamation at all, let alone contemporaneously.

Mountaintop Removal Mining

The impacts of MTM/VF mining on the landscape are dramatic during extraction and persist for decades even where site reclamation has been approved. Many acres of mature forest are removed, and reclamation efforts typically include some soil replacement and planting of grasses and herbs. Reclaimed sites have been found to have lower organic content, lower water infiltration rates and lower nutrient content than pre-mining soils (Palmer et al. 2010). At many reclaimed sites, there is little or no tree growth, and it will be many decades before the soil will be able to support the kind of plant life that was removed.

Mining permits typically require reclamation of the land to “approximate original contour,” but significant leeway appears to be granted in making the approximation and variances are often approved. In some cases 100 feet or more of rock and soil is removed to access the underlying coal. In 2009 the states of Kentucky and West Virginia had approved nearly 2,000 valley fills to dispose of at least 4.9 billion cubic yards of spoil (GAO 2009).

Most analyses of MTM/VF impacts on wildlife focus on aquatic life in affected streams, however loss of forest acreage and fragmentation of habitat zones affect terrestrial wildlife as well. Palmer et al. (2010) note that the deciduous forests in which this mining is taking place “support some of the highest biodiversity in North America, including several endangered species” (p. 148). The FPEIS notes that “[e]cologically, the study area is valuable because of its rich plant life and because it is a suitable habitat for diverse populations of migratory songbirds, mammals and amphibians” (EPA 2005, p. 3).

MTM/VF mining also impacts the surrounding communities in various ways, including increased flooding and erosion; noise, vibrations and dust from blasting; loss of scenic value; effects on property and timber values; and loss of tourism. We have not seen estimates of the economic cost of mining to surrounding communities, though such estimates would be useful. For example, a comparison of the visual, property value and tourism impacts of mining sites and wind energy sites would be informative.

5. Natural Gas

For many years natural gas provided a small percentage of U.S. electricity. This power was generated at plants utilizing boilers and a steam cycle. However the advent of “combined-cycle” technology resulted in a boom in gas power plant construction between 1990 and 2005. With a combined-cycle combustion turbine (CCCT), waste heat from the turbine is used to drive a steam cycle and generate additional electricity. By 2010, gas-fired plants represented about 40% of the nation’s generating capacity, and produced 24% of our electricity (EIA 2011). The latter figure has been increasing since 2010, driven by low gas prices. The vast majority of gas-fired electricity today comes from CCCTs, although some comes from combustion turbines (CTs) without heat recovery equipment, and some still comes from older steam plants.

5.1 Cost and Planning Risks of Natural Gas Power

New CCCTs pose significantly lower planning and cost risk than coal or nuclear projects. This is because CCCTs are less expensive per MW; they are typically smaller (200 – 500 MW); and construction periods are shorter. Total installed costs of CCCTs are typically in the range of $1,100 per kW, or roughly $330 million for a 300 MW plant. Many projects are completed in 3 to 4 years, including initial project development and construction, compared to 5 to 10 years or more for coal and nuclear projects. These shorter lead times allow utilities or markets to track projected load growth more closely, and they reduce interest and other costs during construction. Up-front costs for CCCTs (e.g., feasibility, engineering and environmental studies; permitting and legal fees; project management costs) are also low, meaning that less money is lost in the event of project cancellation. EIA estimates “owner’s costs” at $162 per kW, compared to $430 to $530 for coal and $960 for nuclear (EIA 2010b).[19] Finally, due to the lower risk profile of CCCTs, many of them have been built by non-utility companies. This reduces risk to consumers, because these companies are not able to charge customers for “construction work in progress” or for construction cost overruns.

The primary risk associated with gas-fired power plants is uncertainty around gas prices. Historically, natural gas prices have been volatile, rising during some recent periods to levels nearly 4 times current levels. Prices this high reduce the operating economics of existing gas plants dramatically. Important uncertainties related to the price of natural gas are potential regulations or limits on unconventional drilling, potential regulation of greenhouse gas emissions, and uncertainty around unproven reserves.

5.2 Subsidies to Natural Gas

In this section we address subsidies – intentional uses of taxpayer dollars to support a private industry. Subsidies take the form of tax breaks and direct payments such as grants and appropriations from Congress. Externalities are addressed in the subsections below. These are costs unintentionally imposed; that is, the government has not explicitly approved the shifting of

[19] EIA defines owner’s costs as: development costs; preliminary feasibility and engineering studies; environmental studies and permitting; legal fees; project management; interconnection costs; owner’s contingency; and insurance and taxes during construction.

these costs from industry to consumers. Both subsidies and externalities are hidden costs in that they are not typically included in the cost of electricity from a power plant.

5.2.1 Foregone tax revenues

The Environmental Law Institute has published a review of U.S. tax policies that benefit different energy industries (ELI 2009). This study cites the following policies that benefit the natural gas industry:

- Gas and oil royalty payments to foreign governments can be characterized as foreign taxes paid, reducing a company's U.S. tax liability (IRC Section 901);
- Tax credit for the production of nonconventional fuels (IRC Section 45K) – applicable to gas from geopressurized brine and certain shale formations
- Certain drilling costs can be expensed rather than amortized (IRC Section 617);
- Independent oil and gas producers and royalty owners can deduct 15% of gross income earned from qualifying deposits (IRC Section 613);
- Alternative fuels (including liquefied petroleum gas, compressed natural gas and liquefied natural gas) are exempted from fuel excise taxes (IRC Section 6426(d));
- Tax deduction for clean fossil fuels and refueling property (IRC Section 179A) and tax credit for clean fuel vehicles and refueling property (IRC Section 30C);
- Certain natural gas pipelines are eligible for accelerated depreciation (IRC Section 168(e)(3)(E)(viii)) and certain gathering pipelines can be treated as seven-year property with Alternative Minimum Tax relief (IRC Section 168(e)(3)(C)(iv));
- Natural gas arbitrage exemption (IRC Section 148(b)(4)); and
- Certain geological and geophysical costs are eligible for accelerated depreciation IRC Section 167(h).

5.2.2 Grants and other direct payments

As with coal deposits, the Federal Government has often leased natural gas deposits at below market value, providing a taxpayer-funded subsidy to the gas industry. ELI (2009) notes that Congress has enacted several laws intended to promote drilling in the U.S., which have also reduced revenue from gas leases. Focusing on offshore drilling, the authors cite a GAO review of eight different studies, conducted by Government agencies, private consultants and the oil and gas industry, which all find that the federal offshore leasing program has done a poor job of maximizing revenues in gas leases. The GAO concludes that "the U.S. federal government receives one of the lowest government takes in the world" especially in the Gulf of Mexico (quoted in ELI 2009, p. 13).

Natural gas benefits from less R&D spending than the other technologies examined here. In 2012 DOE allocated $15 million to gas programs, and for 2013 they proposed $17 million (DOE 2012).

Increased heavy truck traffic associated with gas drilling imposes infrastructure costs on towns and counties, in the form of increased road and bridge repair work. While there has been little systematic analysis of these costs, the New York State Department of Transportation recently estimated annual costs between $200 and $300 million to upgrade and repair roads and bridges to accommodate increased truck traffic from fracking activities in the region (Slevin 2011).

Finally, bonds posted by drilling companies are sometimes insufficient to cover the full cost of site reclamation and plugging of exhausted wells, leaving state and federal agencies and private landowners to complete the work. The GAO estimates that from 1988 to 2009 almost $4 million of taxpayer money was spent by BLM to reclaim orphaned oil and gas wells (GAO 2010). This figure does include costs incurred by private landowners.

5.3 Climate Change Impacts of Natural Gas

Natural gas-fired generation is the second largest source of CO_2 in the electric sector (behind coal). In 2010, gas-fired plants emitted approximately 400 million tons of CO_2 (EIA 2011d). Emissions of CO_2 from CCCTs typically fall between 350 and 400 g/kWh, depending on the age and efficiency of the unit. Emission rates at CTs typically fall between 550 and 680 g/kWh.

5.3.1 Lifecycle GHG Emissions from Gas

In addition to emissions from the power plant, there are GHG emissions associated with natural gas extraction, processing, and transport.

Conventional gas drilling has been a known source of methane emissions for many years (EPA/GRI 1996). However, recent analyses by EPA estimate methane emissions for certain aspects of gas production to be as much as 8,000 times greater than previous estimates (EPA 2010b; EPA 2012).

Table 10. Comparison of EPA Emission Factors for Methane from Gas Well Production

Emissions Source Name	EPA/GRI Emissions Factor (1996)	Revised Emissions Factor (2010)	Units
Gas well venting during completions			
Conventional well completions	0.02	0.71	CH4 – metric tons/year per completion
Unconventional well completions	0.02	177	CH4 – metric tons/year per completion
Gas well venting during well workovers			
Conventional well workovers	0.05	0.05	CH4 – metric tons/year per workover
Unconventional well workovers	0.05	177	CH4 – metric tons/year per workover

(Source: EPA 2010b)

This increase in estimated emissions from gas drilling is driven largely by the rapid expansion of unconventional drilling techniques such as high-volume hydraulic fracturing ("fracking"). Fracking involves drilling wells thousands of feet below the surface and adding horizontal sections that can extend thousands of feet more. A mixture of water, sand, and chemical additives ("frack fluid") is then injected at high pressure into the rock formation (shale, tight sands, or coal-bed methane), creating and reopening fractures and releasing the trapped gas. The frack fluid is then drawn back out, during a period known as "flowback," in order to prepare the well for production ("well completion"). A significant amount of methane is brought up during the flowback period and is typically vented to the atmosphere (EPA 2012).

Other recent studies have also concluded that GHG emissions from unconventional gas production are higher than previously thought, although the specific conclusions vary significantly. Hultman et al. (2011) conclude that, overall, electricity generation from shale gas produces 11 percent more GHG emissions than electricity from conventional gas but still less than coal. The study notes that nearly all of the increase in emissions comes from methane released during flowback. Wigley (2011) examined the effect of replacing a portion of coal generation with natural gas (up to 50 percent) on global mean temperature. The study finds that, due in part to increased methane leakage and in part to reduced SO_2 emissions, a substitution of gas for coal actually leads to *increased* global warming for many decades, though the overall temperature difference between the two scenarios is small (less than 0.1 degree Celcius). Wigley concludes that "unless leakage rates for new methane can be kept below 2%, substituting gas for coal is not an effective means for reducing the magnitude of future climate change."

The amount of methane lost in natural gas processing varies widely. Some gas fields produce "pipeline ready" gas for which no processing is required. Other fields produce gas with impurities that must be removed before delivery. The American Petroleum Institute has estimated losses during gas processing at 0.19% (Shires et al. 2009), and EPA has used this figure. At least one study has measured emissions from gas processing at levels up to four times this rate (Chambers 2004).

Finally, additional gas is lost in both the long-distance transmission of gas and local distribution. Kirchgessner et al. (1997) estimate leakage from transmission and distribution at 0.38% to 1.4%. Lelieveld et al. (2005) estimate it at 0.9% to 2.4%. Others have estimated pipeline leakage based on "lost and unaccounted for gas," that is, the difference between gas measured at the wellhead and customers' meters. Estimates calculated this way tend to be higher – in the range of 2.3% to 5.0%; however they can be affected by gas theft, inaccurate meters and other issues.

A set of papers by Howarth, et al. at Cornell University suggest that, given these various upstream methane losses, the use of gas from unconventional wells would have a greater total greenhouse gas footprint than conventional gas, oil, and even coal (Howarth et al. 2011 and 2012). The authors note that it is more appropriate to examine the impacts of methane on a shorter time horizon (20 years) than is commonly used for looking at global warming potential (100 years), because methane has an atmospheric lifetime of only 12 years, meaning its impacts are concentrated in the first 20 years and highly diluted over longer time horizons. When upstream methane losses are taken into account on a twenty-year timescale, Howarth et al. conclude that shale gas has a much larger GHG footprint than other fossil fuels, including coal. In a report requested by the National Climate Assessment, Howarth et al. (2012) summarize current peer-reviewed science on this issue.

All of the above studies emphasize the uncertainty of the data upon which their various methane emission estimates are built. More information is needed on the nature and impact of methane losses from unconventional gas production itself, as well as from the processing, transmission, and distribution of natural gas. Concern over environmental and human health risks, and the need for better information, has been articulated in several recent reports by the Secretary of Energy Advisory Board (SEAB 2011a; SEAB 2011b).

In April 2012, EPA adopted a suite of rules aimed at reducing methane – and VOCs and air toxics, which are discussed below – from oil and gas drilling. The new rules require emission reductions through capture or flaring of fugitive gases until 2015, at which time operators will be required to capture fugitive gases from most types of wells using a process called “reduced-emissions completion,” or green completion. The captured gas must then be made available for use or sale. EPA estimates that green completions can reduce emissions during the natural gas well completion process by 95 percent and that the projected revenues from the sale of the captured gas will offset the costs of the controls to yield a cost savings of $11 to 19 million (EPA 2012). These new rules will not, however, reduce methane emissions from gas processing or pipelines.

5.4 Air Impacts of Natural Gas

Gas-fired CCCTs emit significant amounts of nitrogen oxides (NO_X) and particulate matter (PM), and smaller amounts of CO, VOCs and toxic gases. However, CCCT emission rates are typically lower than at coal fired plants when comparing either existing or new units. For example new coal-fired units with post-combustion emission controls typically have NO_X rates in the range of 0.8 to 1.2 lb/MWh. Gas-fired CCCTs with emission controls have NO_X rates around 0.06 lb/MWh. In 2010, U.S. natural gas plants emitted 141,000 tons of NO_X, compared to roughly 2 million tons from coal-fired plants (EPA 2010a). Emissions of PM from CCCTs are also considerably lower than from coal; however the majority of particulates emitted by natural gas combustion are fine particulates ($PM_{2.5}$), which pose the greatest health risks. See the Overview on page 26 for a discussion of these air pollutants and their effects. A study by the National Academies estimated annual air pollution damages from the U.S. gas fleet in 2005 at nearly $1 billion, stated in 2007 dollars (NAS 2010). This estimate does not include potential effects of climate change.

5.4.1 Lifecycle Air Pollution from Gas

In addition to the methane released during natural gas production, drilling also emits a number of air pollutants, including $PM_{2.5}$, SO_2, NO_X, VOCs and air toxics. Drilling equipment is typically powered by large diesel engines, which emit substantial quantities of $PM_{2.5.}$ Emissions are considerable during the drilling and fracking of deep wells or in large fields where multiple drilling operations occur simultaneously (NAS 2010). Heavy duty diesel trucks must also deliver large quantities of water, sand, and other chemicals for fracking. EPA estimates that water deliveries alone account for 1,660 truck trips per fracking event, leading to significant emissions of diesel air pollutants (EPA 2011c). Pits used as waste repositories for wastewater and other waste materials are also significant sources of air pollution from the volatilization of organic compounds (NAS 2010).

In recent years, regions of the country experiencing rapid growth in natural gas production have seen marked increases in air pollution, particularly ozone-forming pollutants such as NO_X and VOCs. For instance, in the Dallas-Fort Worth area of Texas, where there is significant oil and gas production in the region’s Barnett Shale formation, summer peak emissions of ozone-forming compounds from oil and gas production exceeded even emissions from cars, trucks, and all other forms of on-road mobile sources (Armendariz 2009). In parts of rural Wyoming, Utah, New Mexico, and Colorado, where there are few other sources of air pollution, the natural gas boom has led to high *wintertime* concentrations of ozone – commonly thought of as an urban, summertime air quality problem – with levels exceeding EPA's current health-based limits[20] (Rodriguez et al. 2009).

In a preliminary report on the human health risks of air emissions from unconventional natural gas resources, researchers found that residents living near unconventional gas wells are at greater risk of cancer and other health effects from exposure to air pollutants – especially benzene and other hydrocarbons – and that the highest concentrations of pollutants were observed during the well completion (fracking) process (McKenzie 2012).

As noted, EPA recently promulgated a suite of rules that will reduce VOCs, air toxics, and methane from oil and gas drilling. By 2015, the new rules are expected to reduce emissions of these pollutants by up to 95% at new wells.

5.5 Water Impacts of Natural Gas

5.5.1 Cooling Water Use

Simple-cycle CTs use negligible amounts of water; however CCCTs require water for cooling as part of the steam cycle. Most CCCTs have closed-loop cooling systems using either a wet or dry cooling tower (see the Overview on page 16). Wilson et al. (2012) estimate roughly 60% of existing CCCTs have dry cooling systems, 31% have wet cooling towers and most of the remainder have open-loop systems. Table 11 shows water use rates at CCCTs from Stillwell et al. (2009).

Table 11. Cooling Water Use Rates at Gas-Fired CCCTs

System Type	Withdrawals (gal/MWh)	Consumption (gal/MWh)
Closed Loop (Dry)	<100	50 – 70
Closed Loop (Wet)	230	180

5.5.2 Water Impacts of Gas Drilling

Gas drilling uses considerable amounts of water and has contaminated surface and groundwater in a number of cases. Coalbed methane recovery draws down groundwater levels by large amounts. Notably, gas drilling is not currently regulated under the Clean Water Act or the Safe Drinking Water Act; however, in 2011, EPA launched a large-scale study of the relationship between fracking and drinking water resources. The study will examine lifecycle water use in hydraulic fracturing and identify the factors that may lead to drinking water contamination and human exposure. The results of the study may lead to regulations to protect drinking water resources.

Water Use in Gas Drilling

In 2010, EPA estimated that fracking shale wells can use anywhere from 2 to 10 million gallons of water per well (Kargbo et al. 2010). This water is commonly extracted from on-site surface or groundwater supplies. Such huge water withdrawals raise serious concerns about the impacts on

[20] NOAA website: http://researchmatters.noaa.gov/news/Pages/utah.aspx; see also: http://www.esrl.noaa.gov/news/2009/winter_ozone.html. Accessed June 14, 2012.

ecosystems and drinking water supplies, especially in areas under drought conditions, areas with low seasonal flow, locations with already stressed water supplies, or locations with waters that have sensitive aquatic communities (Kargbo et al. 2010).

Coalbed methane extraction also has significant impacts on groundwater, which is typically pumped out in large quantities to release pressure and access the methane. In the Powder River Basin, such activities have drawn down groundwater levels by as much as 625 feet in some areas, and extracted 172 billion gallons of water from 1997 to 2006 (Clarey et al. 2010). Although the groundwater will eventually be replenished, the recharge rates are often quite slow, and it may take thousands of years for some aquifers to recharge to pre-drilling levels (Bleizeffer 2009). Further, it is costly to treat the water removed from aquifers for use, and therefore little of the it is used. The National Academy of Sciences reports that in Montana and Wyoming over two thirds of water produced from coalbed methane development is not put to productive use (NAS 2010b). In addition coalbed methane development can contaminate aquifers and lead to methane seepage into drinking water wells and under homes, creating significant health hazards.

Groundwater contamination

Groundwater contamination can occur during unconventional gas production as a result of drilling, ruptured well casings, failed cement jobs, or surface spills of fracking fluids or wastewater, which can contain chemical additives and naturally occurring materials such as brines, metals, radionuclides, and hydrocarbons; however, whether the fracking process itself can directly cause groundwater contamination is still a matter of scientific debate (MIT 2011; EPA 2011; Ohio DNR 2008). The following cases are among those in which groundwater contamination due to fracking has been documented.

- In a 1987 report to Congress, EPA concluded that hydraulic fracturing can contaminate drinking water and cited a case in West Virginia where fracking fluids were found in a private water well located just 1,000 feet from the gas well (EPA 1987). In that report, EPA cited sealed settlements with landowners as a significant impediment to further investigation of fracking’s impacts on drinking water resources.
- Recently, EPA released a preliminary study linking fracking to the contamination of several wells in the town of Pavillion, Wyoming, where extensive fracking has taken place (EPA 2011e).
- In 2008 in rural Sublette County, Wyoming, home to one of the largest natural gas fields in the country, the BLM found that several drinking water wells were contaminated with benzene at concentrations up to 1,500 times a safe level (Lustgarten 2008).
- Scientists from Duke University released a report last year documenting what they called “systematic evidence for methane contamination of drinking water wells associated with shale gas extraction” in the Marcellus and Utica shale formations in Pennsylvania and New York (Osborn et al. 2011).
- In 2007, after one home exploded and 19 others had to be evacuated, the Ohio Department of Natural Resources determined that migration of natural gas from a fracked well caused gas to invade the overlying aquifers. The gas was then discharged through

local water wells, ultimately leading to the conditions that caused the explosion (Ohio DNR 2008).

The Natural Resources Defense Council maintains a list of dozens of cases around the country in which fracking is suspected as the cause of drinking water contamination, and EPA is currently conducting a national investigation into whether fracking poses a risk to groundwater resources (NRDC 2012; EPA 2011c).

Surface water contamination

In addition to groundwater contamination, there are significant concerns regarding surface water contamination from the handling and disposal of wastewater produced during fracking as well as from accidents and spills. There are many documented cases of spills, wastewater impoundment pond failures, and inadequate wastewater treatment leading to the contamination of surface waters from unconventional gas wells (Madsen 2011; Lustgarten 2008). This wastewater typically contains fracking fluid chemicals (such as diesel fuel and other toxic compounds), high levels of total dissolved solids, metals, and naturally-occurring radioactive materials (EPA 2012e).

Wastewater from fracking is most often disposed of through underground injection or discharge to treatment facilities, though some producers are recycling and re-using a portion of their wastewater. Underground injection of fracking wastewater raises concerns about groundwater contamination and earthquakes resulting from such injections (Ellsworth 2012; Horton 2012). Discharge to treatment facilities is problematic because these facilities, many of which are publicly-owned treatment works, are not often equipped to treat the kind of contaminants that are present in fracking wastewater (EPA 2012e). In April 2011, the Pennsylvania DEP cited concerns over the increased risk of contamination of public drinking water when it asked gas drillers to stop sending their wastewater to the state's wastewater treatment plants (Maykuth 2011).

At present, no comprehensive set of national standards exists for the disposal of wastewater discharged from natural gas extraction activities. In August of 2011, the DOE's Secretary of Energy Advisory Board made several recommendations intended to protect surface and ground water quality during fracking activities, including disclosure of fracking fluid composition and elimination of diesel fuel as a fracking fluid, background testing of water wells before fracking occurs, measurement, tracking, and public reporting of water stocks throughout the fracking process, and adoption of best practices in well development and construction (SEAB 2011a). While some of these recommendations have been acted on, in its final report, the SEAB expressed concern that inaction on its initial recommendations would lead to "excessive environmental impacts" from shale gas production (SEAB 2011b).

5.6 Land Impacts of Natural Gas

In 2009, the National Academies estimated the land typically occupied by unconventional drilling pads at up to 5 acres per pad (NAS 2010). However pads and waste pits together can exceed this. In order to prepare the drilling site for access roads and well pads, forests must be cleared and earth moved. Lease contracts typically require reclamation, but some contracts do not fully cover reclamation. The BLM oversees reclamation at drilling sites on federal lands, along with the appropriate federal surface management agency or non-federal surface owner. Reclamation typically requires replacement of top soil and native vegetation and restoration of the natural contour of the land. In some areas, such as New York's Broome County, which sits on the Marcellus Shale, a two year monitoring period is required to ensure topsoil thickness, drainage, rock content and crop production (NY DAM 2012).

As with coal mining, bonding is required to ensure that gas companies fulfill reclamation requirements. However bond levels are not based on site-specific estimates of reclamation costs, and there is usually a maximum required bonding level per company, regardless of the number of wells drilled (Kuipers and Associates 2005). This approach to bonding can leave taxpayers and landowners with significant residual cleanup costs. The GAO estimates that from 1988 to 2009 almost $4 million was spent by BLM, using taxpayer funds, to reclaim orphaned oil and gas wells (GAO 2010). This figure does not include costs incurred by private landowners. The GAO reports that the BLM currently holds almost 4,000 bonds, valued at $162 million (GAO 2010).

Gas drilling also affects wildlife populations. A recent University of Montana study on the viability of the Powder River Basin sage-grouse, conducted for the BLM, found an 82% decline in sage grouse population from 2001 to 2005 within areas of expansive coalbed methane production. The sage-grouse requires large, intact expanses of sagebrush, suggesting that with continued development, the viability of the species in northeastern Wyoming could be compromised. Further, the sage-grouse has been identified as an indicator species, one that represents the conservation needs of many other species living in the sagebrush landscape (Taylor et al. 2012).

5.7 Other Impacts of Natural Gas

The development of shale gas is unusual, because it is occurring in populated areas as well as remote ones. These populated areas, primarily in Texas, Pennsylvania and New York, are suburban or rural and have not previously been subject to oil and gas operations (SEAB 2011b). Some residents have tried to stop the drilling, citing adverse impacts such as noise, heavy truck traffic, damage to roads and other infrastructure, reduced real estate values and impacts on hunting and recreation. As noted, heavy duty trucks are required to deliver large quantities of water, sand and chemicals for fracking, with water deliveries alone accounting for well over a thousand truck trips per fracked well (EPA 2011c). Roads and bridges often must be repaired or upgraded as a result of this traffic, at the expense of local taxpayers.

6. Nuclear

Nuclear power generation imposes perhaps the highest hidden costs of the technologies examined here. Nuclear plants pose high risks to electricity ratepayers in the form of very long project lead times and a history of construction cost overruns. Taxpayers have covered significant costs in the development of nuclear technology, and they are legally liable for potentially exorbitant costs associated with long-term waste storage or a major accident. Moreover, the unrecovered environmental and human health costs from an accident, natural disaster or terrorism could dwarf the costs actually paid in damages.

Nuclear power represents approximately 10% of U.S. installed generating capacity and produces nearly 20% of total electricity (EIA 2011). Most U.S. nuclear power plants were built between 1970 and 1988. However, large cost overruns in this generation of nuclear projects, along with increasing public opposition, effectively stopped nuclear power development in the U.S.

6.1 Cost and Planning Risks of Nuclear Plants

The cost overruns that caused the flight from nuclear in the U.S. were dramatic: many units ended up taking years longer to build than expected and costing three times the original estimates or more. Table 12 presents data from the Congressional Budget Office showing the average cost overruns at projects commenced between 1966 and 1977.

Table 12. Cost Overruns at Nuclear Plants 1966-1977 (CBO 2008)

Project Start Year	Number of Units	Utilities' Estimated Cost (billion $)	Actual Cost (billion $)	Overrun (%)
1966-67	11	0.6	1.3	109
1968-69	26	0.7	2.2	194
1970-71	12	0.8	2.9	248
1971-73	7	1.2	3.9	218
1974-75	14	1.3	4.8	281
1976-77	5	1.6	4.4	169
Average	13	0.9	3.3	207

In recent years, several new nuclear projects have been proposed in the U.S. The industry is focused on controlling costs and reducing construction periods with standardized reactor designs and streamlined permitting. However, the experience to date is not promising.

- Progress Energy's two-reactor project in Florida was originally projected to be online by 2016 at a cost of $17 billion. The latest estimate is an online date of 2024 and a cost of $22.5 billion, or roughly $10,000 per kW (Progress Energy 2010).
- In late 2010, Constellation Energy scrapped plans for a new reactor at Calvert Cliffs after finding the terms of a Government loan guarantee unacceptable (Economist 2010).
- The effort to develop two new reactors at the South Texas plant was scrapped in April 2011. The project being developed by NRG and Toshiba, and the disaster at Fukushima was cited as the key reason for the abandoning the project. However, cost escalation had already put the project in a precarious position: cost estimates had risen to $18 billion, or

$6,700 per kW, and another partner, CPS Energy, had already reduced its share from 50% to 7.6%. NRG has written off its $331 million investment in the project (Souder 2011).

- Georgia Power's original (2006) cost estimate for the 2-unit expansion at the Vogtle plant was $14 billion, or roughly $6,400 per kW. The company has not officially revised this estimate since 2006. (Georgia Power experienced cost overruns of approximately 300% on a real-cost basis for the original Vogtle units.)

As with coal projects, utilities can often begin charging ratepayers for a new nuclear plant before it is in service, and in Florida and Georgia, laws have been passed ensuring that utilities can do this. This shifts the risk of project delays or cancellation from utilities to consumers. Customers are already paying for the two new units proposed in Georgia and the four proposed in Florida. One Florida newspaper estimated that ratepayers would pay over $750 million in 2011 alone (Sun Sentinel 2011), despite the fact that Florida Power and Light has said it will *decide in 2014* whether or not to build two of the units. The ratepayer backlash has been significant in these states: a bill to overturn the cost recovery law was introduced in the Florida Senate in February 2012, and although the bill failed, consumer groups are planning to challenge the costs at the State Supreme Court.

6.2 Subsidies to Nuclear Power

Here we address subsidies – intentional uses of taxpayer dollars to support a private industry. Externalities are addressed in the subsections below. Subsidies typically take the form of tax breaks and direct payments such as grants. However the nuclear industry presents unique risks, and taxpayers have been made responsible for a significant portion of these risks. The shifting of risk from private industry to taxpayers is another form of subsidy.

6.2.1 Tax expenditures and foregone revenues

The primary tax incentives for nuclear power are as follows. Other tax incentives may also be available; an exhaustive review of this issue was beyond the scope of this work.

- A production tax credit of 1.8 cents per kWh is available to the first 6,000 MWs of new nuclear capacity built. Each new plant can receive the credit for the first eight years of operation, and the credit is capped at $125 million per plant per year.
- Tax law provides accelerated depreciation for reactors.
- Uranium mining companies can use "percentage-depletion" allowances, reducing taxes paid on uranium mined.
- Federal law requires no royalty payments for the extraction of minerals from public lands.
- Federal tax law and some state codes subsidize reactor decommissioning with reduced tax rates on investment earnings in decommissioning trust funds. Koplow (2011) estimates these provisions to cost taxpayers between $450 million to $1.1 billion per year.

6.2.2 Direct Payments and other cost shifting

Nuclear energy is currently receiving more DOE R&D funding than any other energy technology. In 2012, $1.6 billion went to nuclear programs, including both fission and fusion programs. The

2013 budget request was for roughly $1.5 billion. The next largest amount requested was just over $800 million for energy conservation (DOE 2012).

Socializing the Risks of New Nuclear Plants

In an effort to facilitate the development of new nuclear projects, the Government has shifted project development risks to taxpayers with two mechanisms. First, the Energy Policy Act of 2005 provides “Standby Support” for the first six new nuclear units. This support takes the form of licensing and litigation insurance during project development and construction. Each of the first two plants is eligible for up to $500 million of standby support coverage, and each of the subsequent four plants can receive $250 million of coverage.

Second, new nuclear projects are eligible for federal loan guarantees. This is unprecedented for a mature technology (roughly 100,000 MWs installed today); however, lending institutions have been unwilling to finance a new nuclear project without a guarantee. To date, $18.5 billion has been authorized for nuclear loan guarantees and $4 billion for front-end fuel cycle facilities. Nuclear loan guarantees tend to be for significantly larger amounts than guarantees for other technologies. In 2011 the Vogtle project received the first conditional guarantee of $8.4 billion, more than five times larger than the next largest energy loan guarantee.

Storage of High-Level Radioactive Waste

With the 1982 Nuclear Waste Policy Act, the U.S. Government took responsibility for the long-term storage of high-level waste, agreeing to begin accepting waste from utilities by January, 1988. Not surprisingly, however, the effort to site a long-term storage facility has been protracted and contentious. Yucca Mountain in Nevada was originally designated by law as the only candidate for a geologic repository in the U.S. (NRC 2009, 99); however in 2011, after years of study and investment of over $13 billion, the Government announced its intention to seek alternative sites. Spent nuclear fuel remains stored at nuclear plants, either in pools or dry cask storage. Most nuclear utilities have sued the Government for not taking waste by January, 1988. By mid 2010, the Government had paid over $700 million in settlements (Koplow 2011), and DOE estimates the total liability at $16 billion *if it were to begin taking waste by 2020, the original target for opening Yucca Mountain* (Maremont 2011).

There are two aspects to the subsidization of radioactive waste storage. First, the funds being collected from utilities may not be sufficient to cover the cost of long-term storage, leaving taxpayers to fund the shortfall. Nuclear plant owners pay the Government a fee of 0.1 cent per kWh to fund long-term storage of high-level waste. The account holding these funds and payments from the Department of Defense was valued at over $23 billion at the end of 2009 (Koplow 2011). Whether or not this fund will ultimately cover the design, construction and long-term operation of storage facilities is subject to debate. The DOE’s 2008 cost estimate for building a federal repository and moving existing waste into it was roughly $100 billion (Maremont 2011). Stanford economist Geoffrey Rothwell has estimated that the fee paid by utilities is a third of what it needs to be (Koplow 2011).

The second subsidy of waste storage lies in the fact that the Government will provide long term storage services to the industry on a non-profit basis. Other energy technologies must pay the private sector to handle wastes, including a sufficient return on capital to those private sector companies. The Government will provide long-term waste storage services on, at best, a breakeven basis. Using rates of return for other companies in the nuclear industry, Koplow (2011) estimates that utilities would have to pay an additional $700 million to $1.2 billion per year to a private company providing the same services.

Accident Liability

The 1957 Price-Anderson Act put statutory caps on private liability for nuclear facilities such as reactors, transporters, enrichment facilities, mines and mills. While originally considered a temporary measure, Price-Anderson has been extended repeatedly with only minor increases in required coverage, even though accumulated actuarial data and improved underwriting practices suggest that private insurance would be available for amounts well in excess of the statutory caps (Koplow 2011). Under Price-Anderson, each utility is required to hold liability insurance up to one cap, and in the event of an accident, all reactor owners would contribute to costs in excess of that, up to a second cap. Payments from other companies would be made retrospectively, over a period of roughly seven years after the accident. Total coverage from primary and pooled insurance has been estimated at over $12 billion, or $8.5 billion on a present value basis (Koplow 2011).

In September of 2011, Tokyo Electric Power Company was facing damage claims close to $60 billion related to the Fukushima plant (Inajima and Okada 2011), and in December, a Japanese Government panel reported that total costs could exceed 250 billion (Reuters 2011). In addition, reviewing information from the Insurance Information Institute, Koplow (2011) finds that, since 1991, the costs of each of the ten most costly global disasters have exceeded utilities' Price-Anderson cap of $8.5 billion. Based on these numbers it seems likely that, in the event of a major nuclear accident in the U.S., taxpayers would pay tens of billions.

Power Plant Decommissioning Costs

All power plants will require decommissioning at the end of their useful lives, and because the plants are not producing revenue at this point there is always a risk that the owner will not decommission the site adequately or will abandon it altogether, leaving tax payers to fund any decommissioning that is done. However, decommissioning risk to taxpayers is higher at power plants where decommissioning is costly and complex and/or where hazardous materials are involved. Nuclear plants meet both of these criteria. In addition, many U.S. nuclear units are owned by single-asset, limited liability subsidiaries of larger corporations. While there would certainly be efforts to access a parent company's assets to cover unfunded decommissioning costs, the companies are legally structured to prevent this.

Reflecting the high cost and risks of nuclear decommissioning, nuclear utilities are required to pay into Nuclear Decommissioning Trust (NDT) funds. The adequacy of these funds is a source of ongoing debate. NDT funds may be inadequate where either decommissioning is more costly than expected or funds are lower in value than expected when they are needed.

On the cost side, it is reasonable to expect that there will be a wide range of decommissioning costs across the U.S. nuclear fleet, with costs extremely high at some sites where there is soil contamination or other problems. However, NDTs are based on typical expected decommissioning costs; there is no provision for spreading very high-cost events across the industry. This means that taxpayers would likely be required to fund the balance of decommissioning at very high cost sites.

Regarding NDT fund value, assumptions about future portfolio performance are important. NDTs lost considerably value in 2008, and in 2009 the NRC identified shortfalls at 26 units (Smith 2009). Williams (2007) demonstrates that the adequacy of NDTs depends heavily on portfolio performance assumptions and that more pessimistic assumptions render many funds inadequate to meet average expected costs.

Uranium Mining and Enrichment

As discussed, uranium mining has left thousands of contaminated sites across the Western U.S.; thirty of these sites are on the Superfund National Priorities List. In 1978 the Uranium Mill Tailings Radiation Control Act was signed, charging DOE with surface reclamation of 24 inactive uranium sites and 16 facilities currently licensed by the NRC.

After mining and milling, uranium must be enriched for use in power plants. The first U.S. enrichment facilities were for military purposes. In the mid 1960s these plants were consolidated into the U.S. Uranium Enrichment Enterprise (UEE), a government-owned operation, run out of DOE and serving both commercial and military needs. Government ownership of UEE and the company's close ties to the military resulted in considerable subsidies to U.S. commercial reactors. First, UEE operated on a tax-free, non-profit basis. Second, UEE's prices to utilities were often well below those of enrichment companies in other countries (Koplow 2011), and at times they appear to have been below UEE's cost of production (Montange 1990). Koplow (1993 and 2011) estimates the subsidy provided by UEE to U.S. utilities at between $270 and $1,350 million per year in 2007 dollars.

The terms of UEE privatization in 1998 were extremely favorable for the resulting company and its utility customers. A company called U.S. Enrichment Corporation was created and granted most UEE assets. Liabilities – including most environmental liabilities – remained with the Government. (Koplow (2011) provides a detailed analysis of the privatization deal.) Thus, uranium pricing to utilities today includes the subsidies embedded in the creation and operation of UEE and the shifting of billions in liabilities to the taxpayer in the privatization.

As it turned out, the liabilities at U.S. enrichment sites were considerable. Sites in Oak Ridge, TN, Paducah, KY, and Portsmouth, OH were heavily contaminated. Congress addressed the funding for remediation of these sites in the Energy Policy Act of 1992. This law created a fund into which both utilities and taxpayers would pay, reflecting both commercial and military responsibility for the contaminated enrichment sites. Several estimates of commercial versus military responsibility were proposed, including a 1991 DOE estimate of 50% each. Under heavy industry lobbying, Congress elected to recover roughly a third of the funds from utilities and two-thirds from taxpayers. Over time, it became apparent that the funding provided for in this law would be insufficient by a large margin. During hearings in 2007, James Rispoli, Assistant Secretary for Environmental Management at DOE, estimated the shortfall at $8 to $21 billion (Rispoli 2007).

Nuclear Security

Nuclear power plants and the spent fuel stored at them present perhaps the greatest security risk of any power plant type. Security costs can be shifted to taxpayers in two ways. First, if plant security is inadequate, then utilities avoid certain operating expenses and the public is at risk. Second, if the government provides security measures in addition to the utility's measures, taxpayers bear the cost.

NRC regulations require utilities to be able to defend against a threat level defined as the "design basis threat" (DBT). Utilities maintain armed security teams at all commercial reactors, and the NRC tests readiness with simulated attacks. The DBT was reworked significantly after 9/11; however it does not require the ability to defend against weapons other than hand-held, and the GAO has asserted that the nuclear industry successfully pressured the NRC to exclude from the DBT elements it believed were too costly (GAO 2006). A number of analysts have argued that the public bears significant residual security risks.

Apart from the debate over the DBT, the Government stationed National Guard troops at all nuclear plants for a period of time after 9/11, at taxpayer expense. We have not seen data on the cost of these security efforts.

Finally, the same uranium enrichment process used to serve power plants can produce weapons-grade nuclear materials, and it is virtually impossible to police the flow of information between commercial and potentially military activities. The most notable example of this is the Pakistani scientist A.Q. Khan's sale of nuclear technology and equipment to states including Iran and North Korea. The costs associated with proliferation risk, including more stringent monitoring requirements, increased military expenditures and potential damages from an attack, are difficult to quantify (see, e.g., Koplow 2011; NRC 2009).

6.3 Climate Change Impacts of Nuclear Power

While the generation of electricity in a nuclear plant is largely emission free, there are significant air emissions from the nuclear energy lifecycle. A number of analyses have been published of the GHG emissions from the nuclear power lifecycle, and several of these studies also address other air pollutants. The GHG estimates reported in these studies vary considerably, and this is not surprising, given the number of processes for which data must be obtained or assumptions made. The key drivers of results in nuclear lifecycle analyses are:

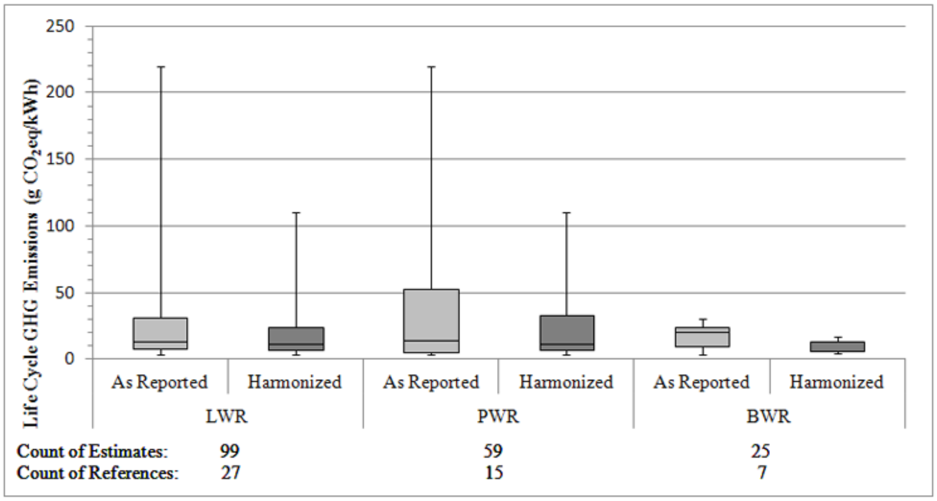
- The system boundaries (i.e., which aspects of the lifecycle are included),
- The methods of uranium mining and enrichment,
- The electricity fuel mix for input processes such as enrichment,
- The distance from uranium mining to power plant,
- The type of reactor,
- Whether spent fuel is recycled, and
- Whether temporary storage of spent fuel is assumed or permanent disposal.

Weisser (2006), Sovacool (2008) and Beerten et al. (2009) provide useful analyses of why selected studies have reached different conclusions.

As part of their LCA harmonization project, NREL reviewed most of the nuclear GHG lifecycle analyses published in English (Warner and Heath 2012). They began with 274 estimates, and screened them for methodological soundness and completeness of data reporting. The screening process left 99 different estimates for light water reactors (a category which includes most reactors operating today). NREL harmonized these estimates, focusing on the global warming potentials used, assumed plant life, capacity factor, thermal efficiency, and assumptions about uranium enrichment and upstream system electricity mix. Key assumptions were normalized to: a plant life of 40 years, a capacity factor of 92% and a thermal efficiency of 33%. Enrichment method and system electricity mix were evaluated as variables.

Vertical lines show minimum and maxim rates, and boxes show the 25th and 75th percentiles.

Figure 3 shows the lifecycle GHG emission rates reported in the studies NREL evaluated. Rates both before and after harmonization are shown. Across all reactor types, harmonized lifecycle GHG emissions range from 3.7 to 110 g $CO_{2\text{-eq}}$/kWh. Mean harmonized values were lower (11 g $CO_{2\text{-eq}}$/kWh) for boiling water reactors (BWR) and higher (22 g $CO_{2\text{-eq}}$/kWh) for pressurized water reactors (PWR).



Vertical lines show minimum and maxim rates, and boxes show the 25th and 75th percentiles.

Figure 3. Harmonization of Nuclear Lifecycle GHG Analysis (from Warner and Heath 2012).

6.4 Air Impacts of Nuclear Power

We found three estimates of other (non-CO_2) air emissions from the nuclear lifecycle, shown in Table 13. These studies were performed by European utilities to produce information for disclosure to customers. The British Energy study (2009) focused on the Torness plant in Scotland; Vatenfall (2010a) focused on the Forsmark plant in Sweden; and Vattenfall (2010c) focused on the Ringhals plant, also in Sweden. These studies are highly rigorous and address impacts from all stages of the nuclear power lifecycle.

These studies make different assumptions about various parameters – different from the normalized assumptions in the NREL study discussed above and different from each other. These assumptions are shown in Table 13 along with the reported lifecycle emission rates and tons of each pollutant.

Table 13. Comparison of Lifecycle Emissions Estimates for Nuclear Power

	Units	British Energy (2009)	Vattenfall (2010a)	Vattenfall (2010c)
Plant		Torness	Forsmark	Ringhals
Size	MW	1,250	3,138	3,707
Plant Life	Years	40	50	50
Capacity Factor	%	85%	83%	77%
SO_2	g/kWh	0.04	0.03	0.04
NO_X	g/kWh	0.03	0.03	0.03
PM	g/kWh	not reported	0.02	0.02
Cadmium	g/kWh	9.7×10^{-7}	7.4×10^{-7}	7.4×10^{-7}
VOCs	g/kWh	not reported	5.1×10^{-4}	5.6×10^{-4}
HCl	g/kWh	not reported	1.7×10^{-4}	1.8×10^{-4}
HF	g/kWh	not reported	4.8×10^{-5}	5.2×10^{-5}

Each of the studies also reports lower level emissions of other pollutants such as ground-level ozone precursors, lead, mercury and arsenic.

6.5 Water Impacts of Nuclear Power

6.5.1 Water Withdrawals and Consumption

Nuclear power has more critical cooling requirements than other thermal technologies, and consumes significantly more water. Table 14 shows ranges of cooling water withdrawal and consumption at nuclear plants with different cooling systems. For more information on cooling systems, see the Overview on page 16.

Table 14. Cooling Water Use Rates at Nuclear Plants from Stillwell et al. (2009)

System Type	Withdrawals (gal/MWh)	Consumption (gal/MWh)
Open Loop	20,000 – 60,000	400
Closed Loop	700 – 1,100	720

6.5.2 Lifecycle Water Use Estimates

The best estimates of upstream water use from nuclear generation are from British Energy (2009), Vattenfall (2010a) and Vattenfall (2010c). These studies estimate lifecycle water use, *not including cooling water withdrawals or consumption*. Water impacts per MWh generated are shown in Table 15, along with key parameters that differ among these plants.

Table 15. Estimates of Lifecycle Water Use at Nuclear Plants

	Units	British Energy (2009)	Vattenfall (2010a)	Vattenfall (2010c)
Plant		Torness	Forsmark	Ringhals
Plant Size (MW)	MW	1,250	3,138	3,707
Plant Life	Years	40	50	50
Capacity Factor	%	85%	83%	77%
Water Use	gal/MWh	6,900	2,600	3,200
Wastewater	gal/MWh	not reported	6.3	7.4

6.5.3 Ground and Surface Water Contamination

Today, most uranium in the U.S. is mined using an *in situ* process in which chemicals are injected into a porous aquifer and the uranium is pumped out in solution. While *in situ* mining is environmentally preferable to traditional mining and milling, the aquifer's water quality is compromised and remediation efforts are needed to return the aquifer to "class-of-use" conditions. The NRC requires mining companies post bonds to cover the cost of restoring aquifers, and it monitors compliance, ultimately determining when remediation efforts can cease.

Typical remediation efforts involve first pumping ground water out of the mined area and allowing the area to refill with water from adjacent rock. This is usually done multiple times. Water removed from the aquifer is either pumped into a deep disposal well or allowed to evaporate from settling ponds (Davis and Curtis 2007). Finally, the water remaining in the mined area is filtered and chemicals are added to adjust pH levels. Davis and Curtis (2007) reviewed data from two restoration projects approved by the NRC and found significant changes from baseline water quality including elevated concentrations of arsenic, selenium, radium, uranium, molybdenum and vanadium. They conclude that:

> Long-term trends in concentrations of these elements are important in establishing whether the groundwater restoration activities have been adequate to ensure the stability of the aquifer water quality and the class of use required by regulatory authorities. (p. 23)

It is not clear whether mining companies could be held liable for longer term water quality at sites where the NRC has approved the remediation.

6.6 Land Impacts of Nuclear Power

As discussed above, uranium mining and processing has left a legacy of environmental damage across the Western states. Until recently, uranium was mined by extracting ore with explosives and transporting it to mills where it was washed in a chemical bath to extract the uranium. The waste ore, along with the process chemicals and any other contaminants present in the ore, were permanently stored onsite in tailing impoundments. From 1944 to 1986 an estimated 3.9 million tons of uranium ore was unearthed across the Western U.S. (Pasternak 2006). In many cases companies abandoned mines when they were finished, often leaving vast open pits and unmarked tailings. EPA maintains a database of approximately 15,000 contaminated sites (EPA 2012i).

Elevated cancer rates have been documented among miners, and other health effects have been documented in people living near mines and processing facilities.[21] Cancer rates on the Navajo reservation, home to hundreds of abandoned mines and four processing mills, rose sharply between 1970 and 1990, and in some areas, unmarked tailings were inadvertently used for concrete in home construction (Pasternak 2006; DOE 2008). In 2008, DOE and several other agencies finalized a 5-year plan to clean up the Navajo sites posing the highest risks (DOE 2008).

[21] Early uranium mining took a heavy toll on miners. A U.S. Public Health Service study in 1960 found the rate of lung cancer among uranium miners to be four to five times the national average for white men. In 1967, the Department of Labor established the first air quality standards (targeting radon) for uranium mines. See also literature collected at: http://www.wise-uranium.org/uhr.html.

6.6.1 Radioactive Waste

As discussed above, spent fuel and high-level radioactive waste will need to be secured from accidents, natural disasters and terrorism for thousands of years. The U.S. Government is legally obligated to secure high-level waste; however work has not begun on a geologic repository, and waste remains stored at nuclear plants.

The radioactivity of medium and low-level waste can range from very high to just above background levels. Less radioactive material is often stored onsite until it can be disposed of in an ordinary landfill. Power plant operators are allowed store low-level waste onsite in buildings with special shielding. More radioactive material is shipped to one of two active depositories, located in South Carolina and Washington State. Four other U.S. depositories exist but are no longer accepting waste. Waste is transported in DOT approved trucks to these facilities, where it is buried under several feet of soil.

Table 16 shows the estimates from British Energy and Vattenfall of radioactive waste produced in the nuclear lifecycle. One major difference between the two studies is the assumption that spent fuel from British Energy's plant is reprocessed while fuel from Vattenfall's is not. This is a key driver of the large difference in spent fuel volume, although there may be other drivers as well.

Table 16. Estimates of Lifecycle Radioactive Waste Production

	Units	British Energy (2009)	Vattenfall (2010a)	Vattenfall (2010c)
Plant		Torness	Forsmark	Ringhals
Plant Size	MW	1,250	3,138	3,707
Plant Life	Years	40	50	50
Capacity Factor	%	85%	83%	77%
Spent Fuel		Reprocessed	Stored	Stored
High-Level Waste	m^3/kWh	8.4×10^{-11}	7.0×10^{-9}	7.0×10^{-9}
Medium-Level Waste	m^3/kWh	2.1×10^{-8}	2.7×10^{-9}	7.0×10^{-10}
Low-Level Waste	m^3/kWh	5.8×10^{-8}	5.2×10^{-9}	1.9×10^{-8}
Demolition Waste	m^3/kWh	not reported	2.9×10^{-8}	2.1×10^{-8}
Spent Fuel	m^3/kWh	1.4×10^{-9}	not reported	not reported
Spent Fuel	g/kWh	not reported	5.4×10^{-3}	4.6×10^{-3}

It is not clear whether British Energy is ignoring demolition waste or including it in one of the other categories.

6.6.2 Solid Waste

Table 17 shows Vattenfall's two estimate of other solid waste production over the nuclear lifecycle. British Energy's study does not provide these numbers.

Table 17. Solid Waste from the Nuclear Lifecycle (g/kWh)

Waste Type	Vattenfall (2010a)	Vattenfall (2010c)
Waste to recycling	0.97	0.99
Waste to landfill	41	46
Waste to incineration	0.06	0.08
Hazardous Waste	0.07	0.10

6.7 Other Impacts of Nuclear Power

The U.S. military uses depleted uranium, a byproduct of the enrichment process, in conventional munitions, improving these weapons' ability to penetrate armor and concrete. However, these weapons may leave enough radioactivity in war zones to put civilians at risk. One of the first careful studies of this, focused on cancer, infant mortality and birth sex ratio in the Iraqi town of Fallujah, found that "[w]hilst the results seem to qualitatively support the existence of serious mutation-related health effects in Fallujah, owing to the structural problems associated with surveys of this kind, care should be exercised in interpreting the findings quantitatively." (Busby et al. 2010). If a link between depleted uranium shells and civilian cancer rates is established, it would raise difficult questions about the safety of U.S. soldiers versus the safety of civilians in war zones.

7. Solar Power

This section focuses on both photovoltaic (PV) and concentrating solar power (CSP) plants, which together represent less than 1% of total U.S. generating capacity today.[22] All PV cells use a semiconductor to convert solar energy directly into electricity. The dominant cell technology today is crystalline silicon; however "thin film" technologies are gaining market share, including cells using amorphous silicon technology (a-Si), cadmium telluride (CdTe) and copper indium gallium selinide (CIGS).

Aggressive subsidies for PV in Europe during the past several years have led to significant growth in PV module production capacity. Today, these subsidies are being reduced, leaving surplus capacity and very low prices for PV modules. Pushing prices down ever further, many Chinese panel manufacturers have been selling panels at prices below cost to capture market share. As a result of these dynamics, the current installed costs of PV systems are at all-time lows; however the PV supply sector is undergoing significant consolidation and it is not clear where installed costs will go from here.

CSP plants use mirrors to focus sunlight onto a working fluid, and they generate electricity using a traditional steam cycle. Parabolic trough systems use line-focusing, parabolic mirrors to concentrate sunlight onto a tube containing the working fluid. The fluid is circulated to the power block, where steam is generated and used in a Rankine cycle, as in a typical coal-fired plant. Another CSP system, the power tower, uses an array of ground mounted mirrors to direct sunlight onto a working fluid housed in a central tower. Systems using dish-shaped concentrators are also under development; however we focus here on trough and tower systems.

Over the past decade, the cost of CSP capacity has been high relative to other technologies, but several companies are developing new project designs that they hope will bring costs down. Roughly 8,700 MW of new CSP capacity is currently under development in the Southwestern U.S. (Kearney and Morse 2010).

Like wind energy, PV energy is dependent on a fluctuating resource and cannot be dispatched at will. This gives PV less capacity value than dispatchable resources. However, PV can be sited on rooftops close to the point of use, avoiding all transmission and some distribution costs. In contrast, CSP plants can store energy thermally – as heat in the working fluid. Storage allows a CSP plant to continue generating energy into the evening hours, when the sun is setting but demand is still high. However, CSP plants require strong, direct sunlight and occupy large areas. Therefore they rely on transmission lines to deliver energy to load centers.

7.1 Cost and Planning Risks of Solar Plants

Cost and planning risk are quite low for PV systems. Distributed PV projects range in size from several kWs to several MWs, and small projects take as little as several months to complete. Megawatt-scale projects can take several years to complete, and the largest "utility-scale" projects appear to be taking roughly four years to complete. Smaller PV projects allow decision makers – be they utilities, homeowners or power capital markets – to respond very quickly to fluctuations in load growth.

[22] CSP is also known as solar thermal power.

For larger projects, up-front costs per kW are significant: EIA estimates "owner's costs" of $650 per kW for a 7-MW project and $470 per kW for a 150-MW project (EIA 2010b).[23] Much of this money would be at risk in the event of project cancellation. However, most PV projects today are developed by either non-utility developers or home or building owners. Non-utility companies recover costs through contracts with utilities or sales into competitive power markets; therefore they cannot charge customers for "construction work in progress" or pass construction cost overruns to captive ratepayers. As discussed in the coal and nuclear sections, such cost recovery has been highly controversial recently.

For ground-mounted PV projects, the large land area needed exposes projects to higher risks of environmental and archeological permitting delays. Analysts at FitchRatings report considerable permitting and construction delays at several projects "caused by concerns about the displacement of, or impact on, wildlife such as kit foxes and desert tortoises, and the discovery of artifacts from earlier civilizations" (FitchRatings 2012).

The cost and planning risk of CSP plants are higher than those of PV plants. CSP Plants tend to be larger – 15 MW to over 100 MW – requiring significant amounts of capital. Publicly available cost estimates are in the range of $4,000 to $6,000 per kW (EIA 2010b; E3 Analytics 2011; Lazard 2010; Black & Veatch 2011), putting the cost of a 100-MW plant between $400 and $600 million. Up-front costs are also high: EIA estimates owner's costs at $610 per kW (EIA 2010b). However, like PV projects, U.S. CSP projects are being developed by non-utility companies, insulating consumers somewhat from escalating costs and project delays.

7.2 Subsidies to Solar Power

In this section we address subsidies – intentional uses of taxpayer dollars to support a private industry. Subsidies take the form of tax breaks and direct payments such as grants and appropriations from Congress. Externalities are addressed in the subsections below. Both subsidies and externalities are hidden costs in that they are not typically included in the cost of electricity from a power plant.

The Environmental Law Institute (ELI 2009) cites the following tax policies that benefit the solar industry:

- Investment Tax Credit for companies investing in solar projects (IRC Section 48),
- Five Year Modified Accelerated Cost Recovery (IRC Section 168(e)(3)(B)); and
- Tax Credit for Clean Renewable Energy Bonds (IRC Section 54).

In addition to these tax policies, many states provide grants or tax credits to property owners who install PV systems. Some states have also established renewable portfolio standards (RPSs) to incentivize the development of renewable energy. These programs require that electricity suppliers obtain a certain percentage of their electricity from eligible renewable resources. The

[23] EIA defines owner's costs as: development costs; preliminary feasibility and engineering studies; environmental studies and permitting; legal fees; project management; interconnection costs; owner's contingency; and insurance and taxes during construction.

eligible resources differ from one state to another, but PV energy is eligible for the vast majority of RPSs.

Other subsidies to the solar industry include R&D spending and loan guarantees. In 2012 DOE R&D spending on solar energy was $289 million, and the amount requested for 2013 was $310 million (DOE 2012). Solar companies and projects are also eligible for §1703 and §1705 federal loan guarantees.

7.3 Climate Change Impacts of Solar Power

Virtually all GHG emissions from a PV plant occur prior to operation, during materials extraction and processing, component manufacture and plant construction. Decommissioning emissions are small relative to upstream emissions. The majority of GHG emissions are also upstream for CSP plants, but emissions from plant operation are not negligible. First, CSP plants use significant amounts of auxiliary energy to prevent fluids from freezing and for other processes. Second, some CSP plants – hybrid plants – supplement the solar energy captured with natural gas-fired generation.

Key drivers of lifecycle GHG emissions from PV systems include:

- Location (which drives "irradiance," or kWh/m^2/year),
- System lifetime,
- Mounting type (e.g., ground mounted, flat roof, sloped roof, façade),
- Upstream electricity fuel mix,
- Performance ratio, and
- PV cell efficiency.

Longer system lifetimes tend to reduce lifecycle emission rates, as upstream emission are spread over more energy. Ground and flat roof mounted systems tend to produce more energy also, due to optimal tilt. Systems mounted on sloped roofs and facades produce less energy. The upstream electricity fuel mix refers to the fuels and power plant types that provide electricity for cell manufacture and other upstream processes. Performance ratio adjusts panel output from optimal temperature and other conditions to real world conditions.

Key drivers of lifecycle GHG emissions from CHP systems include:

- Location (which drives irradiation),
- Plant lifetime,
- Use of natural gas for additional generation,
- Auxiliary energy use,
- Upstream electricity grid fuel mix, and
- Energy storage capability.

Storage capability affects emissions, as it requires a larger plant, increasing upstream energy requirements, but also increases annual energy production.

As part of its meta-study of lifecycle GHG emissions, NREL and its collaborators have screened the literature and summarized the results of the most recent and rigorous studies of solar generation. For PV, it is especially important to focus on recent studies, as both manufacturing techniques and materials used have changed significantly over time. As part of this effort, NREL has published harmonization studies for crystalline silicon PV systems (Hsu et al. 2012), thin-film PV systems (Kim et al. 2012) and trough and tower CSP systems (Burkhardt et al. 2012).

7.3.1 Lifecycle GHG Emissions of PV Systems

For crystalline silicon systems, NREL selected 41 GHG estimates for harmonization from an initial pool of 397 studies. They harmonized four different assumptions. Lifetime average module efficiency was adjusted to 14% for mono-Si and 13.2% for multi-Si cells, with efficiency degrading by 0.5% per year. System life was adjusted to 30 years, and the performance ratio was set to 75% for rooftop systems and 80% for ground mounted systems. The irradiation level was also harmonized: results are presented at both 1,700 and 2,400 kWh/m^2/year. The former figure is consistent with irradiation levels in southern Europe, and the latter, with levels in the Southwestern U.S.

For thin-film systems, only five estimates were selected from 109 studies. The same four assumptions were harmonized as in the crystalline silicon analysis. Cell efficiencies were harmonized to: 6.3% for a-Si, 10.9% for CdTe, and 11.5% for CIGS, with efficiency again degrading by 5% per year. Irradiance, performance ratio and system life were harmonized to the same values as in the crystalline silicon analysis.

Figure 4 summarizes the data from Hsu et al. (2012) and Kim et al. (2012).[24] Harmonized estimates of emissions from crystalline silicon projects cluster in the range of 40 to 50 g/kWh. Estimates for thin film projects tend to be lower than this.

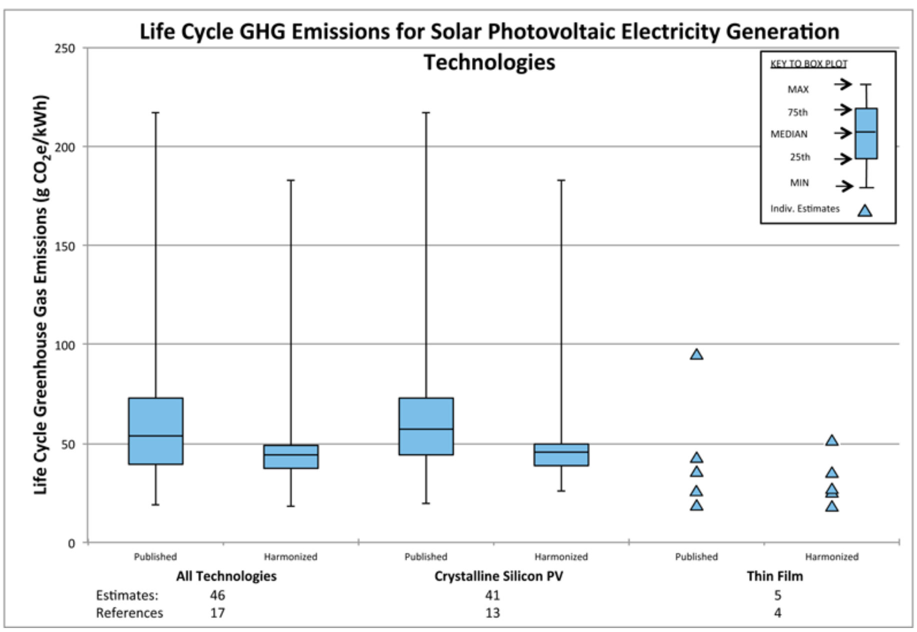


Figure 4. Summary of Lifecycle GHG Data from NREL (Hsu et al. 2012; Kim et al. 2012)

[24] Figure downloaded from: http://www.nrel.gov/analysis/sustain_lca_pv.html on July 1, 2012.

7.3.2 Lifecycle GHG Emissions of CSP Systems

The NREL harmonization analysis of CSP studies (Burkhardt et al. 2012) is the first meta-study of this literature. The authors selected 42 estimates for harmonization out of 125 studies. Of the 42 studies, 19 focused on trough systems, 17 on tower systems and 6 on dish systems. We follow the authors in focusing on the trough and tower data. Six assumptions were harmonized. Direct normal irradiance was adjusted to 2,400 kWh/m^2/year. Conversion efficiency was adjusted to 15% for trough systems and 20% for towers. Project lives were set to 30 years, and global warming potentials were adjusted to the IPCC's latest 100-year values.

The other two adjustments removed the effects of other energy use during plant operation. First, some of the studies selected focused on hybrid CSP plants that generate some electricity with natural gas. For consistent comparisons, the authors removed GHG emissions from gas. Second, all CSP plants require auxiliary energy for plant operation; however the amount used is highly plant specific. Therefore, the authors removed emissions associated with this process as well. Because emissions from hybrid plants and auxiliary energy have been removed, the harmonized data understate lifecycle GHGs. As discussed below, the authors were able to examine the impact of auxiliary energy use on the results.

Table 18 summarizes the harmonized data for trough and tower projects. The range of estimates for both plants types is relatively small, and the data are clustered fairly tightly around the mean. Also note that the lifecycle GHG rates for these technologies are very similar, suggesting that the efficiency advantage of tower systems comes at the cost of higher upstream energy requirements.

Table 18. Summary of *Partial* Lifecycle CSP GHG Emission Rates in g/kWh* (from Burkhardt et al. 2012)

	Trough CSP Systems (n=19)	Tower CSP Systems (n=17)
Mean	23	22
Median	22	23
Std. Deviation	10	10
Minimum	13	9
Maximum	55	42

**These emission rates are likely to understate total lifecycle emission rates, as they do not include emissions from gas-fired generation at hybrid plants or emissions from auxiliary energy.*

Five of the estimates for trough systems provided sufficient data for Burkhardt et al. to perform additional harmonization, including adding back in auxiliary energy use. Lifecycle emissions increased for three of these estimates, with the increase ranging from 19% to 77%. The other two estimates decreased by 9% and 30%. Thus, more work is needed to characterize the impact of hybrid operation and auxiliary energy use on LC GHG emissions.

7.4 Air Impacts of Solar Power

A number of studies examine the lifecycle air pollution impacts of solar generation. The most common pollutants addressed are SO_2 and NO_X. In some studies, all acidifying pollutants are converted to SO_2-equivalent emissions are reported together, and all ozone-forming pollutants are reported together in ethene-equivalent emissions. Emissions of PM, VOCs, CO and air toxics are reported less often.

The important factors driving lifecycle air pollutant emissions from solar projects are the same as those driving GHG emissions (see discussion above).

Most of the studies examining the lifecycle impacts of PV report GHG emissions. Far fewer of them report emissions of other air emissions. Further, some of the studies that do report other air pollutants do not present them in the units used here. We found three studies that report air pollutant emissions in mass per kWh, as shown in Table 19. A meta-study of the PV literature would be useful, with the goal of increasing the number of comparable estimates and determining how different assumptions affect lifecycle emissions.

Table 19. Summary of Estimated Lifecycle Air Emissions from PV Systems (g/kWh)

Study	Cell/Mounting	SO_2	NO_X	$PM_{2.5}$	VOCs
Frankl et al. (2005)	mono-Si, ground mounted	0.14	0.09	0.01	0.05
Frankl et al. (2005)	mono-Si, tilted roof retrofit	0.16	0.10	0.02	0.05
Frankl et al. (2005)	mono-Si, flat roof retrofit	0.14	0.11	0.01	0.05
Frankl et al. (2005)	mono-Si, tilted roof integrated	0.15	0.08	0.01	0.05
Frankl et al. (2005)	mono-Si, vertical façade integrated	0.24	0.14	0.02	0.08
Fthenakis et al. (2008)	mono-Si, ground mounted	0.15	0.08	NR	NR
Fthenakis et al. (2008)	CdTe, ground mounted	0.07	0.04	NR	NR
Fthenakis et al. (2008)	mono-Si, ground mounted	0.38	0.19	NR	NR
Fthenakis et al. (2008)	CdTe, ground mounted	0.16	0.08	NR	NR
Pacca et al. (2006)	mixture of cell types	0.27	0.19	NR	0.06

Given the number of variables involved in these estimations, the data cover relatively small ranges. Rates for NO_X range from 0.1 to 0.4 g/kWh, and SO_2 rates range from 0.05 to 0.2. Ranges of $PM_{2.5}$ and VOC rates are much smaller (though all the estimates are from one study).

The growing use of cadmium for CdTe cells raises concern over potential releases of this metal during the cell lifecycle.[25] Fthenakis et al. (2008) evaluate lifecycle cadmium emissions from CdTe PV systems and compared these with emissions from other generation technologies. They estimate direct cadmium emissions from upstream processes (mining, smelting and purifying of cadmium, synthesizing CdTe and manufacturing modules) at 0.02 g/GWh. Indirect emissions are an order of magnitude higher (0.28 g/GWh) than direct, with the dominant source of indirect emissions being coal-fired generation for steel manufacture. (The analysis assumes that European grid electricity is used.) Interestingly, the study estimates lifecycle cadmium emissions from CdTe to be lower (0.3 g/GWh) than from crystalline silicon PV (0.9 g/GWh). The authors estimate cadmium emissions from U.S. coal-fired generation to be between 2 and 7 g/GWh.

As with the PV literature, most CSP lifecycle studies address GHGs, and only some address other air emissions. We found two studies that present lifecycle air emissions in mass per kWh, and as shown in Table 20, the estimates differ significantly between the two studies.

[25] Gallium arsenide also include toxic substances, but they are not used outside of space exploration and satellite applications and are therefore manufactured on a relatively small scale.

Table 20. Summary of Estimated Lifecycle Air Emissions from CSP Systems (g/kWh)

Study	Plant Type	Acidification (SO_2-eq)	Ozone Formation (ethene-eq)	SO_2	NO_X	PM_{10}	$PM_{2.5}$	VOCs
Lechon et al. (2008)	Tower Hybrid	0.61	0.03	NR	NR	NR	NR	NR
Lechon et al. (2008)	Trough Hybrid	0.59	0.03	NR	NR	NR	NR	NR
Viebahn et al. (2008)	Tower Hybrid	NR	NR	0.04	0.13	0.02	0.01	0.04
Viebahn et al. (2008)	Tower S.O.	NR	NR	0.04	0.05	0.02	0.01	0.01
Viebahn et al. (2008)	Trough Hybrid	NR	NR	0.05	0.16	0.03	0.01	0.05
Viebahn et al. (2008)	Trough S.O.	NR	NR	0.05	0.08	0.03	0.01	0.02

Note: "S.O." indicates solar only operation and "NR" indicates data not reported.

Viebahn et al. (2008) estimate very low SO_2 emissions, while Lechon et al. (2008) estimate all SO_2 -equivalent emissions to be an order of magnitude higher. Given that SO_2 is the dominant acidifying pollutant, this suggests that Lechon et al. are estimating much higher SO_2 emissions than Viebahn et al. Further, Viebahn et al. estimate NOx in the range of 0.05 to 0.16 g/kWh, depending on plant type and gas-firing. Lechon et al. estimate all ozone-forming emissions, including NO_X, to be below this range (0.03). Further analysis of these and other CSP studies is needed to better characterize lifecycle air pollution.

7.5 Water Impacts of Solar Power

The operation of PV systems requires a small amount of water for periodic panel washing. Fthenakis and Kim (2010) estimate lifecycle water withdrawals to be in the range of 520 gal/MWh for crystalline silicon panels and 225 gal/MWh for CdTe. We also found two studies that estimate lifecycle eutrophication impacts in mass per kW (Anselma and de Wild-Scholten 2006 and SENSE 2008). With additional analysis these estimates could be converted to mass per kWh.

For CSP plants, cooling water use can be considerable. (See Overview on page 16 for a description of cooling systems.) CSP plants that use wet (evaporative) cooling towers consume approximately 800 gal/MWh (Stillwell et al 2009; Macknick et al 2011). The use of dry cooling can reduce this to about 80 gal/MWh (Stillwell et al 2009). Hybrid cooling systems are also under development, which use more water than dry cooling, but less than wet cooling.

Burkhardt et al. (2011) examine lifecycle water use at a 103-MW, non-hybrid trough plant, with 6.3 hours of storage. They examine scenarios with wet and dry cooling systems. Assuming a wet cooling tower, they estimate lifecycle water use at 1,240 gal/MWh, with 89% coming from plant operation and 10% from manufacturing. With a dry cooling system, lifecycle water use is 290 gal/MWh, with 50% coming from operation and 46% from manufacturing. Dry cooling is estimated to increase plant capital costs by about 8%, due mainly to a larger collector field and more embodied materials. However, the authors note that, in cooler weather, the dry-cooled plant would produce more electricity than the wet-cooled plant, despite the dry-cooled plant's less efficient steam cycle. In fact, they report higher average annual generation from the dry-cooled plant.

Lechon et al. (2008) examine hybrid tower and trough plants, as described above. They report lifecycle water impacts in terms of freshwater and marine aquatic ecotoxicity and eutrophication impacts. Toxicity is reported in terms of equivalent 1,4 dichlorobenzene (DB), and eutrophication is reported in equivalent phosphate (PO_4).

Table 21. Summary of Lifecycle Water Impacts from CSP

Study	Water Use (gal/MWh)		Freshwater Toxicity (kg 1,4 DB-eq)		Marine Toxicity (kg 1,4 DB-eq)		Eutrophication (mg PO_4-eq)	
	Trough (wet cooling)	Trough (dry cooling)	Tower	Trough	Tower	Trough	Tower	Trough
Burkhardt et al. (2011)	1240	290	NR	NR	NR	NR	NR	NR
Lechon et al. (2008)	NR	NR	8.7	9.3	115	112	49.6	49.7

Note: "NR" indicates data not reported.

These studies provide useful starting points for assessing lifecycle CSP water impacts. Additional work in this area would be useful.

7.6 Land Impacts of Solar Power

The amount of land occupied by PV systems varies considerably. Roof-mounted and building-integrated systems use no land, although in some cases PV may compete for roof space with other uses. Ground-mounted PV occupies significant areas, and these systems are less energy dense than many other plant types, providing less capacity per unit of area. Typical PV panels provide 60 to 130 Watts per m^2, with crystalline silicon providing higher power density and thin film, lower (Pacca et al. 2006; Frankl et al. 2005).

One estimate puts typical land occupied by ground-mounted PV projects in the range of 6 to 10 acres per MW, or 24 to 40 m^2 per kW (FitchRatings 2012). In addition, NREL is currently working on a comparison of land use at different ground-mounted PV projects, with release expected in late 2012.

We found one estimate of the lifecycle land impacts of PV generation. Frankl et al. (2005) estimate land use impacts (including resource extraction and landfilling of retired panels) for crystalline silicon panels in a variety of configurations. Estimates range from 4.3×10^{-4} m^2/kWh for roof-integrated panels to 5.5×10^{-3} m^2/kWh for a ground-mounted system. More work is needed on lifecycle land use of PV.

Several studies have assessed land occupation by CSP plants. This information, shown in Table 22, suggests that trough plants require less land per kW than tower plants. We found no studies that address lifecycle land impacts of CSP plants.

Table 22. Estimates of Land Occupied by CSP Plants

Study	Plant Type	Total Occupied Land (m^2)	Land per kW (m^2/kW)	Land per Lifetime kWh (m^2/kWh)
Burkhardt et al. (2011)	Trough (wet cooled)	4,100,000	40	3.2×10^{-4}
Burkhardt et al. (2011)	Trough (dry cooled)	4,140,000	40	3.1×10^{-4}
Lechon et al.(2008)	Tower	1,500,000	88	5.8×10^{-4}
Lechon et al.(2008)	Trough	2,000,000	40	4.3×10^{-4}

The use of heavy metals in PV cells raises questions about the disposal of panels at the end of their useful lives. Regulations governing the handling and recycling of retired PV panels are needed to ensure that metals do not leach into soil or groundwater. Similar regulations exist in the U.S. for recycling other products manufactured with toxic substances, and the handling of retired PV panels is already regulated in Europe. In SENSE (2008) the authors include metals recycling in a PV lifecycle analysis, and find that recycling slightly increases lifecycle energy requirements – from 0.2% for a-Si systems to 2.4% for CIGS systems.

8. Wind Power

In 2010, wind power represented 3.7% of U.S. installed capacity and produced approximately 2.3% of U.S. electricity (EIA 2011). The American Wind Energy Association reports 6,810 MW of new onshore wind capacity added in 2011, raising the total installed U.S. capacity to 46 GW and representing an annual growth rate of 17%. To date, no offshore wind projects have been built in the U.S., although several thousand MWs have been installed in Europe. Aggressive targets for new offshore wind capacity have been established in both the U.S. and Europe. The U.S. DOE's current goal is 54 GW installed by 2030 (DOE 2011b). Several offshore projects are in various stages of development (but not yet construction) in the Northeastern U.S.

8.1 Cost and Planning Risks of Wind Plants

The installed cost of onshore wind projects has been falling since reaching a high in 2010. Costs for the 2012 to 2013 period are projected to be in the range of $1,700 to $1,950 per kW (Wiser et al. 2012).[26] Of the technologies reviewed here, only gas CCCTs are less costly. The up-front costs of wind projects (e.g., engineering and environmental studies, permitting and legal fees) are the lowest of any technology examined here, with "owner's costs" estimated at $140 per kW (EIA 2010b).[27] Therefore, less money is lost in the event of project cancellation. Project development and construction can be completed for a several hundred MW project in 3 to 4 years, and total capital requirements per project are modest – $680 to $780 million for a 400 MW project. Moreover, large wind sites are often developed in phases, allowing developers to respond to changing market conditions.

Estimated costs for offshore wind projects currently under development in Europe are in the range of $4,300 per kW (NREL 2010). The costs of the first U.S. projects are likely to be considerably higher than this, given that the construction infrastructure (e.g., ports and construction vessels) is better developed in Europe. We estimate that the first U.S. projects will cost around $6,000 per kW. However, if construction and operation goes well for these projects, costs are likely to fall rapidly as U.S. developers benefit from experience in Europe.

Like installed costs, the cost and planning risk associated with offshore wind is considerably higher than that for onshore projects. Because the offshore projects being developed are first-of-kind projects in the U.S., there is considerable risk of regulatory and construction delays and cost overruns. Further, the up-front costs of offshore project development are much higher than for onshore projects; EIA estimates owner's costs for current offshore projects at nearly $1,200 per kW – the highest of any technology examined here (EIA 2010b). These costs are likely to fall as the U.S. industry matures, but they will still remain well above onshore costs, due to the challenges of site characterization and feasibility analysis at sea.

The capacity factors of both offshore and onshore wind plants are typically much lower than those of coal and nuclear units, and this affects the cost of wind energy per MWh. For example, despite

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[26] Wiser et al., 2012 cite a range of $1,600 to $1,850 ($2010) for 2012 and 2013 projects, not including interconnection costs. We add $100 per kW for interconnection costs.

[27] EIA defines owner's costs as: development costs; preliminary feasibility and engineering studies; environmental studies and permitting; legal fees; project management; interconnection costs; owner's contingency; and insurance and taxes during construction.

capital costs far below new coal-fired plants, recent onshore wind costs per MWh have been similar to energy costs from new coal plants – both in the range of 7 to 10 ¢/kWh. (Although current estimates for new onshore projects put energy costs below 7 ¢/kWh (Wiser et al. 2012)).

The output of wind projects is dependent on wind and is therefore not dispatchable on demand. This gives a wind project much less capacity value than a coal, nuclear, gas or biomass project of the same size. Thus, wind projects must recover the vast majority of their costs in energy markets.

Finally, many wind projects are being developed today by non-utility companies. These companies recover costs through contracts with utilities or sales into competitive power markets; therefore they cannot charge customers for "construction work in progress" or pass construction cost overruns to captive ratepayers. As discussed in the coal and nuclear sections, such cost recovery has been highly controversial recently.

8.2 Subsidies to Wind Power

In this section we address subsidies – intentional uses of taxpayer dollars to support a private industry. Subsidies take the form of tax breaks and direct payments such as grants and appropriations from Congress. Externalities are addressed in the subsections below. These are costs unintentionally imposed; that is, the government has not explicitly approved the shifting of these costs from industry to consumers. Both subsidies and externalities are hidden costs in that they are not typically included in the cost of electricity from a power plant.

The Environmental Law Institute has published a review of U.S. tax policies that benefit different energy industries (ELI 2009). This study cites the following policies that benefit the wind industry:

- Production Tax Credit for renewable energy (IRC Section 45);
- Five Year Modified Accelerated Cost Recovery (IRC Section 168(e)(3)(B)); and
- Tax Credit for Clean Renewable Energy Bonds (IRC Section 54).

In addition to these tax policies, many states have established renewable portfolio standards (RPSs) to incentivize the development of renewable power plants. These programs require that electricity suppliers obtain a certain percentage of their electricity from eligible renewable resources. The eligible resources differ from one state to another, but wind energy is eligible for that vast majority of RPSs.

Other subsidies to the wind industry include R&D spending and loan guarantees. In 2012 DOE R&D spending on wind energy was $93 million, and the amount requested for 2013 was $95 million (DOE 2012). Wind companies and projects are also eligible for §1703 and §1705 federal loan guarantees.

8.3 Climate Change Impacts of Wind Power

The GHG emissions from the operation of a wind project are quite low; however there are significant emissions from equipment manufacture, transportation, on-site construction and decommissioning. Many lifecycle GHG analyses have been published, and the LCA harmonization project underway at NREL reviewed most of them, adjusting key assumptions for consistency (Dolan and Heath 2012). The authors screened 172 references for soundness of methodology and completeness of data reporting. This screening left 72 references to which the harmonization steps were applied. Global warming potentials in the studies were harmonized to the IPCC's most recent 100-year potentials. Wind farm capacity factors were harmonized to 30% for onshore plants and 40% for offshore, and plant lifetimes were harmonized to 20 years.[28] For any studies that did not assess a portion of the lifecycle, the authors added the average value for this portion from the other studies.

Figure 5 summarizes the data from the studies chosen for harmonization. Estimates as reported in the original studies are summarized as well as the harmonized data. For the harmonized data, the maximum value was 45 g $CO_{2\text{-eq}}$/kWh, and the minimum was 3.0 g $CO_{2\text{-eq}}$/kWh, both from studies of onshore wind. The mean value from studies of onshore wind was 15 g $CO_{2\text{-eq}}$/kWh, and the mean from offshore studies was 12 g $CO_{2\text{-eq}}$/kWh.

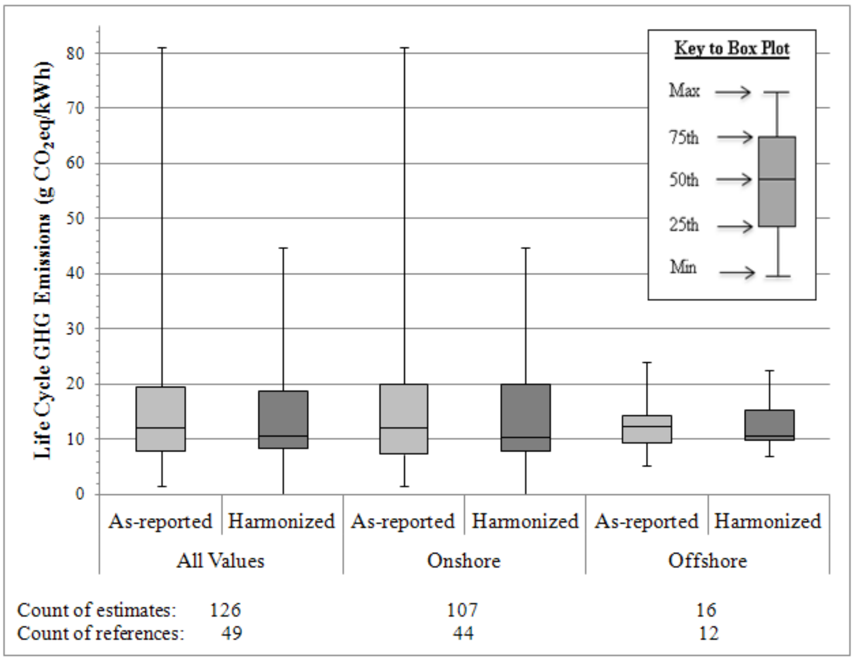

Figure 5. Wind Power Lifecycle GHG Emission Rates from Dolan and Heath (2012)

Dolan and Heath (2012) do not discuss the potential for the release of sequestered carbon in the construction of a wind project. At projects on farm or ranch land or in the arid west, sequestration losses are likely to be negligible, but at projects on forested ridgelines, forest clearing could result in significant losses. More work is needed to estimate the percentage of new wind capacity resulting in forest clearing and the typical amount of clearing at such projects.

8.4 Air Impacts of Wind Power

The most comprehensive lifecycle analysis of wind energy we found was performed by Vattenfall AB as part of its environmental product disclosure initiative (Vattenfall 2010b). The company owns 615 MW of wind capacity in five European countries, including 316 MW of offshore capacity. For

[28] The NREL authors note that most wind projects installed today are achieving capacity factors higher than 30%, but they normalized to 30% because most of the studies reviewed used a figure close to 30%.

the lifecycle analysis, Vattenfall analyzed a representative subset of these projects. The selected projects typically generate about 69% of the company's total annual wind generation. Each selected project was individually assessed, including construction, operation and decommissioning, using actual capacity factors and an assumed service life of 20 years.

Table 23. Wind Lifecycle Air Pollutant Emission Rates from Vattenfall (2010b)

Pollutant	g/kWh
SO_2	0.03
NO_X	0.03
PM	0.02
Cadmium	2.3×10^{-6}
VOCs	1.8×10^{-3}
HCl	4.5×10^{-4}
HF	2.9×10^{-4}

Not surprisingly, Vattenfall reports that the vast majority of emissions come from the production of materials (steel, concrete and composites), the construction of supply factories and the transportation of components. The study does not report whether there was a significant difference in the lifecycle emissions of onshore and offshore projects.

8.5 Water Impacts of Wind Power

As with air emissions, the water impacts of operating a wind project are negligible, but there are water impacts from other phases of the lifecycle. Fthenakis and Kim (2010) cite four different studies that estimate lifecycle water use from wind projects between 45 and 85 gal/MWh. Vattenfall (2010b) estimates lifecycle water use at 77 gal/MWh.

8.5.1 Impacts on Fishing and Marine Life

The construction process for offshore wind projects disturbs marine environments with noise and increased boat and barge traffic (Carstensen et al. 2006). Noise during specific activities could drive away fish over a broad area, with adverse impacts on fishing. The Environmental Impact Study (EIS) for the Cape Wind project off Massachusetts characterized construction impacts on fishing as "minor" (MMS 2009). The impacts of turbine operation on fishing are likely to be smaller, with a well-sited project. The Cape Wind EIS characterized operational impacts as "negligible to minor," with potential "moderate" impacts from increased vessel traffic (MMS 2009). Other sources conclude that with careful siting, heavily fished areas can be avoided, minimizing impacts on commercial fishing (UNC 2009).

The impacts of the construction phase of offshore projects on marine mammals and fish is significant. The most important impact is noise, with pile driving operations able to create extremely high sound pressure levels underwater (Thomsen et al. 2006). Mitigation measures are important, including acoustic isolation of the ramming pile, slow daily ramp up of activity and acoustic deterrent devices. Noise and sediment disturbance reduce marine life density during construction, however most sea life returns to the area after construction. Noise levels from operating wind turbines are believed to have minor impacts on marine life (Thomsen et al. 2006; Madsen et al. 2006). The Cape Wind EIS characterizes noise impacts during construction as "minor" and impacts during operation as "negligible" (MMS 2009).

Several studies have found that offshore turbines provide benefits by creating habitat and food sources for plants, shellfish and other aquatic life (Wilhelmsson 2006; Vattenfall 2010b; UNC 2009). Vattenfall has monitored its offshore projects since they were brought online and found that the introduction of "hard surfaces" (towers, foundations and gravel beds) has created new populations of seaweed, mussels, worms and hydroids. These populations create small ecosystems that support several fish species drawn to the new food source (Vattenfall 2010b). A UNC study lists the same "micro-habitat" benefits that Vattenfall describes as well as enhanced local upwelling and oxygen mixing near turbines (UNC 2009).

8.6 Land Impacts of Wind Power

The land encompassed by a wind project varies based on the number of turbines and turbine spacing, which is a function of site topography and other factors. However, the turbines take up a small fraction of the total land encompassed, and the remaining land typically retains it prior use after operation of the plant commences. This land use is typically farming, ranching or wilderness/recreation.

Factories for manufacturing towers and turbines also require land, as does the mining of raw materials for these processes. However, mining impacts for a wind farm are far smaller than the impacts of a typical coal or nuclear plant. Vattenfall's lifecycle analysis of its wind plants (Vattenfall 2010b) provides a detailed study of land use at the generation sites, but it does not address upstream land use (i.e., mining and manufacturing). The analysis of the wind farm sites establishes four categories of land, ranging from pristine land of ecological importance ("critical biotope") to developed land ("technotope"). The analysis then evaluates the amount of land that moves from one category to another as a result of project development. The average for all projects assessed is 0.002 m^2 per MWh moving into the developed category (roads, foundations, graded gravel) from other categories. This is a useful analysis, however it has been performed for so few other plant types that comparisons are difficult. More work is needed to preform effective comparisons of land use across different power plant technology types.

Table 24 shows the lifecycle solid waste produced from wind energy per unit of generation, according to Vattenfall (2010b). Vattenfall also reports a negligible amount of radioactive waste (1.8×10^{-9} g/kWh) from the wind lifecycle.

Table 24. Solid Waste from the Wind Power Lifecycle from Vattenfall (2010b)

Waste Type	(g/kWh)
Waste to recycling	2.8
Waste to landfill	17
Waste to incineration	0.1
Hazardous Waste	0.1

8.6.1 Impacts on Wildlife

Assessments of wind impacts on wildlife typically focus on bird and bat mortality. In 2010, the National Academies estimated annual bird deaths from wind turbines at less than 100,000, compared to total anthropogenic bird deaths between 100 million and 1 billion annually (NAS 2010). Two studies have attempted to state avian mortality from wind turbines as a function of energy produced, indicating a range of 0.279 deaths per GWh (Sovacool 2009) to 2.94 deaths per GWh (Willis et al. 2009). Transmission and distribution lines are also a significant cause of avian mortality, killing up to 175 million birds annually (Manville 2005).

NAS (2010) find that only raptor mortality in certain California locations could pose a population-level problem. Altamont Pass in California is one of the most often criticized sites, with one report stating that almost 2,600 raptors, on average, are killed there each year (Altamont Pass Avian Monitoring Team 2008). The same analysis suggests that deployment of modern high-capacity turbines could significantly reduce avian mortality. Moreover, Altamont Pass is now considered to be a poorly sited wind farm, as it lies in an important migration route (Distefano 2007).

The threat that wind turbines pose to bats is more challenging than the risk to birds, because bats can be attracted to the movement of the blades or to insects near the blades. Bats are also of concern because they occupy an important niche in ecosystems, and because their long life span makes recovery from population declines slower (NAS 2007). In 2010 the National Academies noted that no member of an endangered bat species had been reported killed by a wind turbine; however they also noted that, with the rapid growth of the wind industry, bat mortality generally is a significant concern (NAS 2010).

Work is underway to find ways to reduce wind turbines' impacts on bats. One study measured the relationship between turbine cut-in speed and bat mortality. The study found that bats are more attracted to slower blade speeds, and that higher cut-in speeds could reduce mortality as much as 93% with less than a 1% loss in total annual power output (Arnett et al. 2010). Others have concluded that some bat species (those that migrate long distances) are at greater risk than others (Kunz et al. 2007; Horn et al. 2008). This suggests that careful siting could significantly reduce bat mortality.

While wildlife impact assessments typically focus on avian mortality, wind projects can affect ecosystems and habitat. On land that is currently being farmed or ranched, these impacts are likely to be negligible. On land not in use, such as on forested ridgelines, construction activity, roads and tower foundations could adversely affect species highly sensitive to such disruptions.

8.7 Other Impacts of Wind Power

Aesthetic Issues (visual and noise impacts) are the most commonly discussed externalities associated with wind energy; however we found remarkably little rigorous analysis of these issues.

Visual impacts are often at the forefront of wind siting cases. These impacts stem from the tower height, required lighting for aircraft safety, and the siting of turbines in highly visible areas such as ridgelines and open spaces. Turbines can also cast horizontal flickering shadows for some distance when the sun is near the horizon. Concerns about turbine noise have also been raised regarding existing and proposed wind projects, as have concerns about more general annoyance.

The first comprehensive review of the health effects of exposure to wind turbines was recently released in Massachusetts (MA DEP and MA DPH 2012). The authors reviewed scientific literature as well as other sources to assess, in part, the relationship between the effects of seeing a wind turbine, noise and vibration, shadow flicker and annoyance of people exposed to wind turbines. The study finds that the evidence available today does not support the conclusion that wind turbines cause health problems. However, the authors note the very limited amount of data available as well as significant problems with that data.[29]

Visual impacts of onshore wind projects are likely to be greater, on average, than those of conventional power plants. This conclusion is based on the fact that wind projects can rarely be hidden in valleys or behind trees, they consist of tall structures, and are often spread over a much wider area than central station power plants. Siting proceedings are likely to prevent the construction of wind turbines in National Parks or on other land that has been deemed to have scenic value. Still, wind projects are being sited in other rural and remote areas, and these projects are visible from surrounding communities. We are not aware of any attempts to date to quantify these costs.

The costs imposed by shadow flicker are likely to be far smaller than those imposed by the visual effect on the landscape, because the number of people affected by flicker is far smaller and because the phenomenon occurs for so few hours each year.

While visual impacts of wind projects are likely to be greater in general than those of conventional power plants, it is more difficult to discern whether wind projects, on average, impose greater noise costs on nearby residents. The magnitude, frequency and quality of noise from wind turbines is different than that from a conventional power plant, and different individuals find different types of noise disruptive. Further, wind turbine noise levels at any place or time reflect myriad factors including distance from turbine, wind direction, surrounding terrain, temperature gradients, and atmospheric stability. However, the total cost imposed by turbine noise is likely to be far smaller than from visual impacts, because noise costs are imposed on far fewer people. A typical turbine emits sound on the order of 103 dBA (similar to a motorcycle), but the noise level diminishes rapidly with distance – for example, to 40 dBA at 400 m (MA DEP and MA DPH 2012).

Finally, concerns have been raised that proximity to wind turbines could affect property values. In December 2009, Lawrence Berkeley National Lab released a comprehensive analysis of those possible impacts, building on the previous literature and using multiple models to test the effects of visual and other impacts (Hoen et al. 2009). The study found no evidence that home prices surrounding wind facilities are significantly affected by either the view of wind facilities or the distance of the home to those facilities.

[29] "Existing studies are limited by their cross sectional design, self-reported symptoms, limited ability to control for other factors, and to varying degrees of non-response rates" (MA DEP and MA DPH 2012, p.27).

The comprehensive report entitled Environmental Impacts of Wind-Energy Projects (NRC 2007) outlines a detailed assessment that can be used to inform the regulatory process regarding whether a project should be approved or rejected on the basis of visual impacts, or if a project would be acceptable with appropriate mitigation techniques (NRC 2007, Appendix D). In addition, a recent technical report for the Appalachian Mountain Club presents the results of a GIS-based analysis that can be used to inform the decision process, including a detailed scoring system and overlay analysis (Publicover et al. 2011).

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