2011

Survey and sustainability of energy technologies

Joshua Donald Gifford
Iowa State University

Survey and sustainability of energy technologies

by
Josh Gifford

A thesis submitted to the graduate faculty

in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

Major: Mechanical Engineering

Program of Study Committee:
Robert Brown, Major Professor
Gregory Maxwell
James McCalley

Iowa State University

Ames, Iowa

2011

Table of Contents

Acknowledgements

I would first like to thank my parents Donald and Leanne Gifford for all of the support and advice they have provided me with throughout my entire life. I would also like to thank my sister, Elizabeth, for her support.

I would like to acknowledge Dr. Brown, whose guidance and wisdom helped me gain a great deal of insight into transportation fuels and electricity production, particularly in the role that biomass can play in both. I would also like to thank my colleagues and staff at CSET and within the NETSCORE21 group, in particular Justin Voss and Mark Wright. Justin assisted me in conducting research in electricity production, while Mark helped me through his expertise on techno-economic analysis.

This work was supported by the National Science Foundation under their Emerging Frontiers on Research and Innovation program, award number 0835989.

Abstract

This thesis is composed of three articles that survey and assess the sustainability of various automotive and power generation technologies.

"Four economies of sustainable automotive transportation" is a journal article has been accepted by *Biofuels, Bioproducts, and Biorefining*, while "Survey of power generation technologies" is a draft chapter for the upcoming book *Handbook of Data Mining for Power Systems*, and finally, "Four economies of sustainable power generation" is a draft journal article.

Vehicles fueled by compressed natural gas were found to offer the best overall performance considering operating cost, water usage, energy efficiency, and greenhouse gas emissions for the automotive scenarios analyzed in first paper. The second paper is a review of power generation technologies, from which no conclusions are drawn. Offshore wind power was found to have the best overall performance considering cost of electricity, water usage, energy conversion efficiency, and greenhouse gas emissions of the power generation technologies and metrics analyzed in the third paper.

General Introduction

Concerns over environmental issues and resource availability have prompted many to evaluate the way energy is produced and consumed. Individual studies generally focus on transportation fuels, vehicle platforms (referred to collectively as automotive scenarios), or power generation technologies. A method that takes into account all processes involved in either creating, operating, or dismantling an energy technology has become popular over the past few decades. This method is commonly referred to as life-cycle analysis when applied to power generation technologies and well-to-wheels (WTW) analysis when applied to automotive scenarios.

WTW analysis traditionally focuses on the energy requirements and emissions (greenhouse gases, particulate matter, volatile organic compounds, oxides of sulfur, etc.) associated with the creation and utilization of fuel. However, it is becoming more apparent that other metrics should be included when evaluating the overall sustainability of transportation fuels, specifically water usage and cost of operation. Most life-cycle studies of power generation technologies include economic as well as a wide variety of environmental metrics, generally in the form of various emissions previously mentioned. Water usage, however, is less commonly included in this sector as well.

The primary focus of the present study is on both automotive scenarios and power generation technologies. Both categories of energy technologies are surveyed and analyzed for their overall sustainability from a broad perspective.

Background

In 1991, DeLuchi conducted a comprehensive survey of greenhouse gas (GHG) emissions from transportation fuels and power generation technologies. [(1)] His work provided a foundation for the GREET model, which was first introduced in 1996. [(2)] The GREET model has gone through several revisions since then, and is now widely utilized for evaluating transportation fuels on a WTW basis. [(3), (4), (5)] In 1994, Gleick [(6)] conducted an extensive survey of the water consumption associated with various transportation fuel processing and power generation technologies. The purpose of Gleick's study was to examine the link between water consumption and energy production.

Both Gleick's work and DeLuchi's work are among the few papers that simultaneously evaluate automotive scenarios and power generation technologies. The remainder of this section offers a brief look at the history of analysis done for either automotive scenarios or power generation technologies.

Automotive Scenarios

Well-to-wheels analysis is currently one of the more popular forms of life-cycle analysis of automotive scenarios. Many WTW studies strictly evaluate automotive scenarios for their technical characteristics, usually energy consumption and greenhouse gas emissions, without drawing any conclusions from these attributes. [(7), (8), (9)] In fact, Simpson [(8)] surveyed over 30 automotive scenarios, while Brinkman et al [(7)] evaluated over 100 automotive scenarios. Both of these reports provided information of the WTW energy use and emissions of light duty vehicles. Beer et al examined heavy duty vehicles for their air quality and GHG emissions, as well as other occupational health and safety, functionality and viability, and sustainable ecological development issues. (10) Their study compared these metrics for fifteen fuels from a wide variety of feedstocks against low sulfur diesel. However, the study cited insufficient knowledge of appropriate risk-weighting factors for evaluating the relative effects of the metrics they chose. (10) It is therefore unclear which fuel scenario is the overall best performer from this analysis.

Other studies focus more on technologies for resource extraction and refinement into final fuel products, and offer less intensive analysis on vehicle platforms. While these studies are not always on a full WTW basis, they do provide useful techno-economic information regarding the processes involved in fuel production. Brandt has published several papers related to energy requirements and GHG emissions of synthetic crude oil production and use from both tar sands and oil shale. (11), (12) Bartis et al analyzed the viability of utilizing oil shale in the U.S. for synthetic crude oil production considering the cost and performance of available extraction and processing technologies. (13)

There are some studies that draw overall conclusions from multi-criteria comparisons. Safaei Mohamadabi, Tichowsky, and Kumar developed a comparison methodology based on the fuel cost, relative vehicle cost, distance between refueling stations, GHG emissions, and market share of each vehicle type (referred to as “number of consumer options” in their paper). (14) Their study included six vehicle platforms: gasoline, diesel, biodiesel, E85, compressed natural gas (CNG), and electric-hybrids. They concluded that gasoline vehicles did the best when economic factors had higher weighting, while hybrid vehicles did the best when environmental factors had higher weighting. (14) Tzeng, Lin, and Opricovic studied twelve scenarios for alternative fuel buses in

Taiwan. [15] Their results showed that hybrid electric buses using gasoline were the most suitable in the near term, while pure electric buses would become the best alternative once the driving range could be extended. [15]

Power Generation

Multi-criteria and externality assessments are two of the most common ways to evaluate power generation technologies on a life-cycle basis. Externality studies assign costs to the environmental impacts of power plants (i.e. dollar amount of damage caused by emissions). Multi-criteria assessments evaluate and rank power generation technologies based on their performance under a given set of metrics. Mirasgedia and Diakoulaki compared these two methodologies by ranking seven power generation technologies using each method to test the accuracy of externality analysis. [16] Their results showed that externality assessments did in fact give reasonable results when environmental metrics were included as part of the multi-criteria analysis. [16]

Roth and Ambs studied the externalities of fourteen power generation technologies, and their results indicated that landfill gas recovery power plants were the cheapest when external costs were accounted for. [17] Afgan and Carvalho conducted a multi-criteria analysis of ten power generation technologies considering their energy conversion efficiency, capital cost, electricity production cost, carbon dioxide emissions, and land requirement. [18] The focus of their study was to demonstrate the usefulness of the methodology they developed, rather than make critical assessments of power generation technologies. Pohekar and Ramachandran published a very comprehensive review article on the application of multi-criteria assessment for energy planning.

[19] The purpose of this study was to comment on the general trend and functionality of multi-criteria assessment tools.

Other studies strictly evaluate technologies based on a common set of metrics. The International Energy Agency (IEA) has released a series of technology briefs that highlight the techno-economic and environmental attributes of various power generation technologies, including: coal [20], gas-fired [21], geothermal [22], hydroelectric [23], marine [24], and nuclear power [25]. The U.S. Energy Information Administration has reported the heat rate and capital costs of 18 technologies as part of the documentation of their National Energy Modeling System software. [26] There have also been several books published in recent years that offer a detailed and comprehensive look at power generation technologies. [27], [28], [29], [30]

Some life-cycle analysis studies have also been conducted for a specific geographic region. Pacca and Horvath examined the life-cycle GHG emissions of five power plants assuming they were to be built and operated in the Upper Colorado River Basin. [31] Their results showed that wind farms and hydroelectric plants had the lowest greenhouse gas emissions out of the included technologies. [31] Hondo [32] conducted a similar study of nine power generation technologies in a Japanese context, while Kannan et al [33] surveyed the energy usage, emissions, and cost of five technologies in Singapore.

Thesis Organization

This thesis is the culmination of two journal articles and a book chapter: "Four economies of sustainable automotive transportation" [34], "Four economies of sustainable power production" [35], and "Survey of power generation technologies" [36].

"Four economies of sustainable automotive transportation", a journal article, evaluates and ranks thirty automotive scenarios according to: operating cost, water usage, energy consumption, and greenhouse gas emissions. Each scenario is assigned a score based on the relative performance difference between itself and the best performing scenario. This score is used as a measure of overall sustainability relative to the other technologies evaluated.

"Survey of power generation technologies", a book chapter, reviews twenty power generation technologies either currently in use or under development. Technologies are evaluated under a set of eighteen possible metrics, and estimates on capital cost reductions from gains in experience are also provided.

"Four economies of sustainable power production" is a short article that evaluates and ranks ten power generation technologies using the same methodology that was developed for, and applied to, automotive scenarios.

Four Economies of Sustainable Automotive Transportation

A paper accepted by *Biofuels, Bioproducts & Biorefining*

Joshua D. Gifford[a] and Robert C. Brown[a,b].

[a]Department of Mechanical Engineering
[b]Center for Sustainable Environmental Technologies
Iowa State University

Abstract

Life cycle analysis for automotive transportation, commonly known as wells-to-wheels (WTW) analysis, has traditionally focused on greenhouse gas (GHG) emissions and primary energy consumption. Clearly, economizing on the use of primary energy sources and the amount of greenhouse gas emission associated with automotive transportation are important sustainability metrics. Other important metrics are water usage and cost of vehicle operation. Thus, we propose the evaluation of four economies in WTW analysis: primary energy consumption, greenhouse gas emissions, water usage, and cost of vehicle operation. No scenario is likely to simultaneously minimize all four metrics, suggesting the identification of a single figure of merit that encompasses all four economies of transportation fuels. We employed a normalization scheme that allowed calculation of a single composite score for each scenario called the CWEG (Cost-Water-Energy-GHG) score. Automotive transportation scenarios evaluated in this paper included a variety of fossil and renewable primary energy sources; several energy carriers as transportation fuels; and three distinct vehicle platforms including internal combustion engines, battery electric vehicles, and fuel cell electric vehicles. Compressed natural gas scored highest, with CWEG scores of 71 to 74 out of a possible score of 100, well above the next highest score,

which was 45 for conventional diesel hybrid electric vehicles. Fuel cell vehicles running on hydrogen generated using power from the U.S. electric grid had the lowest CWEG scores, ranging from 13 to 15.

1. Introduction

The value chain of transportation fuels includes four major operations: *resource recovery,* consisting of extraction, harvesting, or otherwise recovering a primary energy source; *fuel refining*, which converts the primary energy source into fuel molecules or electrochemical energy; *fuel utilization,* which converts stored chemical energy into motive power; and *energy distribution*, which moves primary energy sources and finished fuel products among the other operations of fuel production. Each operation must be considered in the life cycle analysis of transportation fuels, which is known as “well-to-wheels” (WTW) analysis.[1-4] Previous WTW studies typically focus on primary energy consumption and greenhouse gas (GHG) emissions.[1-4] Clearly, economizing on primary energy sources and GHG emissions are important considerations in devising sustainable energy options, but other metrics should also be considered. Water is now recognized as an increasingly scarce resource that should be economized in the production of transportation fuels. In addition to these three environmental metrics, the cost of operating a vehicle should be considered as a metric of economic sustainability. Thus, we propose evaluating four economies in WTW analysis: primary energy consumption, greenhouse gas emissions, water usage, and operating cost. Of course, other economies such as sulfur and nitrogen emissions, water pollution discharges, and land use requirements might be considered, but these are beyond the scope of the current study.

The objective of this study is to perform comparative WTW analyses for several advanced automotive transportation scenarios using the proposed set of four sustainability metrics. As shown by Figure 1, no scenario simultaneously minimizes all four metrics, suggesting the identification of a single figure of merit that encompasses all four economies of transportation fuels. We combine these four metrics to provide a relative measure of sustainability for these automotive transportation scenarios called the CWEG (Cost-Water-Energy-GHG) score.

2. Automotive Transportation Scenarios

Our analysis evaluated five different engine platforms: conventional internal combustion engines (ICE), hybrid electric vehicles (HEV), fuel cell electric vehicles (FCEV), fuel cell hybrid electric vehicles (FCHEV), and lithium-ion battery electric vehicles (BEV). Six different transportation fuels were considered (gasoline, diesel, natural gas, electricity, hydrogen, and ethanol) produced from a variety of primary energy sources (both fossil and renewable) and evaluated for one or more engine platforms.

Three fossil primary energy sources were evaluated for gasoline and diesel production: petroleum, tar sand derived synthetic crude oil (TS SCO), and oil shale derived synthetic crude oil (OS SCO). Two fossil primary energy sources were evaluated for hydrogen production: electrolysis using power from the U.S. electric grid and coal gasification. Two electric power generation pathways were included for evaluating BEV's: power from the U.S. electric grid and power from a natural gas-fired combined cycle power plant (NGCC). Ethanol from both corn grain and cellulosic feedstocks were included in this comparison, as well as compressed natural gas-fueled (CNG) internal combustion engines. Acronyms used to describe these various technologies are found in Table 1.

Combinations of primary energy resource, transportation fuel, and engine platform are referred to as *automotive transportation scenarios*. These scenarios are categorized as either hybrid vehicles or non-hybrid vehicles for the purpose of discussing the results. Each of these two categories includes 15 automotive transportation scenarios, which are summarized in Table 2.

3. Methodology

3.1 Definition of Metrics

All metrics are expressed on the basis of a unit distance traveled (one kilometer). Operating costs have units of cents per kilometer; water usage is expressed as liters per kilometer; primary energy consumption has units of megajoules per kilometer; and GHG emissions are expressed as grams of carbon dioxide equivalent per kilometer. These units were selected for their convenience in graphically comparing the results of the analysis.

We employed a normalization scheme to calculate an unweighted average of the four metrics to generate a single composite score for each scenario as a baseline case. Four additional cases using weighted averages of the four metrics were also explored. This composite scoring of the four sustainability metrics is called the CWEG (cost-water-energy-GHG) score. The calculation of CWEG begins by normalizing the values for each of the four metrics in the range of 0 to 100. For each metric, the automotive transportation scenario with the best economy (that is, lowest fuel operational cost, water usage, energy consumption, or GHG emissions per kilometer traveled) was assigned a score of 100. Other automotive transportation scenarios were assigned scores that were inversely proportional to the ratio of the metric values for that particular scenario and the best performing scenario. Formally, the normalized score, $S_{i,j}$ for the i^{th} scenario with respect to metric j was calculated according to:

$$S_{i,j} = {}^{X_{L,j}}\!/_{X_{i,j}} * 100 \quad (1)$$

where $X_{i,j}$ is the value of metric j for the i^{th} scenario and $X_{L,j}$ is the lowest value (best economy) of metric j among the various scenarios. The composite score for the i^{th} scenario, $CWEG_i$, is calculated as the average of all four normalized scores for that scenario.

$$CWEG_i = \frac{1}{4}\sum_{j=1}^{4} S_{i,j} \quad (2)$$

It is important to note that $S_{i,j}$ and $CWEG_i$ must be recalculated if a new scenario is introduced that has one or more metrics that are lower than the previous set of scenarios.

3.2 CWEG Data

WTW analysis is composed of two parts: well-to-tank and tank-to-wheels.[1,2] The well-to-tank (WTT) portion represents all processes that take place before the fuel is stored within a vehicle. Tank-to-wheels (TTW) characterizes the conversion of this energy into mechanical work (the vehicle's fuel consumption). The TTW data used here was adapted from Simpson,[1] who drew heavily on data from a report by Beer et al.[3] and other sources.[4] Data for WTT comes from many sources as subsequently described.

For a given automotive transportation scenario, the published literature reveals wide ranges for the four metrics. An arithmetic average gives undue weight to high range values under this circumstance, thus the geometric mean was used to calculate average values for metrics.

3.2.1 Operating Cost

The operating cost of a vehicle includes fuel refining costs and capital costs of the vehicle platform. Fuel refining cost is the sum of the cost of primary energy used for fuel production and other processing costs such as labor, utilities, and chemicals.[5] Because primary energy resources have proved highly variable over time, average inflation-adjusted costs (2010 dollars) were calculated over time frames indicated below for various primary energy sources. Inflation factors came from the Bureau of Labor Statistics.[6] Capital costs for vehicles and vehicle subsystems (such as battery packs) were straight line depreciated over their expected lifetimes. Other operating costs associated with an automotive transportation scenario, such as infrastructure depreciation for new kinds of fueling stations, have been deliberately excluded in this analysis. These are often difficult to calculate and can distort comparisons between technologies that require new infrastructure investment (fuel cell, battery electric, or compressed natural gas vehicles) and those that rely on existing but aging infrastructure (internal combustion engines fueled by liquid hydrocarbons). Estimated fuel refining (or electric generation) costs used in this study are summarized in Table 3.

The cost of refining petroleum-based gasoline and diesel is the sum of the monthly-averaged market price (rather than extraction cost) of petroleum between 1989 and 2009[7] and other fuel refining costs as reported in Gary, Handwerk, and Kaiser.[8] The cost of refining synthetic gasoline and diesel from tar sands (TS) and oil shale (OS) is the sum of the production cost of synthetic crude oil from these alternative energy resources (rather than the market price of petroleum) and other fuel refining costs as reported in Gary, Handwerk, and Kaiser.[8] The production costs of synthetic crude oil from tar sands (TS SCO) was assumed to be $73 per barrel in 2010 dollars, which is based on Shell's Athabasca Oil Sands Project in Canada.[9] As a caveat, TS SCO production costs in the U.S. are likely to be higher due to less favorable characteristics of TS deposits in the U.S.[10] Unlike TS, oil shale (OS) has yet to be commercially exploited to any significant extent, and there is more uncertainty about the cost of producing synthetic crude oil from oil sands (OS SCO). First-of-a kind OS SCO facilities will likely produce SCO in the range of $78 to $106 per barrel (2010 dollars).[11,12] For this analysis, a geometric mean of $91 per barrel was assumed for OS SCO.

For automotive transportation scenarios based on compressed natural gas (CNG), the monthly-averaged market price for natural gas in the U.S. from 1989 to 2009 was employed.[13] Other processing costs for this scenario, consisting mostly of gas compression, are estimated from Beer, et al.[3]

In the case of battery electric vehicles, fuel refining is the generation of electric power to charge electric vehicles (that is, the fuel is electrochemical energy stored in batteries). One electric vehicle scenario assumes power is obtained from the U.S. electrical grid, which charges different rates to different kinds of customers. For this analysis it was assumed that industrial electricity rates applied. The cost, averaged between all months from 1996 to 2009, was 6 cents per kilowatt-hour.[14] The other electric vehicle scenario assumed power was obtained from natural gas-fired combined cycle (NGCC) plants, which are more energy efficient and emit fewer greenhouse gases than the rest of the U.S. electric grid. This cost was 7 cents per kilowatt-hour in 2010 dollars.[15]

The cost of hydrogen produced via electrolysis and from coal gasification come from the U.S. National Research Council Committee report on hydrogen energy.[16] The cost of cellulosic ethanol was found by taking the geometric mean of several values presented by Kazi, et al.[17] The production cost of ethanol from grain was obtained from the study by Kwiatkowski et al.[18]

Offer, et al provided vehicle capital cost estimations for the BEV, gasoline ICE, FCEV, and FCHEV platforms.[19] It was assumed that the ethanol ICE and HEV platforms had identical costs to their gasoline counterparts.[20] Capital costs for the other vehicle platforms (gasoline HEV, diesel ICE, diesel HEV, CNG ICE, and CNG HEV) were found by multiplying data presented by Offer, et al[19] by the ratio between the cost of a vehicle platform and the cost of a gasoline ICE vehicle. This ratio was found by consulting manufacturer data.[21,22,23]

It was assumed that the battery in a BEV will last 1,000 cycles, which translates into a lifetime of roughly 150,000 kilometers when combined with manufacturer data on driving range per cycle.[24] FCEV’s are estimated to have lifetimes of 100,000 kilometers, and it was assumed that FCHEV’s had identical lifetimes.[25] All other vehicle platforms were assumed to have lifetimes of 240,000 kilometers. Vehicle lifetime and power train costs for HEV’s and ICE’s burning hydrogen were assumed to be equal to HEV’s and ICE’s running on CNG.

The capital costs and vehicle lifetimes used in this analysis are tabulated in Table 4.

3.2.2 Water Usage

Water usage is defined as withdrawal from any water source, and is mainly the result of primary energy extraction and fuel refining. Water usage data are summarized in Table 5. Most water usage data (OS SCO, TS SCO, petroleum-based gasoline and diesel, hydrogen from coal gasification, and CNG) were adapted from Gleick.[26] Water usage analysis for scenarios based on electricity, hydrogen, and ethanol are described below.

Water usage for electric power generation varies widely for different kinds of primary energy consumption (biomass, coal, natural gas, nuclear, wind, etc). For this study a national average was estimated that took into account the mix of power generation technologies in the United States and their different water consumption rates. This required calculating both the amount of water consumed in extracting fossil fuels and converting these primary energy sources into electricity. Water consumption for coal and natural gas extraction came from Gleick as well as King and Webber.[26,27] These data were weighted according to their contribution to total electricity production in the U.S.[27] No carbon capture and sequestration was assumed for any of the electric power scenarios. Water consumption for coal-fired (steam) power plants came from Torcellini, Long, and Judkoff[28] while water consumption for natural gas-fired (combined cycle) power plants was calculated by adding the water needed for fuel extraction[27] to the water needed for steam condensing.[15]

Water usage for production of hydrogen via electrolysis was calculated according to water decomposition stoichiometry. It should be noted that water directly consumed by electrolysis is small compared to the water consumed to produce the electricity needed for electrolysis, whether the electricity comes from a steam power plant or hydroelectric power plant.

Water consumption in crop production depends upon whether the crop is irrigated. Only 4% of the U.S. corn crop is currently irrigated,[29] but it accounts for much of the water usage associated with grain ethanol. Water consumption for converting corn grain to ethanol also comes from data presented by Aden.[29] Water usage for production of cellulosic biomass was based on non-irrigated cropping systems.[29] Water consumption for cellulosic biofuels depends upon whether the process is biochemical or thermochemical. For this analysis, the geometric mean in water consumption for these two options was employed.[29]

3.2.3 Energy Consumption

Primary energy consumption for the production of gasoline and diesel from petroleum comes from Simpson.[1] Primary energy consumption for the use of compressed natural gas in internal combustion engines also comes from Simpson.[1]

The overall thermodynamic efficiency of the U.S. electric grid was estimated from 2008 data obtained from the U.S. Energy Information Administration.[30] Net electric generation for each power plant was divided by the national total amount of energy consumed for generating electricity. These results were then summed to obtain a nationally averaged electric generation efficiency, which was roughly 33%.

In several instances WTT energy consumption was calculated from overall energy efficiencies of processes reported in the literature. This included 54% for OS SCO;[31] 70-75% for TS SCO;[32] 62.3% for hydrogen from coal gasification;[33] 54% for NGCC electric power;[34] 38% for grain ethanol;[35] 36% for cellulosic ethanol.[2]

Table 6 includes both TTW energy consumption and WTW energy consumption. The calculation of TTW is based on lower heating values of fuels, which are tabulated in Table 3.

3.2.4 Greenhouse Gas Emissions

Greenhouse gas emissions for each automotive transportation scenario are presented on the basis of both energy consumption (g CO2/MJ) and distance driven (g CO2/km) in Table 6. Greenhouse gas emissions associated with petroleum-derived fuels and compressed natural gas were adopted from Simpson.[1]

TS SCO and OS SCO emissions were estimated by taking the geometric mean of the high and low cases given by Brandt and Farrell,[12] who state that the order of magnitude of the GHG emissions estimate for OS SCO has been corroborated by other sources, but the exact value is highly uncertain.

Greenhouse gas emissions for power from the electric grid (g CO_2/MW) were found by dividing the total emissions attributed to the electric sector (g CO2/yr) by the net generation (MWh) for

2008. [14,35] The GHG emissions associated with NGCC were adopted from Klara and Wimer,[15] which assumes no carbon capture and sequestration is employed.

GHG emissions for hydrogen production using power from the electric grid are from Brinkman et al.[4] for the P90 scenario (90% probability that values will be at or below what is specified). Greenhouse gas emissions for hydrogen produced via coal gasification were estimated from data presented in the U.S. National Research Council Committee report assuming use of currently available technology and no carbon capture.[16]

Grain ethanol GHG emissions are estimated as the geometric mean of the values presented for several configurations of ethanol plants presented in Liska et al.[36] while emissions for cellulosic ethanol are from Farrell et al.[37]

4. Results

CWEG scores for non-hybrid vehicle platforms are given in Figure 2. CWEG scores for hybrid vehicle platforms are shown in Figure 3. These results are discussed below.

4.1 Compressed Natural Gas

Despite reliance on fossil fuels, compressed natural gas (CNG) powered vehicles had the highest CWEG scores among all the automotive transportation scenarios, scoring well in all sustainability metrics. Vehicles fueled with CNG had CWEG scores of 71 and74 for non-hybrid and hybrid scenarios, respectively, compared to 45 for the next highest scoring fuel scenario. CNG needs little processing once extracted, which helps minimize primary energy consumption.

The amount of water consumed for fuel processing is also very low at 0.02 and0.03 L/km for the non-hybrid and hybrid scenarios, respectively, compared to an average of 3 L/km.[26] Vehicle operating costs of CNG are roughly one-fourth the average cost among the scenarios investigated, making it the least expensive automotive scenarios on the basis of dollars per kilometer. On the other hand, GHG emissions from CNG are significantly higher than any of the renewable energy scenarios. It should be noted that the price of CNG used in this analysis is based on historical prices; future prices could increase significantly if CNG was widely used for transportation. Because of its wide use to heat homes and businesses, CNG prices are extremely sensitive to weather, historically varying by as much as a factor of seven in the past decade,[38] which detracts from its attractiveness as transportation fuel.

4.2 Electricity

The battery electric vehicle (BEV) scenario using electric power from a natural gas-fired combined cycle (NGCC) power plant performed well in this analysis, with CWEG scores of 39 and 37, respectively, for the non-hybrid and hybrid vehicle categories. This BEV scenario ranked third in non-hybrid vehicle category. The greatest factors in lowering the overall score of NGCC BEV scenarios were vehicle operating costs and the high water usage associated with steam condensing at the NGCC power plant. Although the cost of electricity per kilometer driven is attractive compared to other fuel options, the high cost of batteries and their relatively short life added considerably to the operating cost of the BEV.

Low primary energy consumption was the leading reason the NGCC BEV scenarios scored so well. In fact, the NGCC BEV had the lowest WTW energy consumption of all the automotive transportation scenarios. Battery electric vehicles have a distinct advantage over vehicles powered by combustion engines because of the higher efficiency of converting electrochemical energy to motive power compared to burning fuels in internal combustion engines. This advantage is lessened when combustion engines are operated as hybrid systems.

BEVs charged from the U.S. electric grid did not fare as well in this analysis placing in the bottom fourth of both groups. Battery electric vehicles charged from the current U.S. electric grid scored between 23 and 24. This scenario suffered from relatively high water usage, which is attributable to the relatively large contribution of hydroelectric power to the U.S. grid. The large impoundments of water maintained for hydroelectric stations promote evaporation of water, which must be counted against water usage for this scenario.[28] High power train costs and a relatively short vehicle lifetime were also responsible for the grid BEV scoring so low.

4.3 Ethanol

Cellulosic ethanol placed fourth in the non-hybrid group with a score of 37, and fifth among the hybrids with a score of 41. Cellulosic ethanol has relatively low GHG emissions and water usage. On the other hand, primary energy consumption is well above the average of the scenarios. Fuel refining cost is also higher than average, which is attributable to both relatively high cost of biomass feedstocks compared to fossil fuels and fuel processing costs that remain high at present. Grain ethanol did not fare nearly as well as cellulosic ethanol, with CWEG scores of 28 and 33 for the non-hybrid and hybrid vehicle groups, respectively, which is well below petroleum-derived gasoline and diesel. High water usage and primary energy consumption account for the relatively poor showing of grain ethanol. This could be improved by eliminating irrigated corn from the feedstock supply and reducing drying and distillation costs in fuel production.

4.4 Hydrogen

The fuel cell electric vehicle (FCEV) and fuel cell hybrid electric vehicle (FCHEV) powered by hydrogen produced from coal gasification scenarios respectively scored 29 and 31 in the non-hybrid and hybrid groups. Total energy usage associated with FCEV's powered by hydrogen from coal, although not as low as for the BEVs, is lower than most other scenarios presented here. Greenhouse gas emissions on the basis of grams of carbon dioxide-equivalent per kilometer traveled are lower than the average among the scenarios, which can be explained by the superior efficiency of the FCEV or FCHEV compared to an ICE or HEV. Water usage for this automotive transportation scenario is also lower than the average among the scenarios. High power train costs combined with a relatively short lifetime made the vehicle operating costs the main contributing factor to the low score of these scenarios.

The ICE vehicle fueled by hydrogen from coal gasification had a CWEG score of 37 within the non-hybrid vehicle group, which made it slightly superior to petroleum-based gasoline and slightly inferior to petroleum-based diesel. When operated as a hybrid vehicle, the hydrogen-powered ICE vehicle had a CWEG score of 45, which placed it just below HEV's fueled by anything petroleum-based. All vehicle scenarios based on hydrogen from coal gasification consumed less water than petroleum-based fuels, which can be attributed to the high water consumption of enhanced recovery methods sometimes used for crude oil.[26] The ICE and HEV platforms do not have the high operating costs of the FCEV platform, which explains the higher score of these scenarios.

Hydrogen from electrolysis using power from the electric grid had CWEG scores of 13 and 17, respectively, for the non-hybrid and hybrid vehicle groups, which are the second lowest scores among the automotive vehicle scenarios evaluated in this study. Much of the disadvantage arises from high primary energy consumption required to overcome multiple conversion losses including those associated with electric power generation, electrolysis, and compression of hydrogen. Water usage is fairly high compared to the other fuel types, mostly due to generation of grid electricity.

4.5 Petroleum-Derived Gasoline and Diesel

Petroleum-derived gasoline and diesel ranked in the top half of the non-hybrid group and in the top three in the hybrid group with diesel scoring 41 and 45, respectively, and gasoline scoring 36 and 44, respectively. Gasoline and diesel have ICE’s and HEV’s have the lowest power train costs, highest vehicle lifetimes, and relatively low fuel refining costs among the scenarios, making their operating costs lower than most other scenarios. Since this scenario assumes purchase of crude oil at market prices, production costs would likely be significantly lower if a petroleum company extracted its own crude oil and refined it into final fuel products. The primary energy consumption for both gasoline and diesel is significantly lower than most other fuels. Low primary energy consumption and operating costs are the main reasons that these scenarios scored as well as they did.

4.6 Synthetic Crude Oil

Diesel derived from tar sand synthetic crude oil (TS SCO) respectively ranked sixth and seventh for the hybrid and non-hybrid groups.. TS SCO gasoline scored just below TS SCO diesel in both groups. CWEG scores for TS SCO diesel were 33 and 38 for non-hybrid and hybrid options, respectively. CWEG scores for TS SCO gasoline were 27 and 35 for non-hybrid and hybrid options, respectively. The higher cost of synthetic crude oil from tar sands compared to petroleum purchased at market prices is primarily responsible for the different CWEG scores among these scenarios. It is very likely the price differential with be exacerbated if the tar sands are extracted in the U.S. Production costs were based on experience with commercially-attractive deposits of tar sand in Alberta,[10] whereas deposits in the U.S. have not been found attractive to exploit to date. Greenhouse gas emissions associated with TS SCO diesel and gasoline, while better than the average among vehicle scenarios evaluated, are worse than petroleum-based diesel and gasoline.

Synthetic gasoline and diesel from oil share synthetic crude oil (OS SCO) scored well below petroleum-based gasoline and diesel for both non-hybrid and hybrid groups. The costs for both of these fuels were based on an OS SCO production cost of about $90 per barrel, which is more than twice the assumed cost of petroleum.[11] Greenhouse gas emissions associated with OS SCO diesel and gasoline scenarios were much higher than most other scenarios investigated, and were far worse than petroleum-based scenarios. However, water usage for OS SCO derived fuels was lower than all other fuel types except for CNG. Diesel from OS SCO scored 27 and 30, respectively, while gasoline from OS SCO scored 22 and 28, respectively, for non-hybrid and hybrid options.

4.7 CWEG Scores with Unequal Weighting

CWEG scores for selected automotive transportation pathways were recalculated using different weighting factors for the four metrics. The technologies selected as representative of the diversity of scenarios included: CNG ICE, cellulosic ethanol ICE, grain ethanol ICE, and grid electrolysis hydrogen FCEV. A weight of 50% was applied to each of the four metrics in turn, with the remaining 50% divided equally among the other three metrics. The resulting weighted CWEG scores are plotted in Figure 4 (labeled cost, water, energy and GHG corresponding to the metric that was weighted at 50%) along with the previously calculated unweighted CWEG scores for these four scenarios.

In the case of unweighted CWEG scores, CNG had the highest score among the four selected scenarios followed by cellulosic ethanol, grain ethanol, and electric grid hydrogen. Very little change in the relatively scoring of the four scenarios is observed with changes in weighting except for the case where the GHG metric is weighted at 50%. In this case, cellulosic ethanol s slightly outscores the CNG scenario.

5. Conclusion

In evaluating automotive transportation scenarios, economies in cost, water usage, primary energy consumption, and greenhouse gas emissions should all be included as sustainability metrics. To better facilitate comparisons among fuel scenarios, a composite score of these four metrics called the CWEG was devised.

Thirty automotive transportation scenarios were evaluated, which consisted of hybrid and non-hybrid versions of fifteen distinct energy utilization pathways. Compressed natural gas had the highest CWEG scores (71 and 74, respectively, for non-hybrid and hybrid options) out of a possible score of 100, which are well above the next highest score, which was 45 for conventional diesel HEV's. The study quantifies the advantages of natural gas for automotive transportation, whether used as compressed natural gas directly in vehicles or used to generate electric power for BEVs. However, both CNG and BEV scenarios are disadvantaged by the need for expensive infrastructure changes, including vehicles, fuel storage and distribution, and fueling stations, before wide-scale adoption can be achieved. The cost of these infrastructure changes is difficult to estimate accurately, but clearly will add significantly to the overall operating cost of these automotive transportation scenarios. Nevertheless, cost is only one of four economies included in this analysis and the natural-gas based transportation scenarios are likely to remain relatively attractive in a CWEG analysis even if new infrastructure is included as a depreciated cost of vehicle operation.

Fuel cell vehicles running on hydrogen generated with power from the U.S. electric grid had the lowest CWEG score, ranging from 13 to 15. This poor showing resulted from having low scores for all four CWEG sustainability metrics. Although eliminating coal plants from the U.S. electric grid would greatly reduce GHG emissions for hydrogen fuel scenarios, the other metrics (operating cost, primary energy consumption, and water usage) remain among the highest of all the scenarios evaluated.

6. References and Notes

1. Simpson AG. Full-Cycle Assessment of Alternative Fuels for Light-Duty Road Vehicles in Australia. University of Queensland, Australia (2005)

2. Unnasch S. Alcohol Fuels from Biomass: Well-to-Wheel Energy Balance. Technical Report. TIAX LLC, Cupertino, CA

3. Beer T, Grant T, Morgan G, Lapszewicz J, Anyon P, Edwards J, et al. Comparison of Transport Fuels, Australian Greenhouse Office, Canberra (2001)

4. Brinkman N, Wang M, Weber T, Darlington T. Well-to-Wheels Analysis of Advanced Fuel/Vehicle Systems – A North American Study of Energy Use, Greenhouse Gas Emissions, and Criteria Pollutant Emissions. General Motors (2005)

5. Brown RC. Biorenewable Resources: Engineering New Products from Agriculture. Wiley-Blackwell, Ames, IA (2003)

6. U.S. Bureau of Labor Statistics. U.S. Bureau of Labor Statistics. http://www.bls.gov/cpi/ [accessed 16 March 2010]

7. U.S. EIA. Petroleum Navigator. U.S. Energy Information Administration. http://tonto.eia.doe.gov/dnav/pet/pet_sum_top.asp [accessed 27 April 2010]

8. Gary JH, Handwerk GE, Kaiser MJ. Petroleum Refining: Technology and Economics. 5th ed. Marcel Dekker, Inc, New York (2007)

9. Stockman L. Tar Sands Oil Means High Gas Prices. Corporate Ethics International (2010)

10. U.S. DOE. Tar Sands Fact Sheet. U.S. Department of Energy. Available from: http://fossil.energy.gov/programs/reserves/npr/Tar_Sands_Fact_Sheet.pdf [accessed 22 March 2010]

11. Bartis JT, LaTourrette T, Dixon L, Peterson DJ, Cecchine G. Oil Shale Development in the United States: Prospects and Policy Issues. RAND, Santa Monica, CA (2005)

12. Brandt AR, Farrell AE, Scraping the bottom of the barrel: greenhouse gas emission consequences of a transition to low-quality and synthetic petroleum resources. Climatic Change, pp. 241-263 (October 2007)

13. U.S. EIA. Natural Gas Prices by Sector. U.S. Energy Information Administration. http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_m.html [accessed 27 April 2010]

14. U.S. EIA. Electric Power Monthly. U.S. Energy Information Administration. http://www.eia.doe.gov/cneaf/electricity/epm/epm_sum.html [accessed 27 April 2010]

15. Klara JM, Wimer JG, DOE-National Energy Technology Laboratory. http://www.netl.doe.gov/energy-analyses/pubs/deskreference/B_NGCC_051507.pdf [accessed 16 March 2010]

16. U.S. National Research Council Committee on Alternatives and Strategies for Future Hydrogen Production and Use, National Academy of Engineering, U.S. National Academy of Sciences. The Hydrogen Economy: Opportunities, Costs, Barriers, and R&D Needs. National Academies Press, Washington, D.C. (2004)

17. Kazi FK, Fortman JA, Anex RP, Hsu DD, Aden A, Dutta A, et al., Techno-economic Comparison of Process Technologies for Biochemical Ethanol Production from Corn Stover. Fuel (2010)

18. Kwiatkowski JR, McAloon AJ, Taylor F, Johnston DB. Modeling the process and costs of fuel ethanol production by the corn dry-grind process. Industrial Crops and Products, pp. 288-296 (2006)

19. Offer, G. J., Howey, D., Contestabile, M., Clague, R., and Brandon, N.P. Comparative analysis of battery electric, hydrogen fuel cell and hybrid vehicles in a future sustainable road transport system. Energy Policy 38 (1) (2010), pp. 24-29.

20. Safaei Mohamadabadi, H. Tichkowsky, G., and Kumar, A. Development of a multi-criteria assessment model for ranking of renewable and non-renewable transportation fuel vehicles. Energy 34 (1) (2009), pp. 112-125.

21. American Honda Motor Company, Inc. Honda cars. American Honda Motor Co. Inc.; 2011. See also: http://automobiles.honda.com/.

22. Toyota Motor Sales U.S.A., Inc. Toyota cars, trucks, SUVs & accessories. Toyota Motor Sales U.S.A.; 2011. See also: http://www.toyota.com.

23. Volkswagen of America, Inc. Volkswagen of America. Volkswagen of America, Inc; 2011. See also: http://www.vw.com/en.html.

24. Nissan USA. Nissan cars, hybrid, electric, crossovers, SUVs, trucks. Nissan USA; 2011. See also: http://www.nissanusa.com.

25. IEA. IEA Energy Technology Essentials: Fuel Cells. International Energy Agency. http://www.iea.org/techno/essentials6.pdf [accessed 30 January 2011]

26. Gleick PH. Water and Energy. Annual Review of Energy and the Environment, pp. 267-299 (1994)

27. King CW, Webber EM, The Water Intensity of the Plugged-In Automotive Economy. Environmental Science & Technology, pp. 4305-4311 (February 2008)

28. Torcellini P, Long N, Judkoff R. Consumptive Water Use for U.S. Power Production. Technical Report. National Renewable Energy Laboratory, Golden, CO (2003)

29. Aden A. Southwest Hydrology. http://www.swhydro.arizona.edu/archive/V6_N5/feature4.pdf [accessed 16 March 2010]

30. U.S. EIA. Electricity Database Files. U.S. Energy Information Administration. http://www.eia.doe.gov/cneaf/electricity/page/eia906_920.html [accessed 29 November 2010]

31. Brandt AR, Converting Green River oil shale to liquid fuels with the Alberta Taciuk Processor: energy inputs and greenhouse gas emissions. Environmental Science & Technology (August 2008)

32. Lee S, Speight JG, Loyalka SK. Handbook of Alternative Fuel Technologies. CRC Press, Boca Raton, FL (2007)

33. Ruether J, Ramezan M, Grol E. Life-Cycle Analysis of Greenhouse Gas Emissions for Hydrogen Fuel Production in the United States from LNG and Coal. Technical Report. National Energy Technology Laboratory (2007)

34. Kehlhofer R, Hannemann F, Stirnimann F, Rukes B. Combined-Cycle Gas & Steam Turbine Power Plants. 3rd ed. Pennwell, Tulsa, OK (2009)

35. U.S. EIA. Emissions of Greenhouse Gases Report. U.S. Energy Information Administration. http://www.eia.doe.gov/oiaf/1605/ggrpt/carbon.html [accessed 16 March 2010]

36. Liska AJ, Yang HS, Bremer VR, Klopfenstein TJ, Walters DT, Erickson GE, et al. Improvements in Life Cycle Energy Efficiency and Greenhouse Gas Emissions of Corn-Ethanol. Journal of Industrial Ecology (2008)

37. Farrell AE, Plevin RJ, Turner BT, Jones AD, O'Hare M, Kammen DM, Ethanol Can Contribute to Energy and Environmental Goals, Science, pp. 508-506 (January 2006)

38. U.S. EIA. Natural Gas Data, Reports, Analysis, Surveys. U.S. Energy Information Administration. http://www.eia.gov/oil_gas/natural_gas/info_glance/natural_gas.html [accessed 15 August 2010]

39. Kroposki B, Levene J, Harrison K, Sen PK, Novachek F. Electrolysis: Information and Opportunities for Electric Power Utilities. NREL, Golden, CO, (2006)

40. U.S. EIA. Average Retail Price of Electricity to Ultimate Customers: Total by End-Use Sector. U.S. Energy Information Administration. http://www.eia.doe.gov/cneaf/electricity/epm/table5_3.html [accessed 27 April 2010]

41. Unnasch S, Pont J, Hooks M, Chan M, Waterland L, Rutherford D. Full fuel cycle assessment well to tank energy inputs, emissions, and water impacts. TIAX LLC, Cupertino, CA (2007)

42. ORNL. Oak Ridge National Laboratory. http://bioenergy.ornl.gov/papers/misc/energy_conv.html [accessed 16 March 2010]

Appendix

Table 1: Nomenclature used with automotive transportation scenarios

Abbreviation	Meaning
CNG	Compressed Natural Gas
NGCC	Natural Gas Combined Cycle
TS SCO	Tar Sands Synthetic Crude Oil
OS SCO	Oil Shale Synthetic Crude Oil
BEV	Battery Electric Vehicle
FCEV	Fuel Cell Electric Vehicle
FCHEV	Fuel Cell Hybrid Electric Vehicle
ICE	Internal Combustion Engine
HEV	Hybrid Electric Vehicle

Table 2: Automotive transportation scenarios

Primary Energy Source	Energy Carriers	Primary Movers
Conventional Crude Oil	Gasoline	ICE, HEV
Conventional Crude Oil	Diesel	ICE, HEV
Tar Sands Synthetic Crude Oil	Gasoline	ICE, HEV
Tar Sands Synthetic Crude Oil	Diesel	ICE, HEV
Oil Shale Synthetic Crude Oil	Gasoline	ICE, HEV
Oil Shale Synthetic Crude Oil	Diesel	ICE, HEV
Natural Gas	Compressed Natural Gas	ICE, HEV
Natural Gas	Electricity	BEV
Electric Grid	Electricity	BEV
Electric Grid	Hydrogen	ICE, HEV
Electric Grid	Hydrogen	FCEV, FCHEV
Coal	Hydrogen	ICE, HEV
Coal	Hydrogen	FCEV, FCHEV
Corn Grain	Ethanol	ICE, HEV
Corn Stover	Ethanol	ICE, HEV

Table 3: Fuel refining costs*

Fuel	Price	Price Units	LHV	LHV Units
Gasoline	1.32[7,8]	$/gal	121[42]	MJ/gal
Diesel	1.47[7,8]	$/gal	138[42]	MJ/gal
Grain Ethanol	1.16[18]	$/gal	80[42]	MJ/gal
Cellulosic Ethanol	6.05[17]	$/GGE	121[42]	MJ/gal
CNG	5.75[3,13]	$/1000 ft^3	981[42]	MJ/1000 ft^3
Electricity	0.06[14]	$/kWh	-	-
Coal Hydrogen	1.11[16]	$/kg	120[16]	MJ/kg
Grid Hydrogen	5.00[16]	$/kg	120[16]	MJ/kg
OS Gasoline	2.38[8,11]	$/gal	121[42]	MJ/gal
OS Diesel	2.64[8,11]	$/gal	138[42]	MJ/gal
TS Gasoline	1.95[8,9]	$/gal	121[42]	MJ/gal
TS Diesel	2.16[8,9]	$/gal	138[42]	MJ/gal

*All values ammended by author as described in the methodology section

Superscripted numbers represent numerical references used in this paper

Table 4: Vehicle platform costs

Platform	Cost ($)	Lifetime (km)
Gasoline ICE	2,200[19]	240,000
Gasoline HEV	3,100	240,000
Diesel ICE	2,591	240,000
Diesel HEV	3,651	240,000
CNG ICE	3,548	240,000
CNG HEV	4,999	240,000
Ethanol ICE	2,200	240,000
Ethanol HEV	3,100	240,000
BEV	26,700[19]	150,000[24]
FCEV	47,400[19]	100,000[25]
FCHEV	19,700[19]	100,000

Superscripted numbers represent numerical references used in this paper.

Table 5: Water usage

Feedstock	Water Usage (L/MJ)
Crude Oil	0.253[26]
Corn Grain	1.646[29,42]
Corn Stover	0.160[29,42]
NG	0.009[26]
Grid Electricity	2.305[27,28]
NGCC Electricity	0.362[27,37]
Coal	0.062[26]
Grid Electroylsis	2.380[27,28*]
OS SCO	0.182[26]
TS SCO	0.307[26]

*Value ammended by author as described in the methodology section

Superscripted numbers represent numerical references used in this paper

Table 6: Summary of primary energy consumption (WTW), greenhouse gas emissions (WTW GHG), refining costs, and water usage for thirty automotive transportation scenarios

Platform	WTT Energy (%)	WTT Energy (MJ/MJ)	TTW[1] (MJ/km)	WTW (MJ/km)	WTW GHG (gCO2/MJ)	WTW GHG (gCO2/km)	Operating Cost (cents/km)	Water Use (L/km)
Gasoline ICE	87.72[1]	1.14[1]	3.25	3.71	88.80[1]	288.60	3.55	0.94
Gasoline HEV	87.72[1]	1.14[1]	2.47	2.82	88.80[1]	219.34	2.69	0.71
TS SCO Gasoline ICE	74.46[31,32]	1.38[31,32]	3.25	5.14	119.12[12]	387.15	5.24	1.38
TS SCO Gasoline HEV	74.46[31,32]	1.38[31,32]	2.47	3.91	119.12[12]	294.23	3.98	1.05
OS SCO Gasoline ICE	53.83[31]	1.86[31]	3.25	8.10	176.23[12]	572.74	6.39	1.10
OS SCO Gasoline HEV	53.83[31]	1.86[31]	2.47	6.20	176.23[12]	435.29	4.86	0.84
Diesel ICE	79.00[1]	1.27[1]	2.62	3.32	91.90[1]	240.78	2.79	0.84
Diesel HEV	79.00[1]	1.27[1]	2.21	2.80	91.90[1]	203.10	2.35	0.71
TS SCO Diesel ICE	74.46[31,32]	1.38[31,32]	2.62	4.14	119.12[12]	312.10	4.10	1.11
TS SCO Diesel HEV	74.46[31,32]	1.38[31,32]	2.21	3.49	119.12[12]	263.26	3.46	0.94
OS SCO Diesel ICE	53.83[31]	1.86[31]	2.62	7.30	176.23[12]	461.72	5.01	0.89
OS SCO Diesel HEV	53.83[31]	1.86[31]	2.21	6.20	176.23[12]	389.47	4.23	0.75
Grain Ethanol ICE	60.27[36]	1.66[36]	3.08	8.11	44.60[36]	137.37	4.47	5.07
Grain Ethanol HEV	60.27[36]	1.66[36]	2.33	6.13	44.60[36]	103.92	3.38	3.84
Cellulosic Ethanol ICE	35.54[2]	2.81[2]	3.08	8.67	11.00[37]	33.88	15.40	0.49
Cellulosic Ethanol HEV	35.54[2]	2.81[2]	2.33	6.56	11.00[37]	25.63	11.65	0.37
CNG ICE	91.74[1]	1.09[1]	2.95	3.22	66.50[1]	196.18	1.73	0.03
CNG HEV	91.74[1]	1.09[1]	2.37	2.58	66.50[1]	157.61	1.39	0.02
Coal H2 ICE	62.30[16]	1.61[16]	2.71	5.07	156.33[16]	423.66	2.51	0.27
Coal H2 HEV	62.30[16]	1.61[16]	2.03	3.80	156.33[16]	317.36	1.88	0.20
Grid H2 ICE	30.70[4]	3.26[4]	2.71	13.17	315.50[4]	855.01	11.29	21.01
Grid H2 HEV	30.70[4]	3.26[4]	2.03	9.87	315.50[4]	640.47	8.46	15.74
Grid Li-Ion BEV	35.29[30]	2.83[30]	1.14	3.23	159.08[14,35]	181.35	1.90	7.45
NGCC Li-Ion BEV	54.41[34]	1.84[34]	1.14	2.41	83.86[30]	95.60	2.22	0.76
Coal H2 FCEV	62.30[16]	1.61[16]	1.66	3.11	156.33[16]	259.51	1.54	0.17
Coal H2 FCHEV	62.30[16]	1.61[16]	1.55	2.90	156.33[16]	242.32	1.43	0.15
Grid H2 FCEV	30.70[4]	3.26[4]	1.66	7.90	315.50[4]	523.73	6.92	12.87
Grid H2 FCHEV	30.70[4]	3.26[4]	1.55	7.38	315.50[4]	489.03	6.46	12.02

Superscripted numbers represent numerical references used in this paper

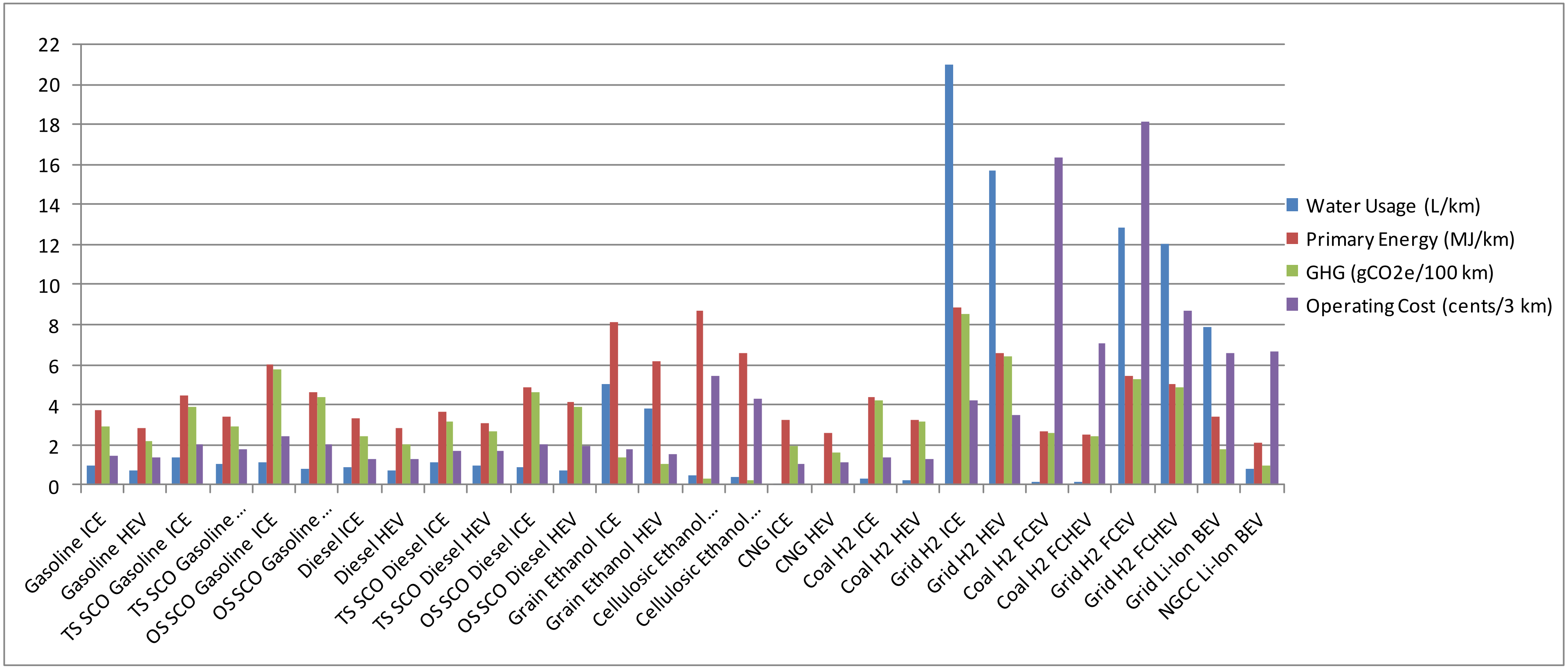

Figure 1: Four economies of vehicular transportation scenarios: water usage, primary energy, greenhouse gas (GHG) emissions, and fuel refining cost. Units are different for each of the four economies; refer to chart legend for appropriate units. See Table 1 for description of acronyms.

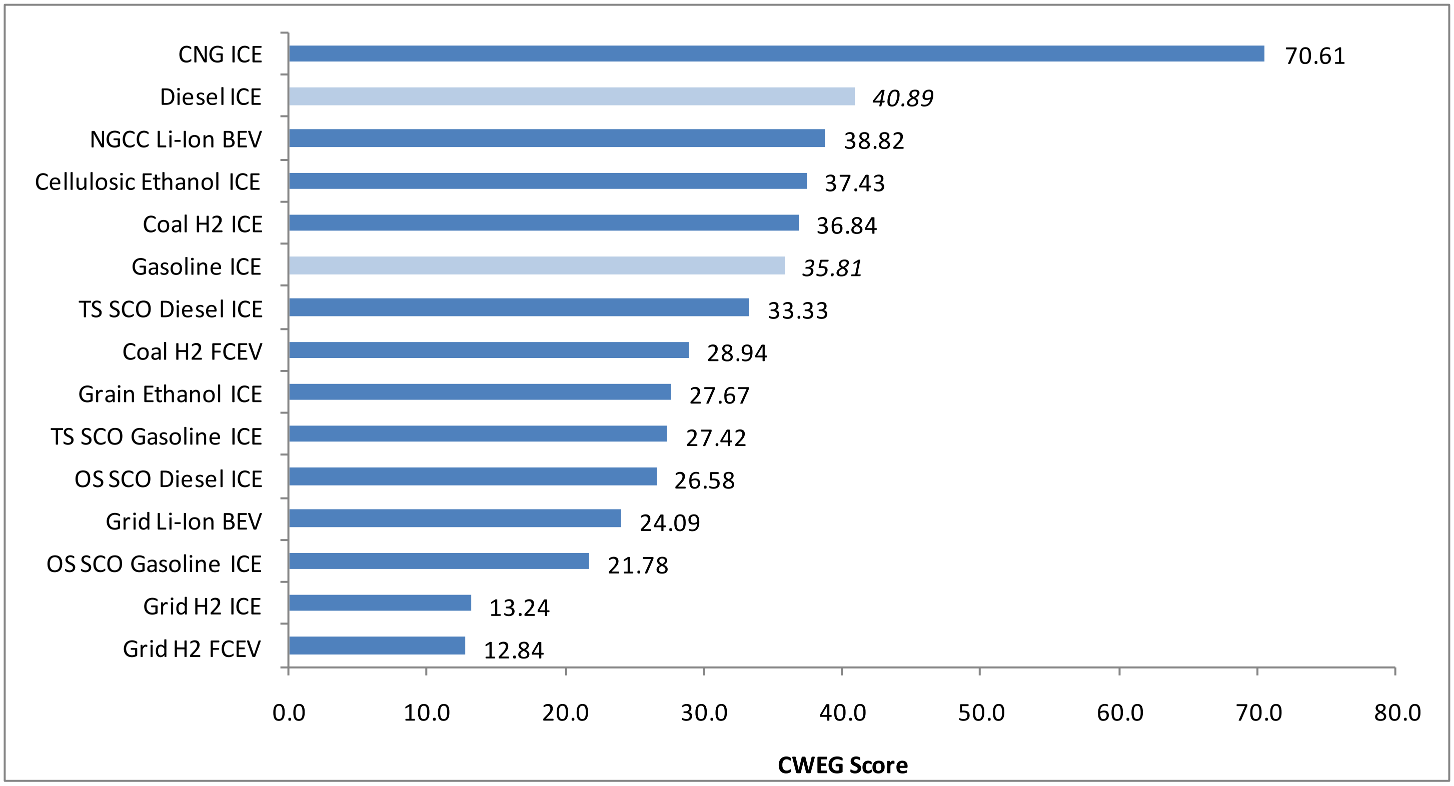

Figure 2: CWEG scores for fifteen non-hybrid vehicular transportation scenarios. See Table 1 for descriptions of acronyms.

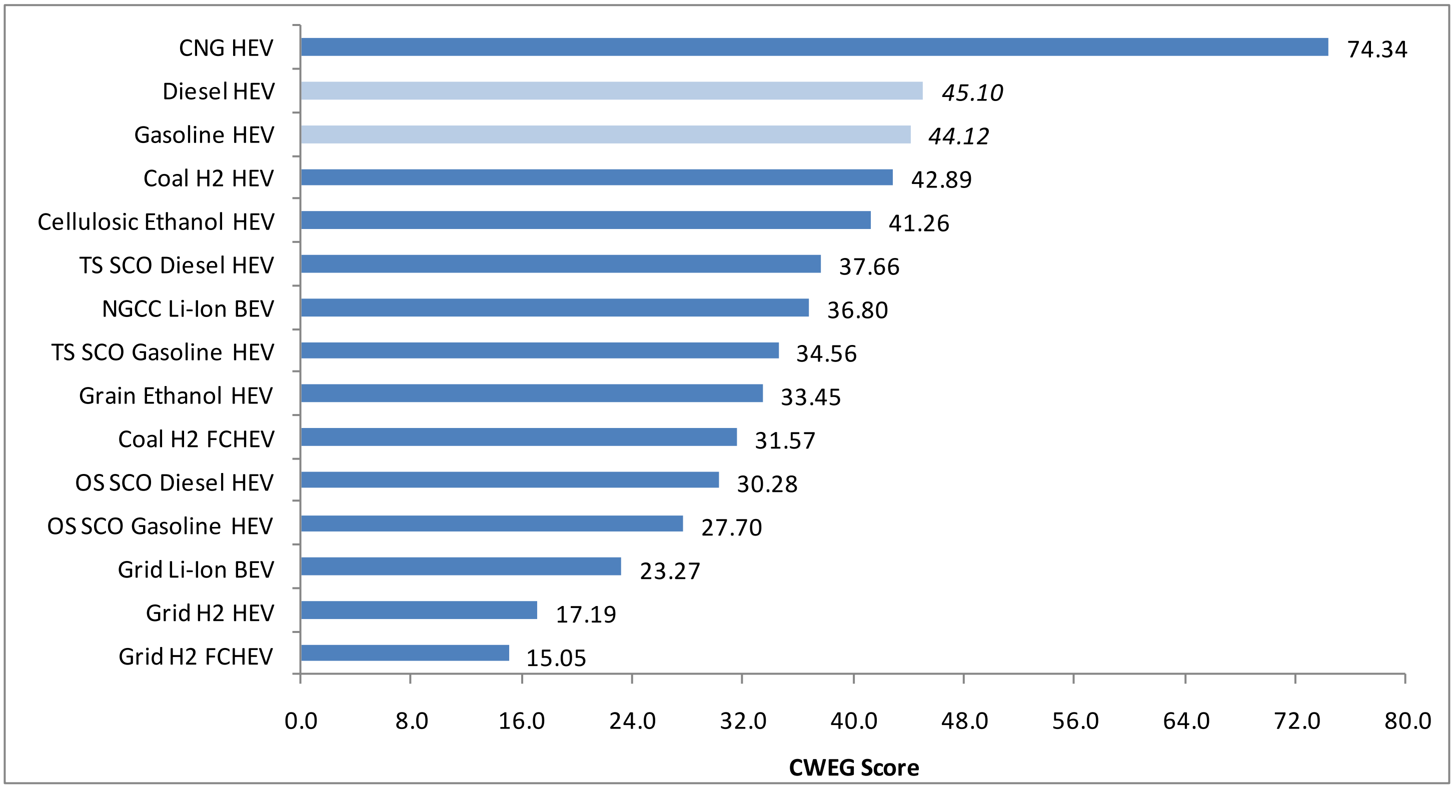

Figure 3: CWEG scores for fifteen hybrid vehicular transportation scenarios. See Table 1 for descriptions of acronyms.

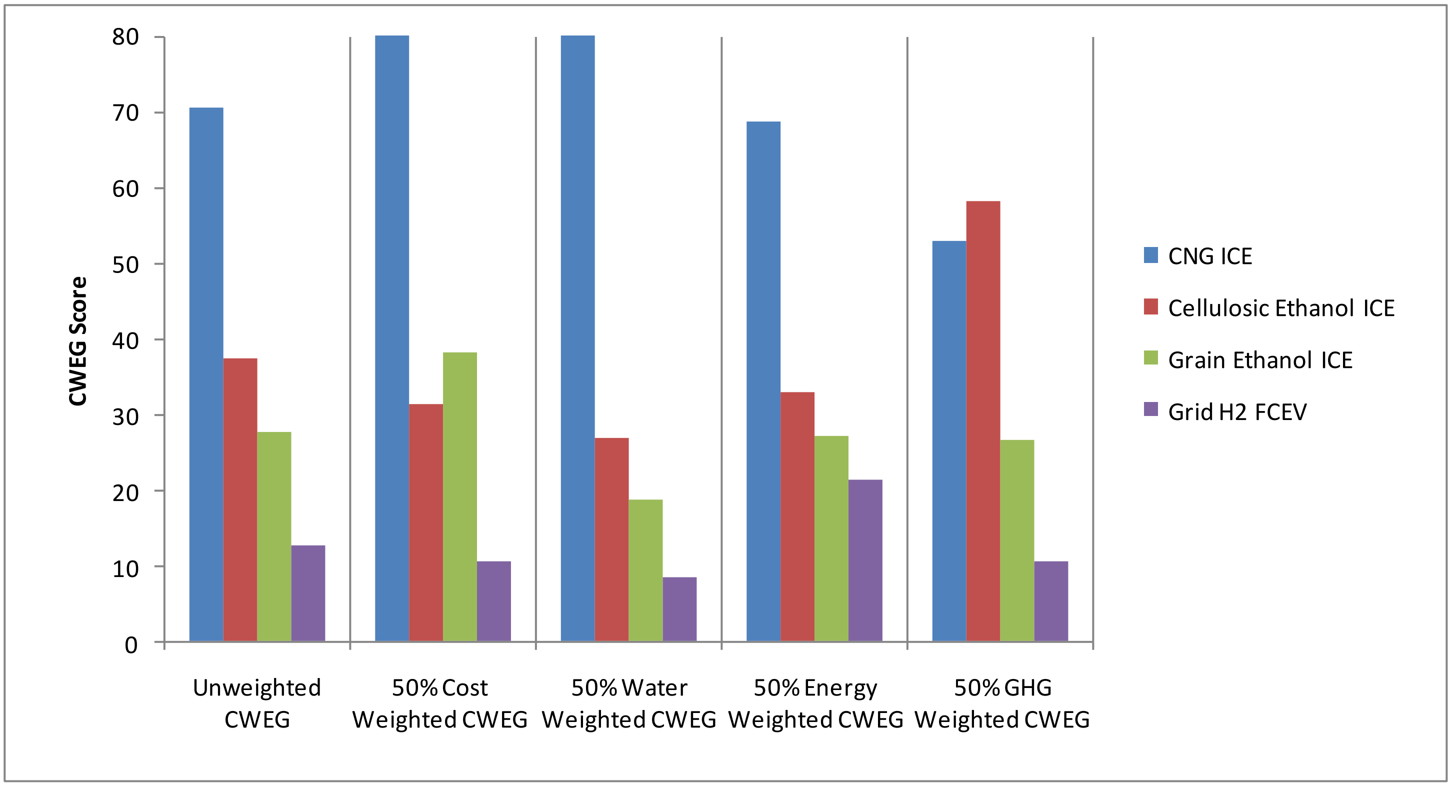

Figure 4: Effect of consecutive 50% weighting for each of the four metrics for four of the automotive scenarios.

Survey of Power Generation Technologies

A draft book chapter for *Handbook of Data Mining for Power Systems*

Josh D. Gifford[a], Robert C. Brown[a,b], Justin S. Voss[a]
[a]Department of Mechanical Engineering, Iowa State University
[b]Center for Sustainable Environmental Technologies, Iowa State University

Abstract

This chapter reviews twenty power generation technologies. Performance metrics include capital costs, operation and maintenance costs, criteria pollutants, energy conversion efficiency, greenhouse gas, non-methane volatile organic compound, oxides of sulfur and nitrogen, and particulate matter emissions. Estimates of capital cost reductions achieved by incremental capacity addition, commonly referred to as the learning rate for a new technology, have also been given.

Introduction

This chapter reviews twenty power generation technologies using a wide variety of metrics, which are defined in the next section. Surveyed technologies include fossil, nuclear, and renewable energy. This chapter is divided up into subsections corresponding to a specific technology. Each section contains information gathered from a literature review for each technology type, as well a brief description of how each technology works. Some technologies presented here, such as pulverized coal, nuclear, and solar thermal, can be categorized further into more specific technology types. In order to give a more general overview, the information presented here is an aggregate of these subcategories of technologies. Finally, estimates on capital cost reduction from capacity expansion are also given in the last section of this chapter.

Definition of Metrics

Performance metrics are summarized in Table 1. All cost data is adjusted for inflation to 2010 dollars using data from the Bureau of Labor Statistics. (1) The investment cost, given as million dollars per megawatt of capacity, represents the capital needed to build the facility. Retirement costs are typically assumed to range from negligibly small to anywhere from 3 to 15% of the investment cost. (2), (3), (4) This database assumes a retirement cost of 7.4% of the investment cost, which is the geometric mean of the assumed decommissioning costs found in Rama as well as Kannan, et al. (3), (4). Fixed operation and maintenance (O&M) costs have units of dollars per kilowatt of capacity per year, and are representative of things such as employee salaries and routine maintenance. (5) Variable operation and maintenance costs are given as dollars per megawatt-hour and are composed of costs arising from unexpected outages, lube oil, spare parts, etc. (5), (6) Variable O&M costs also include fuel costs, but these estimates have been excluded from this database.

The heat rate for a power plant is the ratio of fuel energy input to electrical energy output, and has units of million BTU per megawatt-hour (MMBTU/MWh). The thermodynamic conversion efficiency is found by multiplying the heat rate by a unit conversion factor:

$$\eta = \left(\frac{3.41}{HR}\right) * 100 \qquad (1)$$

where η is the conversion efficiency, HR is the heat rate (in units of million BTU per megawatt-hour), and 1 megawatt-hour is equal to 3.41 million BTUs.

Regulated emissions from power plants include oxides of nitrogen (NOx) and sulfur (SOx), particulate matter (PM), non-methane volatile organic compounds (NMVOC), and greenhouse gases (GHG). These are reported as kilograms per megawatt-hour of electrical energy out. Nitrogen dioxide (NO_2) is registered as a GHG gas and is excluded from the NOx category. Methane emissions are also accounted for under the GHG emissions category. Construction GHG emissions represent the greenhouse gas emissions that can be attributed to building a power plant, and are often expressed in the literature as kilograms of carbon dioxide equivalent (CO2e) per megawatt-hour. However, construction GHG emissions can also be expressed in terms of capacity instead of energy output. The estimated construction GHG emission category converts the GHG emissions per unit energy into Mg CO2e per megawatt of capacity by multiplying unit conversion factors with the mean construction time, given in years under the lead/lag time metric. This is formally expressed as:

$$EC = \frac{C * 8{,}760 * L}{1{,}000} \qquad (2)$$

where EC is the estimated construction GHG emissions, C is the construction GHG emissions (in kilograms CO2e per megawatt-hour), L is the lead/lag time of the power plant (in years), 8,760 is the number of hours per year and there are 1,000 kilograms in a Mg.

The facility land requirement is the physical footprint of the power plant, excluding land used for mining and offsite fuel preprocessing, per unit energy delivered over the lifetime of the plant expressed as square meters per megawatt-hour. The estimated facility land requirement is the physical footprint of the power plant per unit of power output, and has units of hectares per megawatt of capacity. This is found by multiplying unit conversion factors with the facility land requirement and lifetime of the plant, expressed in years under the lifetime metric. The estimated facility land requirement is formally expressed as:

$$EF = \frac{F * 8{,}760 * LT}{10{,}000} \qquad (3)$$

where EF is the estimated facility land requirement, F is the facility land requirement (in square meters per megawatt-hour), LT is the lifetime of the power plant (in years), 8,760 is the number of hours per year and 10,000 is the number of square meters in a hectare.

Forced outage rate (FOR), expressed as a percentage, estimates the probability that a power plant will have to shut down for an unexpected reason. (6)

The literature generally reveals a high range of values for these metrics, and as such, the high, mean, and low values are reported for each metric. In some cases there is insufficient data available to calculate a mean; only one value is reported under these circumstances.

Table 1: Summary of metrics

Metric	Units
Investment Cost*	$
Retirement Cost*	$
Fixed O&M*	$
Variable O&M*	$
Heat Rate	MMBTU/MWh
Conversion Efficiency	%
Operational NOx	kg/MWh
Operational SOx	kg/MWh
Operational PM	kg/MWh
Operational NMVOC	kg/MWh
Operational GHG	kg CO2e/MWh
Construction GHG	kg CO2e/MWh
Estimated Construction GHG	Mg CO2e/MW
Facility Land Requirement	m^2/MWh
Estimated Facility Land Requirement	ha/MW
Lifetime	years
Lead/Lag Time	years
FOR	%

*2010 dollars

Power Generation Technologies

This section provides the survey results of twenty power generation technologies. These technologies range from more conventional technologies such as pulverized coal, to less conventional technologies such as wave power. Power plants that rely on thermal energy input (i.e. biomass, coal, natural gas, and nuclear) typically use one of two thermodynamic cycles to create electricity: the Rankine cycle, and the Brayton cycle.

In the Rankine cycle, steam is produced in a boiler and sent through a steam turbine. The turbine spins a generator in order to create electricity. The steam then exists the turbine and is condensed into liquid water and pumped back into the boiler; completing the cycle. In the Brayton cycle, ambient air is drawn in, compressed, and sent into a gas turbine. (6) The air mixes with fuel, which then ignites in the combustion chamber of the turbine. The hot gases move through the turbine, which spins a generator, before being exhausted. Some power plants will use the exhaust of a Brayton cycle to provide the heat input for a Rankine cycle.

Nuclear

In the U.S. there are only two categories of commercially operating nuclear power plants : boiling water reactors (BWRs) and pressurized water reactors (PWRs). In both designs heat is produced from the fission of the fuel in the reactor, typically uranium. BWRs use the Rankine cycle to produce electricity. Typical temperatures and pressures for steam entering the turbine are around 300 °C and 7 MPa. (7)

PWRs are divided into two parts, the primary side and the secondary side. The primary side is enclosed within a containment structure and includes the reactor, pressurizer, reactor coolant pump(s), and steam generator(s). The pressurizer acts as a surge volume and helps maintain the primary side of the plant at the appropriate pressure. (7) High pressure water at approximately 14-16 MPa (5) is passed through the reactor on the primary side of the plant, where it is heated to around 320 °C. (7) The high temperature, high pressure water then goes into a steam generator where it transfers its heat to water on the secondary side of the plant. The high temperature, high pressure water then enters the steam generator where water from the secondary side of the plant is boiled to steam at a temperature of 300 °C and pressure of 8 MPa. (5) The steam is expanded through a turbine, which spins a generator to produce electricity. The steam is condensed into liquid water and pumped back into the steam generator.

The investment cost of nuclear power plants range from around \$2 to \$3.4 million per megawatt. (8), (9) Fixed O&M costs varied between \$34 to \$94 per kilowatt per year. (9), (10), (11) Variable O&M costs ranged from \$0.5 to \$6 per megawatt-hour. (9), (10) The heat rate varied between 9.7 and 10.6 million BTU per megawatt-hour, which corresponds to a thermal efficiency range of 32-35%. (9), (12), (13) Nuclear power plants have no operational emissions, providing a distinct advantage over many other types of power plants. GHG emissions associated with the construction of nuclear power plants are approximately 2 kilograms of carbon dioxide-equivalent per megawatt-hour. (14) Plant lifetime is between 30 and 60 years. (8), (15) The lead/lag time for constructing a new plant varies between 4 and 6.7 years. (8), (9) Estimates of the forced outage rate fell between 5% and 12%. (9), (15), (16) The high, mean, and low values for each metric for nuclear power has been tabulated in Table 2. The values reported here are typical for a Generation II nuclear facility.

Pulverized Coal

Coal-fired power plants made up approximately 45% of all electricity produced in the US in 2009. (17) These power plants use the Rankine cycle to produce power. Steam exists the boiler at temperatures typically around 600 °C pressures around 25 MPa. (6)

The investment cost for pulverized coal plants varies between \$1 and \$2.4 million per megawatt. (9), (18) Fixed O&M costs range from about \$16 to \$74 per kilowatt per year, while variable O&M costs are typically between \$2 and \$3.7 per megawatt-hour. (9), (11), (18) The heat rate for pulverized coal plants varies from 7.3 to 11.4 million BTU per megawatt-hour, which respectively correspond to thermodynamic efficiencies of 47% and 30%. (9) The operational NOx emissions are between 0.2 and 1.3 kilograms per megawatt-hour, and operational SOx emissions vary between 0.1 to 3 kilograms per megawatt-hour. (11), (18), (19) Operational particulate matter emissions range from around 0.01 to 0.16 kilograms per megawatt-hour. (11), (18), (19) Non-methane volatile organic compound emissions are roughly $2x10^{-3}$ kilograms per megawatt-hour. (18) Construction GHG emissions are estimated to be 21.3 kilograms of carbon dioxide equivalent per megawatt-hour. (14) Operational GHG emissions are between approximately 730 and 890 kilograms of carbon dioxide equivalent per megawatt-hour. (11), (12), (19) The estimated facility land requirement for pulverized coal plants varies between 0.2 and 1.1 hectares per megawatt. (20) The lifetime of pulverized coal plants ranges between 30 and 40 years. (12), (14), (18), (19) The lead/lag time for pulverized coal varies between 3.3 to 4.2

years. (9), (10), (21) The forced outage rate is between 2% and 8%. (9), (19) The high, mean, and low values for each metric for pulverized coal power plants have been tabulated in Table 3.

Combustion Turbines

Combustion turbines, or gas turbines, use the Brayton cycle to produce electricity, and are typically used to meet peak loads in electricity demand because of their ability to start-up quickly. (5), (6) Ambient air is compressed to pressures typically ranging between 1.5-2 MPa. (6) The ambient air is combined with fuel, typically natural gas, and ignited, producing exhaust gas at temperatures as high as 1,400 °C. (6)

The investment cost for a combustion turbine power plant ranges from a low of \$0.32 to a high of \$0.63 million per megawatt. (5) The fixed O&M costs vary between \$8.4 and \$26.4 per kilowatt per year. (9) The variable O&M costs range from \$3.2 to \$5.3 per megawatt-hour. (9), (10) The heat rate, which is taken from data presented in Kehlhofer, et al. (9), is estimated to be between 8.12 and 9.74 million BTU per megawatt-hour. This corresponds to a thermodynamic efficiency range of 35-42%. The operational NOx emissions range from 0.05 and 0.6 kilograms per megawatt-hour. (18), (22) Operational particulate matter vary between 0 and 0.01 kilograms per megawatt-hour, while the operational NMVOC emissions range from 0 to $3x10^{-3}$ kilograms per megawatt-hour. (18), (22) Operational GHG emissions are between roughly 480 and 575 kilograms of carbon dioxide equivalent per megawatt-hour. (12), (22), (23) The range of values presented by the literature for the expected lifetime of the plant is 25 to 30 years. (12), (18), (22) The lead/lag time varies from 1 to 2.5 years. (9), (10), (22) The forced outage rate varies between

5% to 10%. (9), (22) The high, mean, and low values for each metric for combustion turbine power plants are given in Table 4.

Natural Gas Combined Cycle

Natural gas combined cycle (NGCC) power plants consist of a Brayton (gas) cycle and a Rankine (steam) cycle operated in tandem. The hot exhaust gas from the combustion turbine in the Brayton cycle generates steam for the Rankine cycle. The Brayton side of the power plant is commonly referred to as the topping cycle, while the Rankine side is referred to as the bottoming cycle. Heat transfer between the cycles is accomplished with a heat recovery steam generator (HRSG). Typical temperature and pressures for the inlet of the steam turbine are roughly 540 °C and 10-16 MPa; respectively. (9)

Literature values for the investment cost for a natural gas combined cycle power plant vary from $0.58 to $0.84 million per megawatt. (9) Fixed O&M costs range widely from $7.9 to $70.4 per kilowatt per year. (9) The variable O&M costs range between $1.7 and $4.2 per megawatt-hour. (9), (11) The heat rate varies between 5.78 to 6.82 million BTU per megawatt-hour, corresponding to an efficiency range of 50-59%. (9) Operational NOx emission estimates ranges from 0.03 to 0.7 kilograms per megawatt-hour. (11), (18), (22), (24) Operational particulate matter emission estimates vary between 0 and approximately 0.01 kilograms per megawatt-hour. (11), (18), (22) NMVOC emissions range from 0 to $3x10^{-3}$ kilograms per megawatt-hour. (18), (22) Operational GHG emission estimates vary from about 330 to 410 kilograms of carbon dioxide equivalent per megawatt-hour. (11), (12), (22) Construction related GHG emissions are estimated to be roughly 420 Mg of carbon dioxide equivalent per megawatt. (25)

Table 2: Survey of nuclear power plants

Metrics	High	Mean	Low
Investment Cost (million$/MW)	3.43	2.72	2.11
Retirement Cost (million$/MW)	0.25	0.20	0.16
Fixed O&M Cost ($/kW-yr)	93.54	53.73	33.76
Variable O&M Cost ($/MWh)	6.08	2.90	0.52
Heat Rate (MMBTU/MWh)	10.62	10.32	9.74
Estimated Efficiency (%)	35.00	33.07	32.10
Construction GHG (kg CO2e/MWh)	1.90		
Estimated Construction GHG (Mg CO2e/MW)	111	86.89	66.55
Lifetime (yr)	60.00	40.00	30.00
Lead/Lag Time (yr)	6.67	5.22	4.00
FOR (%)	12.00	8.25	5.00

Table 3: Survey of pulverized coal power plants

Metrics	High	Mean	Low
Investment Cost (million$/MW)	2.36	1.54	1.06
Retirement Cost (million$/MW)	0.17	0.11	0.08
Fixed O&M Cost ($/kW-yr)	74.47	32.00	15.83
Variable O&M Cost ($/MWh)	3.69	2.64	1.97
Heat Rate (MMBTU/MWh)	11.37	9.12	7.26
Estimated Efficiency (%)	47.00	38.50	30.00
Operational NOx (kg/MWh)	1.30	0.79	0.18
Operational SOx (kg/MWh)	2.85	0.92	0.11
Operational PM (kg/MWh)	0.15	0.08	8.00E-03
Operational NMVOC (kg/MWh)	2.01E-03		
Operational GHG (kg CO2e/MWh)	886	834	730
Construction GHG (kg CO2e/MWh)	1.30		
Estimated Construction GHG (Mg CO2e/MW)	47.43	43.40	37.95
Facility Land Requirement (m^2/MWh)	0.03	0.02	0.01
Estimated Facility Land Requirement (ha/MW)	1.14	0.55	0.16
Lifetime (yr)	40.00	36.25	30.00
Lead/Lag Time (yr)	4.17	3.81	3.33
FOR (%)	8.00	5.33	2.00

The lifetime of a NGCC facility is estimated at 30 years. (12), (18), (22) The lead/lag time estimates vary from 1.67 to 3 years. (9), (10), (26) The forced outage rate varies between 6% and 10%. (9), (22) The high, mean, and low values for each metric for natural gas combined cycle power plants are given in Table 5.

Integrated Gasification Combined Cycle

Coal

Integrated gasification combined cycle (IGCC) coal power plants closely resemble NGCC power plants except that the fuel gas for the IGCC plant comes from gasifying coal or other solid fuels. (9) The so-called syngas is burned in the gas turbine cycle in the same manner as natural gas in the NGCC plant.

The investment cost vary from $1.2 to $2.8 million per megawatt. (10), (11), (16), (18) Estimates for fixed O&M costs range between $23.5 and $72 per kilowatt per year, while estimates for variable O&M costs vary between $1.1 and $3 per megawatt-hour. (10), (11), (16), (18) An exchange rate of 1 CAD to 0.83 USD is assumed when converting 2005 Canadian dollars into 2005 US dollars. (27) The heat rate varies between 7.78 and 8.89 million BTU per megawatt-hour, which indicates a thermodynamic efficiency range of around 38% to 44%. (9), (11), (18) Operational NOx emissions range between 0.1 and 1.3 kilograms per megawatt-hour, while operational SOx emission estimates vary from 0.1 to 2.9 kilograms per megawatt-hour. (9), (11), (18)

Table 4: Survey of combustion turbines

Metrics	High	Mean	Low
Investment Cost (million$/MW)	0.63	0.47	0.32
Retirement Cost (million$/MW)	0.05	0.04	0.02
Fixed O&M Cost ($/kW-yr)	26.38	15.90	8.44
Variable O&M Cost ($/MWh)	5.28	4.09	3.17
Heat Rate (MMBTU/MWh)	9.74	8.84	8.12
Estimated Efficiency (%)	42.00	38.75	35.00
Operational NOx (kg/MWh)	0.62	0.33	0.05
Operational PM (kg/MWh)	1.02E-02	5.11E-03	0.00
Operational NMVOC (kg/MWh)	3.25E-03	1.62E-03	0.00
Operational GHG (kg CO2e/MWh)	575	504	478
Lifetime (yr)	30.00	28.33	25.00
Lead/Lag Time (yr)	2.50	1.88	1.00
FOR (%)	10.00	7.67	5.00

Table 5: Survey of natural gas combined cycle power plants

Metrics	High	Mean	Low
Investment Cost (million$/MW)	0.84	0.71	0.58
Retirement Cost (million$/MW)	0.06	0.05	0.04
Fixed O&M Cost ($/kW-yr)	70.36	35.56	7.91
Variable O&M Cost ($/MWh)	4.22	2.79	1.68
Heat Rate (MMBTU/MWh)	6.82	6.28	5.78
Estimated Efficiency (%)	59.00	54.50	50.00
Operational NOx (kg/MWh)	0.62	0.31	3.00E-02
Operational PM (kg/MWh)	1.02E-02	3.40E-03	0.00
Operational NMVOC (kg/MWh)	3.25E-03	1.62E-03	0.00
Operational GHG (kg CO2e/MWh)	407	369	330
Construction GHG (kg CO2e/MWh)		18.85	
Estimated Construction GHG (Mg CO2e/MW)	495	420	275
Lifetime (yr)	30.00	30.00	30.00
Lead/Lag Time (yr)	3.00	2.54	1.67
FOR (%)	10.00	8.00	6.00

Operational particulate matter emissions are estimated to range between $2.5x10^{-3}$ to 0.2 kilograms per megawatt-hour. (9), (11), (18) Operational NMVOC emissions are said to be $2x10^{-3}$ kilograms per megawatt-hour. (18) GHG emissions associated with fuel combustion range between approximately 700 to 980 kilograms of carbon dioxide equivalent per megawatt-hour. (9), (11), (16) GHG emissions associated with power plant construction are estimated to be roughly 1 kilogram of carbon dioxide equivalent per megawatt-hour. (23) The lifetime of the an IGCC facility is estimated to be between 35 and 40 years. (18), (19) Estimates on the construction lead/lag time vary between 3.75 and 5 years. (16), (21), (28) Forced outage rate estimates vary between 8% and 21%. (19), (21) The high, mean, and low values for each metric for natural gas combined cycle power plants are given in Table 6.

Biomass

Integrated gasification combined cycle biomass power plants are very similar to their coal-fueled counter parts. Differences in the physical and chemical properties of biomass and coal usually require different kinds of gasifiers and gas clean-up equipment, but the power producing equipment is identical.

The investment cost for integrated biomass gasification combined cycle power plants ranges from around \$1.6 to \$2.2 million per megawatt. (6), (29), (30), (31) The fixed O&M costs varies from approximately \$60 to \$67 per kilowatt per year, while the variable O&M costs range from \$4.9 to \$5.2 per megawatt-hour. (31) Estimates on the heat rate vary from 9.2 to 10 million BTU per megawatt-hour, which corresponds to a thermal efficiency range of 37 to 36%. (29), (30), (31) Operational NOx emissions vary from 0.2 to 1 kilograms per megawatt-hour. (29), (30) Operational SOx emission estimates range from 0.02 to 0.1 kilograms per megawatt-hour, while operational particulate matter emission estimates range from $2x10^{-3}$ to $5x10^{-3}$ kilograms per megawatt-hour. (29), (30) Operational NMVOC emissions are estimated to be 0.5 kilograms per megawatt-hour, and operational GHG emissions are estimated to be roughly 50 kilograms of carbon dioxide equivalent per megawatt-hour. (29) GHG emissions attributed to plant construction are estimated at 12 kilograms per megawatt-hour. (29) The estimated facility land requirement is about 3 hectares per megawatt. (20) Mann and Spath as well as Bain, et al. estimate the plant lifetime to be 30 years. (29), (31) The lead/lag time is estimated to be 2 years. (31) The high, mean, and low values for each metric for integrated gasification combined cycle biomass power plants have been tabulated in Table 7.

Integrated Pyrolysis Combined Cycle

Integrated pyrolysis combined cycle (IPCC) is another route for utilizing biomass to create electricity. It is similar to IGCC except that solid biomass is turned into a liquid known as bio-oil instead of syngas. The bio-oil is used as a fuel for the gas turbine cycle, while the waste heat from the gas turbine is used to produce steam on the Rankine side of the plant just like NGCC or IGCC. (32)

All data for integrated pyrolysis combined cycle power plants are adopted from Sandvidg et al. (32). The investment cost varies between around \$2 to \$3.7 million per megawatt.

Table 6: Survey of integrated gasification combined cycle coal power plants

Metrics	High	Mean	Low
Investment Cost (million$/MW)	2.76	2.12	1.22
Retirement Cost (million$/MW)	0.20	0.16	0.09
Fixed O&M Cost ($/kW-yr)	72.04	50.06	23.53
Variable O&M Cost ($/MWh)	3.04	2.26	1.15
Heat Rate (MMBTU/MWh)	8.89	8.43	7.78
Estimated Efficiency (%)	43.84	40.55	38.34
Operational NOx (kg/MWh)	1.30	0.57	0.08
Operational SOx (kg/MWh)	2.85	1.01	0.07
Operational PM (kg/MWh)	0.15	0.07	2.50E-03
Operational NMVOC (kg/MWh)		2.01E-03	
Operational GHG (kg CO2e/MWh)	980	785	700
Construction GHG (kg CO2e/MWh)		1.00	
Estimated Construction GHG (Mg CO2e/MW)	43.78	37.22	32.84
Lifetime (yr)	40.00	37.50	35.00
Lead/Lag Time (yr)	5.00	4.25	3.75
FOR (%)	21.00	15.67	8.00

Table 7: Survey of integrated gasification combined cycle biomass power plants

Metrics	High	Mean	Low
Investment Cost (million$/MW)	2.24	1.91	1.59
Retirement Cost (million$/MW)	0.17	0.14	0.12
Fixed O&M Cost ($/kW-yr)	67.10	63.13	59.53
Variable O&M Cost ($/MWh)	5.19	5.07	4.94
Heat Rate (MMBTU/MWh)	10.03	9.56	9.17
Estimated Efficiency (%)	37.20	35.72	34.00
Operational NOx (kg/MWh)	1.00	0.56	0.19
Operational SOx (kg/MWh)	0.09	0.06	2.27E-02
Operational NMVOC (kg/MWh)		0.52	
Operational GHG (kg CO2e/MWh)		49	
Construction GHG (kg CO2e/MWh)		12.00	
Estimated Construction GHG (Mg CO2e/MW)		210	
Facility Land Requirement (m^2/MWh)		0.13	
Estimated Facility Land Requirement (ha/MW)		3.31	
Lifetime (yr)		30.00	
Lead/Lag Time (yr)		2.00	

Fixed O&M costs ranges from about $120 to $144 per kilowatt per year, while variable O&M costs are estimated to be around $16 per megawatt-hour. The heat rate, and corresponding thermodynamic efficiency, are respectively about 9 million BTU per megawatt-hour and 37%. Finally, the lead/lag time is estimated at 2 years. The high, mean, and low values for each metric for integrated pyrolysis combined cycle power plants are given in Table 8.

Oil-Fired

Oil can be direct-fired in an internal combustion engine or a gas turbine to generate electric power. The over-night investment cost for an oil-fired power plant varies between $1 to $1.7 million per megawatt. (6), (18) The fixed O&M costs range from $13 to $20 per kilowatt per year, and the variable O&M costs range from $1.6 to $6 per megawatt-hour. (18), (33) The high values are indicative of a oil-fired gas turbine, while the low values correspond to a oil-fired power plant using a steam turbine. (33) The heat rate varies very little between sources, ranging from 9.2 to 9.4 million BTU per megawatt-hour. (12), (18), (34) This corresponds to a thermodynamic efficiency range of 36-37%. Operational NOx emissions, adopted from Breeze as well as Roth and Ambs, vary widely from 0.7 to 20 kilograms per megawatt-hour. (6), (18) Operational SOx emissions range from 2 to 14 kilograms per megawatt-hour. (18), (24) Operational particulate matter and NMVOC emissions, found from data presented by Roth and Ambs, are respectively 0.2 and $4x10^{-3}$ kilograms per megawatt-hour. (18) Operational GHG emissions are between 700 and 760 kilograms of carbon dioxide equivalent per megawatt-hour (12), (23). The operating lifetime of an oil-fired power plant is between 20 and 30 years. (12), (33) The lead/lag time is estimated to be 3 years. (28) The high, mean, and low values for each metric for oil-fired power plants have been tabulated in Table 9.

Municipal Solid Waste

Municipal solid waste can be burned in a boiler similar to a traditional coal-fired power plant, gasified like coal or biomass, or used as the feedstock in a pyrolysis unit.

Investment cost estimates for municipal solid waste power plants vary from$ 5.6 to $11.2 million per megawatt. (6), (18) Fixed O&M costs are estimated to be $215 per kilowatt per year, while the variable O&M costs are estimated to be around $22.5 per megawatt-hour. (18) The heat rate are estimated to be roughly 16.9 million BTU per megawatt-hour, which corresponds to a thermal efficiency of 20%. (18) Operational NOx emissions range from 0.01 to 1.6 kilograms per megawatt-hour. (18), (35) Operational SOx emissions are estimated at 0.6 kilograms per megawatt-hour and operational particulate matter emissions at 0.04 kilograms per megawatt-hour. (18) Operational NMVOC and GHG emissions are respectively estimated at 0.01 and 150 kilograms per megawatt-hour. (18) The lifetime is estimated at 25 years. (18) The high, mean, and low values for each metric for municipal solid waste power plants have been tabulated in Table 10.

Landfill Gas Recovery

Landfill gas, consisting of about 70% methane and 30% carbon dioxide, can be used for electric power generation. (36). Most landfill gas recovery power plants are too small for steam or gas turbine systems. They currently use engine generator sets although micro-turbines and fuel cells may eventually find markets in landfill gas power generation.

Table 8: Survey of integrated pyrolysis combined cycle power plants

Metrics	High	Mean	Low
Investment Cost (million$/MW)	3.71	2.85	2.00
Retirement Cost (million$/MW)	0.27	0.21	0.15
Fixed O&M Cost ($/kW-yr)	144	132	119
Variable O&M Cost ($/MWh)		16.12	
Heat Rate (MMBTU/MWh)		9.11	
Estimated Efficiency (%)		37.42	
Lead/Lag Time (yr)		2.00	

Table 9: Survey of oil-fired power plants

Metrics	High	Mean	Low
Investment Cost (million$/MW)	1.71	1.44	1.03
Retirement Cost (million$/MW)	0.13	0.11	0.08
Fixed O&M Cost ($/kW-yr)	19.83	16.75	13.38
Variable O&M Cost ($/MWh)	6.08	3.21	1.58
Heat Rate (MMBTU/MWh)	9.43	9.36	9.22
Estimated Efficiency (%)	37.00	36.45	36.16
Operational NOx (kg/MWh)	20.00	9.23	0.68
Operational SOx (kg/MWh)	14.15	8.22	2.29
Operational PM (kg/MWh)		0.17	
Operational NMVOC (kg/MWh)		3.56E-03	
Operational GHG (kg CO2e/MWh)	762	733	704
Lifetime (yr)	30.00	26.67	20.00
Lead/Lag Time (yr)		3.00	

Investment costs range from around $1.9 to $2.8 million per megawatt of capacity. (10), (18), (37) Fixed O&M costs are estimated to vary between $74.5 and $119 per kilowatt per year, while the variable O&M costs range from $0 to $0.01 per megawatt-hour. (10), (18) Estimates for the heat rate vary between 10.4 and 13.6 million BTU per megawatt-hour, which corresponds to a thermal efficiency range of 25% to 33%. (10), (18), (38) Operational NOx emissions range from approximately 0.2 to 2.2 kilograms per megawatt-hour. (31) Operational particulate matter emission estimates vary from 0.04 to 0.4 kilograms per megawatt-hour. (31) The lifetime of these power plants is estimated to be 20 years. (18) The lead/lag time of landfill gas recovery facilities is estimated to be 3 years. (10) The high, mean, and low values for each metric for landfill gas recovery power plants are given in Table 11.

Fuel Cells

Fuel cells employ electrochemical rather than thermo-mechanical processes to turn chemical energy into electricity. They consist of positive and negative electrodes where fuel and oxygen are converted to ions and an intervening liquid or solid electrolyte that expedites the counter flow of positive ions (cations) and negative ions (anions) that generates the electromotive force between the electrodes. (36)

Investment costs range between $2.1 and $5 million per megawatt. (6), (18), (10) Estimations for fixed O&M costs vary widely between approximately $6 to $323 per kilowatt per year, while variable O&M costs are estimated to range from $41 to $50 per megawatt-hour. (10), (18) Literature values for the heat rate for fuel cell power plants range between 5.7 and 8.5 million BTU per megawatt-hour, which translates to a thermal efficiency between 40% and 60%. (18), (39), (40) Operational NOx emissions estimates vary from $2x10^{-3}$ to 0.02 kilograms per megawatt-hour, while both SOx and particulate matter emissions range from 0 to $9x10^{-4}$ and 0 to $1.4x10^{-3}$kilograms per megawatt-hour; respectively. (18), (40) NMVOC emissions vary between 0 and 0.01 kilograms per megawatt-hour. (18), (40) Operational GHG emission estimates range from 180 to 510 kilograms of carbon dioxide equivalent per megawatt-hour. (18), (40) Construction GHG emissions are estimated to be 2 kilograms of carbon dioxide equivalent per megawatt-hour. (41) Power plant lifetime is estimated at 25 years. (18) The forced outage rate is 3%. (10), (28) The high, mean, and low values for each metric for fuel cell power plants have been listed in Table 12.

Solar Photovoltaic

Solar photovoltaic (PV) panels work by directly converting solar energy, more specifically photons, into electricity. In a process known as the photoelectric effect, incoming photons displace electrons thus creating electricity. A semiconductor material usually provides the electrons in a solar PV panel. (42) Solar PV power plants are generally made up of many arrays of PV panels, which can either be stationary or have a tracking mechanism that follows the sun. Investment costs vary from \$5.6 to \$6.2 million per megawatt. (6), (10), (18) Fixed O&M costs range from \$12 to around \$14 per kilowatt per year, while variable O&M costs are estimated to be 0. (10), (18) Sunlight to electricity conversion efficiencies for solar PV power plants range from 13% to 14%. (6), (18) Estimates for construction GHG emissions range from 220 to 375 kilograms of carbon dioxide equivalent per megawatt-hour. (6), (42)

Table 10: Survey of municipal solid waste power plants

Metrics	High	Mean	Low
Investment Cost (million$/MW)	11.20	8.10	5.60
Retirement Cost (million$/MW)	0.83	0.60	0.41
Fixed O&M Cost ($/kW-yr)		216	
Variable O&M Cost ($/MWh)		22.46	
Heat Rate (MMBTU/MWh)		16.87	
Estimated Efficiency (%)		20.21	
Operational NOx (kg/MWh)	1.55	0.66	7.74E-02
Operational SOx (kg/MWh)		0.59	
Operational PM (kg/MWh)		3.56E-02	
Operational NMVOC (kg/MWh)		1.38E-02	
Operational GHG (kg CO2e/MWh)		148	
Lifetime (yr)		25.00	

Table 11: Survey of landfill gas recovery power plants

Metrics	High	Mean	Low
Investment Cost (million$/MW)	2.78	2.28	1.91
Retirement Cost (million$/MW)	0.21	0.17	0.14
Fixed O&M Cost ($/kW-yr)		119	
Variable O&M Cost ($/MWh)		0.00	
Heat Rate (MMBTU/MWh)	13.65	12.07	10.40
Estimated Efficiency (%)	32.79	28.61	24.99
Operational NOx (kg/MWh)	2.15	1.06	0.15
Operational PM (kg/MWh)	0.41	0.22	3.63E-02
Lifetime (yr)		20.00	
Lead/Lag Time (yr)		3.00	

The estimated facility land requirement for falls between 11 and 57 hectares per megawatt. (20) Literature values for the lifetime of solar PV plants range from 30 years to 60 years. (12), (20) The construction lead/lag time is estimated to be 2 years. (10), (28) The high, mean, and low values for each metric for solar photovoltaic are given in Table 13.

Solar Thermal

Solar thermal power plants create electricity by concentrating sunlight into receivers that can reach temperatures of 100 °C to 1,500 °C, depending upon the design. The heat is used to generate steam to drive a Rankine cycle. Several schemes have been developed for concentrating solar energy for thermal cycles: power towers, parabolic troughs, and parabolic dishes. (43)

Investment costs for solar thermal power plants fall between $2.7 and $4.9 million per megawatt. (6), (10), (18) Literature values for fixed O&M costs vary from $59 to $63 per kilowatt per year, while the variable O&M costs range from $0 to $7.4 per megawatt-hour. (10), (18) The heat rate varies from 9.9 to 22.7 million BTU per megawatt-hour, which corresponds to a thermal efficiency range of 15% to roughly 35%. (6), (10) Construction GHG emissions vary from 13 to 40 kilograms of carbon dioxide equivalent per megawatt-hour. (6), (24), (42) The estimated facility land requirement falls between 10 and 15 hectares per megawatt. (20) The power plant lifetime is estimated to be 30 years. (18), (20) The construction lead/lag time is estimated to be 3 years. (10) The high, mean, and low values for each metric for solar thermal power plants have been tabulated in Table 14.

Geothermal

Geothermal power plants convert thermal energy within the earth's crust into electricity usually via a Rankine cycle. Geothermal energy is available worldwide, provided the well is drilled deep enough. In some parts of the world, like Iceland, geothermal energy is very close to the surface. More typically, wells need to be drilled to depths ranging from around 2 to 8 kilometers to reach temperatures high enough to generate steam. (43)

Literature estimates for the investment cost of geothermal power plants range from $1.7 to $4.6 million per megawatt. (10), (44) Fixed O&M costs are estimated to be $171 per kilowatt per year, while variable O&M costs are estimated to be 0. (10) The heat rate varies from 22.7 to 42.6 million BTU per megawatt-hour, which equates to a thermal efficiency range of 8-15%. (10), (44), (45) Operational SOx emissions are estimated between 0 and 0.02 kilograms per megawatt-hour. (42), (44) Estimates for operational GHG emissions range from 0 to 380 kilograms of carbon dioxide equivalent per megawatt-hour. (23), (44), (46) Construction GHG emissions vary widely between 1 to 38 kilograms of carbon dioxide equivalent per megawatt-hour. (23), (42) The estimated facility land requirement varies from roughly 470 to 3,200 hectares per megawatt. (47) The lifetime varies from 30 to 50 years. (44) The construction lead/lag times range from 1 to 4 years. (10), (44) The forced outage rate is estimated at 5%. (44) The high, mean, and low values for each metric for geothermal power plants are given in Table 15.

Land-based Wind Power

Wind turbines convert the kinetic energy of wind into electricity. The wind spins the rotor blades that are attached to a shaft that turns the generator. The energy potential in wind is proportional to the wind speed raised to the third power. (6)

The investment costs of inland wind turbines range from approximately $1 to $2 million per megawatt hour. (10), (18), (48) Fixed O&M costs vary from $12.7 to $38 per kilowatt per year, while variable O&M costs range between $0 and roughly $11 per megawatt-hour. (10), (18), (48) The efficiency of wind turbines is between 26% and 36%. (49) Estimates on construction GHG emissions vary from 10 to 18 kilograms of carbon dioxide equivalent per megawatt-hour. (42), (50) Estimates on land usage vary from around 23 to 61 hectares per megawatt. The lifetime of wind turbines is 25 years. (14), (18) The lead/lag time varies between 1 and 3 years. (10), (28) The forced outage rate is estimated to be 10%. (28) The high, mean, and low values for each metric for inland wind turbines have been tabulated in Table 16.

Offshore Wind Power

Offshore wind farms offer some advantages over inland wind farms, including steadier and more predictable winds along with lower turbulence. Political opposition to siting wind turbines on land in some locations has forced developers to consider offshore wind farms. (6)

Table 12: Survey of fuel cell power plants

Metrics	High	Mean	Low
Investment Cost (million$/MW)	5.04	3.38	1.57
Retirement Cost (million$/MW)	0.37	0.25	0.12
Fixed O&M Cost ($/kW-yr)	323	164	5.87
Variable O&M Cost ($/MWh)	49.80	45.39	40.98
Heat Rate (MMBTU/MWh)	8.53	7.15	5.68
Estimated Efficiency (%)	60.00	48.74	40.00
Operational NOx (kg/MWh)	1.60E-02	8.77E-03	1.55E-03
Operational NMVOC (kg/MWh)	7.74E-03	3.87E-03	0.00E+00
Operational GHG (kg CO2e/MWh)	508	344	181
Construction GHG (kg CO2e/MWh)	2.04		
Estimated Construction GHG (Mg CO2e/MW)	53.68		
Lifetime (yr)	25.00		
Lead/Lag Time (yr)	3.00	3.00	3.00

Table 13: Survey of solar photovoltaic plants

Metrics	High	Mean	Low
Investment Cost (million$/MW)	6.17	5.92	5.60
Retirement Cost (million$/MW)	0.46	0.44	0.41
Fixed O&M Cost ($/kW-yr)	13.66	12.90	12.13
Efficiency (%)	14.00	13.50	13.00
Construction GHG (kg CO2e/MWh)	170	123	99
Estimated Construction GHG (Mg CO2e/MW)	2,977	2,154	1,734
Facility Land Requirement (m^2/MWh)	0.44	0.33	0.16
Estimated Facility Land Requirement (ha/MW)	23.00	11.66	4.31
Lifetime (yr)	60.00	40.00	30.00
Lead/Lag Time (yr)	2.00	2.00	2.00

The investment costs for offshore wind turbines range from $1.6 to $3.5 million per megawatt. (6), (11), (51) Fixed O&M costs vary from $17 to $88 per kilowatt per year, while the variable O&M costs are said to be $0. (6), (11) The efficiency was estimated at 40%. (52) Estimates on the GHG emissions from construction range from 7 to 9 kilograms of carbon dioxide equivalent per megawatt-hour. (6), (42) The lifetime of offshore wind turbines is 20 years. (52) The lead/lag time vary from 2 to 4 years. (10), (28) The forced outage rate varies between 5% and 15%. (28), (53) The high, mean, and low values for each metric for offshore wind turbines are listed in Table 17.

Hydroelectric

Hydroelectric stations convert the potential energy of impounded water or the kinetic energy of flowing water into electricity. The mass of water acting under the force of gravity spins a turbine that is connected to an electric generator. Hydroelectric stations can be located along rivers with high water velocities (run-of-river); dams can be constructed to create a height difference along a river (impoundment hydropower); or water can be pumped to a higher elevation and later released (pumped storage). (43) Investment costs for hydroelectric stations are estimated to be between $2.1 and $5.1 million per megawatt. (10), (54) Fixed O&M costs are estimated at $14 per kilowatt per year, while the variable O&M costs are estimated at $2.5 per megawatt-hour. (10) Estimates on the efficiency of hydroelectric stations vary from about 65% to 76%. (55) Construction GHG emission estimates range from 10 to 13 kilograms of carbon dioxide equivalent per megawatt-hour. (42)

Table 14: Survey of solar thermal power plants

Metrics	High	Mean	Low
Investment Cost (million$/MW)	4.88	3.92	2.69
Retirement Cost (million$/MW)	0.36	0.29	0.20
Fixed O&M Cost ($/kW-yr)	63.04	61.02	58.99
Variable O&M Cost ($/MWh)	7.35	3.68	0.00
Heat Rate (MMBTU/MWh)	22.73	15.26	9.88
Estimated Efficiency (%)	34.50	24.88	15.00
Construction GHG (kg CO2e/MWh)	39.98	25.84	13.40
Estimated Construction GHG (Mg CO2e/MW)	1,051	679	352
Facility Land Requirement (m2/MWh)	0.55	0.46	0.37
Estimated Facility Land Requirement (ha/MW)	14.49	12.05	9.61
Lifetime (yr)	30.00	30.00	30.00
Lead/Lag Time (yr)		3.00	

Table 15: Survey of geothermal power plants

Metrics	High	Mean	Low
Investment Cost (million$/MW)	4.57	3.24	1.69
Retirement Cost (million$/MW)	0.34	0.24	0.13
Fixed O&M Cost ($/kW-yr)		171	
Variable O&M Cost ($/MWh)		0.00	
Heat Rate (MMBTU/MWh)	42.63	31.69	22.73
Estimated Efficiency (%)	15.00	11.34	8.00
Operational SOx (kg/MWh)	0.06	3.08E-02	0.00
Operational GHG (kg CO2e/MWh)	380	112	0.00
Construction GHG (kg CO2e/MWh)	37.79	19.40	1.00
Estimated Construction GHG (Mg CO2e/MW)	1324	425	8.76
Facility Land Requirement (m^2/MWh)	74	46	18
Estimated Facility Land Requirement (ha/MW)	3,238	1,610	473
Lifetime (yr)	50.00	40.00	30.00
Lead/Lag Time (yr)	4.00	2.50	1.00
FOR (%)		5.00	

Table 16: Survey of land-based wind turbines

Metrics	High	Mean	Low
Investment Cost (million$/MW)	1.91	1.51	0.95
Retirement Cost (million$/MW)	0.14	0.11	0.11
Fixed O&M Cost ($/kW-yr)	38.12	25.70	12.71
Variable O&M Cost ($/MWh)	15.25	7.17	0.00
Efficiency (%)	36.53	31.57	26.64
Construction GHG (kg CO2e/MWh)	17.65	13.92	10.20
Estimated Construction GHG (Mg CO2e/MW)	464	244	89.34
Facility Land Requirement (m^2/MWh)	2.78	1.95	1.03
Estimated Facility Land Requirement (ha/MW)	60.81	42.66	22.53
Lifetime (yr)	25.00	25.00	25.00
Lead/Lag Time (yr)	3.00	2.00	1.00
FOR (%)		10.00	

Table 17: Survey of offshore wind turbines

Metrics	High	Mean	Low
Investment Cost (million$/MW)	3.55	2.39	1.60
Retirement Cost (million$/MW)	0.26	0.18	0.12
Fixed O&M Cost ($/kW-yr)	88.31	52.56	16.81
Efficiency (%)		40.00	
Construction GHG (kg CO2e/MWh)	8.90	7.93	6.96
Estimated Construction GHG (Mg CO2e/MW)	312	208	122
Lifetime (yr)		20.00	
Lead/Lag Time (yr)	4.00	3.00	2.00
FOR (%)	15.00	10.00	5.00

The estimated facility land requirement varies widely from 0.1 to 2,200 hectares per megawatt. (20) Lifetime estimates of hydroelectric stations range from 30 years to 100 years. (20), (54) The lead/lag time estimates range from 0.5 to 8 years. (10), (54) The forced outage rate is estimated at 2%. (54) The high, mean, and low values for each metric for hydroelectric stations have been tabulated in Table 18.

Ocean Thermal Energy Conversion

There are two different types of ocean thermal energy conversion (OTEC) power plants: direct and indirect. Direct OTEC plants flash water at around 25 °C into steam, which is then passed through a low pressure turbine. Indirect OTEC plants resemble the bottoming cycle portion of combined cycle power plants. However, ammonia, propane, or Freon is typically used as the working fluid instead of water in these plants. (43)

Estimates on the investment costs for oceanic thermal energy conversion power plants vary widely between $4.5 and $39 million per megawatt. (6), (56), (57) The heat rate ranges from 114 to 171 million BTU per megawatt-hour, which corresponds to a thermal efficiency range of 2% to 3%. (6), (58), (59) Construction GHG emission estimates vary between 4 and 5 kilograms of carbon dioxide equivalent per megawatt-hour. (23), (60) The lifetime of the plant is estimated to be 30 years. (57) The lead/lag time is estimated to be 2 years. (56), (57) The high, mean, and low values for each metric for oceanic thermal energy conversion power plants have been tabulated in Table 19.

Tidal Power

Tidal power plants convert the potential energy in the tides into electrical energy. A basin behind a barrage is used to store water. Changes in the tides spin a r vane that is located below a barrage. Sluice gates are used on either side of the barrage to help control the flow of water into and out of the basin. (6)

Investment cost estimates for tidal power plants vary from $3.4 to $6.6 million per megawatt. (56), (61) The lifetime of tidal power plants ranges from 25 to 80 years. (56), (61) Estimates for the lead/lag time range from 1 to 8.3 years. (56), (61) Finally, the forced outage rate is estimated to be between 2% and 5%. (61) The high, mean, and low values for each metric for tidal power have been listed in Table 20.

Wave Power

There are several ways to convert the kinetic energy of waves into electricity. For example, waves can be used to move a pendulum, or compress an air column that spins a generator. A raised lagoon can also be used to capture water, which can then be used to spin a turbine when it flows back into the ocean through the return line. (6) Investment costs range between $3.7 and $7.6 million per megawatt. (56), (61) The lifetime of the power plant is estimated to vary between 25 and 45 years. (56), (61) The lead/lag time varies from 1 to 3 years. (61) The forced outage rate percentage was estimated to be 5%. (61) The high, mean, and lows for each metric for wave power are given in Table 21.

Table 18: Survey of hydroelectric stations

Metrics	High	Mean	Low
Investment Cost (million$/MW)	5.08	3.96	2.12
Retirement Cost (million$/MW)	0.38	0.29	0.16
Fixed O&M Cost ($/kW-yr)		14.16	
Variable O&M Cost ($/MWh)		2.53	
Efficiency (%)	75.89	70.37	64.56
Construction GHG (kg CO2e/MWh)	13.00	11.50	10.00
Estimated Construction GHG (Mg CO2e/MW)	911	336	43.79
Facility Land Requirement (m^2/MWh)	25	8	0.00
Estimated Facility Land Requirement (ha/MW)	2,188	408	0.08
Lifetime (yr)	100	60.00	30.00
Lead/Lag Time (yr)	8.00	3.33	0.50
FOR (%)		2.00	

Table 19: Survey of ocean thermal energy conversion power plants

Metrics	High	Mean	Low
Investment Cost (million$/MW)	38.50	23.46	4.48
Retirement Cost (million$/MW)	2.85	1.74	0.33
Heat Rate (MMBTU/MWh)	171	142	114
Estimated Efficiency (%)	3.00	2.50	2.00
Construction GHG (kg CO2e/MWh)	5.00	4.35	3.70
Estimated Construction GHG (Mg CO2e/MW)	87.57	76.18	64.79
Lifetime (yr)		30.00	
Lead/Lag Time (yr)	2.00	2.00	2.00

Table 20: Survey of tidal power plants

Metrics	High	Mean	Low
Investment Cost (million$/MW)	6.61	5.18	3.45
Retirement Cost (million$/MW)	0.49	0.38	0.26
Lifetime (yr)	120	62.50	25.00
Lead/Lag Time (yr)	8.33	3.58	1.00
FOR (%)	5.00	3.50	2.00

Table 21: Survey of wave power plants

Metrics	High	Mean	Low
Investment Cost (million$/MW)	7.62	5.70	3.70
Retirement Cost (million$/MW)	0.56	0.42	0.27
Lifetime (yr)	45.00	31.67	25.00
Lead/Lag Time (yr)	3.00	2.00	1.00
FOR (%)	5.00		

Learning Rates

Specific capital costs are often reduced as experience is gained in the design and construction of a certain power generation technology. This phenomenon is commonly referred to as learning-by-doing, and is quantifiable with a methodology known as the experience curve. These curves assume that capital costs per unit capacity reduce by a constant percentage for every doubling of installed capacity. This percentage reduction in cost is known as the learning rate. (62) The experience curve is formally expressed as:

$$P_t = P_o * C_t{}^{-E} \quad (4)$$

where P_t is the specific cost in dollars per capacity of a technology at time t, P_o is the specific cost of one unit of cumulative capacity, C_t is the cumulative capacity installed at time t, and E is the "experience parameter" found according to:

$$E = {}^{-\ln(1-LR)}\big/_{\ln(2)} \quad (5)$$

where LR is the learning rate for a technology. (62)

Learning rates for nuclear, NGCC, combustion turbine, and hydroelectric stations were adopted from the IEA. (63) Data for inland wind, oil-fired power, ICGCC, and solar PV came from Kumbaroglu, et al. and data for fuel cells, geothermal, solar thermal, and offshore wind came from EIA. (10), (28) The learning rate for wave power was taken from data presented by Hammons. (64) Due to similarities between facilities, the learning rates for IGCC biomass power plants and IPCC power plants were assumed to be identical to IGCC coal plants. The learning rates for the capital costs for some of the technologies presented earlier have been tabulated in Table 22.

Table 22: Learning rates of various power generation technologies

Technology	Learning Rate (%)
Nuclear	5.80
Pulverized Coal	5.00
Combustion Turbine	13.00
NGCC	4.00
IGCC (coal)	5.00
IGCC (biomass)	5.00
IPCC	5.00
Oil	1.00
Fuel Cell	20.00
Solar PV	20.00
Solar Thermal	20.00
Geothermal	8.00
Land-based Wind	10.00
Offshore Wind	20.00
Hydro	1.40
Wave Power	18.00

References

1. U.S. Bureau of Labor Statistics. Databases, Tables & Calculators by Subject. [Online].[cited 2010 December 29]. Available from: http://bls.gov/data/.

2. Ho DT, Frunt J, Myrzik JMA. Photovoltaic Energy in Power Market. Energy Market. 2009; p. 1-5.

3. Ramana MV. Nuclear Power Economic, Safety, Health, and Environmental Issues of Near-Term Technologies. Annual Review of Environment and Resources. 2009; 34: p. 127-152.

4. Kannan R, Tso CP, Osman R, Ho HK. LCA-LCCA of oil fired steam turbine power plant in Singapore. Energy Conversion & Management. 2004; 45: p. 3093-3107.

5. Black & Veatch. Power Plant Engineering New York, NY: Springer Science+Buisness Media, LLC; 1996.

6. Breeze P. Power Generation Technologies Burlington, MA: Elsevier; 2005.

7. Shultis JK, Faw RE. Fundamentals of Nuclear Science and Engineering. 2nd ed. Boca Raton, FL: CRC Press; 2008.

8. Morris C, Kranowitz J, Kelly M, Fascitelli B, Hughes M. Nuclear Power Joint Fact-Finding. 2007.

9. Kehlhofer R, Hannemann F, Stirnimann F, Rukes B. Combined-Cycle Gas & Steam Turbine Power Plants 3rd ed. Tulsa, OK: PennWell Corporation; 2009.

10. U.S. Energy Information Administration. Assumptions to the Annual Energy Outlook 2010 with Projections to 2035. 2010.

11. Kennedy S. Wind power planning: assessing long-term costs and benefits. Energy Policy. 2005; 33: p. 1661-1675.

12. Hondo H. Life cycle GHG emission analysis of power generation systems: Japanese case. Energy. 2005; 30: p. 2042-2056.

13. U.S. Energy Information Administration. U.S. Energy Information Administration. [Online]. [cited 2010 Decemeber 22]. Available from: http://www.eia.doe.gov/cneaf/nuclear/page/uran_enrich_fuel/convert.html.

14. White SW, Kulcinski GL. Birth to death analysis of the energy payback ratio and CO2 gas emission rates from coal, fission, wind, and DT-fusion electrical power plants. Fusion

Engineering and Design. 2000; 48: p. 473-481.

15. International Energy Agency. IEA Energy Technology Network. [Online]. 2010 [cited 2010 Decemeber 22]. Available from: http://www.etsap.org/E-techDS/PDF/E03-Nuclear-Power-GS-AD-gct.pdf.

16. Mirzaesmaeeli H, Elkamel A, Douglas PL, Croiset E, Gupta M. A multi-period optimization model for energy planning with CO2 emission consideration. Journal of Environmental Management. 2010; 91: p. 1063-1070.

17. U.S. Energy Information Administration. U.S. Energy Information Administration Independent Statistics and Analysis. [Online]. 2010 [cited 2010 December 22]. Available from: http://www.eia.doe.gov/cneaf/electricity/epm/table1_1.html.

18. Roth FI, Ambs LL. Incorporating externalities into a full cost approach to electric power generation life-cycle costing. Energy. 2004; 29: p. 2125-2144.

19. International Energy Agency. IEA Energy Technology Network. [Online]. 2010 [cited 2010 Decemeber 22]. Available from: http://www.etsap.org/E-techDS/PDF/E01-coal-fired-power-GS-AD-gct.pdf.

20. Fthenakis V, Chul Kim H. Land use and electricity generation: A life-cycle analysis. Renewable and Sustainable Energy Reviews. 2009; 13: p. 1465-1474.

21. Kramer J, Voss S, Sakazaki M. IGCC Engineering and Permitting Issues Summaries. 2006.

22. International Energy Agency. Energy Technology Systems Analysis Programme. [Online].; 2010 [cited 2010 December 22]. Available from: http://www.etsap.org/E-techDS/PDF/E02-gas_fired_power-GS-AD-gct.pdf.

23. San Martin RL. Environmental Emissions from Energy Technology Systesm: The Total Fuel Cycle. Washington, DC; 1989.

24. Norton B, Eames PC, Lo SNG. Full-energy-chain analysis of greenhouse gas emissions for solar thermal electric power generation systems. Renewable Energy. 1998; 15: p. 131-136.

25. Becerra-Lopez HR, Golding P. Dynamic exergy analysis for capacity expansion of regional power-generation systems: Case study for far West Texas. Energy. 2007; 32.

26. Klara JM, Wimer JG. NETL. [Online]. 2007 [cited 2010 Decemeber 22]. Available from: http://www.netl.doe.gov/energy-analyses/pubs/deskreference/B_NGCC_051507.pdf.

27. Bank of Canada. Bank of Canada. [Online]. 2011 [cited 2011 Janurary 5]. Available from: http://www.bankofcanada.ca/cgi-bin/famecgi_fdps.

28. Kumbaroglu G, Madlener R, Demirel M. A real options evaluation model for the diffusion prospects of new renewable power generation technologies. Enery Economics. 2008; 30: p. 1882-1908.

29. Mann MK, Spath PL. Life Cycle Assessment of a Biomass Gasification Combined-Cycle System. ; 1997.

30. Rhodes JS, Keith DW. Engineering economic analysis of biomass IGCC with carbon capture and storage. Biomass & Bioenergy. 2005; 29: p. 440-450.

31. Bain RL, Amos WA, Downing M, Perlack RL. Biopower Technical Assessment: State of the Industry and Technology. Golden, Colorado; 2003.

32. Sandvig E, Walling G, Brown RC, Pletka R, Radlein D, Johnson W. Integrated Pyrolysis Combined Cycle Biomass Power System Concept Definition Final Report. 2003.

33. El-Kordy MN, Badr MA, Abed KA, Ibrahim SMA. Economical evaluation of electricity generation considering externalities. Renewbale Energy. 2002; 25: p. 317-328.

34. Rosen MA, Dincer I. Exergoeconomic analysis of power plants operating on various fuels. Applied Thermal Energineering. 2003; 23: p. 643-658.

35. Ruth LA. Energy from municipal solid waste: a comparison with coal combustion technology. Prog. Energy Combust. Sci. 1998; 24: p. 545-564.

36. Lee S, Speight JG, Loyalka SK. Handbook of Alternative Fuel Technologies Boca Raton, FL: Taylor & Francis Group, LLC; 2007.

37. Willumsen HC. Energy Recovery from Landfill Gas in Denmark and Worldwide. Vilborg, Denmark.

38. Bove R, Lunghi P. Electric power generation from landfill gas using traditional and innovative technologies. Energy Conversion & Management. 2006; 47: p. 1391-1401.

39. Song C. Fuel processing for low-temperature and high-temperature fuel cells Challegnes, and opportunities for sustainable development in the 21st century. Catalysis Today. 2002; 77: p. 17-49.

40. UTC Power. UTC Power A United Technologies Company. [Online]. 2008 [cited 2010

December 22]. Available from: http://www.utcpower.com/fs/com/Attachments/data_sheets/DS0112_093008.pdf.

41. Karakoussis V, Brandon NP, Leach M, van der Vorst R. The environmental impact of manufacturing planar and tubular soild oxide fuel cells. Journal of Power Sources. 2001; 101: p. 10-26.

42. Pehnt M. Dynamic life cycle assessment (LCA) of renewable energy technologies. Renewable Energy. 2006; 31: p. 55-71.

43. Tester JW, Drake EM, Driscoll MJ, Golay MW, Peters WA. Sustainable Energy Choosing Among Options Cambridge, MA: The MIT Press; 2005.

44. International Energy Agency. Energy Technology Systems Analysis Programme. [Online]. 2010 [cited 2010 December 22]. Available from: http://www.etsap.org/E-techDS/PDF/E06-geoth_energy-GS-gct.pdf.

45. Kanoglu M, Cengel YA. Economic evaluation of geothermal power generation, heating, and cooling. Energy. 1999; 24: p. 501-509.

46. Fridleifsson IB. Geothermal energy for the benefit of the people. Renewable & Sustainable Energy Reviews. 2001; 5: p. 299-312.

47. Evans A, Strezov V, Evans TJ. Assessment of sustainability indicators for renewable energy technologies. Renewable and Sustainable Energy Reviews. 2009; 13: p. 1082-1088.

48. McGowan JG, Connors SR. Windpower: A Turn of the Century Review. Annual Review of Energy and the Environment. 2000; 25: p. 147-197.

49. Chang TJ, Wu YT, Hsu HY, Chu CR, Liao CM. Assessment of wind characteristics and wind turbine characteristics in Taiwan. Renewable Energy. 2003; 28: p. 851-871.

50. Chatzimouratidis AI, Pilavachi PA. Objective and subjective evaluation of power plants and their non-radioactive emissions using the analytic hierarchy process. Energy Policy. 2007; 35: p. 4027-4038.

51. Liebreich M, Young W. Offshore Wind: Europe's EUR 90 Billion Funding Requirement. London, UK; 2005.

52. Schleisner L. Life cycle assessment of a wind farm and related externalities. Renewable Energy. 2000; 20: p. 279-288.

53. Musial W, Butterfield S. Future for Offshore Wind Energy in the United States. Palm Beach, FL:; 2004.

54. International Energy Agency. Energy Technology Systems Analysis Programme. [Online]. 2010 [cited 2010 Decemeber 22]. Available from: http://www.etsap.org/E-techDS/PDF/E07-hydropower-GS-gct.pdf.

55. Liu Y, Ye L, Benoit I, Liu X, Cheng Y, Morel G, et al. Economic performance evaluation method for hydroelectric generating units. Energy Conversion & Management. 2003; 44: p. 797-808.

56. Seymour RJ, editor. Ocean Energy Recovery: The State of the Art: American Society of Civil Engineers; 1992.

57. National Oceanic and Atmospheric Administration, University of New Hampshire. Technical Readiness of Ocean Thermal Energy Conversion (OTEC). 2009.

58. Xie C, Wang S, Zhang L, Jack Hu S. Improvement of proton exchange membrane fuel cell overall efficiency by integrating heat-to-electricity conversion. Journal of Power Sources. 2009; 191: p. 433-441.

59. Pontes MT, Falcao A. Ocean Energy Conversion. Lisboa, Portugal.

60. Tahara K, Horiuchi K, Kojima T, Inaba A. Ocean Thermal Energy Conversioni (OTEC) System as a Countermeasure for CO2 Problem- Energy Balance and CO2 Reduction Potential. Energy Conversion Management. 1995; 36: p. 857-860.

61. International Energy Agency. Energy Technology Systems Analysis Programme. [Online]. 2010 [cited 2010 December 22]. Available from: http://www.etsap.org/E-techDS/PDF/E08-Ocean%20Energy-GS-gct.pdf.

62. Organisation for Economic Co-Operation and Development, International Energy Agency. Experience Curves for Energy Technology Policy Paris, France: OECD/IEA; 2000.

63. McDonald A, Schrattenholzer L. Learning rates for energy technologies. Energy Policy. 2001; 29.

64. Hammons TJ. Energy potential of the oceans in Europe and North America: tidal, wave, currents, OTEC and offshore wind. International Journal of Power and Energy Systems. 2008; 28.

Four Economies of Sustainable Power Generation

A draft paper

Joshua D. Gifford[a] and Robert C. Brown[a,b].

[a]Department of Mechanical Engineering
[b]Center for Sustainable Environmental Technologies
Iowa State University

Abstract

Sustainability of power generation is primarily composed of two categories: economic and environmental. Economic sustainability has been measured by the levelized cost of electricity, which accounts for capital, operation and maintenance, and fuel costs. Environmental sustainability has been measured by the water usage, energy payback time, and greenhouse gas (GHG) emissions associated with a power plant. This study evaluates these characteristics of power generation technologies from a broad perspective. Renewable, fossil, and nuclear power generation technologies were included in this analysis, and the CWEG (Cost-Water-Energy-GHG) methodology was used for scoring and ranking technologies. Offshore wind ranked first this analysis, which a CWEG score of 66 out of a possible 100. Hydroelectric stations ranked the lowest in this analysis with a CWEG score of approximately 17.

1. Introduction

Sustainable power generation can be broken down into at least two main components: economic and environmental sustainability. Economic sustainability has been measured by the levelized cost of electricity, which accounts for such as capital, operation and maintenance (O&M), and fuel costs. Other expenditures such as taxes and siting permits can also be included in this category, but these are beyond the scope of this study. Environmental sustainability has been measured by the water usage and greenhouse gas emissions associated with a power plant.

The objective of this work is to compare overall sustainability of several power generation technologies from a broad perspective using a previously established comparison methodology called the CWEG. (1)

2. Power Generation Scenarios

Ten power generation scenarios were selected for analysis: conventional coal, natural gas combined cycle (NGCC), integrated coal gasification combined cycle coal (IGCC coal), integrated gasification combined cycle biomass (IGCC biomass), light water nuclear reactors, hydroelectric stations, solar photovoltaic (PV), solar thermal, and inland and offshore wind farms.

3. Methodology

3.1 Definition of Metrics

All metrics are given on the basis of one unit of electrical energy produced, energy payback time, which is expressed as years. Levelized cost of electricity (LCOE) has units of cents per kilowatt-hour (kWh), water usage has units of liters per megawatt-hour (MWh), and GHG emissions are defined as kilograms of carbon dioxide equivalent (CO_2e) per megawatt-hour. The energy payback time is a measure of the time it takes for a power plant to produce as much energy as was consumed for construction.

The levelized cost of electricity is the sum up of the following components: levelized capital, fixed O&M, variable O&M, and fuel costs, which are respectively calculated from Equations 1-4. It was assumed that a 20 year loan with 6% interest was used for plant financing. The levelized capital cost is given by:

$$L_C = \frac{C * 10^6 \frac{\$}{M\$} * 100 \frac{cents}{\$}}{1{,}000 \frac{kW}{MW} * 8{,}760 \frac{hr}{yr} * 20yr * CF} \qquad (1)$$

where L_C is the levelized capital cost (in cents per kWh), C is the capital cost (in million dollars per megawatt), and CF is the capacity factor

The levelized fixed O&M cost can be expressed as:

$$L_{FOM} = \frac{F_{OM} * 100 \frac{cents}{\$}}{8{,}760 \frac{hr}{yr} * CF} \qquad (2)$$

where L_{FOM} is the levelized fixed O&M cost (in cents per kWh), F_{OM} is the fixed O&M cost (in dollars per kilowatt per year), and CF is the capacity factor

The levelized variable O&M cost (excluding fuel) can be formally expressed as:

$$L_{VOM} = \frac{V_{OM} * 100 \frac{cents}{\$}}{1{,}000 \frac{kWh}{MWh}} \qquad (3)$$

where L_{VOM} is the levelized variable O&M cost (in cents per kWh), and VOM is the variable O&M cost (in dollars per MWh)

The levelized fuel cost is given by:

$$L_F = \frac{F * HR}{1{,}000 \frac{kWh}{MWh}} \qquad (4)$$

where L_F is the levelized fuel cost (in cents per kWh), F is the fuel cost (in dollars per million BTU), and HR is the heat rate (in million BTU/MWh)

Finally, the total levelized cost of electricity is given by:

$$LCOE = L_C + L_{FOM} + L_{VOM} + L_F \qquad (5)$$

where LCOE is the levelized cost of electricity

The CWEG methodology developed by Gifford and Brown was used for determining the scores of each technology for the LCOE, energy payback time, water usage, and GHG metrics.(1)

3.2 Data

All cost data was adjusted from inflation using data from the US Bureau of Labor Statistics.(2) Estimates for energy conversion efficiencies, fixed O&M costs, variable O&M costs, heat rates, construction GHG emissions, and operational GHG emissions were taken from the geometric mean of values presented by Gifford, Voss, and Brown.(1) Solar PV facilities were assumed to have a capital cost of $4.11 per watt, which is the geometric mean of values found in the literature.(4), (5), (6) All other capital costs were adopted from Gifford, Voss, and Brown.(3)

The geometric mean of values presented by the literature was used for calculating the capacity factor of a power generation technology. The capacity factor for IGCC biomass power plants was assumed to be 80%.(7) The capacity factor for IGCC coal power plants, roughly 80%.(8), (9) Pulverized coal was assumed to have a capacity factor of roughly 78%.(8), (9) The capacity factor for hydroelectric stations was assumed to be around 46%.(10) NGCC power plants were assumed to have a capacity factor of around 53%.[(9), (11)] The capacity factor for nuclear power, assumed to be 87%, was adopted from data presented by the International Energy Agency.[(12)] Solar PV was assumed to have a capacity factor of about 17% [(5), (6)], while solar thermal power plants were assumed to have a capacity factor of 25% [(6)]. It was assumed that land-based wind and offshore wind had respective capacity factors of 30% [(5)] and 42% [(13)].

It was assumed that biomass could be delivered to the IGCC biomass facility at a price of $5 per gigajoule.[(14)] The averaged price from 1997 to 2009 was used for calculating the cost of natural gas for an electric facility.[(15)] The 1990 to 2009 average coal price was used for determining the fuel cost for both IGCC and pulverized coal-fired power plants.[(16)] The prices of coal and natural gas were converted from dollars per mass, or volume, to dollars per million BTU (MMBTU) by multiplying the price with the energy density, which was found from data presented by ORNL.[(17)] Nuclear power was assumed to have a fuel cost of 0.5 cents per kWh.[(5)] It was assumed that the fuel costs for hydroelectric, solar PV, solar thermal, and wind farms were zero. The fuel costs and capacity factors used in this analysis have been tabulated in Table 1.

Table 1: Capacity factors and fuel costs of selected technologies

Technology	Capacity Factor (%)	Fuel Costs ($/MMBTU)
Coal	78.15	1.03
Hydroelectric	46.23	0.00
IGCC (biomass)	80.00	5.28
IGCC (coal)	80.99	1.03
NGCC	52.51	5.92
Nuclear	87.21	1.47
Solar PV	16.52	0.00
Solar Thermal	25.00	0.00
Wind (land-based)	30.00	0.00
Wind (offshore)	42.00	0.00

Water usage was calculated by taken the geometric mean from data presented in Fthenakis and Chul Kim.[18] Upstream processes, such as resource extraction, were also taken into account when calculating water usage. It was assumed that the water usage for both IGCC biomass and coal facilities were the same, and that non-irrigated biomass was used as fuel.

The energy payback times for coal, hydroelectric stations, NGCC, nuclear, solar PV, and land-based wind turbines were adopted from Kenny, Law, and Pearce.[19] The energy payback time for offshore wind turbines was assumed to be 6 months.[20] Solar thermal power plants were assumed to have an energy payback time of roughly 7 months.[21] IGCC biomass and coal plants have roughly the same lifecycle energy efficiency, ratio of total energy output to total energy input over the lifecycle of a power plant.[22], [23] This can be converted into energy payback time by multiplying the lifecycle energy efficiency with the capacity factor of the power plant.

The LCOE, water use, energy payback time, and GHG emission data used in this analysis are summarized in Table 2.

Table 2: Levelized cost of electricity, water usage, energy payback time, and GHG emissions of selected technologies

Technology	LCOE (cents/kWh)	Water Use (L/MWh)	Energy Payback (yr)	GHG (kg CO2e/MWh)
Coal	4.49	1,640	3.18	815
Hydroelectric	14.52	17,000	2.43	13.3
IGCC (biomass)	5.80	1,455	3.57	61.0
IGCC (coal)	5.13	1,455	3.57	814
NGCC	4.62	397	7.00	386
Nuclear	6.56	2,210	2.50	1.90
Solar PV	46.00	15.00	1.64	127
Solar Thermal	30.01	1,434	0.55	24.0
Wind (land-based)	9.42	4.00	0.75	13.6
Wind (offshore)	11.55	4.00	0.50	7.9

4. Results

CWEG scores for all technologies are plotted on Figure 1. Scores for each technology under each metric are tabulated in Table 3.

4.1 Biomass

IBGCC had a CWEG score of 24, which placed it eighth in the group. This technology did well in terms of LCOE, but poor in the water usage and energy payback time metrics. The specific GHG emissions associated with an IBGCC power plant, while lower than any of the fossil-fueled technologies, were much higher than those from a nuclear plant.

4.2 Coal

Conventional coal-fired power ranked fourth with a CWEG score of roughly 29, while IGCC coal power plants ranked seventh with an overall score of about 26. Both technologies had relatively low LCOE values. On the other hand, both conventional coal and IGCC coal power plants did poorly in terms of GHG emissions and water usage, which were the main contributing factors to the low scores of these technologies. The energy payback time for both of these technologies was also above the group average.

4.3 Hydroelectric

Hydroelectric power ranked tenth in this analysis with a CWEG score of 17. Hydroelectric power had a relatively high cost of electricity, and the highest water usage out of all the present technologies, because of the increased evaporation rates from impoundment hydroelectric stations.[18], [24] It also had a relatively high energy payback time.

4.4 Natural Gas

NGCC ranked sixth with a CWEG score of approximately 26. NGCC had a low LCOE value, which is why it scored as high as it did. The water usage associated with a NGCC facility, while better than the group average, was still several orders of magnitude greater than that of a wind farm. The GHG emissions coming from a NGCC power plant were greater than the group average, and the energy payback time was the highest out of the entire group.

4.5 Nuclear

Nuclear power scored 47, high enough to put it in third place. Nuclear power did poorly in terms of water usage, which is largely attributable to the large amounts of water needed for steam condensing.[18] The levelized cost of electricity and energy payback time for nuclear power plants were slightly less than the group average. However, the GHG emissions arising from construction of nuclear power plants are approximately two orders of magnitude lower than the average, which was the lowest out of the entire group.

4.6 Solar

Solar thermal and solar PV respectively placed fifth and ninth place with CWEG scores of roughly 29 and 18. Solar PV had the second lowest water usage out of the entire group, while the water usage for a solar thermal power plant was comparable to IGCC facilities. The energy payback time for solar PV was slightly below the group average, while solar thermal had the second lowest energy payback time. The LCOE values for both solar technologies were among the highest of the technologies analyzed, mainly due to the relatively high capital costs of these plants.

4.7 Wind

Both offshore and land-based wind did well in this analysis, respectively ranking first and second with scores of approximately 56 and 57. Offshore wind had a slightly lower energy payback time, and much lower GHG emissions when compared to inland wind. The LCOE for both options were just above the group average. The two technologies tied for the lowest water usage, which was significantly below the group average.

Table 3: Individual metric scores for selected technologies

Technology	Cost	Water	Energy	GHG
Wind (offshore)	38.8	100	100	24.1
Wind (land-based)	47.6	100	67.1	14.0
Nuclear	68.4	0.18	20.1	100
Coal	100	0.24	15.8	0.23
Solar Thermal	14.9	0.28	91.4	7.91
NGCC	97.0	1.01	7.2	0.49
IGCC (coal)	87.4	0.27	14.1	0.23
IGCC (biomass)	77.4	0.27	14.1	3.11
Solar PV	9.75	26.7	30.5	1.49
Hydroelectric	30.9	0.02	20.7	14.3

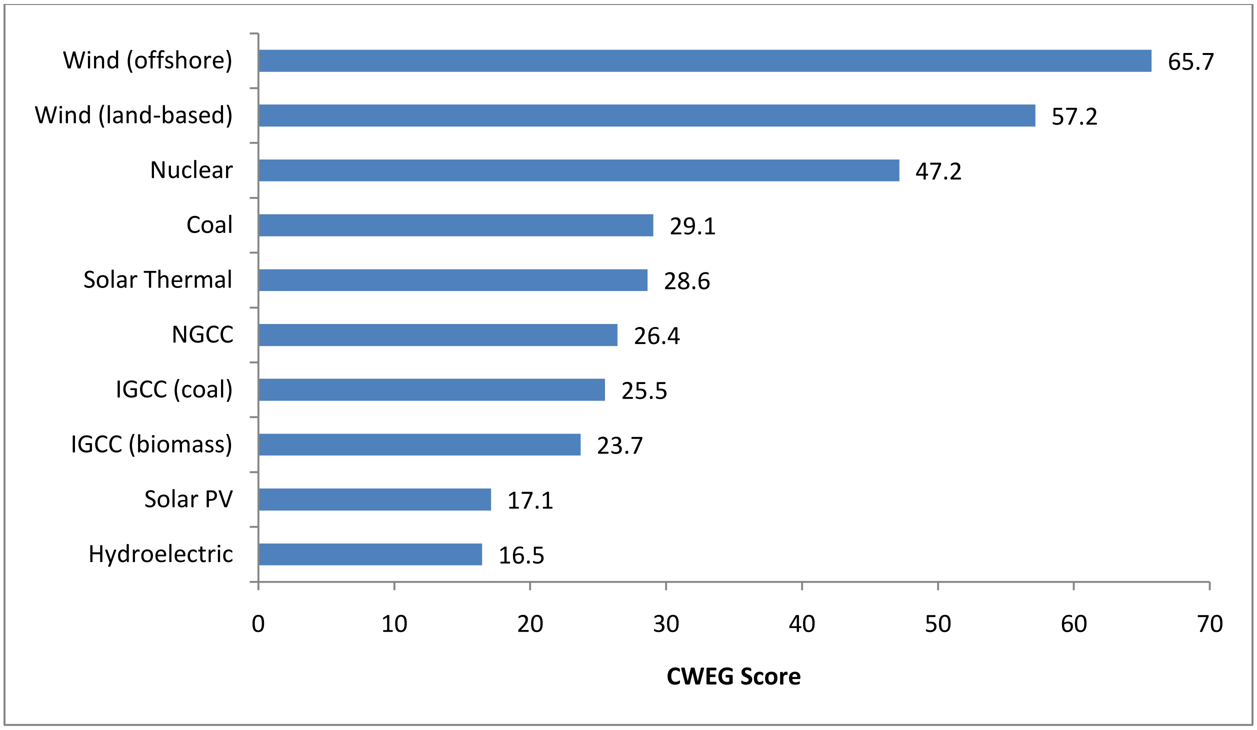

Figure 1: CWEG scores of selected power generation technologies

5. Results Assuming Unequal Weighting

The CWEG scores for offshore wind, nuclear, solar PV, and hydroelectric stations were recalculated while consecutively applying a 50% weight factor to each of the four metrics, while the remaining 50% was equally divided among the remaining three metrics. The original and recalculated results have been plotted in Figure 2, with the x-axis labels corresponding to the metric weighted at 50%.

Offshore wind power is the most attractive option out of the four when either the water usage or energy conversion efficiency metrics are weighted at 50%. Nuclear power is first when the GHG is weighted at 50%, owing to its near-zero emissions. Solar PV is third in the energy and water usage cases, and last in the cost and GHG emissions cases.

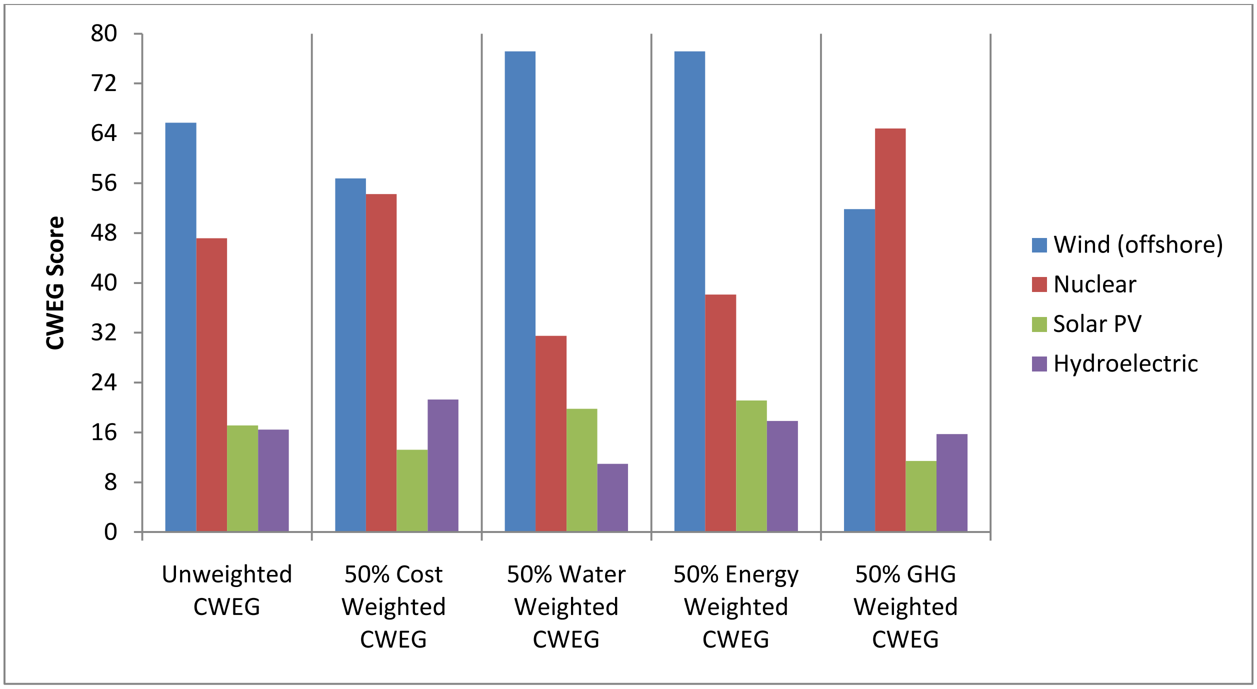

Figure 2: Selected CWEG scores under a 50% weight factor for all four metrics

6. Conclusion

Ten power generation technologies were evaluated for their cost, water usage, energy conversion efficiency, and greenhouse gas emissions. The CWEG methodology was applied to simplify comparisons between technologies.(1) Wind power favored well in this analysis, ranking first and second. Offshore wind power had the highest CWEG score of 66 out of 100, while land-based wind scored around 57. Incredibly low water usage, favorable levelized cost of electricity, low GHG emissions, and a short energy payback time were the main contributions to wind power's high rank. Compared to inland wind, offshore wind's higher LCOE was offset by lower GHG emissions and a shorter energy payback time. Hydroelectric stations had the lowest CWEG score, which was roughly 17. Water usage and upstream GHG emissions were the leading contributors to this low score.

Acknowledgements

This work was supported by the National Science Foundation under their Emerging Frontiers on Research and Innovation program, award number 0835989.

References

1. Gifford JD, Voss JS, Brown RC. Survey of power generation technologies. Handbook of Data Mining for Power Systems. Springer.

2. Fthenakis V, Chul Kim H. Life-cycle uses of water in U.S. electricity generation. 2010; 14(7).

3. Craig KR, Mann MK. Cost and performance analysis of biomass-based intgegreated gasificaiton combined-cycle (BIGCC) power systems. Golden, CO: National Renewable Energy Laboratory; 1996.

4. Gifford JD, Brown RC. Four economies of sustainable automotive transportation. Biofuels, Bioprocessing, Biorefining.

5. Zweibel K. Should solar photovoltaics be deployed sooner because of long operating life at low, predictable cost? Energy Policy. 2010 November; 28(11).

6. Torcellini P, Long N, Judkoff R. Consumptive water use for U.S. power production. Golden, CO: National Renewable Energy Laboratory; 2003. NREL/TP-550-33905.

7. International Energy Agency. IEA Energy Technology Network. [Online]. 2010 [cited 2010 Decemeber 22]. Available from: http://www.etsap.org/E-techDS/PDF/E03-Nuclear-Power-GS-AD-gct.pdf.

8. International Energy Agency. IEA Energy Technology Network. [Online]. 2010 [cited 2010 Decemeber 22]. Available from: http://www.etsap.org/E-techDS/PDF/E01-coal-fired-power-GS-AD-gct.pdf.

9. Rubin ES, Chen C, Rao AB. Cost and performance of fossil fuel power plants with CO2 capture and storage. Energy Policy. 2007 September; 35(9).

10. International Energy Agency. Energy Technology Systems Analysis Programme. [Online]. 2010 [cited 2010 Decemeber 22]. Available from: http://www.etsap.org/E-techDS/PDF/E07-hydropower-GS-gct.pdf.

11. International Energy Agency. Energy Technology Systems Analysis Programme. [Online]. 2010 [cited 2010 December 22]. Available from: http://www.etsap.org/E-techDS/PDF/E02-gas_fired_power-GS-AD-gct.pdf.

12. Roth FI, Ambs LL. Incorporating externalities into a full cost approach to electric power generation life-cycle costing. Energy. 2004; 29: p. 2125-2144.

13. Musial W, Butterfield S. Future for Offshore Wind Energy in the United States.Energy Ocean 2004; 2004; Palm Beach, Florida.

14. Oak Ridge National Laboratory. Bioenergy Conversion Factors. [Online]. [cited 2011 March 8]. Available from: http://bioenergy.ornl.gov/papers/misc/energy_conv.html.

15. U.S. Bureau of Labor Statistics. Databases, Tables & Calculators by Subject. [Online]. [cited 2010 December 29]. Available from: http://bls.gov/data/.

16. US Energy Information Administration. US Energy Information Administration (EIA) - Annual Energy Review. [Online]. 2009 [cited 2011 March 8]. Available from: http://www.eia.doe.gov/emeu/aer/coal.html.

17. US Energy Information Administration. US Natural Gas Prices. [Online]. 2010 [cited 2011 March 8]. Available from: http://www.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm.

18. Fthenakis V, Mason JE, Zweibel K. The technical, geographical, and economic feasibility for solar energy to supply the energy needs of the US. Energy Policy. 2009 February; 37(2).

19. Liu G, Williams RH, Larson ED, Kreutz TG. Design/economics of low-carbon power generation from natural gas and biomass with synthetic fuels co-production. Energy Procedia. 2010.

20. Kenny R, Law C, Pearce JM. Towards real energy economics: Energy policy driven by life-cycle carbon emission. Energy Policy. 2010 April; 38(4).

21. Weinzettel J, Reenaas M, Solli C, Hertwich EG. Life cycle assessment of a floating offshore wind turbine. Renewable Energy. 2009 March; 34(3).

22. Lechon Y, de la Rua C, Saez R. Life cycle environmental impacts of electricity production by solarthermal power plants in Spain. Journal of Solar Energy Engineering. 2008 May; 130.

23. Odeh NA, Cockerill TT. Life cycle GHG assessment of fossil fuel power plants with carbon capture and storage. Energy Policy. 2008 January; 36(1).

24. Mann MK, Spath PL. Life Cycle Assessment of a Biomass Gasification Combined-Cycle System.1997.

General Conclusion

Discussion

Automotive scenarios and electricity generation technologies have been surveyed and analyzed for their overall sustainability. A methodology referred to as the CWEG was used to score and rank both technology groups based on their relative performance in terms of cost, water usage, energy consumption or energy payback time, and greenhouse gas emissions. This methodology adopted a broad perspective when ranking both automotive scenarios and power generation technologies.

Conventional internal combustion engines fueled by compressed natural gas were found to offer the best overall performance. This scenario had the lowest overall water usage and operating costs out of all the automotive scenarios, as well as favorable energy efficiency. Fuel cell vehicles fueled with hydrogen produced from electrolysis using power from the U.S. grid had the worst overall performance out of the group. This scenario did poor in terms of greenhouse gas emissions, operating cost, and water usage, due mostly to the upstream water usage associated with power plants.

Offshore wind farms did the best out of the power generation technologies examined. This technology had the lowest water usage and a relatively high energy conversion efficiency. Hydroelectric technologies ranked the lowest in the power generation group due to poor scores in water usage, cost of electricity, and upstream greenhouse gas emissions.

Future Research

The power generation survey could be expanded to include more technologies. Some technologies were treated as aggregate groups that can be broken down further. For instance, “nuclear” can be broken down into pressurized water reactors, boiling water reactors, gas cooled reactors, etc. A narrowed view would give a better understanding of the characteristics of more specific technologies.

There are other factors that can affect the sustainability of either an automotive scenario or power generation technology. For example, the rate of consumption of natural resources, such as petroleum and natural gas, could also be formed into another metric. This would no doubt affect the results of the sustainability assessments, but it is difficult to predict by how much.

CWEG weighting factors could also be developed to study the sustainability of energy technologies in a regional context. For instance, the relative importance of water usage compared to the other metrics in various geographic regions could be used. However, adding a geographic dependence would also narrow the relevance of the study to that specific region.

References

1. DeLuchi MA. Emissions of greenhouse gases from the use of transportation fuels and electricity, Volume 1: Summary. Argonne, IL: Argonne National Laboratory; 1991.

2. Wang MQ. GREET 1.0- Transportation Fuel Cycles Model: Methodology and Use. Argonne, IL: Argonne National Laboratory, Center for Transportation Research; 1996.

3. Kim H, Kim S, Dale BE. Biofuels, land use change, and greenhouse gas emissions: Some unexplored variables. Environmental Science Technology. 2009; 43.

4. Wu M, Wu Y, Wang M. Energy and emission benefits of alternative transportation liquid fuels derived from switchgrass: A fuel life cycle assesment. Biotechnology Progress. 2008 September; 22(4).

5. Demirdoven N, Deutch J. Hybrid cars now, fuel cell cars later. Science. 2004 August; 305.

6. Gleick PH. Water and energy. Annual Review of Energy and the Environment. 1994; 19.

7. Brinkman N, Wang M, Weber T, Darlington T. Well-to-Wheels Analysis of Advanced Fuel/Vehicle Systems - A North American Study of Energy Use, Greenhouse Gas Emissions, and Criteria Pollutant Emissions. General Motors; 2005.

8. Simpson AG. Full-Cycle Assessment of Alternative Fuels for Light-Duty Road Vehicles in Australia. Australia: University of Queensland; 2005.

9. Unnasch S. Alcohol Fuels from Biomass: Well-to-Wheel Energy Balance. Cupertino, CA: TIAX LLC.

10. Beer T, Grant T, Morgan G, Lapszewicz J, Anyon P, Edwards J, et al. Comparison of transport fuels. Australian Greenhouse Office.

11. Brandt AR, Farrell AE. Scraping the bottom of the barrel: greenhouse gas emission consequences of a transition to low-quality and synthetic petroleum resources. Climatic Change. 2007; 84.

12. Brandt AR. Converting Green River oil shale to liquid fuels with the Alberta Taciuk Processor: energy inputs and greenhouse gas emissions. Working Paper. Berkeley, CA: University of California, Berkeley, Energy and Resources Group; 2007.

13. Bartis JT, LaTourrette T, Dixon L, Peterson DJ, Cecchine G. Oil Shale Development in the United States: Prospects and Policy Issues. Santa Monica, CA: RAND Corporation; 2005.

14. Safaei Mohamadabi H, Tichkowsky G, Kumar A. Development of a multi-criteria assessment model for ranking of renewable and non-renewable transportation fuel vehicles. Energy. 2009; 34.

15. Tzeng GH, Lin CW, Opricovic S. Multi-criteria analysis of alternative-fuel buses for public transportation. Energy Policy. 2005 July; 33(11).

16. Mirasgedia S, Diakoulaki D. Multicriteria analysis vs. externalities assessment for the comparative evaluation of electricity generation systems. European Journal of Operational Research. 1997; 102.

17. Roth FI, Ambs LL. Incorporating externalities into a full cost approach to electric power generation life-cycle costing. Energy. 2004; 29: p. 2125-2144.

18. Afgan NH, Carvalho MG. Multi-criteria assessment of new and renewable energy power plants. Energy. 2002 August; 27(8).

19. Pohekar SD, Ramachandran M. Application of multi-criteria decision making to sustainable energy planning - A review. Renewable and Sustainable Energy Reviews. 2004 August; 8(4).

20. International Energy Agency. IEA Energy Technology Network. [Online]. 2010 [cited 2010 Decemeber 22]. Available from: http://www.etsap.org/E-techDS/PDF/E01-coal-fired-power-GS-AD-gct.pdf.

21. International Energy Agency. Energy Technology Systems Analysis Programme. [Online]. 2010 [cited 2010 December 22]. Available from: http://www.etsap.org/E-techDS/PDF/E02-gas_fired_power-GS-AD-gct.pdf.

22. International Energy Agency. Energy Technology Systems Analysis Programme. [Online]. 2010 [cited 2010 December 22]. Available from: http://www.etsap.org/E-techDS/PDF/E06-geoth_energy-GS-gct.pdf.

23. International Energy Agency. Energy Technology Systems Analysis Programme. [Online]. 2010 [cited 2010 Decemeber 22]. Available from: http://www.etsap.org/E-techDS/PDF/E07-hydropower-GS-gct.pdf.

24. International Energy Agency. Energy Technology Systems Analysis Programme. [Online]. 2010 [cited 2010 December 22]. Available from: http://www.etsap.org/E-techDS/PDF/E08-Ocean%20Energy-GS-gct.pdf.

25. International Energy Agency. IEA Energy Technology Network. [Online]. 2010 [cited 2010 Decemeber 22]. Available from: http://www.etsap.org/E-techDS/PDF/E03-Nuclear-Power-GS-AD-gct.pdf.

26. U.S. Energy Information Administration. EIA- The National Energy Modeling System: An Overview 2009. [Online]. 2009 [cited 2011 March 5]. Available from: http://www.eia.doe.gov/oiaf/aeo/overview/index.html.

27. Black & Veatch. Power Plant Engineering New York, NY: Springer Science+Buisness Media, LLC; 1996.

28. Breeze P. Power Generation Technologies Burlington, MA: Elsevier; 2005.

29. Kehlhofer R, Hannemann F, Stirnimann F, Rukes B. Combined-Cycle Gas & Steam Turbine Power Plants 3 , editor. Tulsa, OK: PennWell Corporation; 2009.

30. Tester JW, Drake EM, Driscoll MJ, Golay MW, Peters WA. Sustainable Energy Choosing Among Options Cambridge, MA: The MIT Press; 2005.

31. Pacca S, Horvath A. Greenhouse gas emissions from building and operating electric power plants in the Upper Colorado River Basin. Environmental Science & Technology. 2002; 36(14).

32. Honda H. Life cycle GHG emission analysis of power generation systems: Japanese case. Energy. 2005; 30.

33. Kannan R, Leong KC, Osman R, Ho HK. Life cycle energy, emissions and cost inventory of power generation technologies in Singapore. Renewable & Sustainable Energy Reviews. 2007; 11.

34. Gifford JD, Brown RC. Four economies of sustainable automotive transportation. Biofuels, Bioprocessing, Biorefining. .

35. Gifford JD, Brown RC. Four economies of sustainable power generation. Draft. .

36. Gifford JD, Voss JS, Brown RC. Survey of power generation technologies. In Handbook of Data Mining for Power Systems.: Springer.

37. Kabir Kazi F, Fortman JA, Anex RP, Hsu DD, Aden A, Dutta A, et al. Techno-economic comparison of process technologies for biochemical ethanol production from corn stover. Fuel. 2010 89; 89.

38. U.S. Bureau of Labor Statistics. Databases, Tables & Calculators by Subject. [Online]. [cited 2010 December 29]. Available from: http://bls.gov/data/.

39. Ho DT, Frunt J, Myrzik JMA. Photovoltaic Energy in Power Market. Energy Market. 2009;: p. 1-5.

40. Ramana MV. Nuclear Power Economic, Safety, Health, and Environmental Issues of Near-Term Technologies. Annual Review of Environment and Resources. 2009; 34: p. 127-152.

41. Kannan R, Tso CP, Osman R, Ho HK. LCA-LCCA of oil fired steam turbine power plant in Singapore. Energy Conversion & Management. 2004; 45: p. 3093-3107.

42. Shultis JK, Faw RE. Fundamentals of Nuclear Science and Engineering. 2nd ed. Boca Raton, FL: CRC Press; 2008.

43. Morris C, Kranowitz J, Kelly M, Fascitelli B, Hughes M. Nuclear Power Joint Fact-Finding. 2007.

44. U.S. Energy Information Administration. Assumptions to the Annual Energy Outlook 2010 with Projections to 2035. ; 2010.

45. Kennedy S. Wind power planning: assessing long-term costs and benefits. Energy Policy. 2005; 33: p. 1661-1675.

46. U.S. Energy Information Administration. U.S. Energy Information Administration. [Online]. [cited 2010 Decemeber 22]. Available from: http://www.eia.doe.gov/cneaf/nuclear/page/uran_enrich_fuel/convert.html.

47. White SW, Kulcinski GL. Birth to death analysis of the energy payback ratio and CO2 gas emission rates from coal, fission, wind, and DT-fusion electrical power plants. Fusion Engineering and Design. 2000; 48: p. 473-481.

48. Mirzaesmaeeli H, Elkamel A, Douglas PL, Croiset E, Gupta M. A multi-period optimization model for energy planning with CO2 emission consideration. Journal of Environmental Management. 2010; 91: p. 1063-1070.

49. U.S. Energy Information Administration. U.S. Energy Information Administration Independent Statistics and Analysis. [Online]. 2010 [cited 2010 December 22]. Available from: http://www.eia.doe.gov/cneaf/electricity/epm/table1_1.html.

50. Fthenakis V, Chul Kim H. Land use and electricity generation: A life-cycle analysis. Renewable and Sustainable Energy Reviews. 2009; 13: p. 1465-1474.

51. Kramer J, Voss S, Sakazaki M. IGCC Engineering and Permitting Issues Summaries. ; 2006.

52. San Martin RL. Environmental Emissions from Energy Technology Systesm: The Total Fuel Cycle. Washington, DC:; 1989.

53. Norton B, Eames PC, Lo SNG. Full-energy-chain analysis of greenhouse gas emissions for solar thermal electric power generation systems. Renewable Energy. 1998; 15: p. 131-136.

54. Becerra-Lopez HR, Golding P. Dynamic exergy analysis for capacity expansion of regional power-generation systems: Case study for far West Texas. Energy. 2007; 32.

55. Klara JM, Wimer JG. NETL. [Online]. 2007 [cited 2010 Decemeber 22]. Available from: http://www.netl.doe.gov/energy-analyses/pubs/deskreference/B_NGCC_051507.pdf.

56. Bank of Canada. Bank of Canada. [Online]. 2011 [cited 2011 Janurary 5]. Available from: http://www.bankofcanada.ca/cgi-bin/famecgi_fdps.

57. Kumbaroglu G, Madlener R, Demirel M. A real options evaluation model for the diffusion prospects of new renewable power generation technologies. Enery Economics. 2008; 30: p. 1882-1908.

58. Mann MK, Spath PL. Life Cycle Assessment of a Biomass Gasification Combined-Cycle System.1997.

59. Rhodes JS, Keith DW. Engineering economic analysis of biomass IGCC with carbon capture and storage. Biomass & Bioenergy. 2005; 29: p. 440-450.

60. Bain RL, Amos WA, Downing M, Perlack RL. Biopower Technical Assessment: State of the Industry and Technology. Golden, Colorado:; 2003.

61. Sandvig E, Walling G, Brown RC, Pletka R, Radlein D, Johnson W. Integrated Pyrolysis Combined Cycle Biomass Power System Concept Definition Final Report. ; 2003.

62. El-Kordy MN, Badr MA, Abed KA, Ibrahim SMA. Economical evaluation of electricity generation considering externalities. Renewbale Energy. 2002; 25: p. 317-328.

63. Rosen MA, Dincer I. Exergoeconomic analysis of power plants operating on various fuels. Applied Thermal Energineering. 2003; 23: p. 643-658.

64. Ruth LA. Energy from municipal solid waste: a comparison with coal combustion technology. Prog. Energy Combust. Sci. 1998; 24: p. 545-564.

65. Lee S, Speight JG, Loyalka SK. Handbook of Alternative Fuel Technologies Boca Raton, FL: Taylor & Francis Group, LLC; 2007.

66. Willumsen HC. Energy Recovery from Landfill Gas in Denmark and Worldwide. Vilborg, Denmark.

67. Bove R, Lunghi P. Electric power generation from landfill gas using traditional and innovative technologies. Energy Conversion & Management. 2006; 47: p. 1391-1401.

68. Song C. Fuel processing for low-temperature and high-temperature fuel cells Challegnes, and opportunities for sustainable development in the 21st century. Catalysis Today. 2002; 77: p. 17-49.

69. UTC Power. UTC Power A United Technologies Company. [Online].; 2008 [cited 2010 December 22]. Available from: http://www.utcpower.com/fs/com/Attachments/data_sheets/DS0112_093008.pdf.

70. Karakoussis V, Brandon NP, Leach M, van der Vorst R. The environmental impact of manufacturing planar and tubular soild oxide fuel cells. Journal of Power Sources. 2001; 101: p. 10-26.

71. Pehnt M. Dynamic life cycle assessment (LCA) of renewable energy technologies. Renewable Energy. 2006; 31: p. 55-71.

72. Kanoglu M, Cengel YA. Economic evaluation of geothermal power generation, heating, and cooling. Energy. 1999; 24: p. 501-509.

73. Fridleifsson IB. Geothermal energy for the benefit of the people. Renewable & Sustainable Energy Reviews. 2001; 5: p. 299-312.

74. Evans A, Strezov V, Evans TJ. Assessment of sustainability indicators for renewable energy technologies. Renewable and Sustainable Energy Reviews. 2009; 13: p. 1082-1088.

75. McGowan JG, Connors SR. Windpower: A Turn of the Century Review. Annual Review of Energy and the Environment. 2000; 25: p. 147-197.

76. Chang TJ, Wu YT, Hsu HY, Chu CR, Liao CM. Assessment of wind characteristics and wind turbine characteristics in Taiwan. Renewable Energy. 2003; 28: p. 851-871.

77. Chatzimouratidis AI, Pilavachi PA. Objective and subjective evaluation of power plants and their non-radioactive emissions using the analytic hierarchy process. Energy Policy. 2007; 35: p. 4027-4038.

78. Liebreich M, Young W. Offshore Wind: Europe's EUR 90 Billion Funding Requirement. London, UK; 2005.

79. Schleisner L. Life cycle assessment of a wind farm and related externalities. Renewable Energy. 2000; 20: p. 279-288.

80. Liu Y, Ye L, Benoit I, Liu X, Cheng Y, Morel G, et al. Economic performance evaluation method for hydroelectric generating units. Energy Conversion & Management. 2003; 44: p. 797-808.

81. Seymour RJ, editor. Ocean Energy Recovery: The State of the Art: American Society of Civil Engineers; 1992.

82. National Oceanic and Atmospheric Administration, University of New Hampshire. Technical Readiness of Ocean Thermal Energy Conversion (OTEC). 2009.

83. Xie C, Wang S, Zhang L, Jack Hu S. Improvement of proton exchange membrane fuel cell overall efficiency by integrating heat-to-electricity conversion. Journal of Power Sources. 2009; 191: p. 433-441.

84. Pontes MT, Falcao A. Ocean Energy Conversion. Lisboa, Portugal.

85. Tahara K, Horiuchi K, Kojima T, Inaba A. Ocean Thermal Energy Conversioni (OTEC) System as a Countermeasure for CO2 Problem- Energy Balance and CO2 Reduction Potential. Energy Conversion Management. 1995; 36: p. 857-860.

86. Organisation for Economic Co-Operation and Development, International Energy Agency. Experience Curves for Energy Technology Policy Paris, France: OECD/IEA; 2000.

87. McDonald A, Schrattenholzer L. Learning rates for energy technologies. Energy Policy. 2001; 29.

88. Hammons TJ. Energy potential of the oceans in Europe and North America: tidal, wave, currents, OTEC and offshore wind. International Journal of Power and Energy Systems. 2008; 28.

89. Klein J, Rednam A, Tavares R, Bender S, Blevins BB. Comparative costs of California central station electricity generation technologies. California Energy Commission; 2007.

90. Zweibel K. Should solar photovoltaics be deployed sooner because of long operating life at low, predictable cost? Energy Policy. 2010 November; 28(11).

91. Lackner MA, Elkinton CN. An analytical framework for offshore wind farm layout optimization. Wind Engineering. 2007; 31(1).

92. Craig KR, Mann MK. Cost and performance analysis of biomass-based intgegreated gasificaiton combined-cycle (BIGCC) power systems. Golden, CO: National Renewable Energy Laboratory; 1996.

93. Fthenakis V, Mason JE, Zweibel K. The technical, geographical, and economic feasibility for solar energy to supply the energy needs of the US. Energy Policy. 2009 February; 37(2).

94. Fthenakis V, Chul Kim H. Life-cycle uses of water in U.S. electricity generation. 2010; 14(7).

95. Torcellini P, Long N, Judkoff R. Consumptive water use for U.S. power production. Golden, CO: National Renewable Energy Laboratory; 2003. Report No. NREL/TP-550-33905.

96. Rubin ES, Chen C, Rao AB. Cost and performance of fossil fuel power plants with CO2 capture and storage. Energy Policy. 2007 September; 35(9).

97. Liu G, Williams RH, Larson ED, Kreutz TG. Design/economics of low-carbon power generation from natural gas and biomass with synthetic fuels co-production. Energy Procedia. 2010.

98. Oak Ridge National Laboratory. Bioenergy Conversion Factors. [Online]. [cited 2011 March 8]. Available from: http://bioenergy.ornl.gov/papers/misc/energy_conv.html.

99. Brown RC. Biorenewable Resources: Engineering New Products from Agriculture Ames, IA: Wiley-Blackwell; 2003.

100. U.S. Energy Information Administration. Petroleum Navigator. [Online]. [cited 2010 April 27]. Available from: http://tonto.eia.doe.gov/dnav/pet/pet_sum_top.asp.

101. Gary JH, Handwerk GE, Kaiser MJ. Petroleum Refining: Technology and Economics. 5th ed. New York: Marcel Dekker, Inc; 2007.

102. Stockman L. Tar Sands Oil Means High Gas Prices. Corporate Ethics International. 2010.

103. U.S. Energy Information Administration. U.S. Natural Gas Prices. [Online].; 2010 [cited 2011 March 8]. Available from: http://www.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm.

104. U.S. Energy Information Administration. Natural Gas Prices by Sector. [Online]. [cited 2010 27 April]. Available from: http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_m.html.

105. U.S. National Research Council Committee on Alternatives and Strategies for Future Hydrogen Production and Use, National Academy of Engineering, U.S. National Academy of Sciences. The Hydrogen Economy: Opportunities, Costs, Barriers, and R&D Needs. Washing, D.C.: National Academies Press; 2004.

106. Kazi FK, Fortman JA, Anex RP, Hsu DD, Aden A, Dutta A, et al. Techno-economic comparison of process technologies for biochemical ethanol production from corn stover. Fuel. 2010.

107. Kwiatkowski JR, McAloon AJ, Taylor F, Johnston DB. Modeling the process and costs of fuel ethanol production by the corn dry-grind process. Industrial Crops and Products. 2006; 23: p. 288-296.

108. Offer GJ, Howey D, Contestabile M, Clague R, Brandon NP. Comparative analysis of battery electric, hydrogen fuel cell and hybrid vehicles in a future sustainable road transport system. Energy Policy. 2010; 38(1).

109. American Honda Motor Company, Inc. Honda Cars. [Online]. 2011. Available from: http://automobiles.honda.com/.

110. Toyota Motor Sales U.S.A., Inc. Toyota cars, trucks, SUVs & accessories. [Online]. Available from: http://www.toyota.com/.

111. Volkswagen of America, Inc. Volkswagen of America. [Online]. 2011. Available from: http://www.vw.com/en.html.

112. Nissan USA. Nissan cars, hybrid, electric, crossovers, SUVs, trucks. [Online]. 2011. Available from: http://www.nissanusa.com/.

113. U.S. Energy Information Administration. U.S. Energy Information Administration (EIA) - Annual Energy Review. [Online]. 2009 [cited 2011 March 8]. Available from: http://www.eia.doe.gov/emeu/aer/coal.html.

114. U.S. Department of Energy. Tar Sands Fact Sheet. [Online]. [cited 2010 March 22]. Available from: http://fossil.energy.gov/programs/reserves/npr/Tar_Sands_Fact_Sheet.pdf.

115. Farrell AE, Plevin RJ, Turner BT, Jones AD, O'Hare M, Kammen DM. Ethanol can contribute to energy and environmental goals. Science. 2006 January.

116. U.S. Energy Information Administration. Natural Gas Data, Reports, Analysis, Surveys. [Online]. [cited 2010 August 15]. Available from: http://www.eia.gov/oil_gas/natural_gas/info_glance/natural_gas.html.

117. Kroposki B, Levene J, Harrison K, Sen PK, Novachek F. Electrolysis: Information and Opportunities for Electric Power Utilities. Golden, CO:, NREL; 2006.

118. U.S. Energy Information Administration. Average Retail Price of Electricity to Ultimate Customers: Total by End-Use Sector. [Online]. [cited 2010 April 27]. Available from: http://www.eia.doe.gov/cneaf/electricity/epm/table5_3.html.

119. Unnasch S, Pont J, Hooks M, Chan M, Waterland L, Rutherford D. Full fuel cycle assessment well to tank energy inputs, emissions, and water impacts. Cupertino, CA:, TIAX LLC; 2007.

120. International Energy Agency. IEA Energy Technology Essentials: Fuel Cells. [Online]. [cited 2011 January 30]. Available from: http://www.iea.org/techno/essentials6.pdf.

121. King CW, Webber EM. The water intensity of the plugged-in automotive economy. Environmental Science & Technology. 2008 Feburary.

122. Aden A. Southwest Hydrology. [Online]. Available from: http://www.swhydro.arizona.edu/archive/V6_N5/feature4.pdf.

123. U.S. Energy Information Administration. [Online]. [cited 2010 November 2010]. Available from: http://www.eia.doe.gov/cneaf/electricity/page/eia906_920.html.

124. Musial W, Butterfield S. Future for Offshore Wind Energy in the United States. Energy Ocean 2004; 2004; Palm Beach, Florida.

125. US Energy Information Administration. US Energy Information Administration (EIA) - Annual Energy Review. [Online]. 2009 [cited 2011 March 8]. Available from: http://www.eia.doe.gov/emeu/aer/coal.html.

126. Kenny R, Law C, Pearce JM. Towards real energy economics: Energy policy driven by life-cycle carbon emission. Energy Policy. 2010 April; 38(4).

127. Weinzettel J, Reenaas M, Solli C, Hertwich EG. Life cycle assessment of a floating offshore wind turbine. Renewable Energy. 2009 March; 34(3).

128. Lechon Y, de la Rua C, Saez R. Life cycle environmental impacts of electricity production by solarthermal power plants in Spain. Journal of Solar Energy Engineering. 2008 May; 130.

129. Odeh NA, Cockerill TT. Life cycle GHG assessment of fossil fuel power plants with carbon capture and storage. Energy Policy. 2008 January; 36(1).