LIFE CYCLE ASSESSMENT AND EMERGY SYNTHESIS OF A THEORETICAL OFFSHORE WIND FARM FOR JACKSONVILLE, FLORIDA

By

STACEY L DOLAN

A THESIS PRESENTED TO THE GRADUATE SCHOOL
OF THE UNIVERSITY OF FLORIDA IN PARTIAL FULFILLMENT
OF THE REQUIREMENTS FOR THE DEGREE OF
MASTER OF SCIENCE

UNIVERSITY OF FLORIDA

2007

To my grandparents, Catherine Alice and James Harold Bailey.

ACKNOWLEDGMENTS

I am extremely grateful to have had the opportunity to work with Dr. H. A. Ingley, III. He has been a great advisor, mentor, and friend; and his guidance has been invaluable. I would also like to thank Dr. Mark T. Brown for introducing me to the concept of emergy, for being an incredible teacher, and for providing his expertise. In addition to my supervisory committee members, I would like to thank Dr. Angela S. Lindner for offering her proficiency in life cycle assessments, which was vital to my research.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

Abstract of Thesis Presented to the Graduate School
of the University of Florida in Partial Fulfillment of the
Requirements for the Degree of Master of Science

LIFE CYCLE ASSESSMENT AND EMERGY SYNTHESIS OF THEORETICAL OFFSHORE WIND FARM FOR JACKSONVILLE, FLORIDA

By

Stacey L Dolan

May 2007

Chair: H. A. Ingley, III
Major: Mechanical Engineering

Wind energy is currently the fastest growing renewable energy resource in the United States. There are, however, only limited locations that have strong enough wind speeds to be suitable as wind farm sites. Throughout the state of Florida there are mostly only Class 1 winds (less than 5.6 m/s), with some Class 2 (5.6 to 6.4 m/s) winds close to the coast. Current wind technology requires a minimum of Class 3 (6.4 to 7.0 m/s) for wind farms to be feasible. Transmission of the electricity produced is a significant contributing factor to the cost of wind power, so minimizing distance is important for economic optimization. Offshore wind offers the advantage of higher wind speeds that are strong enough to be feasible for wind farms, enabling states for which onshore applications are not possible to harness wind power without having to transmit it from neighboring states.

This research analyzed how the implementation of an offshore wind farm for Jacksonville, Florida would compare to that of a natural gas combined-cycle unit and a coal-fired steam turbine power unit with regard to sustainability, global warming impact, and acid rain impact. An emergy analysis was conducted to compare the potential offshore wind farm to a purely coal-fired steam turbine power unit, a steam turbine power unit fueled by a mix of coal and petroleum coke, and a natural gas combined-cycle power generating unit. Parameters for comparison

included emergy yield ratio, environmental loading ratio, and emergy index of sustainability. A life cycle assessment was also conducted to quantify the respective contributions to the environmental impacts of global warming and acid rain of each power system. The environmental stressors inventoried for quantifying the impacts were carbon dioxide, methane, nitrous oxide, sulfur dioxide, and nitrogen oxides.

The emergy analysis determined that the wind farm had an emergy yield ratio of 11.6, compared to 18.2 for the coal system based on Scherer, 18.8 for the coal system based on St. Johns River Power Park, and 12.4 for the natural gas system. The wind farm's environmental loading ratio was orders of magnitude lower, i.e. 0.1, while the coal systems range from 13.1 to 15.1 and the natural gas system was found to be 22.4. Similarly, the emergy index of sustainability for the wind farm was found to have an advantageously higher value 121.9, while the coal systems ranged from 1.2 to 1.4, and the natural gas system was found to have a value of 0.6.

Results of the life cycle assessment included that the global warming and acid rain impacts of the wind farm were far lower than those of the fossil fuel-fired systems. The wind farm was found to have a global warming impact of 24 kg CO_2 equivalents/MWh, and an acid rain impact of 0.2 kg SO_2 equivalents/MWh. The fossil fuel fired systems were found to range from 682 to 1452 kg CO_2 equivalents/MWh, and 5.0 to 6.4 kg SO_2 equivalents/MWh.

CHAPTER 1
INTRODUCTION

1.1 Electricity and Fossil Fuels

Global energy consumption of fossil fuels has steadily increased starting at the turn of the 19th century with the Industrial Revolution, and experienced a drastic increase in the rate of consumption beginning in the 1950s. Currently the global consumption of energy is roughly 420 quadrillion British Thermal Units annually, equivalent to just over 200 million barrels of oil per day (EIA 2006). Coal, oil, and natural gas have various applications such as electricity production, heat generation, and fuel for transportation. The electricity production utilities sector is a significant consumer of fossil fuels, representing 39% of the total energy consumed in the United States (USEPA 2006c). Further, the United States is the country with the largest consumption of electricity, representing just over 25% of the world's consumption (USCIA 2006). Electricity generated in the US in 2004 totaled 3,971 billion kilowatt-hours provided by a mixture of sources, comprising 70.7% fossil fuel-fired power plants, 19.9% nuclear, 6.5% hydroelectric, 2.3% other renewables (wind, solar, etc.), and 0.6% other. Of the fossil fuel power plants, coal represented 49.8%, natural gas 17.9%, and petroleum 3% (EIA 2005).

Because fossil fuels are a non-renewable resource, the world's energy dependence on their consumption is not a sustainable practice. The Energy Information Administration of the U.S. Department of Energy has estimated the year in which peak oil recovery will occur using the mean resource estimate of 3,003 billion barrels ultimately recovered and three different projected annual growth rates of consumption. As can be seen in Figure 1-1, the projected peak years are to occur in 2050, 2037, or 2030, for the respective growth rates of 1%, 2%, or 3%. Historic growth rates have been approximately 2% (Wood and Long 2000). These projections illustrate the pressing need for alternative power production derived from renewable resources to be developed in order to maintain a supply for our energy demands by offsetting the decline in available fossil fuels.

1.1.1 Environmental Impacts of Fossil Fuel Combustion

Further motivation for this transition to renewable energy sources are the environmental impacts resulting from the combustion of fossil fuels. Anthropogenic greenhouse gas emissions from power plants, such as carbon dioxide, methane, and nitrous oxide, contribute to global climate change by accumulating in the atmosphere and blocking infrared radiation from escaping to space. The global warming potential of a process can be measured by the amount carbon dioxide equivalents released by that process and Figure 1-2 shows that, of the economic sectors, electricity production is the largest contributor of carbon dioxide equivalents released in the United States.

Another significant result of fossil fuel combustion is acid rain. Sulfur dioxide and nitrogen oxides (NO_X) emissions from fossil fuel-fired power plants react with water vapor in the atmosphere to form sulfuric acid and nitric acid, resulting in acid rain, a term that encompasses any precipitation (rain, fog, mist, or snow) with a pH of 5.5 or less. Acid rain has been determined to cause damage to plant life, e.g. the high-elevation spruce trees of the Appalachians; to fish and invertebrate aquatic species, e.g. trout populations in lakes and streams in the Adirondack Mountains in New York; and to historic monuments and buildings by corroding metals and deteriorating stone and paint (USEPA 2006b).

Urban ozone is another environmental impact to which fossil-fired power plants contribute by releasing volatile organic compounds (VOCs) and NO_X, which react in the presence of sunlight to form ground-level ozone, the main component of urban smog. Ozone poses various health risks, such as irritation and damage to the respiratory system, eyes, and mucous membranes, as well as detrimental environmental effects, such as damaging sensitive tree species and crops (Carlin 2002).

1.1.2 Environmental Regulations of Air Emissions

Legislation to control the levels of air pollutants in the United States has its basis in the Clean Air Act (CAA) of 1970 and its amendments. The CAA requires the EPA to set National Ambient Air Quality Standards (NAAQS) for pollutants that have been shown to be harmful to human health. The EPA has set these standards for six "criteria pollutants," identifying concentrations above which adverse health effects can occur. These criteria pollutants are ozone, carbon monoxide, nitrogen dioxide, sulfur dioxide, particulate matter smaller than 10 microns, and lead (USEPA 2006a). These criteria pollutants must be monitored, and if an area or community fails to meet these standards it is classified as being in nonattainment. The EPA then establishes a plan of action detailing air pollution reduction measures that the community must implement and a set time frame within which to reduce the pollution levels to meet the NAAQS. All six of the criteria pollutants (although lead only in trace amounts) are emissions of fossil-fired power plants (Carlin 2002).

The main contributing emissions to global climate change, however, are not included in the six criteria pollutants regulated by the NAAQS, such as carbon dioxide, methane, and nitrous oxide. Nevertheless, a range of governmental action is being taken to motivate a reduction in these emissions. Examples of this legislation span from the local level, such as the Florida Renewable Energy Production Tax Credit, to the national level, for instance federal grants such as the USDA Renewable Energy Systems and Energy Efficiency Improvements Program, to the international level of the Kyoto Protocol of the United Nations Framework Convention on Climate Change (UNFCCC). The UNFCCC states its objective is to achieve "stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system" (1992).

The importance of a conversion to non-fossil fuel-based, sustainable energy production systems is being recognized throughout the world, but this conversion is an immense task requiring great changes in energy infrastructure, industry, legislation, technology, economy, etc. Because of this, it will necessarily be a slow and gradual transition. Thus, the initiation of this transition is a pressing issue in order to be far enough into implementation that as the fossil fuel supply declines there will not be a global energy shortage and the intrinsic devastating impacts such an event could have.

1.2 Wind Power

Wind power is currently the world's fastest growing renewable electricity production system because it is the most economically competitive with fossil fuels (Pellerin 2005). Current wind turbine technology was developed in Denmark in the late 1970s with the first wind farms installed in the U.S. in California in the 1980s. At this time wind energy cost roughly 40 cents per kilowatt-hour, but has decreased over the last several decades to 4 to 6 cents per kilowatt-hour due to large growth in the industry (Pellerin 2005). Globally, wind energy has increased at an average rate of 32% annually over the five-year span from 1998 to 2002 (AWEA 2003).

In Europe, governments are subsidizing the cost of wind power installations as a response to the Kyoto Protocol. The benefit of this subsidy is clearly demonstrated by Europe collectively representing 72.8% of the global installed wind power capacity in 2004 (AWEA 2005). The top five countries in the world ranked by installed wind capacity are Germany, Spain, United States, Denmark, and India. Germany is the country with the greatest amount of installed capacity (16,629 MW), and Denmark leads with respect to the proportion that wind power contributes to the country's total energy production, supplying just over 20%. The U.S. has a total installed capacity of 11,603 MW as of December 2006, representing 15.6% of the world's installed wind power capacity (GWEC 2007). The United States offers a federal production tax credit for wind energy, but its expiration in December 2003 and delay in renewal until October 2004 hindered market growth for that time period. However, it is again beginning to experience a more competitive annual increase consistent with market averages (AWEA 2005).

1.2.1 Offshore Wind: Advantages and Disadvantages

Offshore wind power generation offers both advantages and disadvantages compared to onshore wind plants. Offshore winds are typically characterized as having stronger, more consistent speeds, and are less turbulent than onshore winds because of the lack of landscape and buildings to impede the flow, which results in increased power production. Cities and towns tend to be more densely populated closer to the coast, as can be seen in Figure 1-3, and offshore wind also allows for closer proximity to these densely populated coastal cities with high value load centers, reducing electricity transmission costs for these locations. Onshore turbines are limited in size by such physical constraints as roadway size for shipping the turbines to the installation site and cranes for installing them. Offshore locations, where there are fewer physical barriers, may allow for larger turbines to be installed, which may be economically advantageous (Musial 2005).

Aesthetics are a common public concern regarding wind farms, and offshore sites are a far enough distance from the coast that their visual and auditory impacts can be greatly reduced compared to onshore. For instance, the large turbines for the proposed Cape Wind project in Massachusetts are 3.6 MW each and stand 417 feet in height from base to tip of the vertical-positioned blade. They will be 5.6 miles offshore from Cotuit and will appear to a viewer on the coast only one half inch in height above the horizon (Cape Wind Associates, LLC 2006).

There are, however, drawbacks to offshore wind power as well. Offshore wind farms are more expensive due to larger construction and installation costs since they require a more substantial foundation structure, installation of underwater transmission lines, and special installation equipment. They also may have increased maintenance and repair costs due to the damaging effects of a harsher operating environment, i.e. salt water, ocean currents, ice build-up, and storms. In 2004, average costs for the 617 MW of installed offshore wind capacity worldwide were 8-15 cents/kWh (Musial 2005), double or more than the cost of onshore.

Offshore and onshore wind utilities share some of the same human and environmental impact concerns, such as interference with air traffic and risks to migratory birds. Offshore wind, however, also brings rise to additional concerns, such as habitat loss to marine life. It is speculated, though, that offshore wind also may actually create the opposite effect, providing new habitat by means of the "artificial reef effect" of the submerged support structure. For example, the state of Delaware has an Artificial Reef Program administered by the Delaware Department of Natural Resources and Environmental Control's Division of Fish and Wildlife. This program has installed eleven artificial reefs since 1995 in the Delaware Bay and along the Atlantic coast to enhance fisheries habitat and benefit structure-oriented fish (DNREC 2005). Other concerns that are exclusive to offshore wind include the risks of marine traffic collisions, social implications of altering cherished coastal scenery, vibrations hindering marine animals' navigational sensory systems, and seabed disturbance that might decrease marine archaeological value.

1.2.2 Current State of Offshore Wind Technology

There are currently no installed offshore wind power plants in the United States, but several have been proposed, including one for Cape Cod, Massachusetts and one for Long Island, New York. Several offshore wind farms are currently operating in Europe, such as the

Nysted and Horns Rev plants in Denmark and the Scroby Sands and North Hoyle plants in the United Kingdom. Table 1-1 summarizes the offshore wind parks that have been installed as of 2006. The site conditions for these wind plants are different than those for the proposed U.S. sites, however, because they are in shallow, sheltered waters, less than 20 meters deep. Monopile foundations, which have been used in Europe, are suitable for these depths, up to 30 meters. Different supporting structure options for wind turbines in deeper waters are currently being developed, such as tripod foundations that are bottom-fixed for depths of 20-80 meters and floating structures for depths of 40-900 meters, but these have not previously been implemented at these depths (Figure 1-4).

Another factor that is hindering the U.S. development of offshore wind plants is that offshore wind resource data are scarce. The data that do exist are from data collecting buoys, automated measurement stations, and estimates of 10 meter wind speeds and power production potential by satellite instruments. These data are mostly for the ocean surface or only several meters above, and the models used for power estimates have been onshore models, extending their application to off the coast. Thus, they are not necessarily optimal for accurate offshore wind resource assessment. The National Renewable Energy Laboratory has started a program to produce validated wind resource maps and power data for priority offshore regions at a height of 50 meters above the surface. The program is planned to take several years and is beginning in 2006 with the Atlantic coast, spanning from Northern Florida to New England, the Great Lakes, and the western Gulf of Mexico (Elliot and Swartz 2006).

1.2.3 Florida's Wind Power Potential

The state of Florida is the fourth most populated state in the country. Moreover, its population is increasing at a faster than average rate, having increased 11.3% from April 1, 2000 to July 1, 2005, compared to the nation as a whole experiencing a 5.3% increase (U.S. Census

Bureau 2006a). This increasing population brings with it increased energy demands. Traditional wind power options for Florida are highly limited, however, because there are only Class 1 winds (less than 12.5 mph) throughout the state with some Class 2 winds (12.5 to 14.3 mph) close to the coast. Current wind technology requires a minimum of Class 3 (14.3 to 15.7 mph) for wind farms to be economically feasible. A map of Florida's wind resources and an explanation of wind speed classes can be found in Figure 1-5. With regard to offshore wind, however, Florida is a much more appropriate candidate due to its large ratio of coastal area to total land area compared to most other states, as well as its concentrated coastal populations.

Jacksonville, Florida, is the focus of our research. Jacksonville is a densely populated coastal city on Florida's northern Atlantic coast. The impact of hurricanes and tropical storms on an offshore wind plant is an important concern for such southern locations as Florida, and must be considered. Jacksonville is a location where hurricanes hit less frequently than more Southern cities, especially those on the Gulf Coast. The National Oceanic and Atmospheric Administration's (NOAA) Atlantic Oceanographic and Meteorological Laboratory's Hurricane Research Division reports that from 1851 to 2004 Florida has endured 110 hurricanes, 35 of which were major (Category 3 or higher). Of the 110 hurricanes, only 22 were in the Northeast quadrant of the state, compared to 36 in the Southwest, 41 in the Southeast, and 55 in the Northwest. Of the 35 major hurricanes, only 1 hit the Northeast, compared to 12, 15, and 12 for the other respective parts of the state (Landsea 2005).

Wind power offers many advantages to fossil fuel based electricity production, such as being a less polluting, renewable source of energy that is not dependent on foreign imports and is economically competitive with traditional power production systems. Onshore applications are not well suited to all geographic locations, and offshore wind farms offer an alternative electricity production option for coastal regions where land wind speeds are prohibitively low.

1.3 The Jacksonville Case

Jacksonville Electric Authority (JEA) is a municipally-owned utility company that provides the electric utility services for the City of Jacksonville, estimated 2003 population of 773,781 (US Census Bureau 2006), and parts of three adjacent counties. In Fiscal Year 2005, JEA served an average of 391,831 accounts, and sold approximately 16.2 billion kilowatt-hours (kWh) of electricity (JEA 2006). As of 2005, JEA's maximum electricity generating capacity is 3080 MW (JEA 2005); this capacity is achieved through a combination of sole and joint-ownership of 19 electricity generating units. A description of the individual power plant units including their capacities, turbine types, and fuel types is given in Table 1-2. Jacksonville Electric Authority implements a fuel diversification strategy to remain competitive in the energy market; the fuel array providing electricity production in 2005 consisted of approximately 56% coal, 27% petroleum coke, 6% oil (both distillate and residual), 6% natural gas, and 5% other (JEA 2005).

Jacksonville Electric Authority 's expansion plans include working with three other Florida utility companies to jointly plan and construct a $1.4 billion, 800 MW power plant for the purpose of meeting future energy needs of North Florida and in order to "provide reliable power at an affordable price in an environmentally responsible manner" (JEA 2006). Jacksonville Electric Authority 's commitment to seeking cleaner sources of energy includes a "Clean and Green Power Program," in which JEA signed a Memorandum of Understanding with Sierra Club and the American Lung Association to meet the voluntary goal of supplying 4 percent of its generating capacity from clean or green sources by the year 2007, and 7.5 percent by 2015. "Clean or green" sources include solar, biomass, wind, landfill gas, sewer plant digester gas, and certain natural gas technologies (JEA 2002). Future plans include purchases of biomass energy (up to 75 MW from a plant in central Florida) and construction of a 13 MW biomass generation plant (fueled by yard waste from the city of Jacksonville). Jacksonville Electric Authority has also entered into a “Wind Generation Agreement” in which JEA has agreed to purchase 10 MW of capacity over a 20-year period generated from a wind power plant in Ainsworth, Nebraska from Nebraska Public Power District (JEA 2006). In its Annual Disclosure Report of 2005, JEA states, “Wind generation is one of the most preferred and cost effective Green Power alternatives. Prior to its agreement with NPPD, wind generation was not a feasible alternative for JEA due to a lack of sustainable wind resources in the Jacksonville area” (JEA 2006).

Although Jacksonville does not have strong enough onshore winds, it is within close proximity to a potentially feasible offshore wind farm location. The National Buoy Data Center (NBDC), operated by the National Ocean and Atmosphere Administration (NOAA), maintains a set of data-collecting buoys that record wind speed, direction, temperature, etc. and makes these data available to the public on their website. Figure 1-6 shows the NDBC buoys for the state of Florida. Buoy number 41008, off the northeast coast of Jacksonville, has gathered data for over 11 years and measured an average wind speed over this time period of approximately 7 m/s (class 3 winds). This buoy is at a water depth of 18 m, shallow enough for current monopile technology to be implemented for the wind turbines’ foundations. Jacksonville Electric Authority 's interests in expansion, fuel diversification, and clean energy (particularly wind energy), and Jacksonville’s propinquity to this offshore location make it an ideal candidate for an offshore wind farm assessment.

The recent growing interest in offshore wind power applications for the United States necessitates much research spanning all aspects of such systems, including wind resource assessments, feasibility studies, economic assessments, environmental impact assessments, etc. The focus of our research is on the latter, assessing air pollution impacts of installing and operating an offshore wind farm compared to two different conventional, fossil fuel-fired power plants for electricity production. The two conventional power systems examined were a natural gas combined-cycle unit and a coal-fired steam turbine unit. The environmental impacts examined throughout the power plants' life times were global warming and acid rain. An emergy analysis was also performed to identify the emergy yield and a measure of sustainability of the power generating systems.

Table 1-1. Summary of offshore wind parks as of 2006.

Wind Farm Site	Country	Year	Manufacturer	No. of Turbines	Turbine Model	Site Total (MW)
Norgersund	Sweden	1990	Wind World	1	W25-220 kW	0.22
Vindeby	Denmark	1991	Bonus	11	B35-450 kW	4.95
Lely	Netherlands	1994	NedWind	4	NW40-500 kW	2.00
Tuno Knob	Denmark	1995	Vestas	10	V39-500 kW	5.00
Dronten	Netherlands	1996	Nordtank	28	NTK43-600 kW	16.80
Bockstigen	Sweden	1997	Wind World	5	W37-550 kW	2.75
Blyth	UK	2000	Vestas	2	V66-2.0 MW	4.00
Utgrunden	Sweden	2000	Enron Wind	7	EW70-1.5 MW	10.50
Middlegrunden	Denmark	2001	Bonus	20	B76-2.0 MW	40.00
Yttre Stengrunden	Sweden	2001	NEG Micon	5	NM72-2.0 MW	10.00
Horns Rev	Denmark	2002	Vestas	80	V80-2.0 MW	160.00
Ronland	Denmark	2002	Vestas	4	V80-2.0 MW	8.00
Ronland	Denmark	2002	Bonus	4	B82.4-2.3 MW	9.20
Samso	Denmark	2003	Bonus	10	B82.4-2.3 MW	23.00
Setana	Japan	2003	Vestas	2	V47-660 kW	1.32
Frederikshavn	Denmark	2003	Vestas	2	V90-3.0 MW	6.00
Frederikshavn	Denmark	2003	Bonus	1	B82.4-2.3 MW	2.30
Frederikshavn	Denmark	2003	Nordex	1	N90-2.3 MW	2.30
Nysted	Denmark	2003	Bonus	72	B82.4-2.3 MW	158.40
Arklow Bank	Ireland	2003	GE	7	GE104-3.6 MW	25.20
Wilhelmshafen	Germany	2003	Enercon	1	E112-4.5 MW	4.50
North Hoyle	UK	2003	Vestas	30	V80-2.0 MW	60.00
Scroby Sands	UK	2004	Vestas	30	V80-2.0 MW	60.00
Kentish Flats	UK	2004	NEG Micon	30	NM92-2.75 MW	82.50
Dollart/Emden	Germany	2006		1	4.5 MW	4.50
Barrow	UK	2006	Vestas	30	V90-3.0 MW	90.00
Beatrice	UK	2006		2	5.0 MW	10.00
					Total	803.44

Table 1-2. Description of JEA's current power generating stations and individual units.

Station	Unit	Year Installed	Type	Fuel	Capacity (MW)
Kennedy	3	May-73	CT	LO	54
	4	Aug-73	CT	LO	54
	5	Jul-73	CT	LO	54
	7	Jun-00	CT	G/LO	193
				Total	**247**
Northside Generating Station	1	May-02	ST	PC/C/G	298
	2	Feb-02	ST	PC/C/G	298
	3	Jul-77	ST	HO/G	518
	3	Feb-75	CT	LO	52
	4	Jan-75	CT	LO	52
	5	Dec-74	CT	LO	52
	6	Dec-74	CT	LO	52
				Total	**1322**
Brandy Branch	1	May-01	CT	G/LO	193
	2	May-01	CT	G/LO	193
	3	Oct-01	CT	G/LO	193
	4	Jan-05	ST	WH/G	180
				Total	**759**
Saint Johns River Power Park	1	Apr-82	ST	C/PC/LO	336
	2	Apr-82	ST	C/PC/LO	336
				Total	**672**
Plant Scherer	4	Feb-89	ST	C/LO	180
Girvin	*1*	*Jul-97*	*IC*	*LG*	*1*
				Combined Total	**3180**

Notes

CT	Combustion Turbine	G	Natural Gas
ST	Steam Turbine	PC	Petroleum-coke
IC	Internal Combustion	WH	Waste Heat
LO	Light Fuel Oil/Distillate/Diesel (No. 2)	LG	Landfill Gas
HO	Heavy Fuel Oil/Residual (No. 6)	*Not included in this research*	

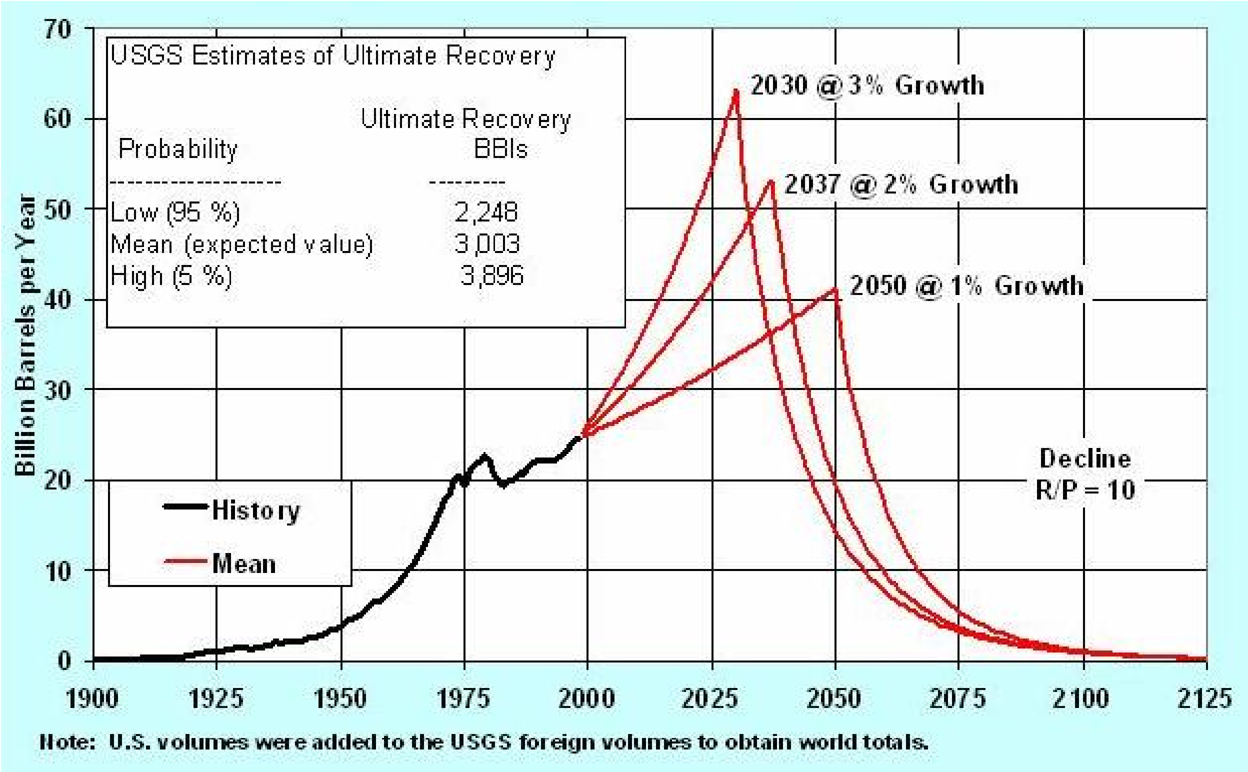

Figure 1-1. Annual crude oil production scenarios for the mean resource estimate and different projected growth rates. Reprinted with permission from: Wood, John and Gary Long. "Long Term World Oil Supply (A Resource Base/Production Path Analysis)." Energy Information Administration. 2000. United States Department of Energy. Last accessed October 2006. <http://www.eia.doe.gov/pub/oil_gas/petroleum/presentations/2000/long_term_supply/index.htm>.

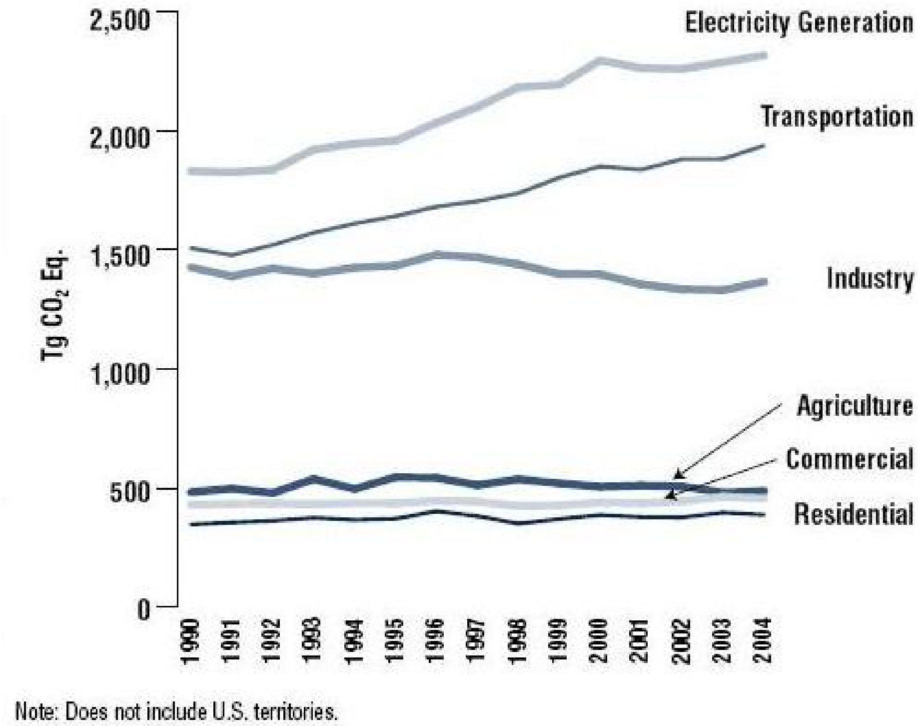

Figure 1-2. U.S. CO_2-equivalents emissions allocated to economic sectors. Reprinted with permission from: United States Environmental Protection Agency (USEPA). "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2004. 2006d. USEPA 430-R-06-002. Last accessed November 2006. <http://www.epa.gov/climatechange/emissions/usinventoryreport.html>.

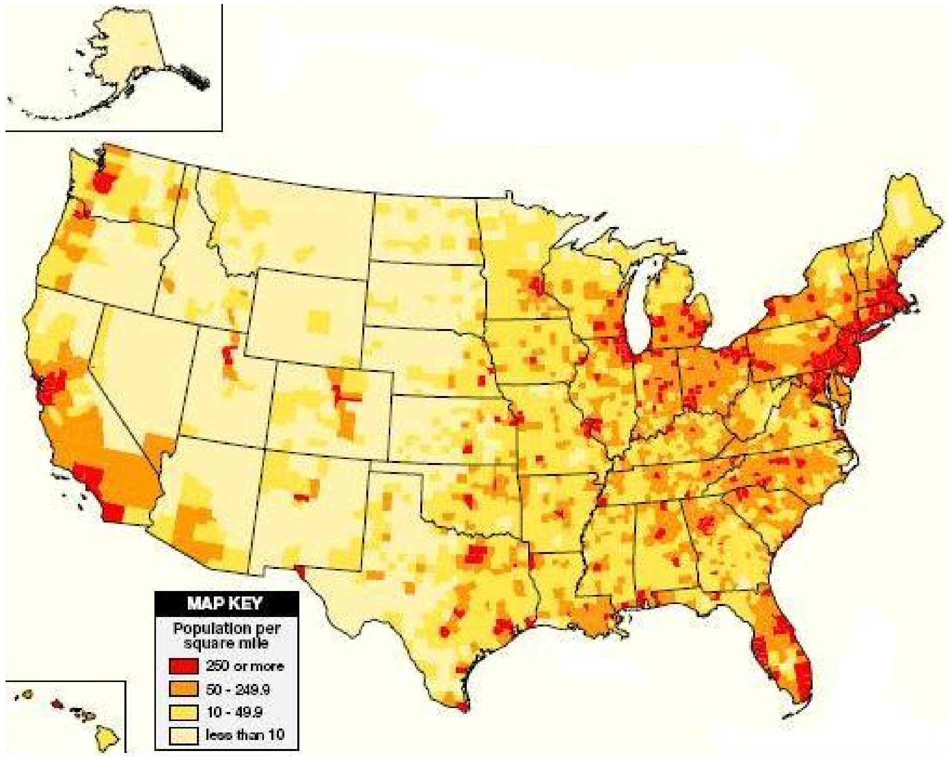

Figure 1-3. United States population density by counties. Reprinted with permission from: United States Census Bureau. “U.S. Population Density (By Counties).” 2006c. Last accessed October 2006. <http://www.census.gov/dmd/www/pdf/512popdn.pdf>.

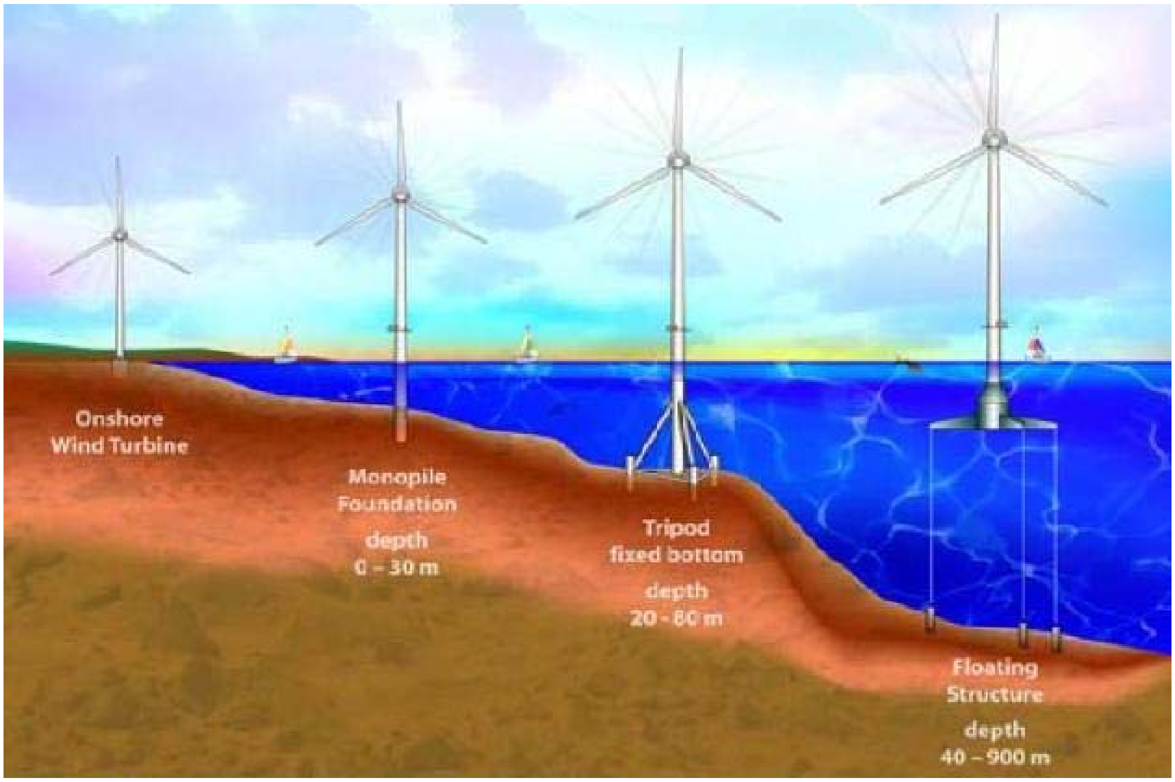

Figure 1-4. Offshore wind turbine foundation development for deep water. Reprinted with permission from: Musial, Walt. "Offshore Wind Energy Potential for the United States." Wind Powering America- Annual State Summit. National Renewable Energy Laboratory. Evergreen, CO, 2005.

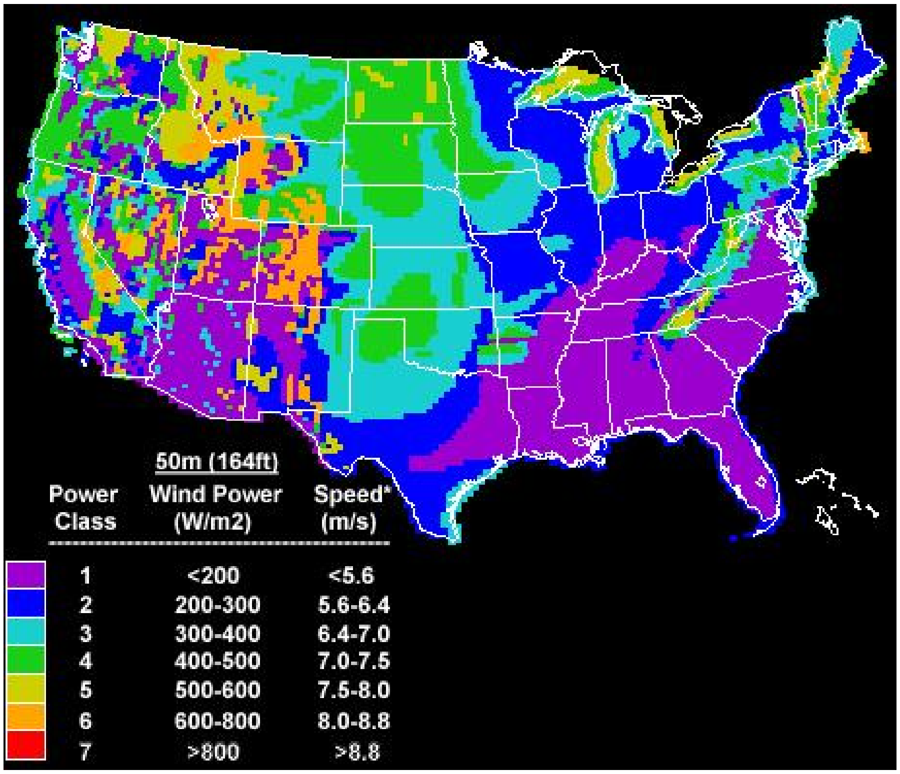

Figure 1-5. Wind power resources and wind power classes for the contiguous United States. Reprinted with permission from: Energy Efficiency and Renewable Energy (EERE). "Wind Energy Resource Potential." 2005. Unites States Department of Energy. Last accessed October 2006. <http://www1.eere.energy.gov/windandhydro/wind_potential.html>.

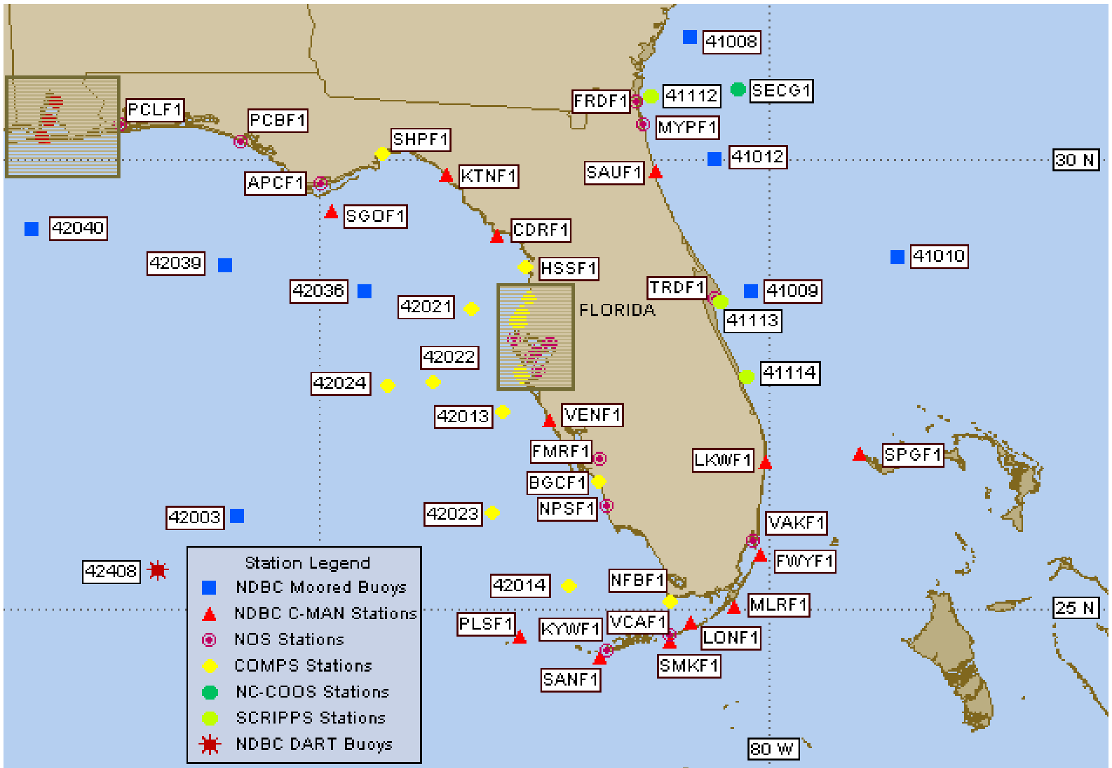

Figure 1-6. NDBC buoys off the coast of Florida. The location of buoy 41008 is the site chosen for the theoretical offshore wind farm. Reprinted with permission from: National Data Buoy Center (NDBC). "Station 41008 – Gray's Reef." National Oceanic and Atmospheric Administration. Last accessed November 2006. <http://www.ndbc.noaa.gov/station_page.php?station=41008>.

CHAPTER 2
LITERATURE REVIEW

2.1 Introduction to Life Cycle Assessments

Life cycle assessment (LCA) is an analysis tool for quantifying environmental impacts of a product or process from the "cradle to grave," i.e. from raw material acquisition to eventual product and waste disposal. LCAs have many uses, such as providing a means to systematically compare inputs and outputs of two products or processes; to identify the stages of a process or a product's life cycle have the greatest environmental or public health impacts; to establish a comprehensive baseline to which future research can be compared; to assist in guiding the development of new products; to provide information to decision makers in industry, government, and non-governmental organizations; and to verify a product's environmental claims or declarations (SETAC 2004). Life cycle assessment guidelines and examples have been established by the International Organization for Standardization (ISO) 14040 family of standards.

A life cycle assessment consists of three stages: inventory analysis, impact assessment, and improvement analysis. The inventory analysis consists of scoping the system under consideration, and data collection. The scoping process defines the LCA's purpose, boundary conditions, and assumptions. Streamlining may be used when defining the boundary conditions, identifying which stages of the process or product's life cycle will be considered and which will be assumed to be outside the scope of analysis. There are also two rules used to further streamline the scope, the five percent and one percent rules. The five percent rule allows for the elimination of a material from the analysis if it is ≤ 5% of the total product mass. The one percent rule allows for the elimination of an input if it is ≤ 1% of the total input mass. Materials or inputs with inherent toxicity are exceptions to these rules and must be included in the analysis regardless of their percent of total mass or inputs (USEPA 2006e). A functional unit (FU) of analysis, defined as the amount of product, material, or service to which the LCA is applied, is used to put the data on a common basis for direct comparison. For example, if the life cycle of Styrofoam cups is being compared to that of ceramic mugs, one appropriate functional unit would be 12 ounces of fluid, and all inputs and outputs would be put on the scale of their contribution per 12 ounces.

When conducting a life cycle assessment, the environmental impacts of interest and the stressors that result in these impacts must be identified (e.g. global warming and CO_2, respectively), and the production of these stressors is inventoried throughout all life cycle stages within the system boundary. The impact analysis stage of an LCA takes these data and systematically quantifies the resulting environmental impacts. Thus, the LCA methodology yields numerical results that allow for direct, analytical comparison between the resulting impacts of the systems under study.

Finally, the improvement analysis stage of the life cycle assessment is using the results of the study to determine ways in which the process or product under investigation can be improved. This can be done by identifying the most harmful or detrimental stages, analyzing the material and energy inputs, outputs, and processes involved in those stages, and seeking alternatives that would be less harmful. The methodology of an LCA, i.e. simultaneously analyzing the various stages with respect to the same parameters of interest, is what allows for easy pinpointing of the stages that require the most attention in the improvement analysis.

2.2 Life Cycle Assessments of Electricity Production Systems

2.2.1 Fossil Fuel-Based Systems

Over 70% of U.S. electricity is generated from fossil fuel-fired power plants, with coal accounting for nearly 50%, natural gas roughly 18%, and petroleum 3% (EIA 2005). Although emissions due to the combustion of fossil fuels at power plants are monitored and well documented, taking a life cycle approach to inventorying emissions through several or all stages of power generation and its associated fuel cycles and examining the environmental impacts of such systems offers a more holistic and complete analysis. Numerous life cycle assessments have been performed on various electricity production systems, including fossil fuel, solar, hydroelectric, nuclear, and wind powered systems.

2.2.2 Coal

"A life cycle inventory of coal used for electricity production in Florida" (Babbitt and Lindner 2005) compared four different coal-fired utilities in Florida, inventorying the energy and material inputs and emissions for the raw material extraction, materials processing (coal combustion), and material disposal stages of the life cycle using SimaPro software. This research inventoried nearly forty emissions to land, air, and water, including carbon dioxide, sulfur dioxide, mercury, and lead. This inventory established that 1330 kg of carbon dioxide are released per 1000 kg of coal combusted, on average for the four utilities (Babbitt and Lindner 2005). Table 2-1 is a summary table of the general results of this research, giving, for example, the water and land requirements and the total emissions to land, air, and water per 1000 kg of coal combusted. This table also serves as an example of typical, general results that a life cycle inventory can generate.

The Department of Energy's National Renewable Energy Laboratory performed a "Life Cycle Assessment of Coal-Fired Power Production" (Spath et al. 1999), which examined three different pulverized coal-fired systems. It assessed a plant with emissions and an operating efficiency that represents the current U.S. average of coal-fired plants; a new coal-fired plant that meets the New Source Performance Standards (NSPS); and an advanced plant utilizing a low emission boiler system (LEBS). The life cycle stages included in the study were coal mining, transportation, and electricity generation. Resource consumption, air emissions, water emissions, solid waste generated, and energy requirements were inventoried with respect to the functional unit of per kilowatt-hour of electricity produced. This research determined that 1022 g/kWh of carbon dioxide were emitted from the Average plant, compared to 941 g/kWh of carbon dioxide from the NSPS plant, and 741 g/kWh from the LEBS plant (Spath et al. 1999). For all three systems, greater than 93% of the carbon dioxide emissions were produced from the electricity generation stage of the life cycle. The other most contributing stages were the limestone production and limestone scrubbing reaction stages for the Average and NSPS plants, and the transportation stage for the LEBS plant (Spath et al. 1999). The three stressors inventoried that were used in assessing the global warming impact were CO_2, CH_4, and N_2O. The global warming impact was found to be 1042.1 g CO_2 equivalent/kWh for the Average system, 959.5 g CO_2 equivalent/kWh for the NSBS system, and 756.9 g CO_2 equivalent/kWh for the LEBS system (Spath et al. 1999).

2.2.3 Natural Gas

The National Renewable Energy Laboratory also performed a "Life Cycle Assessment of a Natural Gas Combined-Cycle Power Generation System" (Spath and Mann 2000). This study examined the construction and decommissioning of the power plant, construction of the natural gas pipeline, natural gas extraction, processing, and distribution, ammonia production and distribution (used for NO_X removal), and power generation stages. The power generation unit that served as the model for this study was a 505 MW unit, consisting of two gas turbines, a condensing reheat steam turbine, and a three pressure heat recovery steam generator. This research found that over 99% of the air emissions from this system over the life cycle were carbon dioxide. After CO_2, the next most abundant emission was methane, 74% of which was from the natural gas extraction, processing, and distribution stages, in the form of fugitive emissions (Spath and Mann 2000). In decreasing order of quantity released, the remaining emissions inventoried were non-methane hydrocarbons (NMHC), NO_X, SO_X, CO, particulates, and benzene. The global warming impact for the natural gas combined-cycle unit was calculated based on CO_2, CH_4, and N_2O emissions, and was determined to be 499.1 g CO_2 equivalent/kWh (Spath and Mann 2000).

2.2.4 Fuel Oil

"LCA—LCCA of oil fired steam turbine power plant in Singapore" (Kannan et al. 2004) examined the life cycle and performed a life cycle cost analysis of a hypothetical 250 MW fuel oil-fired steam turbine unit used for power production in Singapore, a country that generates the majority of its electricity from oil and natural gas. This research included the materials extraction and manufacture for the power plant, fuel oil extraction and processing, fuel oil transportation, plant construction, operation, and decommissioning (including demolition and recycling) stages. It assumed a power plant lifetime of 25 years, load factor of 70%, and efficiency of 33%. The focus of this LCA was on specific energy use and global warming impact. The specific energy use was determined to be 11.875 MJ/kWh, 98% of which was due to upstream processes of fuel oil (Kannan et al. 2004). The greenhouse gases inventoried were CO_2, CH_4, and N_2O, and the global warming impact was found to be 932 g CO_2 equivalent/kWh, 89.64% of which was from the operation stage alone (Kannan et al. 2004).

2.2.5 Wind Farm Systems

There have also been several life cycle assessments performed on wind turbine power generating systems. "Energy and CO_2 life-cycle analyses of wind turbines—review and applications" (Lenzen and Munksgaard 2001) assessed 72 previously performed energy and CO_2 analyses of wind turbines for both on-land and offshore systems in many different countries, including the U.S., U.K., Germany, Denmark, Switzerland, Belgium, Argentina, Brazil, Japan, and India. This research found that due to differences in assumptions (e.g. load factors, number of years of wind farm operation) and in the chosen scope and boundaries of the studies (e.g. including transportation, construction, decommissioning, etc.), country of manufacture, and power ratings of the different turbines, the results of these 72 studies demonstrated considerable variation. Energy intensity, defined as required energy invested in the system for manufacture, transport, etc., per unit of electricity produced, normalized over the life cycle was found to vary from 0.014 to 1 kWh_{in}/kWh. Carbon dioxide intensity, that is, CO_2 emitted per unit of electricity produced, normalized over the life cycle, was found to vary from 7.9 to 123.7 g CO_2/kWh (Lenzen and Munksgaard 2001).

"Life cycle assessment of a wind farm and related externalities" (Schleisner 1999) compared energy and emissions from the life cycle of an offshore wind farm to a land-based wind farm. This research implemented a life cycle assessment model developed by the Riso National Laboratory in Denmark that quantifies the energy use and related emissions for the production, manufacture and transportation of 1 kg of material under Danish conditions. Both of the systems upon which this research was based were real systems. The offshore wind farm LCA was based on Tuno Knob wind farm, a 5 MW farm consisting of ten Vestas V39-500 kW turbines located 6 km off the coast of Jutland, Denmark. The land-based wind farm was based on Fjaldene, a 9 MW farm situated in Jutland, consisting of eighteen V39-500 kW turbines. The stages included in this LCA were resource extraction, resource transportation, materials processing, component manufacture, component transportation, turbine construction, turbine operation, decommissioning, and turbine product disposal. Assuming an estimated operating efficiency of 40%, a lifetime of 20 years, and a total power output of 250 GWh, it was found that the energy payback time for the Fjaldene wind farm was 0.26 years, and 0.39 years for Tuno

Knob. Emissions normalized over the lifetime were found to be 9.7 g CO_2/kWh, 0.02 g SO_2/kWh, and 0.03 g NO_X/kWh for the land-based Fjaldene wind plant, compared to 16.5 g CO_2/kWh, 0.03 g SO_2/kWh, and 0.05 g NO_X/kWh for the Tuno Knob offshore plant (Schleisner 1999).

The European Commission has funded a research project that has utilized life cycle assessments in order to analyze the externalities of energy. This program, ExternE, was implemented at the national level by over 50 research teams in over 20 countries in Europe since 1991. Under this program, each participating country performed fuel cycle analyses for conventional fossil fuel-based energy systems and life cycle assessments for renewable energy power generating options. The ExternE project included an LCA for land-based wind farms in Germany and Greece, and both an onshore and offshore wind farm LCA for Denmark (European Commission 1997). Denmark's ExternE project for the two wind farms was conducted by Schleisner (1999) on Tuno Knob and Fjaldene, as previously presented.

Greece's ExternE implementation examined a 1.575 MW wind power plant, consisting of seven 225 kW Vestas turbines on the island of Andros. Stages included in the study were resources extraction, materials processing, component manufacture, turbine construction, turbine operation, plant decommissioning, component final disposal, and transportation between each stage. Assuming a load factor of 35%, wind availability of 80%, and a lifetime of 20 years, it was found that the wind farm produced 8.2 g CO_2/kWh, 0.079 g SO_2/kWh, and 0.032 g NO_X/kWh (European Commission 1997).

Germany's ExternE implementation was based on Nordfriesland Windpark in Schleswig-Holstein, consisting of fifty-one 250 kW Husumer Schiffswerft HSW-250 turbines, for a total capacity of 127.5 MW. Construction, transport, operation, and dismantling of the turbines were included in the LCA. The research assumed a total power output of 486 GWh over a 20 year lifetime, based on 2 years of wind data measured at the park. It was established that the wind farm produced 6.46 kg CO_2, 15 g SO_2, 20 g NO_X, 20 g CH_4, 0.07 g N_2O, and 4.6 g particulates per MWh of electricity produced (European Commission 1997). Germany's ExternE research also examined the effects of wind turbines on birds. Seven locations with 69 wind turbines were observed for one year and it was concluded that 32 birds could have been killed by collisions with the turbines. It was concluded that neither solitary wind turbines nor wind parks pose a serious threat to birds, especially when compared to other common threats such as traffic (European Commission 1997).

Although there have been several LCAs performed for offshore wind farms, it is important to note that the data and consequently the results of LCAs are site-specific, and to date, an LCA for an offshore wind farm for the United States has not been published.

Table 2-2 summarizes the life cycle carbon dioxide emissions of the aforementioned fossil fuel-based and wind powered electricity production systems, as well as additional references. It can be seen from this table that fossil fired systems range from 499.1 to 1050 g CO_2/kWh, with natural gas representing the lower end of the range, followed by fuel oil systems spanning the middle of the range, and coal-fired power systems having the largest carbon dioxide emissions over the life cycle. Wind power systems have been found to range from 6.46 to 123.7 g CO_2/kWh, with offshore systems producing greater emissions than land-based wind farms.

2.3 Introduction to Emergy Synthesis

Emergy is a concept conceived by Howard T. Odum, resulting from several decades of research on energy quality in ecosystems and human systems throughout the 1960s, '70s, and '80s (Brown and Ulgiati 2004). The term emergy was coined by David Scienceman, a visiting scholar from Australia working with H.T. Odum, and is a contraction of the phrase "embodied energy." Emergy is defined as an expression of all the energy of one kind previously used in the work processes and input flows that are required to generate a product or service. Those work processes include both work done by society and by nature. Emergy can be thought of as "energy memory" and is a way of including all inputs to a system on a common basis. This common unit of measure for emergy is the solar emjoule, abbreviated sej (Brown and Ulgiati 2004).

Energy is constantly undergoing transformations from one quality to another, and these different qualities demonstrate the existence of an energy hierarchy. For example, one joule of fossil fuels has higher quality than one joule of sunlight, and one joule of electricity has higher quality than one joule of fossil fuels. The quality of an energy type is related to its flexibility and ease of use (Odum 1994). The quality of energy increases as the energy becomes more concentrated. Solar energy is the most abundant energy, but is also the most diffuse energy and has the lowest quality. As energy is transformed to higher qualities it becomes more concentrated and is therefore available in smaller quantities. During every energy transformation some energy loses its ability to do work, as stated by the 2nd Law of Thermodynamics, and this further contributes to higher quality energy being less abundant. Energy quality is measured by the Unit Emergy Value (UEV), which can be calculated on either an energy or mass basis. The solar transformity is the energy-based UEV, which measures emergy per unit available energy and has units of sej/J. Specific emergy is the mass-based UEV, which measures emergy per unit mass and has units of sej/g. UEVs can be thought of as a measure of efficiency, since they are a ratio of output to required inputs (Brown and Ulgiati 2004). Energy quality can also be calculated on a monetary basis with units of sej/$. Unit Emergy Values for some common items are given in Table 2-3 (Brown and Ulgiati 2004).

Exergy is commonly used for energy analysis because it is a measure of the energy in a product that is available to do work, and the ability to do work is the typical aspect of interest for an energy analysis. In contrast to exergy, however, emergy includes all previous energy inputs that were required in making the product, regardless of whether those inputs contribute to the final product's available energy. Because it includes inputs from the environment as well as those from society, emergy accounting can be thought of as a way of measuring the true wealth of a system on the larger, biosphere scale, in contrast to traditional energy analyses where certain inputs and services are neglected because they do not have an associated energy measure in fuel equivalents (Brown and Herendeen 1996). Examples of such inputs are environmental services (e.g. oxygen supply for combustion or pollution abatement); environmental energy and material inputs (e.g. solar energy that was converted to biomass and eventually converted to fossil fuels); or human services inputs (e.g. labor). Power generation systems are systems where services provided by the environment are largely unaccounted for, such as heat dissipation, absorption and dilution of harmful emissions, and insolation and biomass required to create the fuels. Therefore, emergy accounting may provide a means to include and quantify this work in the analysis and reveal the systems' level of environmental loading and sustainability.

A fundamental first step in emergy synthesis is to construct a system diagram to clearly illustrate and define the system boundaries, components, interactions, and flows. Figure 2-1 explains the more commonly used systems diagramming symbols. Examples of these symbols include sun or tides as sources; a tank of water or a reserve of food or fuels as storages; building a wooden table or cooking a meal as interactions; biomass as producers; and animals or people as consumers. For further explanation of systems diagramming and symbols, refer to "Environmental Accounting: Emergy and Environmental Decision Making" (Odum 1996).

Figure 2-2 is an example system diagram of global processes of the geobiosphere. Important to note is that the system components, including the external sources, are arranged from left to right in order of energy quality, i.e. in order of increasing transformity or specific emergy. Notice that the three external energy inputs to the earth are solar energy, tidal energy, and deep earth heat. It is these three energy flows upon which all emergy accounting calculations are based. These three flows act as a single coupled system driving the geobiosphere. Values for the inflows of these three energy sources to the geobiosphere have been measured, and thus transformities for solar energy (1 sej/J, by definition), tidal energy (7.39E+04 sej/J), and deep earth heat (1.20E+04 sej/J) were calculated. From this the total solar emergy driving the earth was determined to be 15.83E+24 sej/year. For a more detailed explanation of these calculations, refer to Brown and Ulgiati (2004).

Some of the parameters used to measure system performance in an emergy synthesis are emergy yield ratio (EYR), emergy investment ratio (EIR), environmental loading ratio (ELR), and emergy index of sustainability (EIS). Figure 2-3 is a systems diagram that illustrates and defines these parameters. The emergy yield ratio is the ratio of the system yield, which is the sum of all the emergy flows driving the process or system, to the purchased goods and services from outside sources. This ratio is a way to measure how much imported emergy the process or system requires in order to produce its yield. Another way to interpret the EYR is that it measures the extent to which the system makes use of the local renewable and nonrenewable resources in order to produce its yield. The emergy investment ratio is the ratio of the emergy imported to the system for goods and services to the local renewable and nonrenewable resources that also drive the system. The EIR is a way to measure to what extent the process or system utilizes the local resources, both renewable and nonrenewable, compared to how dependent it is on imported goods and services. The environmental loading ratio is the ratio of the sum of the imported goods and services and the local nonrenewable sources to the renewable environmental inputs. It is a way to measure the extent to which the system depends upon environmental emergy inputs, and therefore can be thought of as a measure of level of stress the system puts on the environment. Lastly, the emergy sustainability index is the ratio of the emergy yield ratio to the environmental loading ratio. This parameter is a way to measure the system's contribution to the economy per unit of environmental stress.

2.4 Emergy Analyses of Electricity Production Systems

Emergy synthesis serves as a useful tool for assessing the performance of electricity production systems for several reasons. Similar to life cycle assessment, emergy accounting includes in the analysis indirect as well as direct energy inputs, materials, and services. This parallels the inclusion of all life cycle stages in an LCA, and not solely the operation or product use stage. Another advantage of emergy synthesis for power generation systems is its ability to account for environmental inputs and services in the analysis, such as oxygen supply, cooling water supply, and environmental absorption of emissions.

"Emergy evaluations and environmental loading of electricity production systems" (Brown and Ulgiati 2002) compared six different renewable and nonrenewable power generating systems in Italy, namely, coal, natural gas, oil, geothermal, hydroelectric, and wind power systems, in terms of energy and emergy. Parameters used to assess the systems' performances were output/input energy ratio, emergy-based yield ratio, and environmental loading ratio. Carbon dioxide generated by each system was also assessed. The 2.5 MW wind farm model used for the analysis consisted of ten 225 kW turbines. The model coal plant was 1280 MW, the methane plant was 171 MW, and the oil plant was 1280 MW. It was found that the wind power plant had an energy ratio of 7.66 (energy output/energy input), while the coal plant had an energy ratio of

0.25, the methane plant 0.36, and the oil plant 0.30. The carbon dioxide released, normalized to the amount of electricity produced for each system, was found to be 36.15 g/kWh for the wind farm, 1109.82 g/kWh for the coal system, 759.48 for the methane system, and 923.19 for the oil system (Brown and Ulgiati 2002).

The emergy yield ratio was also determined for each system. It was found to be 7.47 for the wind farm, 5.48 for the coal-fired power unit, 6.60 for the methane-fired unit, and 4.21 for the oil-fired unit. The environmental loading ratio for the wind system was determined to be an order of magnitude lower than the fossil fuel plants, having a value of 0.15, compared to 10.37 for the coal plant, 11.78 for the methane plant, and 14.24 for the oil plant. Another performance indicator included in the analysis was the emergy index of sustainability (EIS), the ratio of the emergy yield ratio to the environmental loading ratio. The wind turbine's EIS was calculated as 48.300, while the coal plant was 0.529, methane plant was 0.560, and oil plant was 0.295 (Brown and Ulgiati 2002). A high EIS value implies a high emergy yield compared to its respective environmental load. These values, therefore, indicate that the wind system performs with a significantly higher emergy yield per unit of environmental loading.

Two other parameters were included in this research that have not been previously defined, emergy density (ED) and percent renewable (%R). Emergy density is defined as the emergy yield per unit area of the power generating plant. As a result of the diffuse nature of wind energy in comparison to fossil fuels, it was found that the ED of the wind farm was three orders of magnitude lower than that of the fossil fuel plants, with a value of 1.19E12, compared to 2.18E15 for coal, 2.61E15 for methane, and 2.48E15 for oil. The percent renewable is defined as the ratio of the local renewable inputs to the total inputs for the system. The wind system's %R was calculated as 86.61, while the coal plant's %R was 8.79, the methane plant's was 7.83, and the oil plant's was 6.56. This parameter can be thought of as another index for measuring sustainability because it identifies the fraction of the system that is driven by renewable inputs, i.e., the fraction of the system that does not rely upon externally supplied goods and services or temporary storages of energy (fossil fuels) that will eventually run out.

"Quantifying the environmental support for dilution and abatement of process emissions – The case of electricity production" (Ulgiati and Brown 2002) is an emergy synthesis that focused on quantifying in greater detail the necessary environmental services provided to electricity production systems, and presenting how the inclusion of these services in the analysis affects the emergy performance indicators. It was an extension of the aforementioned study, performed by the same authors, further examining four of the six power plants in Italy: coal (1280 MW), oil (1280 MW), methane (171 MW), and geothermal (20 MW). These four were chosen because only the emissions from the operational stage of electricity generation were considered while emissions resulting from the construction stages were neglected. Emissions from the geothermal plant during operation include those that are released from deep heat reservoirs, such as H_2S, Radon, and CH_4.

Ulgiati and Brown performed an emergy evaluation for each of the four power systems three different ways. The first analysis included no environmental services required for the dilution of emissions; the second analysis accounted for the environmental services required to dilute thermal and chemical emissions resulting from the operation of the power generation systems down to legal limits; and the third analysis included the environmental services required to dilute the thermal and chemical emissions down to natural background levels. The results of this study demonstrate that including the environmental service of emissions dilution in the emergy synthesis has considerable effects on the performance indicators. The transformities of each system increase when emission dilution is accounted for, since environmental emergy inputs to the system increase. The methane plant showed the smallest increase in transformity, from 1.70E+05 to 1.73E+05 sej/J, attributable to its relatively clean combustion. The emergy yield ratios were reduced in all cases, ranging from a reduction by a factor of 4 for the geothermal plant, a factor of 2 for coal, a factor of 1.7 for oil, and a factor 1.6 for the methane plant, when comparing the no dilution case to the case of dilution down to natural background levels. As expected, environmental loading ratios were increased in all cases when emissions dilution services were included in the analysis. Finally, the emergy index of sustainability (EYR/ELR) was reduced for all systems when emissions dilution was accounted for, since the emergy yield ratios decreased while the environmental loading ratios increased. A summary of these data is given in Table 2-4 (Ulgiati and Brown 2002).

Emergy synthesis serves as an alternative method to evaluate the energy flows of a system. It provides a way to account for differences in energy quality, for environmental services provided to a system, as well as a means to measure a system's level of sustainability. Recently, galvanizing issues such as global warming have brought about a growing awareness and concern for recognizing the limits of the geobiosphere and the environmental services that it can provide. Emergy synthesis may serve as a useful tool for future decision-making for assessing and comparing human dominated systems that rely heavily on inputs and services from the geobiosphere.

2.5 Life Cycle Assessment and Emergy Synthesis

Life cycle assessment and emergy synthesis compliment each other in many ways. Both are a useful tool for presenting a holistic view of a product or process. LCAs traditionally focus more on environmental stressors and their corresponding impacts, while emergy analyses focus more on energy and system sustainability; both address a broader scope than looking solely at the product's use or process' operational stage. LCAs quantify the environmental impacts of the process or product throughout its life cycle, including stages that are often neglected from analysis. Emergy synthesis accounts for all the energy of one type that was previously used up in the transformations required to produce the final product. Emergy synthesis also accounts for environmental services that drive the system, not just the inputs having a monetary value as are typically included in an analysis for a product of human interest or a human dominated process. Combining life cycle assessment with emergy synthesis to evaluate a process results in a comprehensive analysis that provides multiple methodologies for measuring net energy and environmental performance of the system.

Table 2-1. Summary table of the coal life cycle inventory from Babbitt and Lindner (2005).

System Inputs		System Outputs	
Coal	2011 kg	Electricity	9.68 GJ
Chemicals and other materials	430 kg	CCPs	216 kg
Energy	2.31 GJ	Emissions to air	1350 kg
Fuels	27.6 m^3	Emissions to water	60.7 kg
Equipment	3220 ton-mile	Emissions to land	11.2 kg
Infrastructure	330 processes		
Water	7.36 x 10^6 m^3		
Land	185 m^2		

Note: All values are based on a functional unit of per 1000 kg of coal combusted.

Table 2-2. Summary table of life cycle CO_2 emissions of power generating systems from various LCA studies.

Fuel	Reference	Power Unit Description	CO2	Units
Coal	Babbit & Lindner 2005	4 Florida plants	1330	kg/1000 kg coal
	Spath et al. 1999	Average	1022	g/kWh
	Spath et al. 1999	NSPS	941	g/kWh
	Spath et al. 1999	LEBS	741	g/kWh
	Tahara et al. 1997	1000 MW unit	915.9	g/kWh
	Hondo 2005	1000 MW unit	975.2	g/kWh
	Gagnon et al. 2002	Average of numerous LCAs	960-1050	g/kWh
	San Martin 1989	DOE estimated "average"	964	g/kWh
Natural Gas	Spath & Mann 2000	Combined Cycle	499.1	g CO2-eq./kWh
	Gagnon et al. 2002	Average of numerous LCAs	443	g/kWh
	San Martin 1989	DOE estimated "average"	484	g/kWh
Fuel Oil	Kannan et al. 2004	Oil Steam Turbine	932	g CO2-eq./kWh
	Tahara et al. 1997	1000 MW unit	755.7	g/kWh
	Hondo 2005	1000 MW unit	742.1	g/kWh
	Gagnon et al. 2002	Average of numerous LCAs	778	g/kWh
	San Martin 1989	DOE estimated "average"	726	g/kWh
Wind	Lenzen & Munksgaard 2001	72 various wind farms	7.9-123.7	g/kWh
	Schleisner 1999	Fjaldene (onshore)	9.7	g/kWh
	Schleisner 1999	Tuno Knob (offshore)	16.5	g/kWh
	European Commission 1997	Greece	8.2	g/kWh
	European Commission 1997	Germany	6.46	g/kWh
	Hondo 2005	300 kW turbine	29.5	g/kWh
	Gagnon et al. 2002	Average of numerous LCAs	9	g/kWh
	San Martin 1989	DOE estimated "average"	7.4	g/kWh

Table 2-3. Unit Emergy Values of common items and services.

Item	Transformity (sej/J)	Specific Emergy (sej/g)
Sunlight	1.00E+00	
Global wind circulation	2.50E+03	
Peat	3.20E+04	6.70E+08
Coal	6.70E+04	
Cotton	1.40E+05	
Corn	1.60E+05	2.40E+09
Electricity	3.40E+05	
Butter	2.20E+06	
Silk	6.70E+06	
Phosphate fertilizer	1.70E+07	
Shrimp (aquaculture)	2.20E+07	
Steel	8.70E+07	7.80E+09
Human Labor	6.32E+16	

Table 2-4. Comparison of emergy indicators for selected power plants for three different levels of emissions dilution (Ulgiati and Brown 2002).

	Required dilution		
	No dilution of emissions	Thermal and chemical emissions down to legal limits	Thermal and chemical emissions down to natural background
Geothermal			
Transformity (sej/J)	1.47E+05	1.47E+05	1.47E+05
EYR	7.47	4.78	1.87
ELR	0.15	0.44	0.90
EYR/ELR	48.30	10.95	2.07
Thermal (oil)			
Transformity (sej/J)	2.00E+05	2.00E+05	2.33E+05
EYR	4.21	4.14	2.54
ELR	14.24	14.29	17.52
EYR/ELR	0.30	0.29	0.14
Thermal (coal)			
Transformity (sej/J)	1.71E+05	1.71E+05	2.04E+05
EYR	5.48	5.35	2.59
ELR	10.37	10.42	13.51
EYR/ELR	0.53	0.51	0.19
Thermal (methane)			
Transformity (sej/J)	1.70E+05	1.70E+05	1.73E+05
EYR	6.60	6.54	4.13
ELR	11.78	11.79	12.98
EYR/ELR	0.56	0.55	0.32

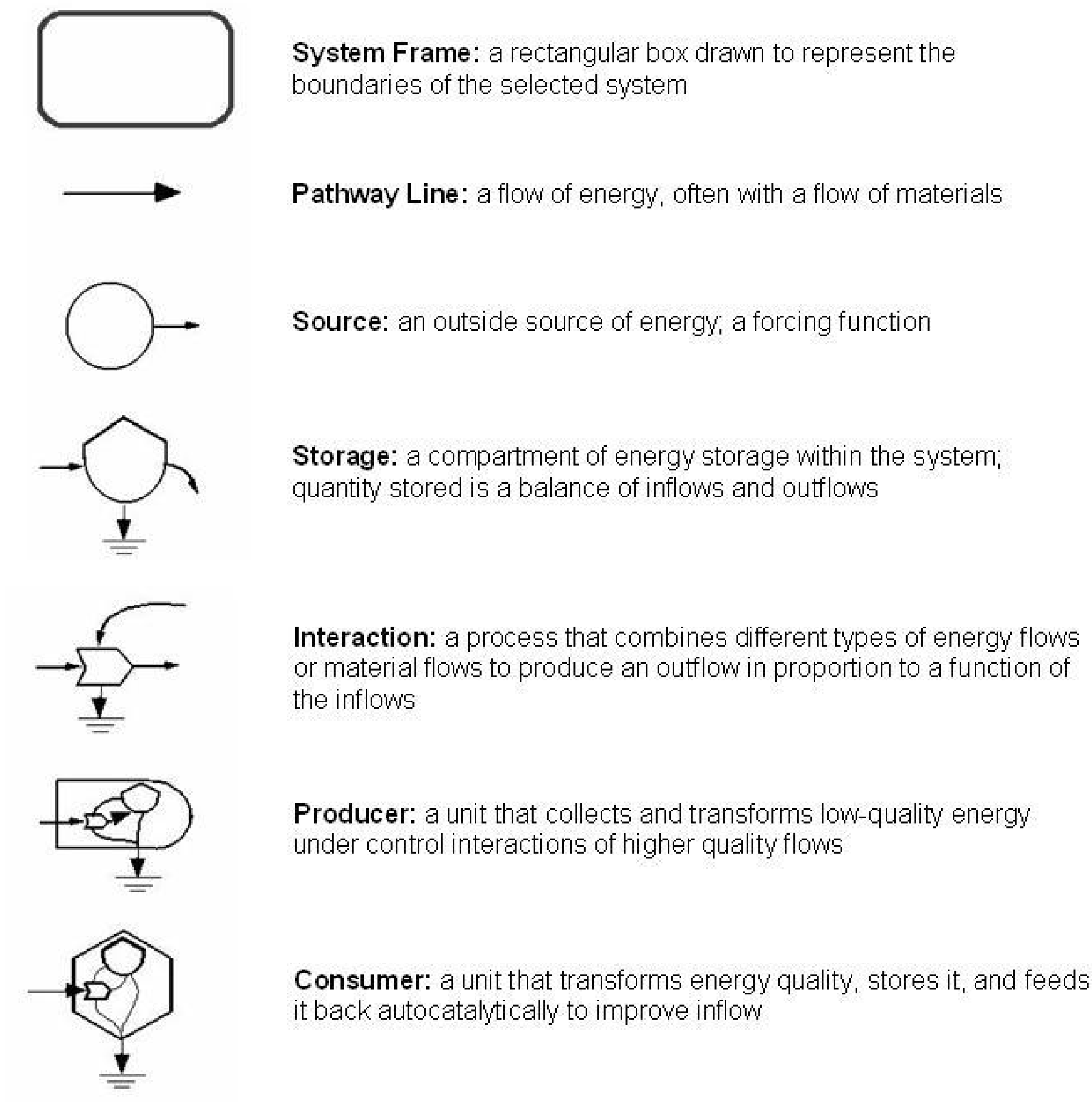

Figure 2-1. Common symbols in systems diagramming. Reprinted with permission from: Odum, Howard T. Environmental Accounting- Emergy and Environmental Decision Making. New York: John Wiley & Sons, Inc., 1996.

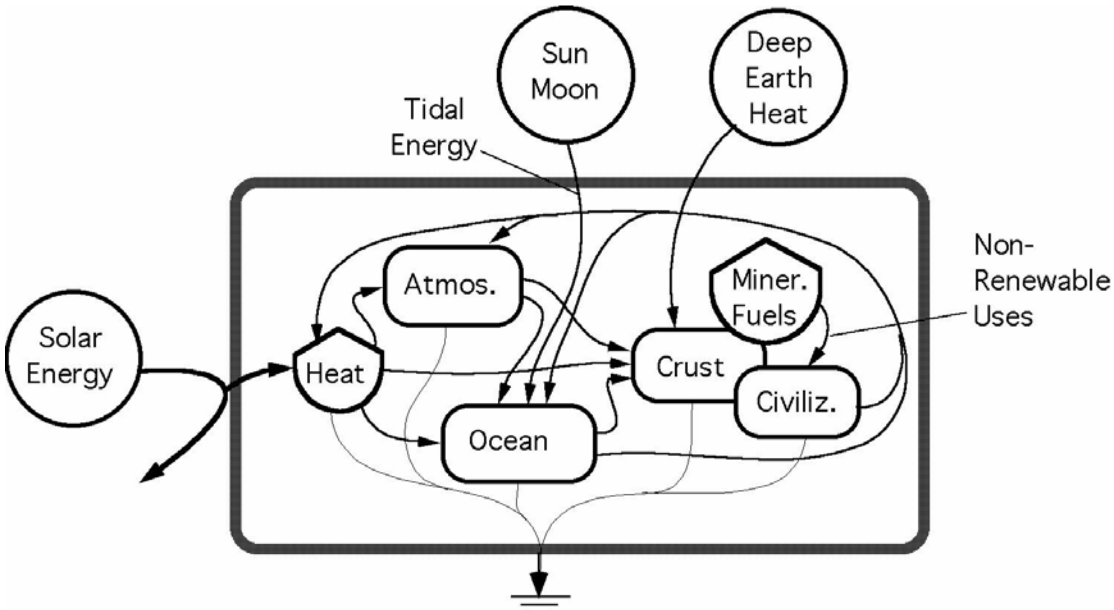

Figure 2-2. Global processes of the geobiosphere. Reprinted with permission from: Odum, Howard T. Environmental Accounting- Emergy and Environmental Decision Making. New York: John Wiley & Sons, Inc., 1996.

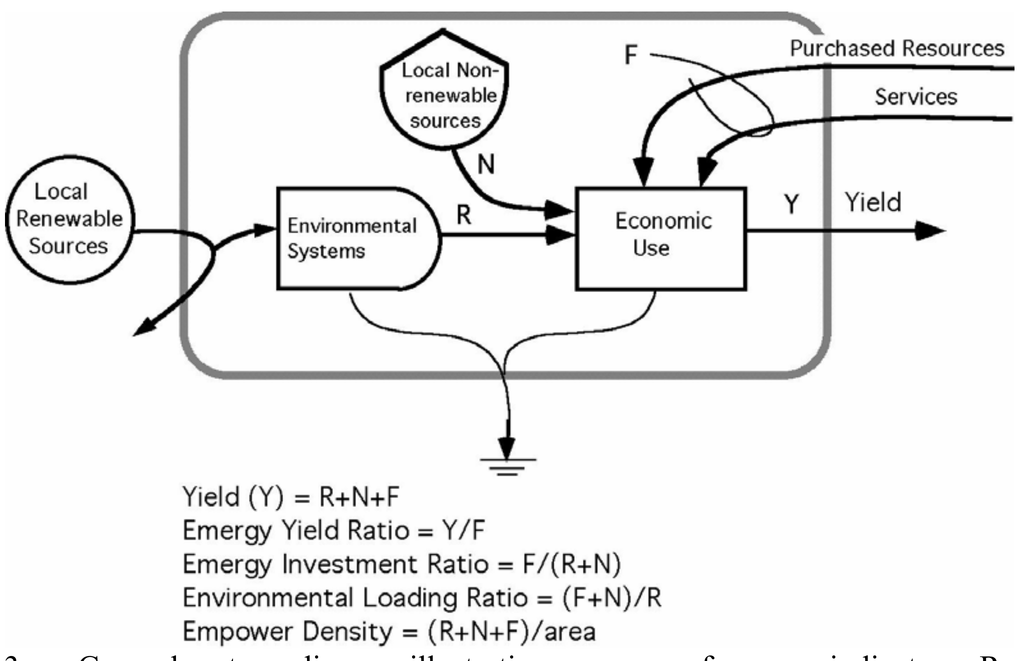

Figure 2-3. General systems diagram illustrating emergy performance indicators. Reprinted with permission from: Brown, M.T., and S. Ulgiati. "Emergy-based indices and ratios to evaluate sustainability: monitoring economies and technology toward environmentally sound innovation." Ecological Engineering 9 (1997): 51-69.

CHAPTER 3
METHODOLOGY

This chapter outlines the procedures followed for the life cycle assessment and emergy synthesis of the theoretical 180 MW wind farm, 360 MW coal-fired power generating unit, and the 505 MW natural gas combined-cycle (NGCC) power generating unit. For both the LCA and emergy synthesis, data collection was a primary task, and this chapter details the sources of all the data used in the models and any assumptions that had to be made in order to perform the analyses. These assumptions are also given in tabular form categorized by life cycle stage in Appendix A.

3.1 Power Generating Systems Models

3.1.1 Turbine Model

For the theoretical offshore wind park, Vestas V80-1.8 MW turbines were used as the model. Vestas is the leading manufacturer of offshore wind turbines, currently representing approximately 50% of all offshore wind installations. The V80-1.8 MW turbine is the largest turbine that Vestas imports to North America. As of 2006, 625 of these turbines have been installed, for a total capacity of 1,125 MW. The V80-1.8 MW turbine is the North American version of the V80-2.0 MW turbine, which has been used extensively in Europe. The two models are identical with the exception of their generators and gearboxes. The V80-2.0 MW model has had 1,578 installations, for a total capacity of 3,156 MW. This is a widely used turbine model with a successful track record, both on land and offshore. The V80-2.0 MW turbine was the model installed at the Horns Rev wind park in Denmark. Installed in 2002, it is currently the world's largest offshore wind park, consisting of 80 turbines for a total capacity of 160 MW. A cutaway diagram of the V80-1.8 MW turbine's nacelle and its power curve are shown in Figures 3-1 and 3-2, respectively; the technical specifications are given in Table 3-1.

3.1.2 Power Plant Models

Jacksonville Electric Authority (JEA) currently produces electricity with both steam turbines and gas turbines, running a fuel mix of coal, petroleum coke, distillate fuel oil, residual fuel oil, and natural gas. To meet their growing electricity demands, recent power plant installations at JEA have been the combined-cycle gas turbine units at Brandy Branch (first constructed in 2001 as simple cycle and retrofitted to combined-cycle in 2005) and the circulating fluidized bed (CFB) coal plants at Northside Generating Station (2002). Therefore, two different conventional power plants were considered in this research. The first was a 360 MW coal fired steam turbine unit consisting of a pulverized coal boiler, baghouse filter, conventional limestone flue gas clean-up (FGC) system, a steam turbine, and a heat recovery steam generator (Spath et al. 1999). The second system was a 505 MW combined cycle natural gas unit, comprising 2 Siemens Westinghouse W501F gas turbines, a condensing reheat steam turbine, and a three pressure heat recovery steam generator (Spath and Mann 2000).

3.2 Life Cycle Assessment

3.2.1 Scope, Boundaries, and Functional Unit

The stages included in the life cycle analysis of the wind farm were raw material extraction and manufacture, wind farm construction, wind farm operation, and wind farm decommissioning (not including disposal). Transportation was included for the shipment of the turbine parts from Denmark to Jacksonville. The life cycle stages included for the coal and natural gas combined-cycle power units were raw materials extraction (including fuels), power plant transportation, power plant construction, fuels transportation, and power plant operation. Decommissioning was not included in the analysis for the fossil-based power plants because it is JEA's current protocol to keep all retired units in inactive reserve for emergency use or future conversion to new systems (JEA 2006). Parts manufacture was not included for any of the power systems due to lack of available data. Level diagrams (Figures 3-3 and 3-4) were created to visually display each of the systems including the inventoried inputs and outputs of each stage.

These level diagrams were expanded to Level 3.0 to show more detail for each system. These can be seen in Figures 3-5 through 3-7. Figures 3-6 and 3-7 are both for the power plant systems. Figure 3-6 illustrates the life cycle stages for the construction of the power plants, which can be compared to that of the wind farm, whereas Figure 3-7 depicts the life cycle stages of the fuel cycles for JEA's current operation. In Figure 3-7 there are 3 simultaneous processes occurring, one for coal, one for oil and petroleum coke, and one for natural gas. Oil and petroleum coke are grouped into the same process because they are both crude oil products.

The inventoried stressors were carbon dioxide, methane, nitrous oxide, sulfur oxides and nitrogen oxides. The functional unit of kilograms of emission per MWh of electricity produced was used for the analysis of both the wind and the fossil fuel-based systems. This allowed for direct comparison of the systems regardless of their generating capacities.

3.2.2 Data Acquisition

The data acquisition process utilized several resources. Jacksonville Electric Authority, Vestas, and Sargent & Lundy LLC provided significant amounts of primary data, which were the preferred data sources when available. The National Renewable Energy Laboratory (NREL) maintains a Life Cycle Inventory (LCI) Database, which is a U.S. national compilation of input and output data of common industrial processes organized into modules. The modules are organized in such a way that the emissions of the process itself are given, as well as a list of the required upstream inputs, but the emissions for these upstream inputs are not included. However, these upstream inputs each have their own separate module. Therefore, upstream emissions can be determined by linking data from the process module to the other modules of the required input processes. Employing this technique, these modules were used extensively for process emission calculations, such as fuels extraction and transportation. Upstream electricity emissions were determined using domestic summary statistics from the U.S. Department of Energy's Energy Information Administration. A summary table of the NREL LCI Database modules used throughout this research can be found in Appendix B. Please refer to Appendix C for upstream electricity emission factors and Appendix D for a sample calculation using the NREL LCI Database. Only the first level upstream inputs were included in the analysis while second level upstream inputs and beyond were considered out of the scope of our research. For example, a barge is a required input for the Petroleum Refining module, so emissions for the combustion of diesel from the barge transport were included (first level upstream); however, emissions for the extraction and refining of the diesel used in the barge were not included (second level), nor were the emissions resulting from the combustion of fuels required for the extraction and refining (third level), etc. Worth noting is that the NREL LCI Database has not been subjected to an internal review. However, the database has been compiled using only peer-reviewed data sources, and its use has been suggested in the literature (Curran 2004).

For the cases where primary data for the power systems could not be obtained and the NREL LCI Database did not apply, information available in the literature on previous life cycle assessments of electricity generating systems was used. If data could not be obtained from the preferred data sources, i.e. JEA, the NREL LCI Database, or the literature, then miscellaneous resources, such as manufacturing company websites, were utilized as data sources. For example, GE's company website was referenced to determine the weight of the locomotive used in the model for the transport of coal.

Allocation of data was required for processes that produce more than one product included in the analysis. Although a process has a certain quantity of inputs, outputs, and emissions associated with it, they must be divided appropriately among the co-products, based on the required energy and material inputs for each. Since JEA utilizes three petroleum products, i.e. residual fuel oil, distillate fuel oil, and petroleum coke, the inputs and outputs from the crude oil extraction stage and the petroleum refining stage were allocated to these three products. Several other co-products are also produced in petroleum refining, but the portions of the inputs and outputs allocated to these co-products were not used in this life cycle assessment. A sample allocation calculation is demonstrated in Appendix E.

3.2.2.1 Wind farm raw materials extraction

The materials included in the wind farm analysis are only the bulk materials that comprise the V80-1.8 MW turbines. These consist of steel, concrete, copper, and glass reinforced epoxy. The sea cables were not included in this analysis due to lack of available data and because they were assumed to represent a negligible mass fraction of the total materials. This assumption is supported by a previous life cycle assessment of an offshore wind park that provided mass data for the sea cables, which represented 1.6% of the total mass of the wind park (Schleisner 2000).

The mass data for the materials that comprise the turbines were obtained directly from Vestas in the turbine's product brochure and through phone conversations with Vestas' engineers, with the exception of the generator. The mass and materials composition of the generator for the V80-1.8 MW turbine could not be determined, however, data were found for a Vestas 225 kW turbine from Greece's national implementation of the ExternE Program (European Commission 1997). These data were scaled up from 225 kW to 1.8 MW to give the weight of the generator. To give a level of confidence to this calculation, the mass of the entire 225 kW turbine was also scaled up and compared to the actual mass of the 1.8 MW turbine, and a 15.7% error was found. This percent error was concluded to be acceptable and further discussion of the results of this assumption is included in the Sensitivity Analysis chapter.

Danish emission factors were used for these materials since Vestas manufactures their turbines in Denmark. These emission factors were found in the literature (Schleisner 2000).

The parts of the turbine included in the analysis were the nacelle, generator, hub, rotor, tower, transition piece, boat landing platform, and monopile foundation. The nacelle, which is the encasement of the generator, gearbox, controls systems, transformers, brakes, etc., was assumed to be 100% steel with the exception of the generator within it. Materials data for the generator could not be found, so it was assumed to be 50% steel and 50% copper, as assumed in a similar wind farm LCA (European Commission 1997). The rotors for the Vestas V80-2.0 turbine are 100% glass reinforced epoxy. The hub, tower, monopile foundation, transition piece, and boat landing platform are 100% steel. The coupling piece is composed of a specially developed, high strength cement grout, but precise composition could not be found, and was therefore assumed to be made of Portland cement. The turbine components, their material composition, and mass data can be found in Table 3-2.

3.2.2.2 Wind farm transport

Since the actual departure location through which Vestas ships turbines to the United States was unable to be determined, the turbines were assumed to be shipped from Aarhus, Denmark's principal port and second largest city. Also, Aarhus is only 40 km from Randers, Denmark, where Vestas is located. From the Vestas website, it was concluded that the turbines would be transported by rail the 40 km to Aarhus and then shipped by ocean bulk freighter to Jacksonville Port, Florida, a rounded-up distance of 4600 miles. For both the rail transport and the ocean freighter transport, the National Renewable Energy Laboratory Life Cycle Inventory Database's (NREL LCI) Transportation module was used to calculate fuel consumption and emissions.

The train used in the analysis was a GE Evolution Series locomotive with a weight of 415,000 lb (GE 2006) towing a series of Freight Car America flatbed cars. It was assumed that each turbine required twelve 89-foot 100-ton flatbeds (two for each of the three blades due to their length, one for each of the three foundation segments, one for the monopile foundation, one for the transition piece, and one for the nacelle, generator, and hub) giving a total of 1200 flatbeds. It was also assumed that each locomotive could tow 100 flatbeds, so 12 locomotives were used.

For the ocean freighter, a bulker was chosen over a tanker or a container ship due to the characteristics of the cargo it is to transport. More specifically, the Panamax ship, the largest ship that can transit the Panama Canal, was chosen based on the deadweight specifications. Deadweight tonnage is defined as the weight that the freighter carries, mostly cargo but also fuels, crew, etc., measured in long tons. Lightweight is defined as the weight of the ship itself. The total weight of the 100 turbines is roughly 67,300 tons and a Panamax bulker can carry between 60,000 to 100,000 deadweight tons (dwt) (Maritime Business Strategies, LLC 2006). The lightweight displacement (the weight of the ship itself) of the Panamax is 10,000 tons (Alexander's Gas and Oil Connections Reports 1997). The amount of fuel required for the trip was calculated using the NREL LCI Database Transportation module, and the weight of the fuel was calculated based on a diesel density of 850 kg/m^3. The weight of the diesel required was determined to be approximately 2600 tons, so a rounded-up weight of 5000 tons to account for fuel, crew, and crew supplies was added to the weight of the bulker. The total weight of the bulker loaded with the wind farm, fuel, crew, and supplies is approximately 82,300 tons. The NREL LCI Database was employed to calculate the emissions generated from this transport.

3.2.2.3 Wind farm construction

The Vestas website states that for offshore installations a jack-up barge is used that can transport four turbines (excluding foundations) at a time (Vestas 2007). Using these data to also calculate the number of trips for the foundations and transition pieces, since each turbine weighs 309,000 kg (330 tons) and each complete foundation (including transition pieces, coupling pieces, and boat landing platforms) weighs 301,000 kg (301 tons), it was assumed that the barge could transport 4 foundations per trip as well. Figure 3-8 illustrates the installation of a nacelle and rotor by jack-up barge and crane. The distance from Jacksonville Port to the location of Buoy 41008 is approximately 90 miles. The NREL LCI Database Transportation module was also used for the fuel consumption and emissions for the construction stage. The weight of the amount of fuel required (as determined by the NREL LCI Database) was also included in the weight of the barge, which therefore was calculated iteratively, since more fuel is required to transport a ship carrying more fuel.

Also included in the construction stage of the wind park was the fuel consumed by the crane fitted on the jack-up barge. The crane was assumed to be a Manitowoc crane, model 2250. It has a lifting capacity of 330 tons to a height of 300 feet. The crane is driven by a Caterpillar engine, model 3406C, a 6-cylinder diesel engine rated at 343 kW and 460 hp, at 2100 rpm. It has a rated fuel efficiency of 17.5 - 23.7 gal/h. Therefore, an average fuel efficiency of 20.6 gal/h was assumed for the analysis. A pile driver is used for installing the monopile foundations, however, the fuel efficiency of a pile driver could not be found. It was therefore assumed to have the same fuel rating as the Manitowoc crane.

3.2.2.4 Wind farm operation and maintenance

The only inventoried emissions resulting from the turbine operation stage are due to maintenance. Vestas states that lubricating grease for components in the nacelle must be replaced every six months (Elsam Engineering A/S 2004). Thus, it was assumed that each turbine would receive biannual maintenance inspections, provided by boat. Vestas also states that 1 four-member crew is scheduled to complete one maintenance servicing per 1.5 days (Poulsen 2004). It was therefore assumed that a total of 150 trips are required every 6 months to service the 100 turbines. The boat was assumed to weigh 30 tons, and a roundtrip distance of 200 miles was used for the calculation. Its fuel consumption and emissions were calculated using the transportation module of the NREL LCI Database.

3.2.2.5 Wind farm decommissioning

The decommissioning stage was assumed to be identical to the construction stage, with the exception of the monopile foundations. It is current protocol to leave in the seabed the sections of the foundations that are below the ocean floor, while the segment above the seabed is cut off and removed (Elsam Engineering A/S 2004). This was accounted for in the model, in that the trips transporting the foundations were assumed to carry half the foundation weight of the trips in the construction stage. This was assumed based on the length of the foundations being 40 meters and the distance driven into the seabed roughly 20 meters. The number of required trips for the jack-up barge, however, remains the same. Again, the Transportation module of the NREL LCI database was used for the fuel requirements and inventoried stressors.

3.2.2.6 Fossil fuel-based power plant raw materials extraction

The materials data for the construction of the two fossil fuel-fired power plants were both based on NREL life cycle assessment papers (Spath et al. 1999; Spath and Mann 2000). Similar to the wind farm analysis, only the bulk materials used in construction were considered. The power plants were assumed to be composed entirely of steel, iron, aluminum, and concrete. U.S. emission factors were used for these materials since that is where they were assumed to be manufactured. The material requirements for the two power plants are given in Tables 3-3 and

3-4. Unlike the wind farm analysis, the power plant analysis must also include raw material extraction for the fuels used during the operation stage. Therefore, crude oil extraction, natural gas extraction, and coal mining were included in this stage. Data for this were obtained from the Primary Fuels Production module of the NREL LCI Database.

3.2.2.7 Fossil fuel-based power plant transportation

The coal-fired steam turbine power unit was assumed to be manufactured by Siemens, which produces its steam turbines at its manufacturing plant in Charlotte, North Carolina (Siemens 2007a). The distance from Charlotte to Jacksonville was found to be 400 miles, and transportation was assumed to be by rail. The transportation emissions were calculated using the NREL LCI Transportation module.

The natural gas combined-cycle power unit was also assumed to be manufactured by Siemens, whose gas turbine manufacturing facility is located in Hamilton, Ontario (Siemens 2007b). The distance from Hamilton, Ontario to Jacksonville was found to be 1200 miles and the NGCC power unit was also assumed to be transported by rail. Emissions were calculated using the NREL LCI Transportation module.

3.2.2.8 Fossil fuel-based power plant construction

Construction data for the two power plant models were obtained through phone conversations with several engineers from the Chicago, Illinois headquarters of Sargent & Lundy LLC, a leading construction contractor to the electric power industry. Data were obtained for an 800 MW coal-fired steam turbine unit, and a 500 MW natural gas combined-cycle unit, consisting of two gas turbines and one heat recovery steam turbine. These data were then scaled as a function of generating capacity size for use in this research. The data obtained from Sargent & Lundy included an estimated number of cranes, dozers, scrapers, pile drivers, and trucks required for construction. A summary of these data can be found in Table 3-5.

3.2.2.9 Fossil fuel-based power plant operation

Since these units would be installed for JEA, the operational stage was assumed to be representative of JEA's current operating trends. Primary emissions data were obtained from JEA for the CO_2, SO_X, and NO_X emissions for each of their 18 units. JEA reported that the SO_X, and NO_X emissions were measured with continuous emission monitors fitted on each of JEA's units, and the CO_2 emissions were calculated using the DOE AP-42 emission factors based on the units' fuel consumption. Methane and nitrous oxide emissions remained to be determined, so to be consistent with JEA's methods, the CH_4 and the N_2O emissions were also calculated using DOE AP-42 emission factors. The emissions factors used are based on fuel type, so for units using multiple fuels, emissions per composite megawatt-hour were calculated based on each fuel's contribution to 1 MWh, using JEA's reported average heating values of the fuels. A sample of this calculation is given in Appendix F.

The operational stage of the natural gas combined-cycle unit was modeled after the operation of JEA's Brandy Branch Station. Brandy Branch is a natural gas combined-cycle unit that was first installed in 2001 as three separate 193 MW simple cycle gas-fired turbines. In 2005, Brandy Branch was retrofitted and converted to a combined-cycle plant with the addition of a 180 MW heat recovery steam turbine, resulting in a total capacity of 759 MW. The operational conditions of Brandy Branch that were applied to the 505 MW combined-cycle model unit of the current research include both intensive and extensive factors. Such intensive factors include operating on a fuel mix comprising 95.6% natural gas and 4.4% distillate fuel oil, and running at a loading factor of 59.3%. A capacity factor of 60% was assumed. Extensive operational data had to be scaled down to apply to the 505 MW capacity size of the model, such as annual fuel consumption and electrical output.

The operational stage of the coal-fired steam turbine was assumed to operate based on two different power plants at JEA, Plant Scherer and St. Johns River Power Park, and therefore two separate scenarios were generated. Plant Scherer is an 841 MW coal-fired generating unit jointly owned by JEA and Florida Power and Light (FPL). Under the Scherer Unit 4 Purchase Agreement, JEA is entitled to 23.64% of Scherer's capacity (180 MW), while FPL receives the other 76.36%. Plant Scherer operates on 99.96% coal and 0.04% distillate fuel oil at a loading factor of 91.7%. The first scenario of the coal-fired plant was modeled to operate according to these conditions, and a capacity factor of 60% was assumed. This plant was chosen to represent one of the scenarios for the operational stage of the coal-fired unit to provide a life cycle assessment of a purely coal-fired system.

St. Johns River Power Park, consisting of two 336 MW circulating fluidized bed steam turbines, was chosen as the second scenario for the operational conditions for the coal-fired power unit because it runs on a fuel mix of roughly 82% coal, 17% petroleum coke, and 1% distillate fuel oil, at a loading factor of 91.7%. As above, the second scenario was modeled to operate according to these conditions, and a capacity factor of 60 % was again assumed. Including these operating conditions affects the entire life cycle of the coal-fired system by necessitating the inclusion of the fuel cycles for the additional fuels, e.g. petroleum coke extraction, refining, transport, etc. St. Johns River Power Park was chosen as a second scenario for the coal-fired plant because of its inclusion of petroleum coke as a fuel source. Jacksonville Electric Authority has been in the process of increasing their use of petroleum coke due to its economic benefit, having generated 17% of their total power supply from petcoke in 2002, and having increased to 27% by 2005 (JEA 2006a).

3.2.2.10 Fuels extraction, processing, and refining

For fuels extraction, processing, and refining stages, the NREL LCI Database's Primary Fuels Production module was used. JEA's coal-fired plants run on bituminous coal (JEA 2006a), so the Bituminous Coal Production database was used for calculations of emissions. For natural gas, the Natural Gas Extraction and Processing database was referenced. For petroleum coke and fuel oil, the Crude Oil Extraction and Petroleum Refining databases were used. These two databases provide emissions based on the extraction and refining of 1000 kg of crude oil, so allocation was implemented in order to assign emissions to each of the resulting petroleum products.

3.2.2.11 Coal transport

Jacksonville Electric Authority has fuel contracts to supply the majority of their fuels, and obtains the rest in the open market. In 2005, JEA purchased 82% of their coal requirements through Southern Coal & Land Company and the remaining 18% through RAG Coal Sales of America (now know as Foundation Energy Sales, Inc.).

Coal is supplied to JEA through a combination of rail and ship. JEA owns 4 sets of 90-car trains operated by CSX Transportation Inc., with each car having a carrying capacity of 105 tons of coal. Coal arriving by rail comes from mines in Kentucky and West Virginia (JEA 1997). These four trains were modeled as GE Evolution Series locomotives towing 90 Aluminum Quad Hopper cars, which have a load capacity of 117.05 tons (FreightCar America 2006), the most similar to JEA's aluminum hopper cars for which data were found.

Coal transported by ship or barge arrives at the St. Johns River Coal Terminal, a 30-acre site located on Blount Island that can handle up to 3 million tons of coal per year. The coal is then transported to the Power Park by a 3.2 mile-long enclosed conveyor system. Receiving coal by ship offers the economic benefit of being able to purchase coal on the spot market when prices are lower than those of JEA's coal purchasing contracts (JEA 1997). The ships were modeled as Panamax ocean cargo bulkers.

Emissions resulting from coal transportation were calculated using the NREL LCI Database Transportation module. It was assumed that 75% of the coal arrived by rail and the remaining 25% arrived by ship. The distance used for rail transport was the average distance between Lexington, KY and Jacksonville and Charleston, WV and Jacksonville. This distance was calculated to be 555 miles, so a rounded up distance of 600 miles was assumed. For the coal arriving by ship, it was found that the U.S. imports 99% of its coal from Columbia, Venezuela, Indonesia, and Canada (EIA 2007). Thus, the following ports were chosen from each country and distances to Jacksonville were calculated: Santa Marta, Columbia; Maracaibo, Venezuela; Jakarta, Indonesia; and Charlottetown, Canada. These distances were weighted by their respective fraction of U.S. coal imports that they represent, and this final weighted average distance of 2165 miles was used for the ship transport emissions calculations using the NREL LCI Transportation module.

3.2.2.12 Petroleum coke transport

In 2005 JEA purchased 64% of their petcoke requirements from Oxbow LLC, 25% from Energy Coal SpA, and the remaining 11% in the spot market (JEA 2006a). Since petcoke is a by-product of petroleum refining, it was assumed that JEA receives their petcoke by ship from U.S. refineries. Texas (including offshore), Alaska, California, and Louisiana produce 78% of the total crude oil produced in the U.S. It was assumed that the crude oil is processed at refineries in relatively close proximity to extraction sites. The following port cities were chosen, one for each of the four states, and average distances to Jacksonville by sea were calculated: Baton Rouge, LA; Baytown, TX; Valdez, AK; and San Francisco, CA. It was assumed that the Valdez and San Francisco tankers would travel through the Panama Canal, and the Baton Rouge and Baytown tankers would travel around the southern tip of Florida. The average distance of these four locations to Jacksonville, weighted by percent contribution to U.S. crude oil production, was found to be 3150 miles.

3.2.2.13 Fuel oil transport

JEA maintains a 45 to 60 day supply of oil inventory, and purchases its fuel oil in the open market (JEA 2006a). Being a petroleum product, the transportation of fuel oil was assumed to be the same as petroleum coke transportation, detailed above.

3.2.2.14 Natural gas transport

Jacksonville Electric Authority has a 20 year contract that began in 2001 to purchase a 7,300,000 mmBtu per year of natural gas through EPM (now BGLS). This value is planned to increase to 22,265,000 mmBtu per year in 2007. JEA has a contract to use the Florida Gas Transmission interstate pipeline for transportation of 19,710,000 mmBtu per year. In fiscal year 2005, JEA purchased the majority of their natural gas from EPM.

Natural gas transport emissions were calculated using both the Natural Gas Precombustion database (from the Energy and Fuels Precombustion module) and the Natural Gas Extraction and Processing database (from the Primary Fuels Production module) of the NREL LCI Database. The Precombustion module accounts for extraction, processing, transport, and storage of fuels. Therefore, data from the Extraction and Processing database were subtracted from the data from the Precombustion database to isolate the emissions due solely to natural gas transport and storage.

3.2.3 Lifetime Power Output

The lifetime power output of the wind farm was calculated as the product of the wind farm’s capacity, a capacity factor of 30%, and the number of hours operating over its 20-year lifespan. This results in a power output of 9,467,280 MWh. The lifetime power outputs of the fossil fuel-fired systems were similarly calculated as the product of their capacities, a capacity factor of 60%, a loading factor of 91.7% for the coal-fired unit and 59.3% for the natural gas-fired unit, and the number of hours in their 30-year lifespans. This results in a lifetime power output of 52,088,975 MWh for the coal-fired units (both the Scherer-based and St. Johns River Power Park-based units), and 47,251,983 MWh for the natural gas-fired unit. The reason the power outputs for the coal plant and the NGCC unit were based on different loading factors is because they were assumed to operate as JEA currently operates similar systems. JEA runs its coal-fired units more continuously than its NGCC unit. Brandy Branch, the natural gas combined-cycle unit at JEA, underwent 103 start-ups in 2004, compared to only 9 start-ups for St. Johns River Power Park.

3.2.4 Environmental Impact Assessment

The impact assessment was conducted using the Environmental Risk Evaluation Method as outlined by Allan and Shonnard (2002). In this method, the dimensionless risk index is calculated by Equation 3-1.

$$(DimensionlessRiskIndex)_i = \frac{[(EP)(IIP)]_i}{[(EP)(IIP)]_B} \qquad (3\text{-}1)$$

where EP is the exposure potential, IIP is the inherent impact potential, *i* is the indexed compound, and B is the benchmark compound. The dimensionless risk index for global warming and acid rain are referred to by Allen and Shonnard (2002) as global warming potential (GWP) and acid rain potential (ARP) respectively. GWP values used in the impact assessment for CO_2, CH_4, N_2O and NO_X are 1, 21, 310, and 40, respectively; ARP values for SO_2 and NO_2 are 1 and 0.7, respectively (Allan and Shonnard 2002). Some of the data sources used reported air emissions as SO_X and NO_X, while other data sources reported air emissions as SO_2 and NO_2 only. In this impact assessment, all of the SO_2 and SO_X data were lumped together, using the

ARP for SO_2. Similarly, the NO_2 and NO_X data values were grouped together with GWP for NO_X and the ARP for NO_2 applied, based on availability of data and dimensionless risk index values. To assess the total index, I, for global warming and acid rain impacts resulting from the air emissions inventoried from all stages of the electricity production systems, Equation 3-2 was used, in accordance with the method outlined by Allan and Shonnard (2002).

$$I = \sum_i [(DimensionlessRiskIndex)_i \times m_i] \qquad (3\text{-}2)$$

where *i* is the indexed stressor (i.e., CO_2, CH_4, N_2O, SO_2, NO_X), the Dimensionless Risk Index is either the GWP of *i* or the ARP of *i* (depending on which impact is being assessed), and m is the total mass of *i* emitted throughout all the life cycle stages considered per functional unit. More details of the GWP and ARP are given below.

3.2.4.1 Global warming potential

According to the Intergovernmental Panel on Climate Change, the GWP is the cumulative infrared energy capture from the release of 1 kg of a greenhouse gas relative to that from 1 kg of carbon dioxide, the benchmark compound (Allan and Shonnard 2002). This can be expressed by Equation 3-3.

$$GWP_i = \frac{\int_0^n a_i C_i \, dt}{\int_0^n a_{CO2} C_{CO2} \, dt} \qquad (3\text{-}3)$$

where a_i is the predicted radiative forcing of gas *i* (W/m^2) (a function of the chemical's infrared absorption properties and C_i), C_i is the predicted concentration in the atmosphere (ppm), and n is the number of years over which the integration is performed. Substituting the calculated GRP_i values and the mass of emissions into Equation 3-2 above produces impact potential units of kg of CO_2 equivalents per MWh.

3.2.4.2 Acid rain potential

The acid rain potential of a compound is determined by the number of moles of H+ it creates per number of moles of the compound (Allan and Shonnard 2002). The acidification is expressed on a mass basis (Equation 3-4) where i is again the compound of interest and ηi is the number of moles H+ per kg i. SO_2 is the benchmark compound for acid rain potential (Allan and Shonnard 2002).

$$ARPi = \eta i / \eta SO_2 \qquad (3\text{-}4)$$

Substituting the ARPi values and the mass of emissions into Equation 3-2 above produces impact potential units of kg of SO_2 equivalents per MWh.

3.3 Emergy Synthesis

3.3.1 Scope and Boundaries

The emergy analysis included the same stages as the life cycle assessment, i.e. raw materials extraction and manufacture, transportation, construction, and operation for all three power generating systems, and decommissioning was also included for the wind farm system.

A system diagram representing the construction, operation, and maintenance of the power plant systems and the wind farm system is shown in Figure 3-9. The external sources included in the analysis are wind, fuels, materials, machinery, and human services. The two main storages are the assets of the power plants and the wind farm. For simplicity, separate components in the systems diagrams were not drawn for the natural gas combined-cycle power unit and the coal-fired steam turbine power unit, because the two components would be identical. Thus, the JEA PP (Jacksonville Electric Authority power plant) component shown in Figure 3-9 represents either of the systems. Separate emergy accounting tables were constructed for these two systems, however, because the energy, materials, and service flows are of different quantities. The dashed line in the system diagram is a monetary flow and represents an exchange of money coming into the system obtained through the sale of electricity, and then leaving the system in exchange for human services. There is also a fraction of this monetary flow that remains in the system as profit; however, this was not included in the analysis and was therefore neglected from the system diagram.

Also for simplicity, the construction and maintenance stages are represented by the same interaction symbol, one for each power system, since they both combine materials with fuels, machinery, and human services, but they operate at different times in the life cycle, never simultaneously. The outflows of the construction/maintenance interaction symbols feed into the storages of the power systems' assets. The operation stages are represented by the interaction symbols located within the boxed boundaries of the individual power systems. The inflows for the coal and natural gas-fired systems are fuels, assets, and human services, while the inflows for the wind park are wind, assets, and human services. The outflows of the interactions representing the operational stage are electricity. Inputs that were considered to be outside the scope of our research include the emergy flows of the construction equipment and cooling water required, and were not included in the analysis. All interactions and storages in the system diagram have heat sinks exiting through the bottom of the symbols, representing the inherent losses of these components. Examples of these losses include energy lost during combustion in the form of heat, or wear and depreciation of assets over the system's life time.

3.3.2 Data Acquisition

The emergy synthesis was performed with the same data used in the life cycle assessment, but some additional data were also required. Additional data included in the emergy analysis were hours of labor for each stage, type of labor (graduated or not specialized), wind energy inputs to the wind farm, and oxygen demand for combustion of fuels. Primary data provided by Sargent & Lundy LLC were used for labor for the construction stage of the fossil-fired power units, and data from the literature were used for the wind farm construction stage. Labor data for other stages had to be assumed, based on equipment requirements, etc. for the process. Oxygen demand for combustion of fuels was calculated based on mole ratios of the associated combustion process, which were then converted to mass ratios.

3.3.2.1 Wind energy inputs to wind farm

Energy inputs to the wind farm system were calculated based on the kinetic energy of the air in the control volume of the wind farm. The size of the control volume was calculated as the product of the sea area required for the wind farm, based on spacing the turbines one half mile apart (Bryant 2007) for a total sea area of 25 square miles (65 square kilometers), and the height of the turbines, measured to the tip of the blades in their vertical position (120 m, based on 80 m tower height and 40 m blade length). This results in a total control volume of 7.8 cubic kilometers. An average wind speed of 6.98 meters per second, as recorded by NOAA's National Data Buoy Center's Buoy 41008 was used for the velocity. The raw wind speed data used for this calculation as well as the conversion calculations performed are given in Appendix G. The kinetic energy of the wind was calculated assuming an air density of 1.225 kg/m^3. The wind energy input to the wind park was determined to be 6.38E+15 J.

3.3.2.2 Labor for wind farm transport

Labor for the transport of the power units was calculated based on the mode of transportation used, size of vehicle, and number of required trips. For the transport of the wind turbines the twenty-five miles from Randers to Aarhus by rail, it was assumed that 120 workers were involved. This allowed for 10 people for each of the 12 locomotives towing 100 flatbeds. It was assumed to take one complete eight-hour work day, for a total of 960 man-hours. It is standard procedure record all flows in an emergy synthesis on a yearly basis. Therefore, for stages such as transportation, construction, and decommissioning, it is necessary to normalize all flows by dividing the total energy, material, and service flows by the life time of the system. Normalizing the transportation labor over the wind farm life time of twenty years results in 48 man-hours/year, or 5.48E-03 years/year.

The transportation of the wind turbines from Aarhus to Jacksonville by sea was assumed to require a crew of 100 people and take two weeks to complete, including the time required to load the turbines onto the Panamax bulker. This resulted in 11,200 man-hours, assuming eight hours of labor for the average day during the trip. Normalizing over the life time of the wind park results in 560 man-hours/year, or 6.39E-02 years/year for the overseas transport stage.

3.3.2.3 Labor for wind farm construction and decommissioning

Labor involved for the construction of the wind farm was assumed to be a crew of 200 workers, half of which were assumed to be graduated labor and the other half non-specialized labor. Construction labor data were obtained from a life cycle assessment performed by Elsam Engineering A/S for Vestas. Installation of each tower requires 20 hours, each nacelle 10 hours, each foundation 20 hours, and each rotor and set of three blades 6 hours (Elsam Engineering A/S 2004). An additional 5 hours per turbine was included for miscellaneous construction labor. This results in a total of 1,220,000 man-hours. Normalizing this to a yearly basis results in 61,000 man-hours/year, or 6.96E+00 years/year (3.48E+00 years/year each of graduated labor and non-specialized labor).

Labor data for decommissioning of the wind park were also obtained from the Elsam Engineering LCA. The number of hours required for dismantling is exactly the same as those required for installation. The only differences in the construction and decommissioning stages are that construction requires pile driving, whereas decommissioning requires that the foundations be cut off at the surface of the seabed and the remaining buried segments be left in the ocean floor. This difference, however, does not have an effect on the required labor time, remaining at 20 hours per foundation (Elsam Engineering A/S 2004). Therefore, the total man-hours required for decommissioning is also 56,000 man-hours/year, or 6.39E+00 years/year. Consistent with the construction stage, the labor for decommissioning was assumed to be comprised of half graduated labor and half non-specialized labor.

3.3.2.4 Labor for wind farm maintenance

Calculation of labor for maintenance of the wind farm is based on the required biannual service calls to each of the turbines. One four-member crew is scheduled to complete one maintenance servicing per 1.5 days (Poulsen 2004). It was therefore assumed that a total of 150 eight-hour work days are required for four people every 6 months to service the 100 turbines, for a total of 9600 man-hours per year, or 1.10E00 years/year.

3.3.2.5 Labor for coal-fired power unit transportation

The coal-fired steam turbine unit was assumed to be transported by rail from the Siemens manufacturing facility in Charlotte, NC. The 400 mile distance was assumed to take 14 hours, a rounded-up estimate for moving at an average speed of 30 mph. The number of 89-foot, 100-ton flatbed cars required for the transport was determined by the total weight of the power unit (83,540 tons), resulting in a rounded up number of 900 flatbeds. Thus, it was assumed that 9 locomotives would be required, each towing 100 flatbed cars. Consistent with the wind farm transportation calculation, it was assumed that 10 workers were required for each locomotive and set of 100 flat cars, resulting in a total crew of 90. Therefore, the labor required for the steam turbine transport was determined to be 1260 man-hours, or 4.79E-03 years/year when normalized to a yearly basis using a power plant life time of thirty years.

3.3.2.6 Labor for natural gas combined-cycle unit transportation

Labor for the natural gas combine-cycle unit transportation was calculated in the same manner as detailed above for the coal-fired steam turbine. The gas turbine unit was assumed to be transported by rail from the Siemens manufacturing plant in Hamilton, Ontario, a distance of 1200 miles, taking 40 hours at an average speed of 30 mph. The total mass of the gas turbine combined-cycle unit is 72,028 tons, requiring a rounded up number of 750 flatbed cars. Thus, it was assumed that eight locomotives were required, resulting in a crew of 80 workers. The total labor for the gas turbine transport was found to be 3200 man-hours, or 1.22E-02 years/year when normalized over the power plant life time.

3.3.2.7 Labor for coal-fired unit construction

Data for the construction stage of the coal fired plant were obtained through phone conversations with engineers from Sargent & Lundy LLC. These data were based on a reference project for the construction of an 800 MW coal-fired steam turbine unit, which required 1500 workers during peak construction, with fewer workers during the beginning and ending phases of construction, and lasting 52 months. These data were then scaled to apply to the 360 MW unit for our research, resulting in 675 workers during peak construction, and construction lasting for 24 months. This calculated time frame for construction is supported by other data found in the literature, i.e. that a 360 MW coal-fired unit requires two years for construction (Spath et al. 1999). Assuming that non-peak construction phases require 300 workers and last for four months at the beginning and end of construction (making up one-third of the total construction time), the total labor required for construction was assumed to be 3,168,000 man-hours, or 105,600 man-hours/year (1.20E+01 years/year) when normalized over the thirty year life time of the power plant.

3.3.2.8 Labor for natural gas combined-cycle unit construction

The reference data provided by Sargent & Lundy engineers for the construction of the natural gas combined-cycle (NGCC) unit were based on a 500 MW unit, which was reported to require roughly 80% of the labor of the 800 MW coal-fired steam turbine unit. It was therefore determined that the NGCC unit requires 128% of the labor of the coal-fired system when put on the basis of per MW of capacity. This ratio was used to calculate the labor required for the 505 MW unit that is the model under analysis for the current research, which resulted in 1215 workers during peak construction, 540 during non peak times, and construction lasting for 43 months. It was again assumed that the non-peak construction represented one-third of the total construction time, or in this case 7 months each at the beginning and end of construction. These calculations and assumptions result in 10,270,800 man-hours, or 342,360 man-hours/year (3.91E+01 years/year).

3.3.2.9 Labor for fuels transport

Labor for the fuels transport for the coal system was calculated based on the required trips by rail to transport a year's supply of coal. The 360 MW coal system modeled after Plant Scherer, for which 99.96% of its power generation is supplied by coal, requires approximately 790,000 tons of coal per year. Making use of JEA's utility-owned trains, this would require 90 fully-loaded shipments, i.e. all 90 hopper cars filled to their 105-ton capacity. It was assumed, however, that shipments received were one-third of this maximum capacity, received three times more frequently, due to possible limitations of receiving capabilities and fuel storage facilities. It was assumed that a crew of 10 workers is required for each 90-car train, and the 600-mile average distance trip from Kentucky or West Virginia takes 20 hours, assuming a speed of 30 mph. Accounting for round-trip labor, this results in 108,000 man-hours per year, or 1.23E+01 years/year of non-specialized labor.

Labor for the fuels transport for the steam turbine unit modeled after St. Johns River Power Park was calculated similarly; however, the transport of petroleum coke and distillate fuel oil by ship was also included. The total number of trips required by rail for coal delivery was calculated to be 75 in order to transport the required 646,000 tons of coal per year. The number of shipments of petcoke by small ocean tanker with a carrying capacity of 60,000 deadweight tons (Maritime Business Strategies LLC 2007) was determined to be 2 per year, in order to transport the required 101,000 tons of petcoke consumed annually by the power unit. The number of shipments by small ocean tanker required to transport the 4000 tons of distillate fuel oil required by the power unit per year was determined to be one. The rail labor was calculated in the same manner as for the Scherer based scenario, and the labor for the ship transportation of the petcoke and fuel oil was assumed to take 1 week with a crew of 100 working standard eight hour shifts, per shipment. This results in total labor values of 30,000 man-hours for the rail transport and 24,000 man-hours for the tanker ship transport, or 6.16E+00 years/year of non-specialized labor.

Labor required for the natural gas transport for the natural gas combined-cycle power unit was assumed to be negligible, since it is delivered by pipeline to Jacksonville Electric Authority.

3.3.2.10 Oxygen demand for combustion

Oxygen demand was included in the emergy synthesis as a renewable input required for the combustion of fuels used throughout all stages of the power generating systems' life times, e.g. fuel required for fuels extraction, etc. The oxygen demand was calculated based on mole ratios in the combustion reaction for each fuel. The combustion equation for petroleum coke could not be determined, so it was assumed to have the same oxygen demand as coal. Electricity required for upstream processes was also assumed to have the same oxygen demand as coal, since coal provides roughly 50% of the electricity produced in the United States.

3.3.3 Emergy Accounting Table

After the systems diagram was constructed to clearly define the scope (Figure 3-9), a table that includes all the actual flows of materials, energy, and labor was generated for each power generating system. Another column in this table is the Unit Emergy Value (UEV) for each item.

The actual flow amounts (in grams or Joules) were multiplied by the UEVs (in sej/g or sej/J) to give the emergy flows for each item (in solar emjoules). Following typical emergy accounting procedure, all flows were put on an annual basis, thereby requiring that flows for construction, transportation, and decommissioning be normalized to a yearly basis by dividing these values by the system's life time. The wind park's expected life time was assumed to be twenty years, while the coal-fired and natural gas combined-cycle power plants' expected life times were both assumed to be thirty years. The emergy flows were then summed to give an emergy value to the product, in this case electricity. Lastly, the determined emergy value of the product was divided by the quantity of electricity to give the system's UEV for electricity. Two transformities were calculated, one that includes labor and services and one that does not. Performance indicators were calculated for each of the three systems, including the emergy yield ratio, emergy investment ratio, environmental loading ratio, emergy index of sustainability, and percent renewable.

Table 3-1. Vestas V80-1.8 MW turbine specifications.

Rotor	
Diameter	80 m
Area swept	5027 m^2
Nominal revolutions	15.5/16.8 rpm
Number of blades	3
Power regulation	Pitch/OptiSlip
Air brake	Full blade pitch by three separate hydraulic pitch cylinders
Tower	
Hub height	78 m
Operational Data	
Cut-in wind speed	4 m/s
Nominal wind speed (1800 kW)	15 m/s
Cut-out wind speed	25 m/s
Generator	
Type	Asynchronous with OptiSlip
Nominal output	1800 kW
Operational data	60 Hz 690 V
Gearbox	
Type	Planet/parallel axles
Control	
Type	Microprocessor-based control of all the turbine functions with the option of remote monitoring. Output regulation and optimization via OptiSlip and OptiTip pitch regulation.
Weight	
Nacelle	67 metric tonnes (t)
Rotor	37 t
Tower	195 t

Table 3-2. V80-1.8 MW turbine components, materials, and masses.

Component	Material	Mass (kg/turbine)
Blades	glass reinforced epoxy (GRE)	21000
Hub	steel	16000
Nacelle	steel	58534
Generator	50% steel-50% copper	8466
Tower	steel	205000
Monopile Foundations	steel	200000
Transition Piece	steel	90000
Boat Landing Platform	steel	10000
Coupling Piece	concrete	1000
	Total	610000

Table 3-3. Materials required for the 360 MW coal-fired power plant.

Material	Amount required (kg)
Concrete	57152880
Steel	18259560
Iron	222840
Aluminum	150840
Total	75786120

Table 3-4. Materials required for the 505 MW natural gas combined-cycle power unit.

Material	Amount required (kg)
Concrete	49363245
Steel	15670150
Iron	206040
Aluminum	103020
Total	65342455

Table 3-5. Power plant construction equipment details.

	Hours Used		
Equipment	Coal-Fired Steam Turbine	Natural Gas Combined-Cycle	Model used in analysis
2 large cranes	700	1250	Manitowoc crane, model 2250 330 ton lifting capacity Caterpillar 6-cylinder diesel engine, model 3406C Engine rated at 343 kW, 460 hp, 2100 rpm Fuel efficiency of 17.5 - 23.7 gal/h
10 small cranes	1400	2500	Manitowoc crane, model 6D16-TLA2B 50 ton lifting capacity Caterpillar 6-cylinder diesel engine, model 3126B Engine rated at 149kW, 200hp, 2000 rpm Fuel efficiency of 8.8 to 10.2 gal/h
Wheel dozers	200	350	Medium-sized Caterpillar, model H24H C15 ACERT engine rated at 328 kw, 440 hp Fuel efficiency of 10.9 to 23.5 gal/h
Scrapers	200	350	Medium-sized Caterpillar, model 623G C15 ACERT engine rated at 328 kw, 440 hp Fuel efficiency of 10.9 to 23.5 gal/h
Off-highway trucks	5000	9000	Caterpillar off-highway truck, model 773F 60 ton max payload C27 ACERT engine rated at 740 hp, 1800 rpm Fuel efficiency of 34.3 to 42.5 gal/h

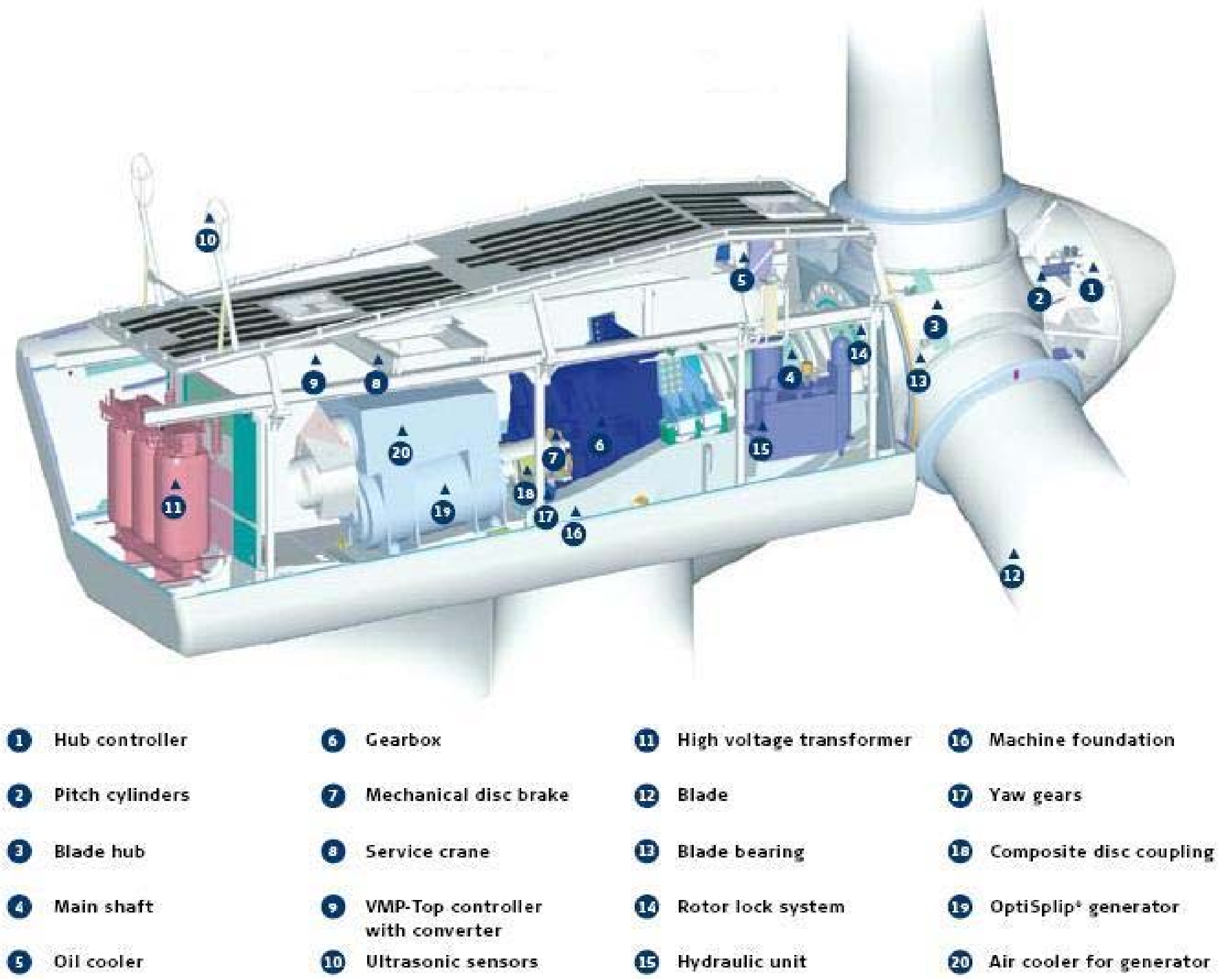

Figure 3-1. Cutaway diagram of Vestas V80-1.8 MW turbine. Reprinted with permission from: Vestas Wind Systems A/S. Randers, Denmark. 2007. Last accessed March 2007. <http://www.vestas.com/>

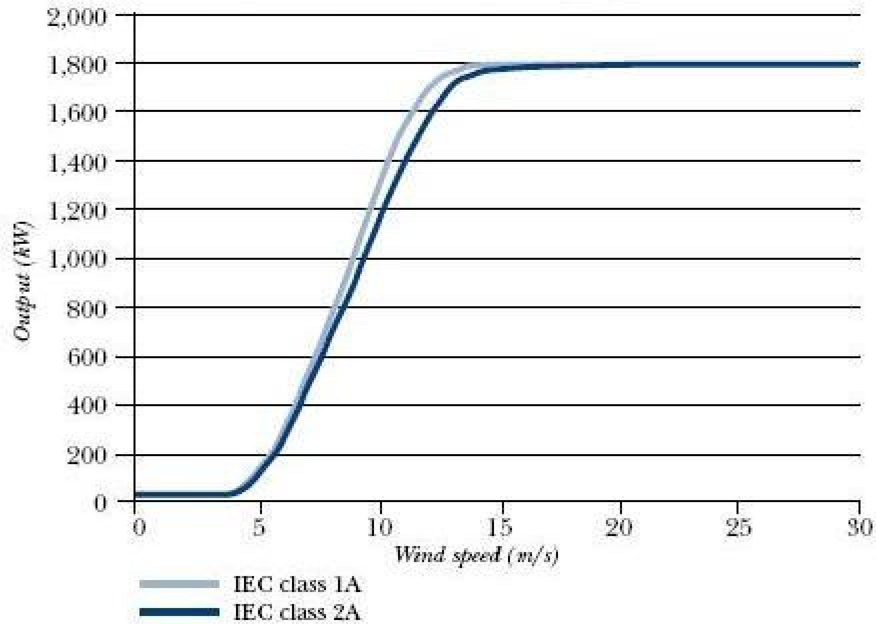

Figure 3-2. Power curve for Vestas V80-1.8 MW turbine. Reprinted with permission from: Vestas Wind Systems A/S. Randers, Denmark. 2007. Last accessed March 2007. <http://www.vestas.com/>

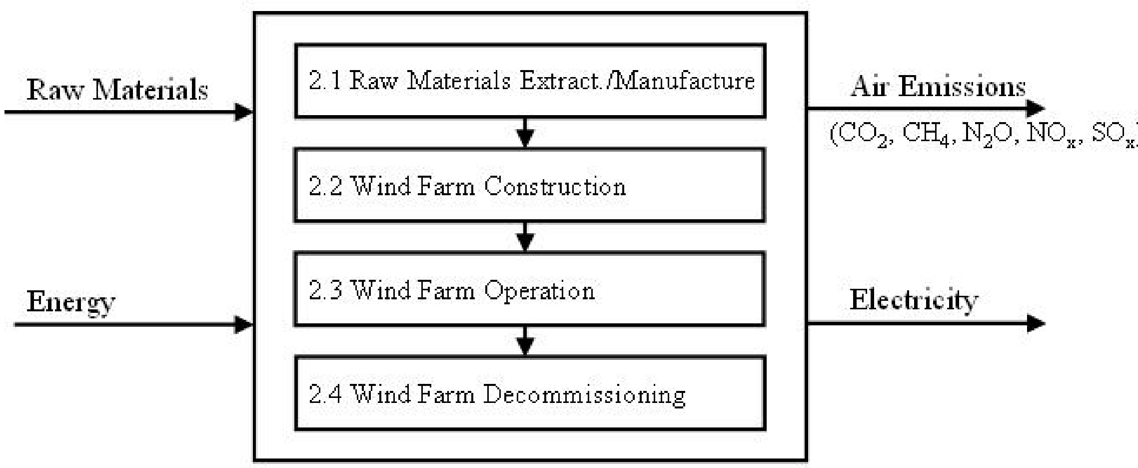

Figure 3-3. Level 1.0 with embedded Level 2.0 diagram for wind farm system.

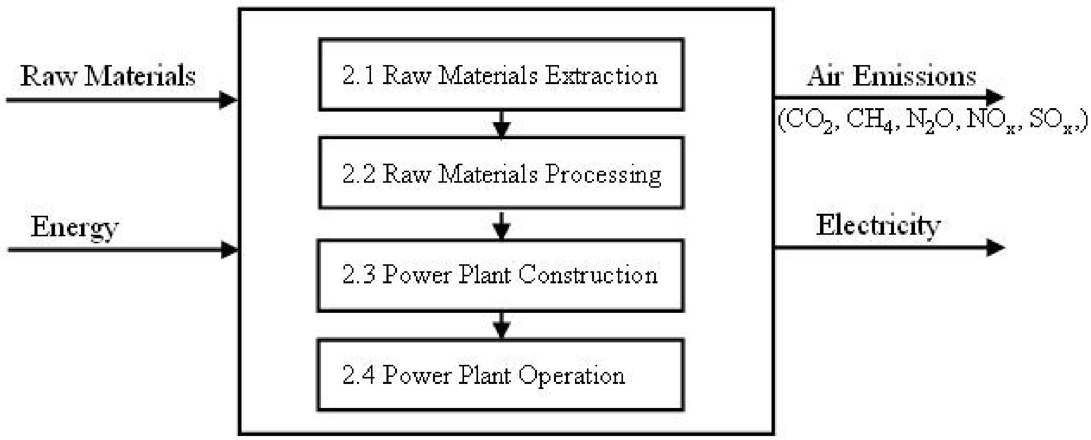

Figure 3-4. Level 1.0 with embedded Level 2.0 diagram for power plant system.

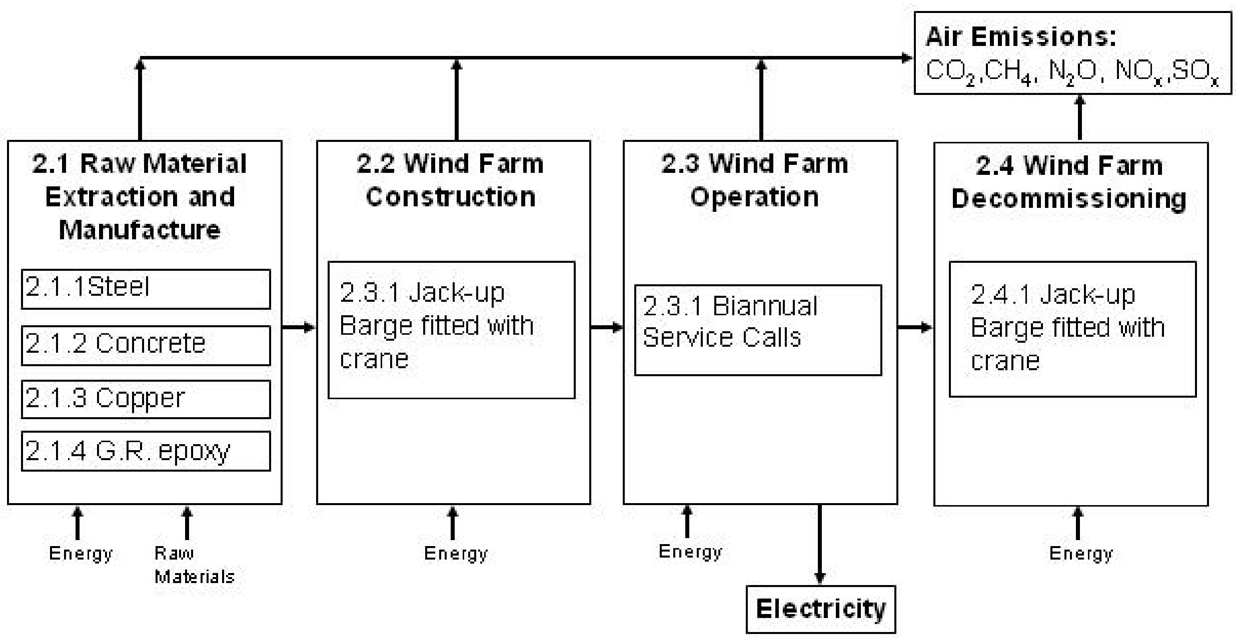

Figure 3-5. Level 3.0 diagram for wind farm system.

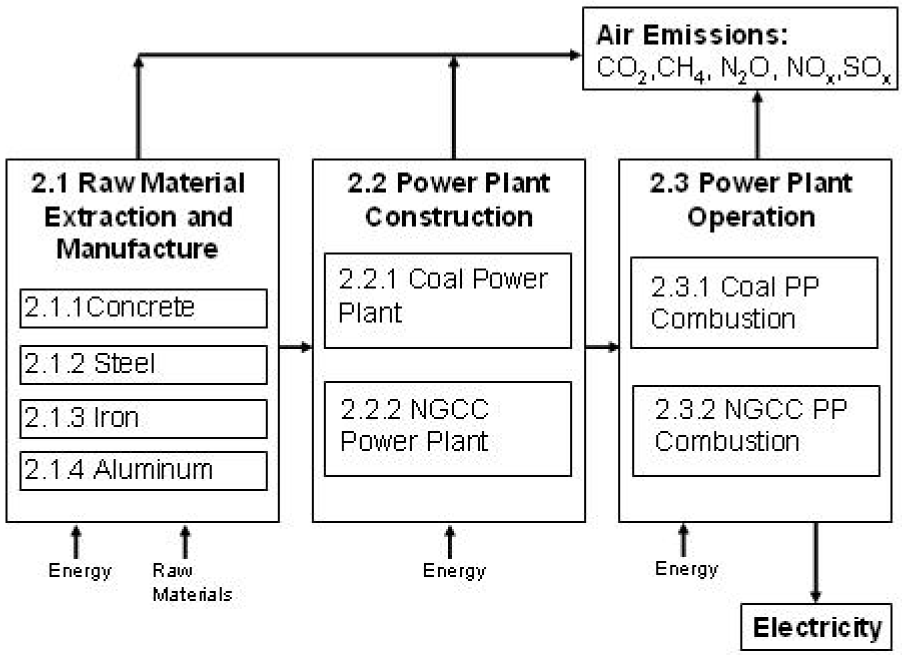

Figure 3-6. Level 3.0 diagram for power plant systems.

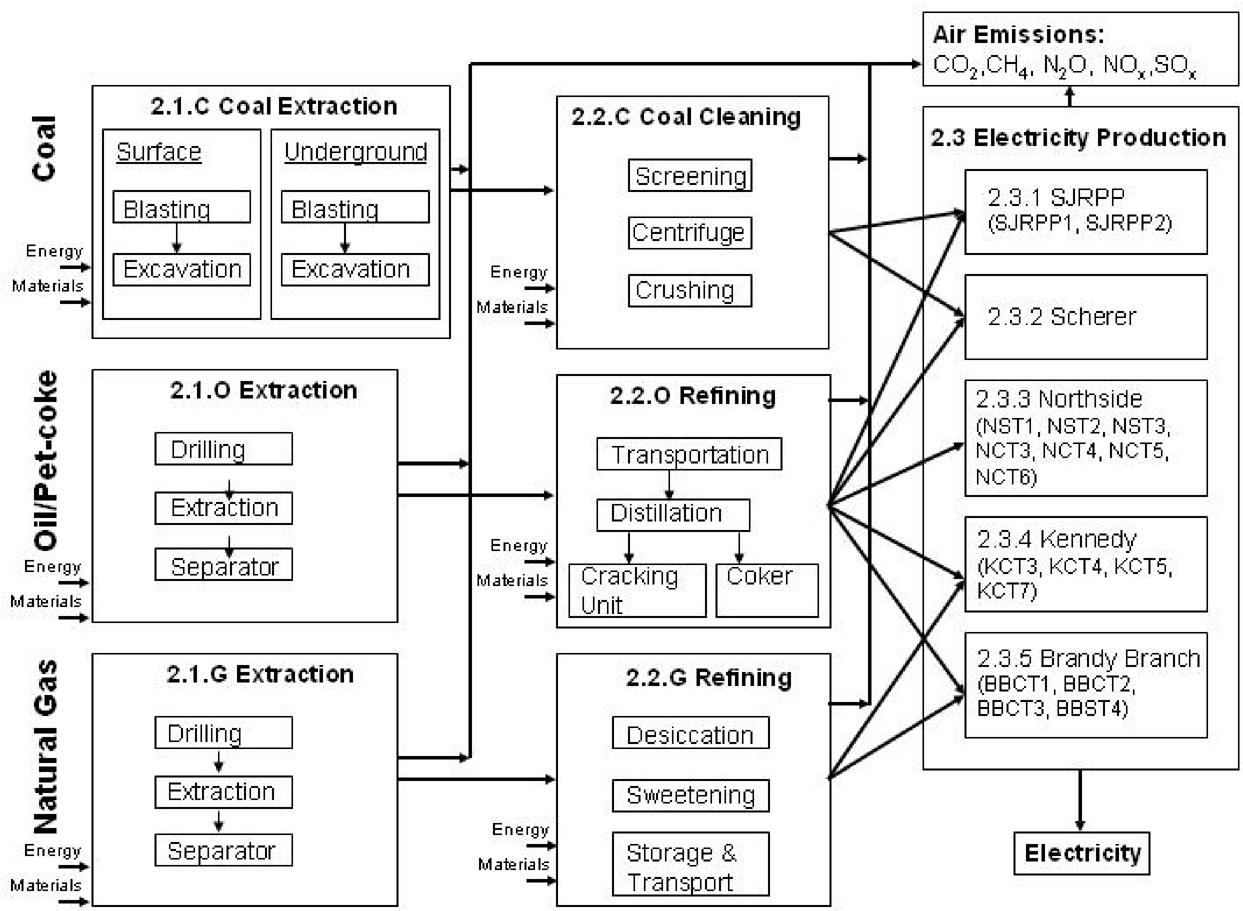

Figure 3-7. Level 3.0 diagram for JEA's current operation.

Figure 3-8. The raising of nacelle and rotor by jack-up barge fitted with a crane. Reprinted with permission from: Vestas Wind Systems A/S. Randers, Denmark. 2007. Last accessed March 2007. <http://www.vestas.com/>

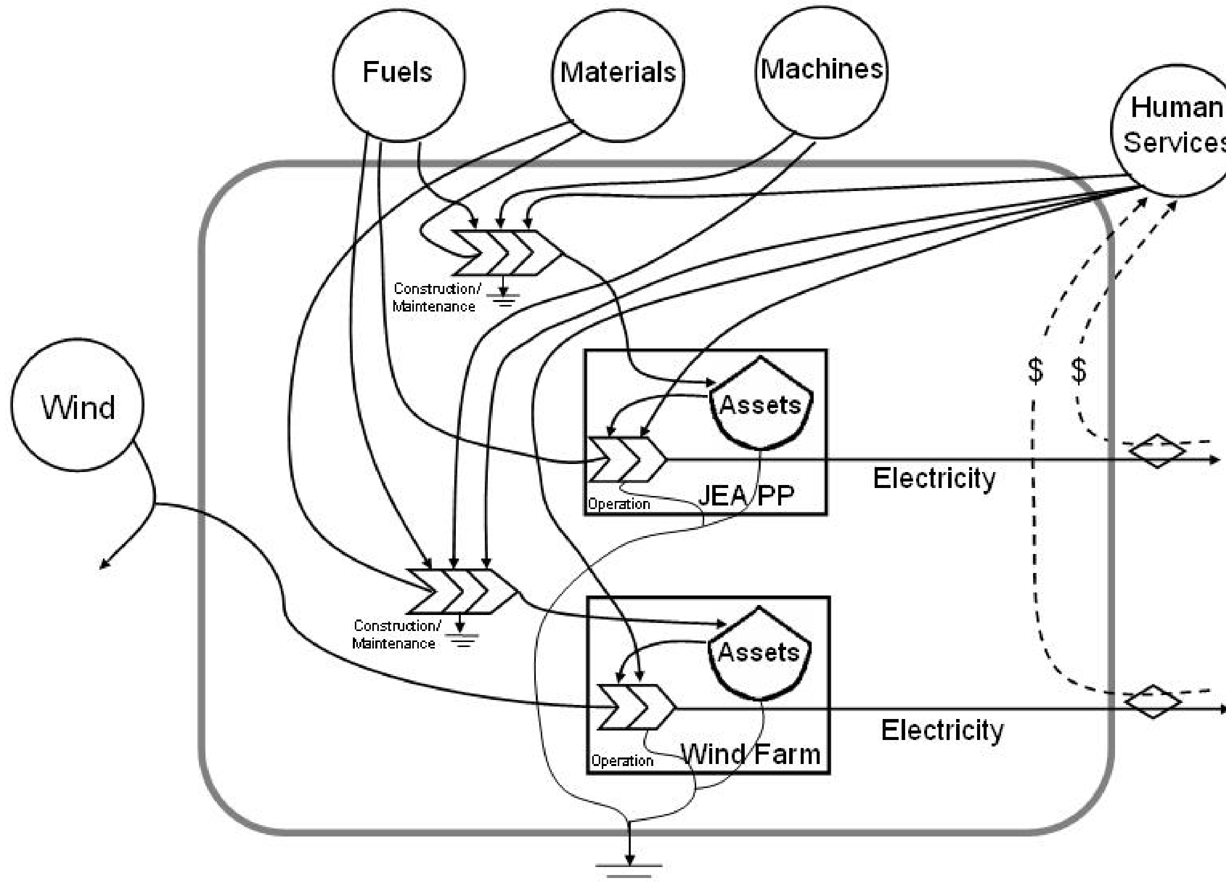

Figure 3-9. System diagram for emergy synthesis.

CHAPTER 4
RESULTS

4.1 Life Cycle Assessment

Overall results of the impact assessment are given in Table 4-1, the global warming potential impact of each power system, and Table 4-2, the acid rain potential impact of each power system. These values are depicted graphically in Figures 4-1 through 4-4. The wide, shaded blue bars represent global warming impact, and these values correspond to the scale on the left y-axis, whereas the narrower green bars represent acid rain impacts, and these values are read from the scale on the right y-axis.

The wind farm system was found to have a global warming impact of 24 kg CO_2 equivalents per MWh of electricity produced, compared to 1452 for the coal-fired steam turbine unit based on operating conditions of Plant Scherer (Coal- Scherer); 1146 for the coal fired steam turbine unit based on operating conditions of St. Johns River Power Park (Coal- SRPP); and 682 for the natural gas combined-cycle power unit based on operating conditions of Brandy Branch (NGCC- BB). Similarly, the acid rain potential impact of the wind farm was also more than an order of magnitude lower than the steam turbine or gas turbine units, having a value of 0.2 kg SO_2 equivalents per MWh, compared to 6.4 for the coal plant based on Scherer, 5.0 for the coal plant based on St. Johns River Power Park, and 6.1 for the natural gas combined-cycle unit.

For the wind farm, the life cycle stage with the greatest environmental impacts was found to be the materials extraction stage, followed by the power unit transportation stage, construction, decommissioning, and lastly, operation/maintenance. In contrast, the operation stage for the fossil fuel-fired systems is by far the stage with the greatest environmental impact, followed by fuels extraction and fuels transport, respectively. The power unit materials extraction, power unit transport, and power unit construction stages all negligibly contribute to the systems' environmental impact potentials.

Figure 4-5 is a side-by-side comparison of the total environmental impacts of the four power systems modeled. This figure clearly depicts the drastic differences in both global warming and acid rain impacts of the wind farm when compared to all three of the fossil fuel-fired power systems. In terms of carbon dioxide equivalents savings, the wind farm produces 1428 kg CO_2 equivalents per MWh less than the coal fired unit based on Plant Scherer. Over the twenty-year life time of the wind farm, this results in a savings of roughly 13,500,000,000 kg, or 15 million tons of CO_2 equivalents. Similarly, the wind farm results in a savings of approximately 12 million tons of CO_2 equivalents over its life time when compared to the coal unit based on operating conditions of St. Johns River Power Park. When compared to the natural gas combined-cycle unit, the wind farm produced 658 kg CO_2 equivalents per MWh less, resulting in a savings of roughly 7 million tons CO_2 equivalents over its life time. As for savings in acid rain emissions, over its life time the wind farm results in approximately 65,000 fewer tons SO_2 equivalents than the Scherer-based coal plant, 63,000 tons less than the natural gas combined-cycle unit, and 50,000 tons less than the St. Johns River Power Park-based coal plant. These values can be found in Table 4-3.

A comparison of the life cycle stages that are common to all four systems, namely, power unit materials extraction, power unit transport, and power unit construction, is shown in Figure 4-6. The material requirements for the power systems are all on the same order of magnitude, with the wind farm consisting of 61,000,000 kg of materials, the coal plant 75,786,000 kg, and the natural gas unit 65,342,000 kg. However, the lifetime power output of the wind farm is an order of magnitude less, having a value of 9,467,000 MWh, compared to 52,089,000 MWh for the coal plant and 47,252,000 MWh for the natural gas unit. This results from several factors, namely, the wind farm having a smaller capacity of 180 MW compared to the 360 MW coal plant and the 505 MW natural gas unit; the wind farm's shorter life time of 20 years as opposed to 30 years for the fossil-fired units; and the wind farm operating at a lower capacity factor of 30% as compared to 60% for the fossil-fired units. Therefore, as illustrated by Figure 4-6, the material requirements are greater for the wind farm system when normalized to a basis of per megawatt-hour of electricity produced. This is as expected, since wind energy is less concentrated than fossil fuel energy and therefore more equipment is necessary to harness an equal amount of energy. It can also be seen in Figure 4-6 how this increased materials requirement for the wind farm per MWh of electricity produced has a trickle-down effect on the other two life cycle stages in the graph, power unit transport and construction.

The global warming and acid rain potential impacts for each of the fuel cycles were also determined. These fuel cycles include the fuels' extraction and processing, transport, and combustion stages only. The fuel cycles analyzed were natural gas, distillate fuel oil burned in a gas combined-cycle turbine, distillate fuel oil burned in a steam turbine, coal, and petroleum coke. These data illustrate the environmental impact potentials as a function of fuel type, whereas the previously discussed impacts were calculated as a function of the power generating unit's operating fuel mix. Thus, those data for each life cycle stage were proportional to the fraction of the composite MWh that each fuel supplied. The fuel cycles' environmental impacts, however, represent the impacts for the case where 100% of the MWh is supplied by that fuel. These data are given in Table 4-4 and graphically in Figure 4-7. It was found that the coal fuel cycle has the largest global warming impact potential, followed by petroleum coke, distillate fuel oil combusted in a gas combined-cycle turbine, DFO combusted in a steam turbine, and lastly, natural gas. As for acid rain, coal was also found to have the highest impact potential, followed by natural gas, petroleum coke, DFO burned in a steam turbine, and lastly, DFO burned in a gas combined-cycle turbine.

4.2 Emergy Synthesis

The emergy accounting tables for the four power generating systems are given in Tables 4-5 through 4-8. These tables include the calculations of the transformities for the electricity produced by each system. Table 4-9 summarizes the data of each system based on type of input, e.g. services, renewable input, etc. It also gives the performance indicators determined for each system. It was found that the wind farm system performs slightly lower but on the same scale as the fossil fuel-based systems in terms of emergy yield ratio, having a value of 11.6, compared to 18.2 for the coal system based on Scherer, 18.8 for the coal system based on St. Johns River Power Park (SJRPP), and 12.4 for the natural gas system based on Brandy Branch. The emergy investment ratios were also on the same scale, with the coal (SJRPP) system having the lowest value of 0.06, the coal (Scherer) system 0.06, the wind farm 0.08, and the natural gas system 0.09. The environmental loading ratio, however, for the wind farm system was found to be much lower than those of the other systems. The wind farm's ELR was determined to be 0.1, while the coal systems ranged from 13.1 to 15.1 and the natural gas system was found to be 22.4.

Because of the large differences in the environmental loading ratios, the emergy index of sustainability (EIS) for the wind farm is much greater, with a value of 121.9. The coal systems were found to have EISs of 1.2 to 1.4, and the natural gas system 0.6. Finally, the percent renewable performance indicator also showed large differences in the wind system compared to the conventional power systems. The wind farm was determined to be driven by 91.3% renewable inputs, while the coal systems ranged from 6.2% to 7.1%, and the natural gas system 4.3%.

Table 4-1. Global warming impact potentials for each power system.

	Wind Farm	Coal - Scherer	Coal - SJRPP	NGCC - BB
Materials Extraction	21.1	8.1	8.1	7.7
Fuels Extraction & Processing	-	104.9	119.1	118.3
Power Unit Transport	2.2	0.1	0.1	0.2
Fuels Transport	-	31.6	37.4	28.2
Construction	0.3	3.1E-04	3.1E-04	6.0E-04
Operation	0.2	1307.4	980.8	527.3
Decommissioning	0.3	-	-	-
Total (kg CO2-eq/MWh)	24.0	1452.1	1145.5	681.7

Note: Values are given in CO_2 equivalents per MWh

Table 4-2. Acid rain impact potentials for each power system.

	Wind Farm	Coal - Scherer	Coal - SJRPP	NGCC - BB
Materials Extraction	1.6E-01	3.1E-02	3.1E-02	3.0E-02
Fuels Extraction & Processing	-	1.0	1.1	5.5
Power Unit Transport	2.0E-02	6.3E-04	6.3E-04	1.8E-03
Fuels Transport	-	0.3	0.4	0.5
Construction	1.6E-03	2.3E-06	2.3E-06	4.6E-06
Operation	1.6E-03	5.0	3.5	0.1
Decommissioning	1.5E-03	-	-	-
Total (kg SO2-eq/MWh)	0.2	6.4	5.0	6.1

Note: Values are given in SO_2 equivalents per MWh

Table 4-3. Lifetime savings in global warming and acid rain impact potentials resulting from implementation of the wind farm system.

	GWP Impact (kg CO2-eq/MWh)	ARP Impact (kg SO2-eq/MWh)	Lifetime Power Output (MWh)	CO2-eq Savings (tons)	SO2-eq Savings (tons)
Wind Farm	24.0	0.2	9,467,280		
NGCC Unit (BB)	681.5	6.2	47,251,983	6,861,604	62,579
Coal ST (Scherer)	1452.4	6.4	52,088,975	14,906,739	64,653
Coal ST (SJRPP)	1141.5	5.0	52,088,975	11,662,378	49,970

Table 4-4. Global warming and acid rain impact potentials for the fuel cycles.

	GWP (kg CO2-eq/MWh)	ARP (kg SO2-eq/MWh)
Natural Gas	656.7	6.3
DFO (gas CC turbine)	1046.2	2.0
DFO (steam turbine)	897.8	2.3
Coal	1444.5	6.4
Petroleum Coke	1323.0	5.3

Table 4-5. Emergy accounting table for the wind farm system.

#	Item	Amount	Units	Unit Emergy Value (sej/unit)	Solar Emergy (sej/yr)	Reference for UEV
Wind Farm Transport*						
1	Diesel	6.39E+12	J	1.11E+05	7.09E+17	[1]
2	Oxygen	3.64E+08	g	5.16E+07	1.88E+16	[2]
3	Labor (not specialized)	6.94E-02	years	2.49E+16	1.73E+15	[3]
Construction*						
4	Steel	2.92E+06	g	5.31E+09	1.55E+16	[1]
5	Copper	2.12E+07	g	3.36E+09	7.11E+16	[1]
6	Glass Reinforced Epoxy	1.05E+08	g	1.50E+09	1.58E+17	[3]
7	Cement	5.00E+06	g	2.59E+09	1.30E+16	[1]
8	Diesel	1.94E+12	J	1.11E+05	2.15E+17	[1]
9	Oxygen	1.11E+08	g	5.16E+07	5.70E+15	[2]
10	Labor (not specialized)	3.48E+00	years	2.49E+16	8.67E+16	[3]
11	Labor (graduated)	3.48E+00	years	4.98E+16	1.73E+17	[3]
Wind Farm operation and Maintenance						
12	Diesel	5.04E+11	J	1.11E+05	2.48E+16	[1]
13	Oxygen	2.87E+07	g	5.16E+07	6.59E+14	[2]
14	Wind	6.38E+15	J	2.52E+03	1.61E+19	[1]
15	Labor (not specialized)	1.10E+00	years	2.49E+16	2.76E+16	[3]
Wind Farm Decommissioning*						
16	Diesel	1.91E+12	J	1.11E+05	2.12E+17	[1]
17	Oxygen	1.09E+08	g	5.16E+07	5.63E+15	[2]
18	Labor (not specialized)	3.48E+00	years	2.49E+16	8.67E+16	[3]
19	Labor (graduated)	3.48E+00	years	4.98E+16	1.73E+17	[3]
Total Inputs					**1.76E+19**	
Product						
20	**Electricity Produced**	**1.70E+15**	**J**	**1.03E+04**	**1.76E+19**	[4]

*Items have been normalized to an annual basis by dividing by 20 year wind farm lifetime

References for Unit Emergy Values

[1] Brown & Ulgiati 2004

[2] Brown & Ulgiati 2002

[3] Ulgiati & Brown 2002

[4] This work, final result of calculations

Table 4-6. Emergy accounting table for coal-fired steam turbine power unit based on the operational conditions of Plant Scherer.

#	Item	Amount	Units	Unit Emergy Value (sej/unit)	Solar Emergy (sej/yr)	Reference for UEV
Fuels Extraction						
1	Coal	7.91E+12	J	6.71E+04	5.30E+17	[1]
2	Diesel	2.44E+14	J	1.11E+05	2.71E+19	[1]
3	Electricity	1.00E+14	J	3.40E+05	3.40E+19	[1]
4	Natural Gas	4.54E+12	J	8.05E+04	3.65E+17	[1]
5	Residual Oil	2.62E+13	J	9.06E+04	2.37E+18	[1]
6	Oxygen	2.71E+10	g	5.16E+07	1.40E+18	[2]
Fuels Transport						
7	Diesel	1.86E+13	J	1.11E+05	2.07E+18	[1]
8	Oxygen	1.06E+09	g	5.16E+07	5.49E+16	[2]
9	Labor (not specialized)	1.23E+01	years	2.49E+16	3.07E+17	[3]
Power Unit Transport*						
10	Diesel	7.78E+11	J	1.11E+05	8.63E+16	[1]
11	Oxygen	4.44E+07	g	5.16E+07	2.29E+15	[2]
12	Labor (not specialized)	4.79E-03	years	2.49E+16	1.19E+14	[3]
Construction*						
13	Concrete	1.91E+09	g	3.48E+09	6.63E+18	[1]
14	Steel	6.09E+08	g	5.31E+09	3.23E+18	[1]
15	Iron	7.43E+06	g	2.50E+09	1.86E+16	[1]
16	Aluminum	5.03E+06	g	1.63E+10	8.20E+16	
17	Diesel	1.11E+12	J	1.11E+05	1.23E+17	[1]
18	Oxygen	6.35E+07	g	5.16E+07	3.28E+15	[2]
19	Labor (not specialized)	6.02E+00	years	2.49E+16	1.50E+17	[3]
20	Labor (graduated)	6.02E+00	years	4.98E+16	3.00E+17	[3]
Operation						
21	Coal	1.83E+16	J	6.71E+04	1.23E+21	[1]
22	Oxygen required	1.91E+12	g	5.16E+07	9.85E+19	[2]
Total Inputs					**1.41E+21**	
Product						
23	**Electricity produced**	**6.25E+15**	**J**	**2.25E+05**	**1.41E+21**	[4]

*Items have been normalized to an annual basis by dividing by 30 year power plant lifetime

References for Unit Emergy Values

[1] Brown & Ulgiati 2004
[2] Brown & Ulgiati 2002
[3] Ulgiati & Brown 2002
[4] This work, final result of calculations

Table 4-7. Emergy accounting table for coal-fired steam turbine power unit based on the operational conditions of St. Johns River Power Park.

#	Item	Amount	Units	Unit Emergy Value (sej/unit)	Solar Emergy (sej/yr)	Reference for UEV
Fuels Extraction						
1	Coal	2.21E+12	J	6.70E+04	1.48E+17	[1]
2	Diesel	6.92E+13	J	1.10E+05	7.62E+18	[1]
3	Electricity	4.26E+13	J	1.85E+05	7.88E+18	[1]
4	Natural Gas	4.00E+13	J	8.10E+04	3.24E+18	[1]
5	Residual Oil	2.97E+13	J	1.10E+05	3.27E+18	[1]
6	Oxygen	1.33E+10	g	5.16E+07	6.87E+17	[2]
Fuels Transport						
7	Diesel	1.77E+13	J	1.30E+05	2.30E+18	[1]
8	Oxygen	1.01E+09	g	5.16E+07	5.21E+16	[2]
9	Labor (not specialized)	6.16E+00	years	2.49E+16	1.53E+17	[3]
Power Unit Transport*						
10	Diesel	2.83E+12	J	1.30E+05	3.67E+17	[1]
11	Oxygen	4.44E+07	g	5.16E+07	2.29E+15	[2]
12	Labor (not specialized)	4.79E-03	years	2.49E+16	1.19E+14	[3]
Construction*						
13	Concrete	1.91E+09	g	5.08E+08	9.68E+17	[1]
14	Steel	6.09E+08	g	2.77E+09	1.69E+18	[1]
15	Iron	7.43E+06	g	2.77E+09	2.06E+16	[1]
16	Aluminum	5.03E+06	g	1.77E+10	8.90E+16	[1]
17	Diesel	3.06E+11	J	1.30E+05	3.97E+16	[1]
18	Oxygen	6.35E+07	g	5.16E+07	3.28E+15	[2]
19	Labor (not specialized)	6.02E+00	years	2.49E+16	1.50E+17	[3]
20	Labor (graduated)	6.02E+00	years	4.98E+16	3.00E+17	[3]
Operation						
21	Coal	5.12E+15	J	6.70E+04	3.43E+20	[1]
22	Petroleum Coke	1.07E+15	J	1.10E+05	1.18E+20	[1]
23	Distillate Oil	5.99E+13	J	1.30E+05	7.79E+18	[1]
24	Oxygen required	6.23E+11	g	5.16E+07	3.22E+19	[2]
25	Labor (not specialized)	0.00E+00	years	2.49E+16	0.00E+00	[3]
Total Inputs					**5.30E+20**	
Product						
26	**Electricity produced**	**6.82E+15**	**J**	**7.77E+04**	**5.30E+20**	[4]

*Items have been normalized to an annual basis by dividing by 30 year power plant lifetime

References for Unit Emergy Values

[1] Brown & Ulgiati 2004
[2] Brown & Ulgiati 2002
[3] Ulgiati & Brown 2002
[4] This work, final result of calculations

Table 4-8. Emergy accounting table for natural gas combined-cycle power generating unit.

#	Item	Amount	Units	Unit Emergy Value (sej/unit)	Solar Emergy (sej/yr)	Reference for UEV
Fuels Extraction						
1	Coal	0.00E+00	J	6.70E+04	0.00E+00	[1]
2	Diesel	1.84E+13	J	1.10E+05	2.03E+18	[1]
3	Electricity	7.67E+13	J	1.85E+05	1.42E+19	[1]
4	Natural Gas	9.32E+14	J	8.10E+04	7.55E+19	[1]
5	Residual Oil	1.26E+13	J	1.10E+05	1.39E+18	[1]
6	Oxygen	7.68E+10	g	5.16E+07	3.96E+18	[2]
Fuels Transport						
7	Natural Gas	5.64E+14	J	8.10E+04	4.57E+19	[1]
8	Oxygen	4.05E+10	g	5.16E+07	2.09E+18	[2]
9	Labor (not specialized)	0.00E+00	years	2.49E+16	0.00E+00	[3]
Power Unit Transport*						
10	Diesel	2.01E+12	J	1.10E+05	2.21E+17	[1]
11	Oxygen	1.15E+08	g	5.16E+07	5.92E+15	[2]
12	Labor (not specialized)	1.22E-02	years	2.49E+16	3.04E+14	[3]
Construction*						
13	Concrete	1.65E+09	g	5.08E+08	8.36E+17	[1]
14	Steel	5.22E+08	g	2.77E+09	1.45E+18	[1]
15	Iron	6.87E+06	g	2.77E+09	1.90E+16	[1]
16	Aluminum	3.43E+06	g	1.63E+10	5.60E+16	[1]
17	Diesel	2.00E+12	J	1.10E+05	2.20E+17	[1]
18	Oxygen	1.14E+08	g	5.16E+07	5.88E+15	[2]
19	Labor (not specialized)	1.95E+01	years	2.49E+16	4.86E+17	[3]
20	Labor (graduated)	1.95E+01	years	4.98E+16	9.71E+17	[3]
Operation						
21	Natural Gas	1.88E+16	J	8.10E+04	1.52E+21	[1]
22	Distillate Oil	6.41E+14	J	1.10E+05	7.05E+19	[1]
23	Oxygen required	1.39E+12	g	5.16E+07	7.16E+19	[2]
24	Labor (not specialized)	0.00E+00	years	2.49E+16	0.00E+00	[3]
Total Inputs					**1.81E+21**	
Product						
25	**Electricity produced**	**5.67E+15**	**J**	**3.20E+05**	**1.81E+21**	[4]

*Items have been normalized to an annual basis by dividing by 30 year power plant lifetime

References for Unit Emergy Values

[1] Brown & Ulgiati 2004

[2] Brown & Ulgiati 2002

[3] Ulgiati & Brown 2002

[4] This work, final result of calculations

Table 4-9. Summary of data and performance indicators for the four power systems.

	Summary of data	Wind Farm	Coal - Scherer	Coal - SJRPP	NGCC	Units
R	Renewable input	1.61E+19	9.99E+19	3.29E+19	7.76E+19	sej
N	Nonrenewable input, without services	0.00E+00	1.23E+21	4.69E+20	1.59E+21	sej
SN	Services and investments for fuel supply	0.00E+00	3.07E+17	1.53E+17	0.00E+00	sej
F	Purchased plant inputs other than fuel, without services	1.24E+18	7.66E+19	2.76E+19	1.46E+20	sej
SF	Labor in plant and services for plant manufacture	2.89E+17	4.50E+17	4.50E+17	1.46E+18	sej
Y	Yield (R+N+F), without services	1.73E+19	1.41E+21	5.29E+20	1.82E+21	sej
YS	Yield (R+N+SN+F+SF), with services	1.76E+19	1.41E+21	5.30E+20	1.82E+21	sej
	Indices					
	Solar Transformity without services, (R+N+F)/energy of output	1.02E+04	2.25E+05	7.76E+04	3.20E+05	sej/J
	Solar Transformity with services, (R+N+SN+F+SF)/energy of output	1.03E+04	2.25E+05	7.77E+04	3.21E+05	sej/J
EYR	Emergy Yield Ratio, EYR = (R+N+SN+F+SF)/(F+SF+SN)	11.6	18.2	18.8	12.4	
EIR	Emergy Investment Ratio, EIR = F/(R+N)	0.08	0.06	0.06	0.09	
ELR	Environmental Loading Ratio, ELR = (N+SN+F+SF)/R	0.1	13.1	15.1	22.4	
EIS	Emergy Index of Sustainability, EIS = EYR/ELR	121.9	1.4	1.2	0.6	
%R	Percent renewable, (R/YS)	91.3%	7.1%	6.2%	4.3%	

Note: SN represents services associated with nonrenewable inputs, e.g. labor required for fuels transport.
SF represents services associated with imported goods, e.g. services required for construction.

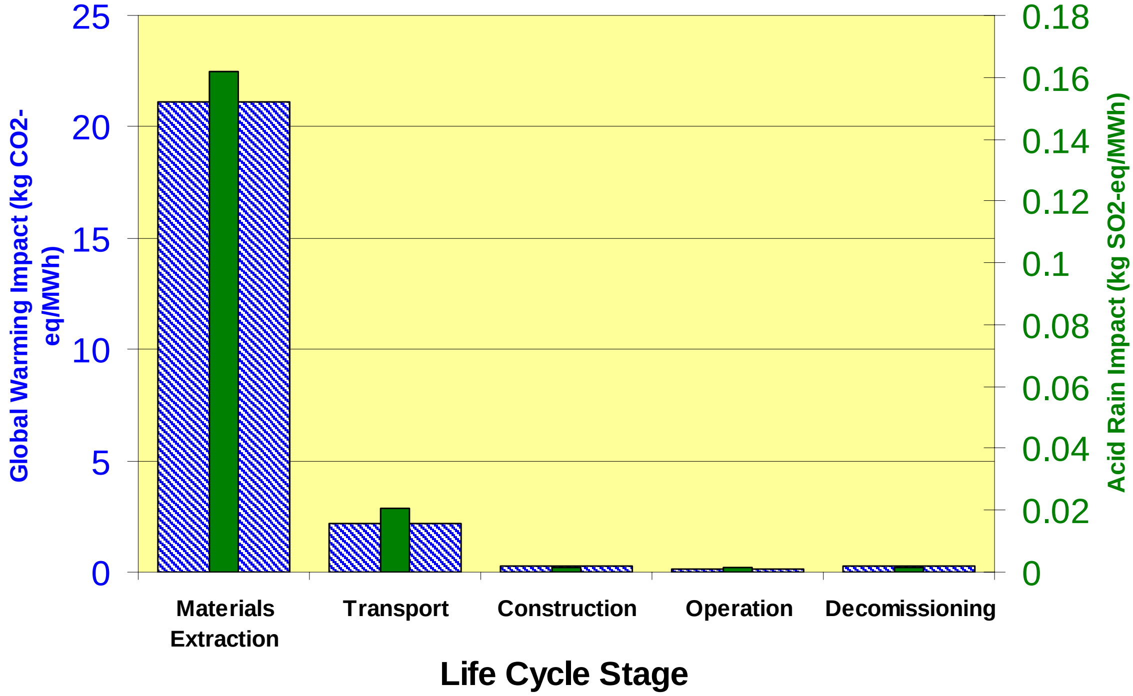

Figure 4-1. Global warming and acid rain impact potentials for the life cycle stages of the wind farm.

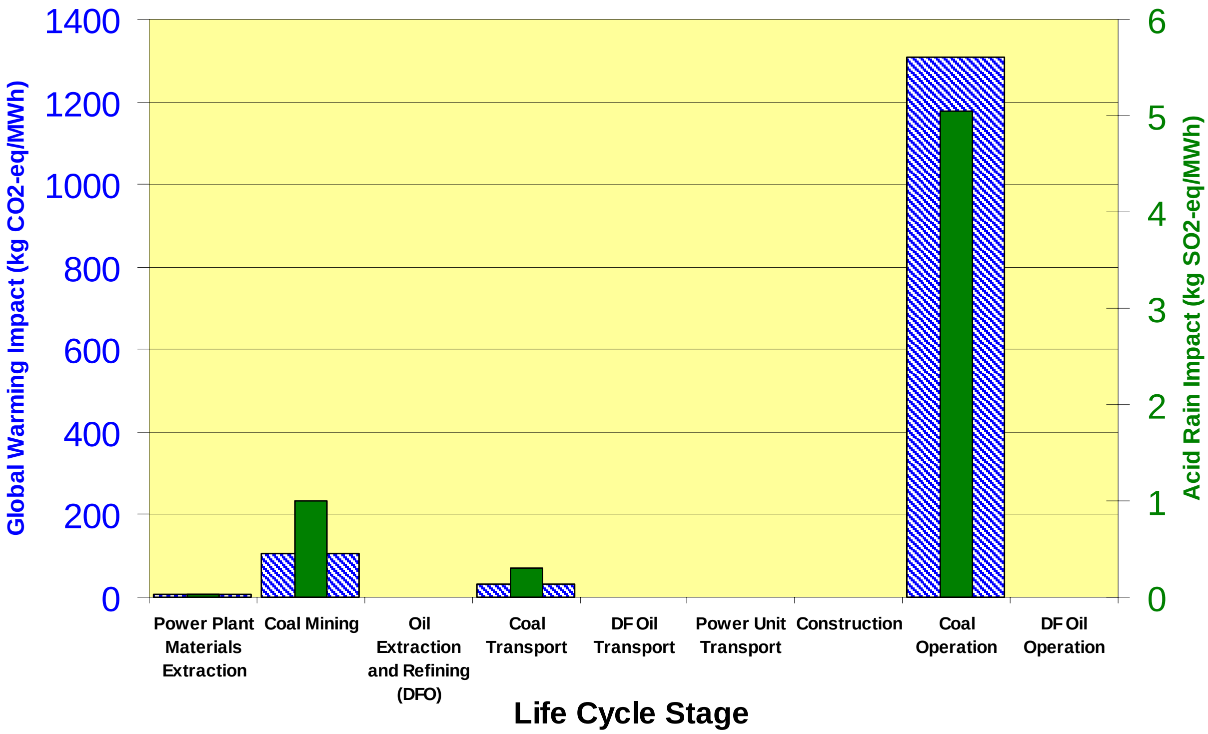

Figure 4-2. Global warming and acid rain impact potentials for the life cycle stages of the coal-fired steam turbine unit based on Plant Scherer.

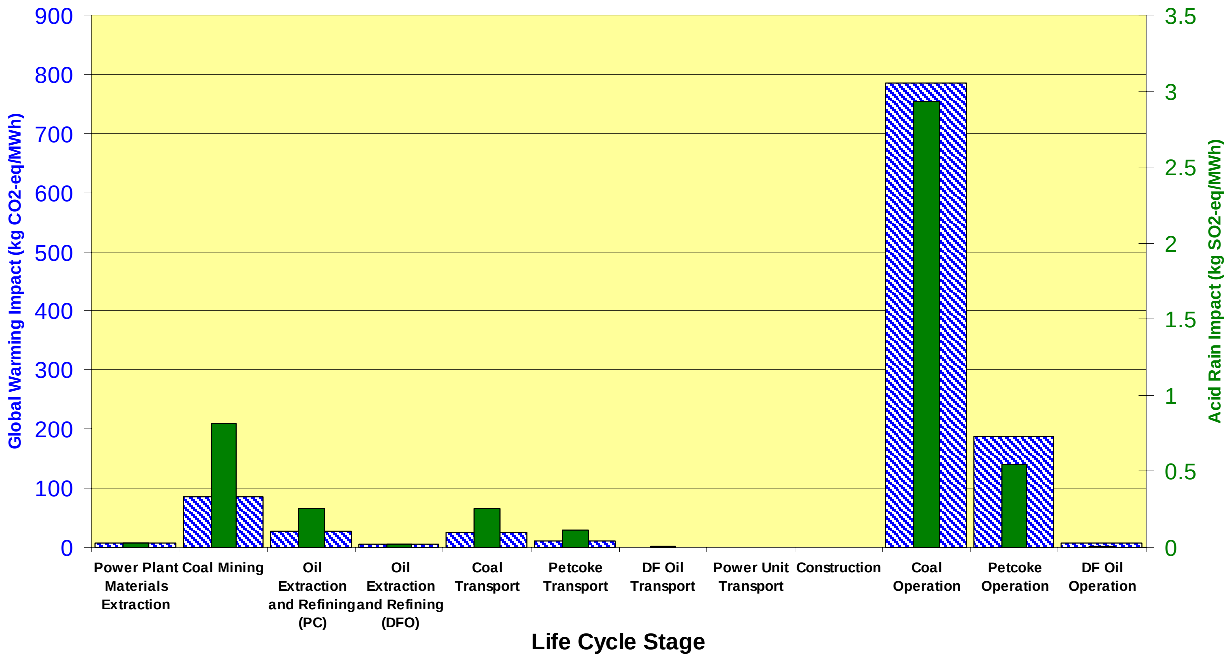

Figure 4-3. Global warming and acid rain impact potentials for the life cycle stages of the coal-fired steam turbine unit based on St. Johns River Power Park.

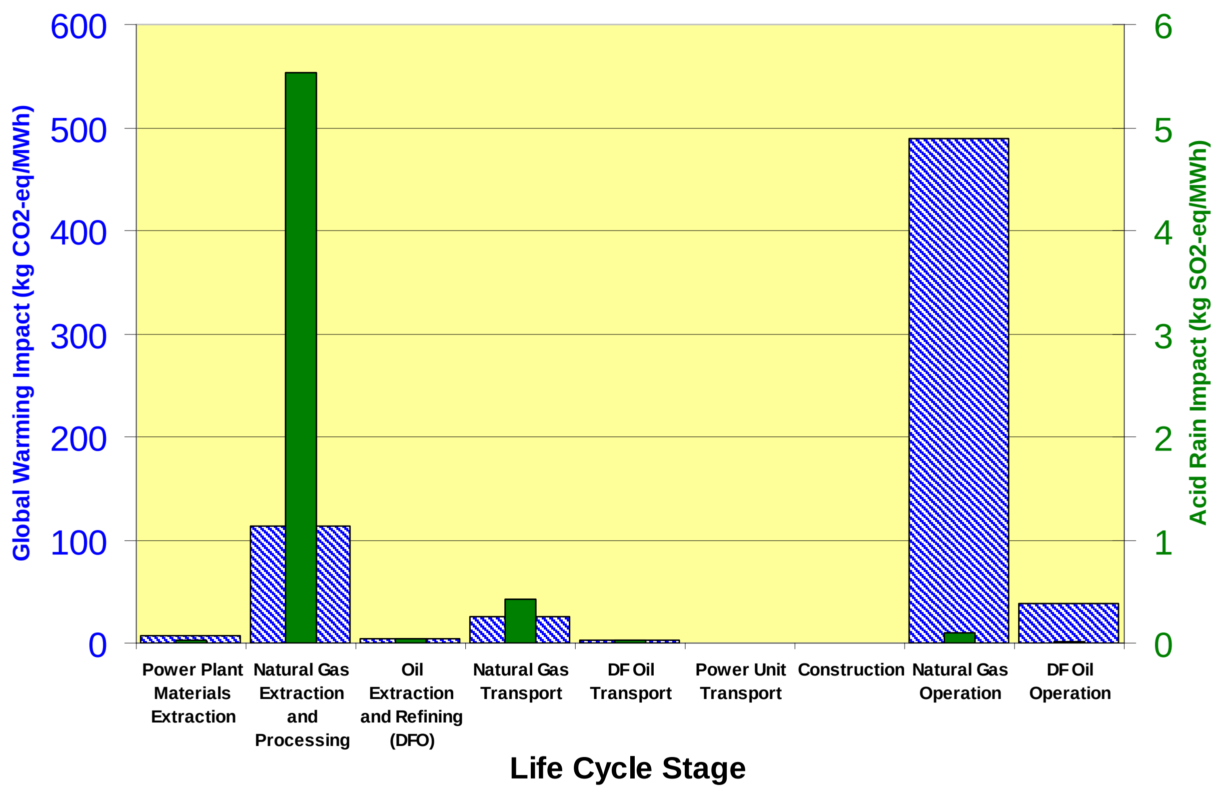

Figure 4-4. Global warming and acid rain impact potentials for the life cycle stages of the natural gas combined-cycle unit based on Brandy Branch.

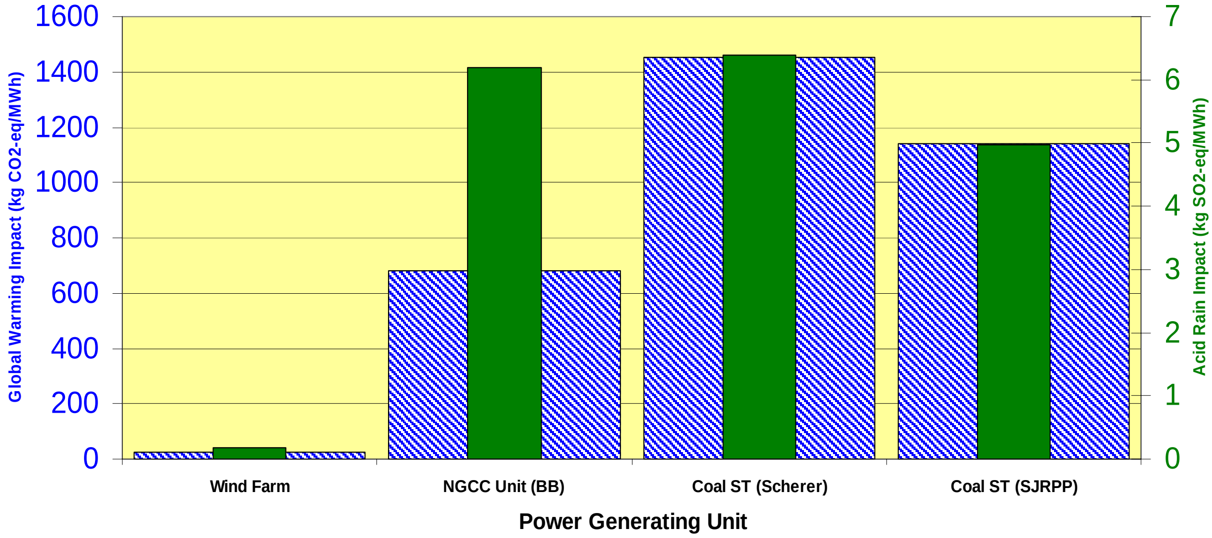

Figure 4-5. Side-by-side comparison of global warming and acid rain impacts over the complete life cycle for the four power generating systems.

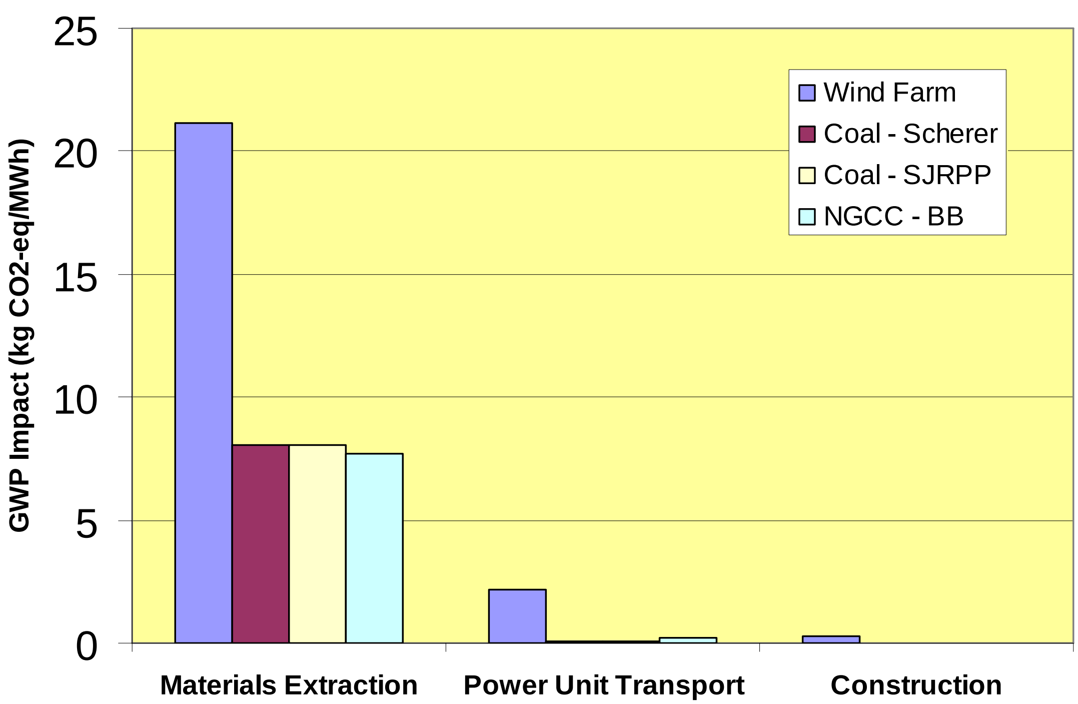

Figure 4-6. Comparison of global warming potential impact of life cycle stages that are common to all four power systems, neglecting the operation stage.

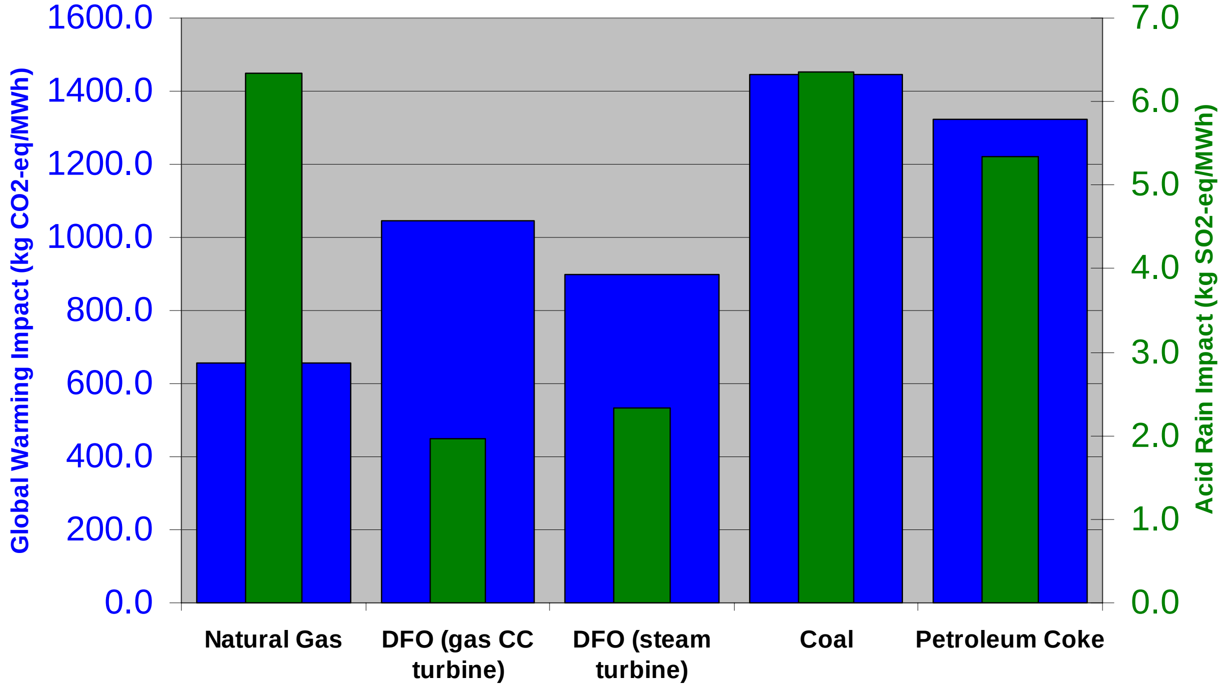

Figure 4-7. Global warming and acid rain impact potentials of the fuel cycles.

CHAPTER 5
SENSITIVITY ANALYSIS

A number of assumptions had to be made in order to perform the life cycle assessment and emergy synthesis. Therefore, a sensitivity analysis was performed in order to assess the extent to which the validity of these assumptions may have affected the results. For both the life cycle assessment and emergy synthesis several different scenarios were analyzed for each of the power systems.

5.1 Wind Farm

For the wind farm, Scenario 1 represents doubling the number of trips required for overseas transport from Aarhus, Denmark to Jacksonville, Florida from one trip to two by Panamax ocean bulker. This was chosen as a scenario because although the carrying capacity of the Panamax in deadweight tons was known, it could not be determined if the size constraints of the Panamax bulker would necessitate more than one trip to transport the turbines due to their large dimensions. This scenario results in a 30% increase in global warming impact potential for the power unit transportation stage of the life cycle. This, however, corresponds to a relatively small 2.7% increase in total global warming impact potential over the wind farm's life cycle. Scenario 1 for the wind farm was also analyzed for the emergy synthesis. This resulted in the emergy yield ratio decreasing by approximately 10%, the environmental loading ratio increasing by roughly 12%, and the emergy index of sustainability decreasing by 20%.

Scenario 2 for the wind farm is based on doubling the number of maintenance services from twice per year to four times per year. Although the assumption of the turbines requiring biannual service calls is based on primary data from Vestas, this scenario was chosen to account for any necessary unscheduled maintenance for repairs, should the turbines become damaged or stop functioning properly. Scenario 2 results in a 100% increase in global warming impact potential for the operational stage, which corresponds to a 0.7% increase in total impact potential over the complete life cycle. With regards to emergy accounting, Scenario 2 resulted in a 5% decrease in emergy yield ratio (EYR), a 5% increase in environmental loading ratio (ELR), and a 10% decrease in emergy index of sustainability (EIS). Both Scenario 1 and 2 for the life cycle assessment of the wind farm are shown in Table 5-1, while these two scenarios for the emergy synthesis are shown in Table 5-2.

Worth noting is that these scenarios have a larger effect on the emergy synthesis than the life cycle assessment, and this is a result of labor. The changes in global warming impacts for the life cycle assessment for these scenarios are a direct result of the changes in quantity of fuel combusted. In contrast, the emergy synthesis accounts for fuel and labor, so doubling the number of trips for transportation in Scenario 1 not only doubles fuel consumption but also labor requirements, which in turn affects all of the performance indicators since they are all a function of either fuels or labor or both.

5.2 Coal-Fired Unit

For the coal-fired steam turbine unit, only the unit based on Plant Scherer is presented, as the unit based on St. Johns River Power Park has the same results for the two scenarios chosen. Scenario 1 represents doubling the fuels and labor required for the construction stage. This was chosen as a scenario because these values were calculated based on rough estimates made by Sargent & Lundy engineers, since data for this stage could not be found in the literature. In terms of changes in environmental impact potentials for the LCA, this results in a negligible 0.00002% increase over the complete life cycle of the power unit. With regard to the emergy synthesis, the EYR and the EIS decreased by less than 1%, and the ELR increased by less than 1%.

Scenario 2 represents doubling the number of required locomotives and flatbed cars for power unit transport. This scenario was chosen because the number of flatbed cars required for transport was based solely on the 230-ton carrying capacity of the flatbeds, and not size constraints. Although the size constraints of the flatbed cars themselves were known (89 feet), the dimensions of the steam turbine parts were not known. Scenario 2 results in a 0.002% increase in global warming impact potential over the life cycle. The effects of Scenario 2 were also negligible with regard to the emergy synthesis. The emergy yield ratio decreased by 0.05%, the environmental loading ratio increased by 0.002%, and the emergy index of sustainability decreased by 0.1%. Table 5-3 gives the sensitivity analysis for the LCA for the coal-fired power unit and Table 5-4 gives its emergy synthesis sensitivity analysis.

5.3 Natural Gas Combined-Cycle Unit

The sensitivity analysis scenarios for the NGCC unit were chosen to be the same as Scenario 1 and 2 for the coal-fired steam turbine unit, since these same stages were the ones based largely on assumptions and estimations. Table 5-5 gives the LCA sensitivity results for the NGCC unit, and Table 5-6 gives the emergy synthesis sensitivity analysis. Results were similar to that of the coal-fired unit, i.e. percent changes resulting from the two scenarios were found to be negligible. The global warming impact potentials changed by less than 1% for both scenarios. The EYR and EIS both decreased by approximately 1%, while the ELR increased by less than 1% for Scenario 1. For Scenario 2, the EYR and EIS decreased by less than 1% and the ELR increased by less than 1%.

In conclusion, it was found that the assumptions did not weigh heavily on the results, especially for the fossil fuel-fired plants. The wind farm was found to be more sensitive to assumptions made, however, not to an unreasonable extent. The largest change in LCA results was found for Scenario 1 for the wind farm, increasing its impact potential by 2.7%. The largest change in emergy synthesis results was also found in Scenario 1 for the wind farm, i.e. a 19.6% reduction in the emergy index of sustainability. For all scenarios, the general trends in the results remain.

Table 5-1. Sensitivity analysis for the LCA of the wind farm.

	Base Case	Scenario 1	% Change	Scenario 2	% Change
Materials Extraction	21.1	21.1		21.1	
Fuels Extraction & Processing	-	-		-	
Power Unit Transport	2.2	2.8	29.5%	2.2	
Fuels Transport	N/A	N/A		N/A	
Construction	0.3	0.3		0.3	
Operation	0.2	0.2		0.3	100.0%
Decommissioning	0.3	0.3		0.3	
Total (kg CO2-eq/MWh)	24.0	24.3	2.7%	24.2	0.7%

Table 5-2. Sensitivity analysis for the emergy synthesis of the wind farm.

	Summary of data	Base Case	Scenario 1	% Change	Scenario 2	% Change
R	Renewable input	1.61E+19	1.61E+19	0.0%	1.61E+19	0.0%
N	Nonrenewable input, without services	0.00E+00	0.00E+00	0.0%	0	0.0%
SN	Services and investments for fuel supply	0.00E+00	0.00E+00	0.0%	0	0.0%
F	Purchased plant inputs other than fuel, without services	1.24E+18	1.42E+18	14.8%	1.293E+18	4.5%
SF	Labor in plant and services for plant manufacture	2.89E+17	2.91E+17	0.6%	3.162E+17	9.4%
Y	Yield (R+N+F), without services	1.73E+19	1.75E+19	1.1%	1.74E+19	0.3%
YS	Yield (R+N+SN+F+SF), with services	1.76E+19	1.78E+19	1.1%	1.771E+19	0.5%

	Indices					
	Solar Transformity without services, (R+N+F)/energy of output	1.02E+04	1.03E+04	1.1%	1.02E+04	0.3%
	Solar Transformity with services, (R+N+SN+F+SF)/energy of output	1.03E+04	1.05E+04	1.1%	1.04E+04	0.5%
EYR	Emergy Yield Ratio, EYR = (R+N+SN+F+SF)/(F+SF+SN)	11.6	10.4	-9.8%	11.0	-4.7%
EIR	Emergy Investment Ratio, EIR = F/(R+N)	0.08	0.1	14.8%	0.1	4.5%
ELR	Environmental Loading Ratio, ELR = (N+SN+F+SF)/R	0.1	0.1	12.1%	0.1	5.4%
EIS	Emergy Index of Sustainability, EIS = EYR/ELR	121.9	98.1	-19.6%	110.2	-9.6%
%R	Percent renewable, (R/YS)	91.3%	90.4%	-1.0%	90.9%	-0.5%

Table 5-3. Sensitivity analysis for the LCA of the coal-fired plant based on Scherer.

	Base Case	Scenario 1	% Change	Scenario 2	% Change
Materials Extraction	8.1	8.1		8.1	
Fuels Extraction & Processing	105.0	105.0		105.0	
Power Unit Transport	0.1	0.1		0.1	47.3%
Fuels Transport	31.6	31.6		31.6	
Construction	3.1E-04	6.1E-04	100%	3.1E-04	
Operation	1307.7	1307.7		1307.7	
Decommissioning	-	-		-	
Total (kg CO2-eq/MWh)	1452.4	1452.4	0.00002%	1452.5	0.002%

Table 5-4. Sensitivity analysis for the emergy synthesis of coal-fired plant based on Scherer.

	Summary of data	Base Case	Scenario 1	% Change	Scenario 2	% Change
R	Renewable input	9.99E+19	9.99E+19	0.0%	9.994E+19	0.0%
N	Nonrenewable input, without services	1.23E+21	1.23E+21	0.0%	1.231E+21	0.0%
SN	Services and investments for fuel supply	3.07E+17	3.07E+17	0.0%	3.068E+17	0.0%
F	Purchased plant inputs other than fuel, without services	7.66E+19	7.67E+19	0.2%	7.661E+19	0.1%
SF	Labor in plant and services for plant manufacture	4.50E+17	9.00E+17	100.0%	4.499E+17	0.0%
Y	Yield (R+N+F), without services	1.41E+21	1.41E+21	0.0%	1.407E+21	0.0%
YS	Yield (R+N+SN+F+SF), with services	1.41E+21	1.41E+21	0.0%	1.408E+21	0.0%
	Indices					
	Solar Transformity without services, (R+N+F)/energy of output	2.25E+05	2.25E+05	0.0%	2.25E+05	0.0%
	Solar Transformity with services, (R+N+SN+F+SF)/energy of output	2.25E+05	2.25E+05	0.0%	2.25E+05	0.0%
EYR	Emergy Yield Ratio, EYR = (R+N+SN+F+SF)/(F+SF+SN)	18.2	18.1	-0.7%	18.2	-0.05%
EIR	Emergy Investment Ratio, EIR = F/(R+N)	0.06	0.1	0.2%	0.1	0.1%
ELR	Environmental Loading Ratio, ELR = (N+SN+F+SF)/R	13.1	13.1	0.04%	13.1	0.002%
EIS	Emergy Index of Sustainability, EIS = EYR/ELR	1.4	1.4	-0.7%	1.4	-0.1%
%R	Percent renewable, (R/YS)	7.1%	7.1%	0.0%	7.1%	0.0%

Table 5-5. Sensitivity analysis for the LCA of the natural gas combined-cycle plant.

	Base Case	Scenario 1	% Change	Scenario 2	% Change
Materials Extraction	7.7	7.7		7.7	
Fuels Extraction & Processing	113.6	113.6		113.6	
Power Unit Transport	0.2	0.2		0.3	47.2%
Fuels Transport	28.2	28.2		28.2	
Construction	6.0E-04	1.2E-03	100%	6.0E-04	
Operation	527.3	527.3		527.3	
Decommissioning	-	-		-	
Total (kg CO2-eq/MWh)	677.0	677.0	0.0001%	677.1	0.014%

Table 5-6. Sensitivity analysis for emergy synthesis of the natural gas combined-cycle plant.

	Summary of data	Base Case	Scenario 1	% Change	Scenario 2	% Change
R	Renewable input	7.76E+19	7.76E+19	0.0%	7.764E+19	0.0%
N	Nonrenewable input, without services	1.59E+21	1.59E+21	0.0%	1.593E+21	0.0%
SN	Services and investments for fuel supply	0.00E+00	0.00E+00	0.0%	0	0.0%
F	Purchased plant inputs other than fuel, without services	1.46E+20	1.46E+20	0.2%	1.456E+20	0.1%
SF	Labor in plant and services for plant manufacture	1.46E+18	2.91E+18	100.0%	1.457E+18	0.0%
Y	Yield (R+N+F), without services	1.82E+21	1.82E+21	0.0%	1.816E+21	0.0%
YS	Yield (R+N+SN+F+SF), with services	1.82E+21	1.82E+21	0.1%	1.818E+21	0.0%
	Indices					
	Solar Transformity without services, (R+N+F)/energy of output	3.20E+05	3.20E+05	0.0%	3.20E+05	0.0%
	Solar Transformity with services, (R+N+SN+F+SF)/energy of output	3.21E+05	3.21E+05	0.1%	3.21E+05	0.0%
EYR	Emergy Yield Ratio, EYR = (R+N+SN+F+SF)/(F+SF+SN)	12.4	12.2	-1.0%	12.4	-0.1%
EIR	Emergy Investment Ratio, EIR = F/(R+N)	0.09	0.1	0.2%	0.1	0.1%
ELR	Environmental Loading Ratio, ELR = (N+SN+F+SF)/R	22.4	22.4	0.1%	22.4	0.002%
EIS	Emergy Index of Sustainability, EIS = EYR/ELR	0.6	0.5	-1.1%	0.6	-0.1%
%R	Percent renewable, (R/YS)	4.3%	4.3%	-0.1%	4.3%	0.0%

CHAPTER 6
CONCLUSIONS

This research examined the differences in environmental impacts of an offshore wind farm, a coal-fired steam turbine, and a natural gas combined-cycle unit for the city of Jacksonville, Florida. Life cycle assessment and emergy synthesis were the methodologies implemented for this analysis. The coal-fired steam turbine unit was analyzed as operating in two different scenarios, one running purely on coal and one fueled by a mix of coal, petroleum coke, and distillate fuel oil.

Both the life cycle assessment and emergy synthesis determined the wind farm to be the favorable power system with respect to the environmental impacts examined and degree of environmental loading. Further, the emergy synthesis determined the wind farm to have a higher measure of sustainability, due to its low level of required non-renewable inputs.

Because of the potential savings in global warming and acid rain impacts from employing the theoretical 180 MW wind farm compared to any of the three fossil fuel-fired power systems modeled, it is recommended that further studies be conducted on the feasibility of an offshore wind farm for Jacksonville, Florida. These future studies might include a more detailed life cycle assessment that considers additional impacts, such as smog formation, land consumption, ecotoxicity, and visual and auditory impacts. Additional studies that would be necessary for the wind farm include a cost analysis, and more in-depth potential power production and feasibility studies.

The operational stages of the analyses were modeled to represent three different power plants currently in operation by Jacksonville Electric Authority: Plant Scherer, St. Johns River Power Park, and Brandy Branch. Of these, Plant Scherer is the unit with the highest combination of global warming and acid rain impacts. It is therefore recommended that if JEA were to replace any of the three units modeled in this analysis with such a wind farm, Scherer would be the best candidate, with regards to these environmental impacts. St. Johns River Power Park has the second largest global warming impact; however, Brandy Branch has the second largest acid rain impact. Therefore, if one of these systems were to be identified as having better environmental performance than the other, a valuation system of the two environmental impacts would have to be implemented.

The wind farm was shown to have an emergy yield ratio comparable to those of the other power systems. However, its low environmental loading ratio, along with its high emergy index of sustainability and percent renewable identify the wind farm as the optimal choice, of the four systems modeled, for a power system that will produce the lowest level of environmental stress.

This research demonstrates the benefits of both the life cycle assessment and emergy synthesis approaches to evaluating power production systems. For example, the acid rain impact for the natural gas-fired system was mainly determined by the natural gas extraction stage of the life cycle. If only the operational stage of the life cycle were considered, the SO_X and NO_X emissions would have been lower by more than one order of magnitude. Emergy synthesis provides measures of sustainability and environmental loading, which other types of energy analyses do not. These performance indicators serve as a means for systematically quantifying the relationship between the power generation systems and the biosphere.

The results of this study demonstrate that offshore wind power is a more environmentally sound power production system with regard to global warming and acid rain when compared to a purely coal-fired, mix of coal, petroleum coke, and distillate fuel oil-fired, or natural gas-fired conventional power plant. Offshore wind may be a way for the United States to help meet its electricity demands while reducing its carbon dioxide, methane, nitrous oxide, sulfur oxides and nitrogen oxides emissions from the utility sector. As offshore wind farm technology continues to advance in Europe with increasing installations every year, it is important for the state of Florida, and other states that have insufficient onshore wind speeds, not to disregard wind power as a viable option for future electricity production systems.

APPENDIX A
LIST OF ASSUMPTIONS CATEGORIZED BY LIFE CYCLE STAGE

Life Cycle Stage	Assumptions
Wind Farm Raw Materials Extraction and Manufacture	Generator weight was scaled-up from Vestas 225 kW turbine data
	Only bulk construction materials considered
	Generator composition is 50% copper, 50% steel
	Coupling piece is made from Portland cement
Wind Turbine Transport	Shipped through Aarhus, Denmark and received through Jacksonville Port, FL
	One trip required by ocean freighter, based on weight
	Each locomotive can tow 100 flatbed cars
Wind Farm Construction	Barge can transport 4 turbines or 4 foundations/trip
	Pile driver's fuel efficiency is same as large crane's
Wind Farm Operation	Biannual service calls are carried out by 30-ton boat
Wind Farm Decommissioning	Monopile foundations are cut off at sea bed and portion under ocean floor is not removed
Fossil Fuel-Based Power Plant Raw Materials Extraction	Only bulk construction materials considered, as well as extraction of fuels required for operation stage
	JEA only uses bituminous coal
Power Plant Transport	Coal-fired unit shipped from Charlotte, NC
	NGCC unit shipped from Hamilton, Ontario, Canada
Power Plant Construction	Data from 800 MW coal and 500 MW NGCC were scaled to proper size based on capacity
Power Plant Operation	Emissions and fuel consumption based on JEA's current operating conditions of similar units (Scherer, SJRPP, BB)
	Both units operate at 60% capacity factor
	Emergy flow of cooling water required was not considered
Fuels Transport	Coal arrives 75% by rail, 600 mi; 25% by ship, 2165 mi
	Fuel oil and pet-coke arrive by ship, 3150 mi
	Natural gas arrives by pipeline
Multiple Stages	Emergy flows of equipment required for construction, transportation, extraction, etc. were not considered
	Labor for all stages was estimated based on equipment required, distance traveled, typical 8 h work days, etc.

APPENDIX B
LIST OF NREL LCI DATABASE MODULES USED

Fuels Extraction	
Coal	Bituminous Coal Production
Distillate Fuel Oil	Crude Oil Extraction
	Petroleum Refining
Residual Fuel Oil	Crude Oil Extraction
	Petroleum Refining
Petroleum Coke	Crude Oil Extraction
	Petroleum Refining
Natural Gas	Natural Gas Extraction and Processing
	Fuels and Energy Precombustion
Upstream Energy Inputs	
Coal	Bituminous Combustion in Industrial Boilers
Distillate Fuel Oil	Distillate Oil Combustion in Industrial Boilers
Gasoline	Gasoline Combustion in Industrial Equipment
Natural Gas	Natural Gas Combustion in Industrial Equipment
Residual Gas	Residual Gas Combustion in Industrial Boilers
LPG	LPG Combustion in Industrial Boilers
Transportation	
Rail	Diesel Fueled Locomotive Transport
Ocean Freighter	Diesel Fueled Ocean Freighter
Truck	Diesel Fueled Combination Truck

APPENDIX C
UPSTREAM ELECTRICITY CALCULATIONS

Values for these calculations are based on U.S. Department of Energy, Energy Information Administration 2004 data (EIA 2004).

$$\frac{kgCO2}{MWhElectricity} = \frac{2{,}456{,}934{,}000 MetricTonsCO2}{3{,}970{,}555{,}000 MWhElectricity} * \frac{1000kg}{1MetricTon} = 618.79\frac{kgCO2}{MWhElectricity}$$

$$\frac{kgSO2}{MWhElectricity} = \frac{10{,}309{,}000 MetricTonsSO2}{3{,}970{,}555{,}000 MWhElectricity} * \frac{1000kg}{1MetricTon} = 2.596\frac{kgSO2}{MWhElectricity}$$

$$\frac{kgNOx}{MWhElectricity} = \frac{4{,}143{,}000 MetricTonsNOx}{3{,}970{,}555{,}000 MWhElectricity} * \frac{1000kg}{1MetricTon} = 1.022\frac{kgNOx}{MWhElectricity}$$

$$\frac{kgN2O}{MWhElectricity} = \frac{30{,}000 MetricTonsN2O}{3{,}970{,}555{,}000 MWhElectricity} * \frac{1000kg}{1MetricTon} = 0.0076\frac{kgN2O}{MWhElectricity}$$

$$\frac{kgCH4}{MWhElectricity} = \frac{13{,}000 MetricTonsCH4}{3{,}970{,}555{,}000 MWhElectricity} * \frac{1000kg}{1MetricTon} = 0.0033\frac{kgCH4}{MWhElectricity}$$

APPENDIX D
SAMPLE CALCULATION OF EMISSIONS USING NREL LCI DATABASE

The sample calculation below is to calculate CO_2 emissions produced by the gasoline used in the extraction of the amount of coal necessary to produce 1MWh of JEA electricity. This example utilizes the NREL LCI Database's Bituminous Coal Production and Gasoline Combustion in Industrial Equipment modules. The emission data given (in the latter module) had the unit of lbs CO_2 emitted per 1,000 gallons of gasoline. This was then multiplied by the quantity of gasoline used per 1000 lbs of coal extracted (ratio from the former module). This was then multiplied by the kg of coal needed to produce 1 MWh of JEA electricity (ratio from JEA primary data). A unit conversion was then carried out to get kilograms of emission per MWh of JEA electricity produced by coal. This process is depicted numerically as:

$$\frac{17{,}400 lbCO_2}{1{,}000 galGasoline} \times \frac{0.1 galGasoline}{1{,}000 lbCoalMined} \times \frac{129.9 kgCoalMined}{1 MWhJEAElectricityFromCoal} \times \frac{2.2 lbCoalMined}{kgCoalMined} \times \frac{1 kgCO_2}{2.205 lbCO_2}$$
$$= 0.226 kgCO_2 / MWhJEAelectricityFromCoal$$

APPENDIX E
SAMPLE ALLOCATION CALCULATIONS FOR PETROLEUM PRODUCTS FROM CRUDE OIL

The following calculations demonstrate the allocation method applied to the three petroleum co-products utilized at JEA: residual fuel oil, distillate fuel oil, and petroleum coke. The calculation allocates a portion of the inputs and outputs from the crude oil extraction process and petroleum refining process to residual fuel oil and converts it into the functional unit form. This specific allocation directly relates the amount of distillate fuel oil required to extract crude oil to produce one MWh of electricity at JEA from residual fuel oil.

All data for the extraction and refining stages is from the NREL LCI Databases, Crude Oil Extraction, and Petroleum Refining modules. The following statements set up the calculations and are obtained from the above sources: 1) there are 0.155 gal of distillate fuel oil used in the extraction of 1,000 lbs of crude oil; 2) for every 1,030 lbs of crude oil sent to the refinery, 49 lbs of residual fuel oil are eventually produced; 3) however, the mass conversion is 1 lb of crude oil for 1 lb of residual fuel oil, as the remaining mass of crude oil is converted into other petroleum products; 4) the average MWh produced on site at JEA per lb of residual fuel oil is 0.0057; 5) upstream emission factors for the distillate oil is assumed to be as follows.

Module: Distillate Oil Combustion in Industrial Boilers - NREL LCI Database.
Values are given in lb/1000 gal DFO

CO_2	CH_4	NOx	N_2O	SO_2
2.28E+04	5.09E-02	2.40E+01	1.10E-01	5.00E+00

The calculation for kilograms of CO_2 produced at JEA due to the extraction process of crude oil per MWh created by residual fuel oil proceeds as follows:

$$\frac{kgCO_2}{MWh} = \left(\frac{0.155\ lbsDistillateFuelOil}{1000\ lbsCrudeOilExtracted}\right) * \left(\frac{1lbCrudeOil}{1lb\ ResidualFuelOil}\right) * \left(\frac{lb\ ResidualFuelOil}{0.0057\ MWh}\right) * \left(\frac{2.28E4lbCO_2}{1000\ lbsDistillateFuelOil}\right) * \left(\frac{kg}{2.2lb}\right)$$

The calculation is repeated for the remaining four emissions.

$$\frac{kgCH_4}{MWh}=\left(\frac{0.155lbsDistillateFuelOil}{1000lbsCrudeOilExtracted}\right)*\left(\frac{1lbCrudeOil}{1lb\,ResidualFuelOil}\right)*\left(\frac{lb\,ResidualFuelOil}{0.0057MWh}\right)*\left(\frac{5.09E-2lbCH_4}{1000lbsDistillateFuelOil}\right)*\left(\frac{kg}{2.2lb}\right)$$

$$\frac{kgNO_x}{MWh}=\left(\frac{0.155lbsDistillateFuelOil}{1000lbsCrudeOilExtracted}\right)*\left(\frac{1lbCrudeOil}{1lb\,ResidualFuelOil}\right)*\left(\frac{lb\,ResidualFuelOil}{0.0057MWh}\right)*\left(\frac{24lbNO_x}{1000lbsDistillateFuelOil}\right)*\left(\frac{kg}{2.2lb}\right)$$

$$\frac{kgN_2O}{MWh}=\left(\frac{0.155lbsDistillateFuelOil}{1000lbsCrudeOilExtracted}\right)*\left(\frac{1000lbCrudeOil}{1lb\,ResidualFuelOil}\right)*\left(\frac{lb\,ResidualFuelOil}{0.0057MWh}\right)*\left(\frac{0.11lbN_2O}{1000lbsDistillateFuelOil}\right)*\left(\frac{kg}{2.2lb}\right)$$

$$\frac{kgSO_2}{MWh}=\left(\frac{0.155lbsDistillateFuelOil}{1000lbsCrudeOilExtracted}\right)*\left(\frac{1lbCrudeOil}{1lb\,ResidualFuelOil}\right)*\left(\frac{lb\,ResidualFuelOil}{0.0057MWh}\right)*\left(\frac{5lbSO_2}{1000lbsDistillateFuelOil}\right)*\left(\frac{kg}{2.2lb}\right)$$

The allocation process for the distillate fuel oil input is then completed similarly for residual fuel oil and petroleum coke. All the other inputs and outputs are completed and the totals of each stressor summed for each co-product. This will provide, for instance, the total amount of CO_2 emitted during the extraction stage for the production of 1 MWh of JEA's electricity from residual fuel oil.

This allocation process would then be completed for the refining stage. These two stages, combined with the combustion stage, provide the total stressors emitted for the production of 1 MWh from distillate fuel oil through its entire life cycle.

APPENDIX F
SAMPLE BACK-CALCULATION FOR SO_X AND NO_X BY FUEL TYPE, SCALED TO MATCH PRIMARY DATA

In order to trace the SO_X and NO_X emissions data for each power generating unit obtained from JEA back to the fuel type, allocation was used. The EPA AP 42 Volume 1, Fifth Edition emission factors were found for SO_X and NO_X based on fuel type, sulfur content, and combustion unit type. The following assumptions had to be made regarding the combustion unit type: 1) For natural gas, lean pre-mix combustion was assumed. Sulfur content was unknown, so the unknown sulfur content emission factor provided by the AP 42 document was used. 2) For distillate oil (No. 2), boiler operating at greater than 100 MMBtu/hr was assumed. Sulfur content was assumed to be 0.036% as suggested by AP 42 document if sulfur content is unknown. 3) For residual oil (No. 6), boiler operating at greater than 100 MMBtu/hr was assumed. Sulfur content was assumed to be 3.5%. 4) For coal, PC, dry bottom, wall-fired, bituminous, NSPS boiler was assumed. Sulfur content was assumed to be 4% (Spath et al. 1999). 5) For pet-coke, anthracite coal emission factors were used (WEC 2006). Sulfur content was assumed to be 3.5%.

Below is a sample calculation of back-calculating the SO_X emission in kg/MWh for natural gas in Northside 1, a unit that burns gas, coal, and pet-coke, from the given emission for the unit (supplied by JEA). EF stands for emission factor.

$$\frac{kgSOx}{MWh} = \left(\frac{\text{primary data emission}}{gasEF * gasfractionofMWh + \text{coalEF} * \text{coalfractionofMWH} + \text{petcokeEF} * \text{petcokefractionofMWh}} \right) * gasEF$$

Substituting values into the equation gives:

$$\frac{0.0004kgSOx}{MWh} = \left(\frac{0.5668 \text{ kg SO}x}{0.005kg / MWhgas * 0.0031 + 10.7\text{kg/MWhcoal} * 0.23 + 7.5\text{kg/MWhpet - coke} * 0.77} \right) * \left(0.005kg / MWhgas\right)$$

This procedure was then repeated for each fuel combusted in the unit.

APPENDIX G
WIND SPEED RAW DATA AND CALCULATIONS

Average wind speed (knots) - Raw data from NOAA's NDBC

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANN
1988	-	-	7.5	9.2	9	9.2	9.8	9	11	11.4	11	9.5	9.8
1989	9.8	10.6	10.1	10	9.4	9.3	8.8	8.6	10.7	11.3	7.1	11.9	9.9
1990	7.6	9.8	8.1	8.8	9.7	8.6	9.8	7.5	9.1	11.4	9.9	9.4	9.2
1991	10.8	9.7	11.2	8.3	9.2	9.9	9.6	8.7	10.8	10.9	10.7	10.5	10
1992	10.9	9.2	9	8.7	-	-	-	-	-	-	-	-	9.5
1997	-	-	-	-	11.9	11.3	10.4	11.1	10.9	12.2	11.9	12.8	11.6
1998	11.1	12.7	11.5	11.8	9.4	10.4	12.2	10.7	11.4	11.4	9.7	11	11.1
1999	9.2	9.9	11.3	11.4	10.8	11.7	9.6	11.8	13.3	12.6	11.3	11.9	11.2
2000	12.2	9.8	10.6	11.8	11.5	11.4	10.8	10.6	13.4	11.4	11.1	13.5	11.5
2001	11.5	8.9	13.2	9.7	10.2	10.7	11.5	10	11.5	13	11.2	10.6	11
AVG	10.4	10.1	10.3	10.0	10.1	10.3	10.3	9.8	11.3	11.7	10.4	11.2	10.5

Average wind speed converted to m/s and with years that have missing data deleted

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANN
1989	5.04	5.45	5.20	5.14	4.84	4.78	4.53	4.42	5.50	5.81	3.65	6.12	5.09
1990	3.91	5.04	4.17	4.53	4.99	4.42	5.04	3.86	4.68	5.86	5.09	4.84	4.73
1991	5.56	4.99	5.76	4.27	4.73	5.09	4.94	4.48	5.56	5.61	5.50	5.40	5.14
1998	5.71	6.53	5.92	6.07	4.84	5.35	6.28	5.50	5.86	5.86	4.99	5.66	5.71
1999	4.73	5.09	5.81	5.86	5.56	6.02	4.94	6.07	6.84	6.48	5.81	6.12	5.76
2000	6.28	5.04	5.45	6.07	5.92	5.86	5.56	5.45	6.89	5.86	5.71	6.94	5.92
2001	5.92	4.58	6.79	4.99	5.25	5.50	5.92	5.14	5.92	6.69	5.76	5.45	5.66
AVG	5.31	5.25	5.59	5.28	5.16	5.29	5.31	4.99	5.89	6.03	5.22	5.79	5.43

Average wind speed converted to 78 m hub height velocities in m/s using log law with anemometer height=5 m above sea level, z0=0.35 mm (surface roughness for open sea)

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANN
1989	6.49	7.02	6.69	6.62	6.22	6.16	5.83	5.69	7.09	7.48	4.70	7.88	6.49
1990	5.03	6.49	5.36	5.83	6.42	5.69	6.49	4.97	6.03	7.55	6.56	6.22	6.05
1991	7.15	6.42	7.42	5.50	6.09	6.56	6.36	5.76	7.15	7.22	7.09	6.95	6.64
1998	7.35	8.41	7.61	7.81	6.22	6.89	8.08	7.09	7.55	7.55	6.42	7.28	7.36
1999	6.09	6.56	7.48	7.55	7.15	7.75	6.36	7.81	8.81	8.34	7.48	7.88	7.44
2000	8.08	6.49	7.02	7.81	7.61	7.55	7.15	7.02	8.87	7.55	7.35	8.94	7.62
2001	7.61	5.89	8.74	6.42	6.75	7.09	7.61	6.62	7.61	8.61	7.42	7.02	7.28
AVG	6.83	6.75	7.19	6.79	6.64	6.81	6.84	6.42	7.59	7.76	6.72	7.45	6.98

LIST OF REFERENCES

Alexander's Gas and Oil Connections Reports. "First VLCC Sale for Scrap, More to Follow." November 02, 1997. Limbach, Germany. Last accessed November 2006. <http://www.gasandoil.com/GOC/reports/rex70601.htm>

Allen, D.; Shonnard, D. Environmentally Conscious Design of Chemical Processes. Prentice Hall: New Jersey, 2002.

American Wind Energy Association (AWEA). "Global Wind Energy Market Report- Wind Energy Expands Steadily in 2004." 2005. Washington, DC. Last accessed October 2006. <http://www.awea.org/pubs/documents/globalmarket2005.pdf>

American Wind Energy Association (AWEA). "Global Wind Energy Market Report- Wind Energy Industry Continued to Grow at Fast Pace in 2002- Global Installations Increased by 28%." 2003. Washington, DC. Last accessed October 2006. <http://www.awea.org/pubs/documents/globalmarket2003.pdf>

Ardente, Fulvio, Marco Beccali, Maurizio Cellura, and Valerio Lo Brano. "Energy performances and life cycle assessment of an Italian wind farm." Renewable and Sustainable Energy Reviews (2006).

Babbitt, Callie W., and Angela S. Lindner. "A life cycle inventory of coal used for electricity production in Florida." Journal of Cleaner Production 13 (2005): 903-912.

Brown, M.T., and S. Ulgiati. "Emergy-based indices and ratios to evaluate sustainability: monitoring economies and technology toward environmentally sound innovation." Ecological Engineering 9 (1997): 51-69.

Brown, M.T., and S. Ulgiati. "Emergy evaluations and environmental loading of electricity production systems." Journal of Cleaner Production 10 (2002): 321-334.

Brown, M.T., and R.A. Herendeen. "Embodied energy analysis and EMERGY analysis: a comparative view." Ecological Economics 19 (1996): 219-235.

Brown, M.T., and Ulgiati, S. "Emergy Analysis and Environmental Accounting." Encyclopedia of Energy 2 (2004): 329-354.

Brown, Mark T., and Sergio Ulgiati. "Energy quality, emergy, and transformity: H.T. Odum's contributions to quantifying and understanding systems." Ecological Modelling 178 (2004): 201-213.

Bryant, Tracey. "Researchers Find Substantial Wind Resource Off Mid-Atlantic Coast." Energy Daily. Feb. 6, 2007. Stanford, NY. Last accessed March 2007. <http://www.energy-daily.com/reports/Researchers_Find_Substantial_Wind_Resource_Off_Mid_Atlantic_Coast_999.html>

Cape Wind Associates, LLC. “Frequently Asked Questions. Cape Wind- America’s First Offshore Wind Farm on Nantucket Sound.” 2006. Boston, MA. Last accessed October 2006. <http://www.capewind.org/FAQ-Category4-Cape+Wind+Basics-Parent0-myfaq-yes.htm>

Carlin, John. “Environmental Externalities in Electric Power Markets: Acid Rain, Urban Ozone, and Climate Change.” Energy Information Administration. United States Department of Energy. 2002. Washington, DC. Last accessed October 2006. <http://www.eia.doe.gov/cneaf/pubs_html/rea/feature1.html>

Curran, M.A. The Status of Life-Cycle Assessment as an Environmental Management Tool. *Environmental Progress*. 2004, 23, 4, 277-283.

Delaware Department of Natural Resources and Environmental Control (DNREC). “Delaware Reef Guide 2005.” 2005. Dover, DE. Last accessed October 2006. <http://www.dnrec.state.de.us/fw/2005reefguide.pdf>

Elliott, D., and M. Schwartz. “Wind Resource Mapping for United States Offshore Areas.” NREL/CP-500-40045. National Renewable Energy Laboratory. Golden, CO, 2006.

Elsam Engineering A/S. “Life Cycle Assessment of Turbines – PSO 1999.” Doc. no. 201673. 2004. Randers, Denmark. Last accessed March 2007. <http://www.vestas.com/NR/rdonlyres/99148F67-F421-4131-B018-88BF0A8E7344/0/LCA_V80_2004_uk.pdf>

Energy Efficiency and Renewable Energy (EERE). “Wind Energy Resource Potential.” 2005. Unites States Department of Energy. Washington, DC. Last accessed October 2006. <http://www1.eere.energy.gov/windandhydro/wind_potential.html>

Energy Information Administration (EIA). “Electric Power Annual.” 2005. United States Department of Energy. Washington, DC. Last accessed October 2006. <http://www.eia.doe.gov/cneaf/electricity/epa/epa_sum.html>

Energy Information Administration (EIA). “International Energy Outlook 2006.” 2006. United States Department of Energy. Washington, DC. Last accessed October 2006. <http://www.eia.doe.gov/oiaf/ieo/pdf/world.pdf>

Energy Information Administration (EIA). “Quarterly Coal Report – U.S. Coal Imports.” 2007. Washington, DC. Last accessed March 2007. <http://www.eia.doe.gov/cneaf/coal/quarterly/html/t18p01p1.html>

European Commission. “ExternE – Externalities of Energy.” Volume 10 – National Implementation.1997. Stuttgart, Germany. Last accessed October 2006. <http://www.externe.info/>

FreightCar America. Company Website. 2007. Chicago, IL. Last accessed November, 2006. <http://www.johnstownamerica.com/products/index.htm>

Gagnon, Luc, Camille Belanger, and Yohji Uchiyama. “Life-cycle assessment of electricity generation options: The status of research in year 2001.” Energy policy 30 (2002): 1267-1278.

General Electric (GE) Power. “Ireland’s Offshore Wind Power.” 2004. Last accessed March 2007. <http://www.gepower.com/businesses/ge_wind_energy/en/downloads/arklow_infosheet_final.pdf>

General Electric (GE) Transportation. 2007. Erie, PA. Last accessed March 2007. <https://www.getransportation.com/general/locomotives/products/evolution.asp?SMSESSION=NO>

Global Wind Energy Council (GWEC). “Global wind energy markets continue to boom – 2006 another record year.” Brussels, Belgium. 2007. Last accessed April 2007. <http://www.awea.org/newsroom/pdf/070202__GWEC_Global_Market_Annual_Statistics.pdf>

Google Maps. 2007. Mountain View, CA. Last accessed November 2006. <http://maps.google.com>

Hondo, Hiroki. “Life cycle GHG emission analysis of power generation systems: Japanese case.” Energy 30 (2005): 2042-2056.

Jacksonville Electric Authority (JEA). “JEA 2005 Annual Report.” 2005. Jacksonville, FL. Last accessed October 2006. <http://www.jea.com/about/pub/downloads/2005AnnualReport.pdf>

Jacksonville Electric Authority (JEA). “JEA Annual Disclosure Report for Fiscal Year Ended September 30, 2005.” 2006a. Jacksonville, FL. Last accessed October 2006. <http://www.jea.com/about/pub/downloads/AnnualDisclosureReport2005.pdf>

Jacksonville Electric Authority (JEA). “JEA Partners with Environmental Groups to Increase the Use of Green Energy.” 2006b. Jacksonville, FL. Last accessed October 2006. <http://www.jea.com/community/cleanpower.asp>

Jacksonville Electric Authority (JEA). “Lighting the Way- The Electric Generating Process.” 2002. Jacksonville, FL. Last accessed October 2006. <http://www.jea.com/about/pub/downloads/lightingtheway.pdf>

Jacksonville Electric Authority (JEA). “Welcome to St. Johns River Power Park” 1997. Jacksonville, FL. Last accessed March 2007. <http://www.jea.com/about/pub/downloads/sjrpbook.pdf>

Kannan, R., C.P. Tso, Ramli Osman, H.K. Ho. “LCA—LCCA of oil fired steam turbine power plant in Singapore.” Energy Conversion and Management 45 (2004): 3093-3107.

Landsea, Chris. “Frequently Asked Questions.” 2005. National Oceanic and Atmospheric Administration (NOAA)- Atlantic Oceanographic and Meteorological Laboratory- Hurricane Research Division. Washington, DC. Last accessed October 2006. <http://www.aoml.noaa.gov/hrd/tcfaq/E19.html>

Lenzen, Manfred, and Jesper Munksgaard. “Energy and CO_2 life-cycle analyses of wind turbines – review and applications.” Renewable Energy 26 (2002): 339-362.

Maritime Business Strategies, LLC. “Standard Brackets of Ship Sizes.” 2007. Delray Beach, FL. Last accessed March 2007. <http://www.coltoncompany.com/shipbldg/statistics/shipsizes.htm>

Musial, Walt. “Offshore Wind Energy Potential for the United States.” Wind Powering America- Annual State Summit. National Renewable Energy Laboratory. Evergreen, CO, 2005.

National Aeronautics and Space Administration. “Earth Fact Sheet.” 2004. National Space Science Data Center. Goddard Space Flight Center. Greenbelt, MD. Last accessed October 2006. <http://nssdc.gsfc.nasa.gov/planetary/factsheet/earthfact.html>

National Data Buoy Center (NDBC). “Station 41008 – Gray’s Reef.” National Oceanic and Atmospheric Administration. Washington, DC. Last accessed November 2006. <http://www.ndbc.noaa.gov/station_page.php?station=41008>

National Oceanic and Atmospheric Administration (NOAA). “Latitude/Longitude Distance Calculator.” 2006. Washington, DC. Last accessed November 2006. <http://www.nhc.noaa.gov/gccalc.shtml>

Odum, Howard T. Ecological and General Systems – An Introduction to Systems Ecology. Niwot, Colorado: University Press of Colorado, 1994.

Odum, Howard T. Environmental Accounting- Emergy and Environmental Decision Making. New York: John Wiley & Sons, Inc., 1996.

Poulsen, Egon V. “Service & Maintenance.” Vestas Wind Systems A/S. 2004. Rinkobing, Denmark.. Last accessed April 2007. <http://www.offshorecenter.dk/log/filer/100604-serv_maint-vestas.pdf>

Pehnt, Martin. “Dynamic life cycle assessment (LCA) of renewable energy technologies.” Renewable Energy 31 (2006): 55-71.

Pellerin, Cheryl. “Wind Power World's Fastest-Growing New Electricity Source.” International Information Programs. United States Department of State. 2005. Washington, DC. Last accessed October 2006. <http://usinfo.state.gov/gi/Archive/2005/Apr/22-869267.html>

San Martin, Robert L. “Environmental Emissions from Energy Technology Systems: The Total Fuel Cycle.” United States Department of Energy. 1989. Washington, DC. Last accessed November 2006. <http://www.fischer-tropsch.org/DOE/DOE_reports/OSTI/OSTI_860643/OSTI%20860643.pdf>

Schleisner, L. “Life cycle assessment of a wind farm and related externalities.” Renewable Energy 20 (2000): 279-288.

Siemens. 2007a. Orlando, FL. Last accessed March 2007. <http://www.powergeneration.siemens.com/en/locations/index.cfm#steamturbines>

Siemens. 2007b. Orlando, FL. Last accessed March 2007. <http://www.powergeneration.siemens.com/en/locations/index.cfm#gasturbines>

Society of Environmental Toxicology and Chemistry (SETAC). “Who We Are – Professional Interest Groups :: Life Cycle Assessment (LCA).” 2004. Pensacola, FL. Last accessed March 2007. <http://www.setac.org/htdocs/who_intgrp_lca.html>

Spath, Pamela L., and Margaret K. Mann. “Life Cycle Assessment of a Natural Gas Combined-Cycle Power Generation System” NREL/TP-570-27715. National Renewable Energy Laboratory. Golden, CO, 2000.

Spath, Pamela L., and Margaret K. Mann. “Life Cycle Assessment of Renewable Hydrogen Production via Wind/Electrolysis- Milestone Completion Report.” NREL/MP-560-35404. National Renewable Energy Laboratory. Golden, CO, 2004.

Spath, Pamela L., Margaret K. Mann, and Dawn R. Kerr. “Life Cycle Assessment of Coal-fired Power Production.” NREL/TP-570-25119. National Renewable Energy Laboratory. Golden, CO, 1999.

Tahara, Kiyotaka, Toshinori Kojima, and Atsushi Inaba. “Evaluation of CO_2 payback time of power plants by LCA.” Energy Conversion and Management 38 (1997): 615-620.

Ulgiati, S., M.T. Brown, S. Bastianoni, and N. Marchettini. “Emergy-based indices and ratios to evaluate the sustainable use of resources.” Ecological Engineering 5 (1995): 519-531.

Ulgiati, Sergio, and Mark T. Brown. “Quantifying the environmental support for dilution and abatement of process emissions- The case of electricity production.” Journal of Cleaner Production 10 (2002): 335-348.

United Nations, “United Nations Framework Convention on Climate Change.” FCCC/ INFORMAL/84, GE.05-62220 (E) 200705. 1992.

United States Census Bureau. “State & County Quick Facts- Florida.” 2006a. Washington, DC. Last accessed October 2006. <http://quickfacts.census.gov/qfd/states/12000.html>

United States Census Bureau. “State and County Quick Facts- Jacksonville, Florida.” 2006b. Washington, DC. Last accessed October 2006. <http://quickfacts.census.gov/qfd/states/12/1235000.html>

United States Census Bureau. “U.S. Population Density (By Counties).” 2006c. Washington, DC. Last accessed October 2006. <http://www.census.gov/dmd/www/pdf/512popdn.pdf>

United States Central Intelligence Agency (USCIA). “Rank Order- Electricity- consumption.” The World Factbook. 2006. Washington, DC. Last accessed September 2006. <https://www.cia.gov/cia/publications/factbook/rankorder/2042rank.html>

United States Environmental Protection Agency (USEPA). “Criteria Pollutants.” Green Book. 2006a. Washington, DC. Last accessed October 2006. <http://www.epa.gov/oar/oaqps/greenbk/o3co.html>

United States Environmental Protection Agency (USEPA). “Environmental Benefits of Reducing Acid Rain.” Region 7 Air Program. 2006b. Last accessed October 2006. <http://www.epa.gov/region7/programs/artd/air/acidrain/acidrn2.htm>

United States Environmental Protection Agency (USEPA). “How does electricity use effect the environment?” Clean Energy. 2006c. Washington, DC. Last accessed September 2006. <http://www.epa.gov/cleanenergy/impacts.htm>

United States Environmental Protection Agency (USEPA). “Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2004. 2006d. USEPA 430-R-06-002. Washington, DC. Last accessed November 2006. < http://www.epa.gov/climatechange/emissions/usinventoryreport.html>

United States Environmental Protection Agency (USEPA). “Life Cycle Assessment: Principles and Practice.” National Risk Management Research Laboratory. Cincinnati, Ohio. 2006e. EPA/600/R-06/060. Last accessed November 2006. <http://www.epa.gov/ord/NRMRL/lcaccess/pdfs/600r06060.pdf>

United States Environmental Protection Agency (USEPA). “Nitrogen Dioxide.” Air Trends. 2006f. Washington, DC. Last accessed October 2006. <http://www.epa.gov/air/airtrends/nitrogen.html>

United States Environmental Protection Agency (USEPA). “Sulfur Dioxide.” Air Trends. 2006g. Washington, DC. Last accessed October 2006. <http://www.epa.gov/air/airtrends/sulfur.html>

Vestas Wind Systems A/S. Randers, Denmark. 2007. Last accessed March 2007. <http://www.vestas.com/>

Wang, Lingmei, Weidou Ni, and Zheng Li. "Emergy evaluation of combined heat and power plant eco-industrial park (CHP plant EIP)." Resources, Conservation and Recycling 48 (2006): 56-70.

Wood, John and Gary Long. "Long Term World Oil Supply (A Resource Base/Production Path Analysis)." Energy Information Administration. 2000. United States Department of Energy. Washington, DC. Last accessed October 2006. <http://www.eia.doe.gov/pub/oil_gas/petroleum/presentations/2000/long_term_supply/index.htm>

BIOGRAPHICAL SKETCH

Stacey Dolan was born and raised in central Massachusetts. She is the daughter of John W. Dolan and Sharon R. Dolan, has an elder brother Jason, and younger sister Jessica. She received her Bachelor of Science in mechanical engineering from Worcester Polytechnic Institute, Worcester, Massachusetts in 2003. Stacey began her graduate studies in the mechanical engineering department's thermal sciences and fluid dynamics group at the University of Florida in the fall of 2005, and upon graduation plans to either pursue a PhD in mechanical engineering or a career in the renewable energy industry.