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Feasibility and Co-Benefits of Biomass Co-Firing: Case in Utah

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FEASIBILITY AND CO-BENEFITS OF BIOMASS CO-FIRING: CASE IN UTAH

by

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ABSTRACT

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by

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Department: Applied Economics

This research examines the physical and economic feasibility of 5% biomass co-firing in the coal-fired power plants of Utah. Transportation models is used to find out the physical feasibility of 5% biomass co-firing, as well as locate the supply zone for each power plant that would minimize the transportation cost. Additional cost required for 5% biomass co-firing and the economic benefits associated with biomass co-firing are calculated. The additional cost required for 5% biomass co-firing is estimated to be $34.84 million. Previous studies on CO_2 emission reduction are used to compute the economic benefit attain from CO_2 reduction by selling carbon credits in the carbon trading market. Based on 2010 emission record in Utah, 5% biomass co-firing might reduce 0.71~2.13 million metric tons of CO_2 and, in turn, bring the annual economic benefit of $11.37~$34.10 million assuming $16/ton of CO_2 in the emission trading market. The regression model is used to find the relationship between PM emission and the human health damage. The regression results show that decreases in 1% of PM25 emission improves the human health in U.S. by 0.65%~0.67% in value. Five percent biomass co-firing generates annual economic benefits of $6.72~$9.93 million in Utah depending on the emission

reduction scenarios. Note that these might not be the precise economic benefit from the biomass co-firing in Utah because elasticities estimated in the regression are expected to be lower in Utah. This is because most of power plants in Utah are located in open areas. Altogether, the economic benefit from 5% biomass co-firing is estimated to be $38.55 million assuming the medium emission reduction scenario, moderate carbon price (≈ $16/ton of CO_2) which is higher than the additional cost of biomass co-firing to generate electricity ($34.84 million). The benefit cost ratio is calculated as 1.107. Five percent biomass co-firing is economically feasible when benefits from all the positive externalities are included.

The findings of the research suggest that in order to make 5% biomass co-firing physically and economically feasible, Utah needs cooperation from Idaho and the price of carbon and biomass would have to be $16 and $20, respectively.

PUBLIC ABSTRACT

Feasibility and Co-Benefits of Biomass Co-Firing: Case in Utah

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This research examines the physical and economic feasibility of 5% biomass co-firing in the coal-fired power plants of Utah. Transportation models is used to find out the physical feasibility of 5% biomass co-firing, as well as locate the supply zone for each power plant that would minimize the transportation cost. Additional cost required for 5% biomass co-firing and the economic benefits associated with biomass co-firing are calculated. The additional cost required for 5% biomass co-firing is estimated to be $34.84 million. Previous studies on CO_2 emission reduction are used to compute the economic benefit attain from CO_2 reduction by selling carbon credits in the carbon trading market. Based on 2010 emission record in Utah, 5% biomass co-firing might bring the annual economic benefit of $11.37~$34.10 million assuming $16/ton of CO_2 in the emission trading market. The regression model is used to find the relationship between PM emission and the human health damage. The regression results show that decreases in 1% of PM25 emission improves the human health in U.S. by 0.65%~0.67% in value and generates annual economic benefits of $6.72~$9.93 million in Utah. Altogether, the economic benefit from 5% biomass co-firing is estimated to be $38.55 million which is higher than the additional cost of biomass co-firing to generate electricity ($34.84 million). The benefit cost ratio is calculated as 1.107. Five percent biomass co-firing is economically feasible when benefits from all the positive externalities are included.

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CHAPTER 1

INTRODUCTION

1.1. Introduction

There are three environmental and policy issues and concerns associated with coal-fired power plants in the U.S. First, coal-fired power plants directly emit air pollutants, for example, particulate matters (PM), sulfur dioxide (SO_2), and nitrogen gases (NO_x). Exposure to these pollutants is harmful for human health. These air pollutants are main sources of respiratory illnesses, cardiopulmonary diseases, and acid rain. These pollutants are regulated by environmental laws such as the Clean Air Act Amendments of 1990, and Clean Air Interstate Rule (CAIR) of 2005.

Second, coal-fired power plants are also emitting greenhouse gases (GHGs) which are contributing to global warming. GHGs emission may be controlled in the near future under the series of the international negotiations, for example, Kyoto Protocol in 1997 and Copenhagen Accord in 2009. The American Clean Energy and Security Act (ACES) of 2009 establishes emission caps that would reduce GHG emissions to 17% below 2005 levels in 2020, 42% below 2005 levels in 2030, and 83% below 2005 levels in 2050 (Center for Climate and Energy Solutions 2009) .

Third, Federal Energy Management Program in the United States Department of Energy (U.S. DOE) is assisting government agencies in developing biomass energy projects to help the nation use more domestic renewable energy resources to increase national energy security (Federal Energy Management Program 2004). The regional Renewable Portfolio Standards (RPS) have emerged to promote clean energy, renewable power supply. The regional RPS' contain the policy establishing that a minimum percentage (2%~30%) of electricity supplied by the electricity retailers must be derived from the renewable energy sources (U.S. Environmental Protection Agency 2009a). Retail suppliers can meet their RPS obligation by either owning renewable energy facilities or purchasing power from eligible generators (U.S. EPA 2009a).

Overall, these regulations and governmental policies have strengthened a demand for environmentally benign renewable energies, i.e., biomass, solar, geothermal, and wind energies. Among them biomass power, the use of biomass to generate electricity, has attracted researchers' and decision makers' attention because it is a viable option in the near future (U.S. Department of Energy/Energy Efficiency and Renewable Energy 2012a).

Generally biomass includes plants (agricultural crop residues and switchgrass)~~,~~ and animal materials that can be used to generate electricity. Biomass power system technologies include direct firing, co-firing, gasification, and pyrolysis (National Renewable Energy Laboratory 2000; National Renewable Energy Laboratory 2001). Among them co-firing biomass, the simultaneous combustion of biomass and coal in the same boiler to generate electricity, has attracted researchers' and policy makers' attention. Biomass co-firing has technical and environmental advantages over other renewable options (Demirbas 2003; Mann and Spath 2001; Tillman 2000).

The biomass co-firing in generating electricity has multiple benefits, (i) reducing GHG emissions, (ii) reducing harmful air pollutants such as PM, (iii) achieving a regional RPS, and (iv) boosting the rural economy (e.g., providing a new income opportunity for farmers). Many previous studies associated with the biomass co-firing have focused on the feasibility and the potential of the biomass co-firing and its implications of GHG emissions, i.e., benefits (i) and (iii); for instance, McCarl et al. (2000), English et al. (2004), Ismayilova (2007), Muang (2008), and De and Assadi (2009). Some literature sources have discussed the biomass co-firing benefits (i) and (iv), for example, Ismayilova (2007) and Perez-Verdin et al. (2008), though not in detail.

It is rare, however, to attempt to investigate and quantify the benefit of reducing harmful air pollutants emissions, benefit (ii). This study attempts to measure the (monetary) value of reducing air pollutants emissions in terms of improved human health. These benefits are understood as the co-benefit (positive externality) of the biomass co-firing. This research provides information on whether the biomass co-firing in Utah is economically feasible or unfeasible for electricity generation to the local policy and decision makers.

In this way, the primary objective of the study aims to investigate these net benefits in Utah. The research objectives are listed and discussed briefly in the following section.

1.2. Research Objectives

The research objectives are:

- Investigating the physical feasibility and the production potential of the biomass in Utah and Idaho for the biomass co-firing (Chapter 2),
- Examining implication of GHG emission reduction through the biomass co-firing in Utah (Chapter 3),
- Quantifying the health benefits from reduction in air pollutants, especially PM, through the biomass co-firing in Utah (Chapter 4), and
- Calculating the benefit-cost ratio to see if the biomass co-firing is economically feasible in Utah in the near future (Chapter 5).

1.2.1. Physical Feasibility and Production Potential of Biomass

The first goal of the study is to examine the physical feasibility and the production potential of biomass for electric power generation in Utah. In particular, the study will answer the following questions:

- *Can the state of Utah supply enough biomass to co-fire to generate electricity? If so, what are the costs? If not, what options may Utah have?*

Answering these questions provides decision and policy makers with information as to whether the biomass co-firing in Utah is feasible. Note that only agricultural crop residues will be considered as biomass feedstock in this research. *Exogenously* determined co-firing percentages, i.e., 5%, 10%, and 15% of co-firing options, are considered as suggested in previous biomass co-firing literature. A transportation model will be built to answer the research question and identify the optimal locations of the supply regions to minimize the cost of transporting biomass. This has not been done in previous biomass co-firing studies.

1.2.2. Implications of Greenhouse Gas Emissions Reduction

The biomass co-firing has the benefit of reducing GHG, particularly CO_2 emissions. The research questions are:

- *How much can the biomass co-firing in the state of Utah reduce GHG emissions from coal-fired power plants? What is the economic benefit of doing so?*

Many previous studies have quantified the implication of GHG emissions in the biomass co-firing using a life-cycle assessment (LCA).[1] This research adopts and applies the previous work~~s~~ for measuring a reduction of GHG emissions. The economic benefit of reduction in GHG emission will be quantified assuming Utah can sell these reductions as carbon credits in carbon trading markets such as Chicago Climate Exchange (CCX) or European Climate Exchange (ECX).

[1] A life-cycle assessment is a technique to assess environmental impacts associated with *all the stage* of the biomass life from planting-growing-harvesting to combustion (to generate electricity in this case) (EPA – Defining Life Cycle Assessment, available at http://www.gdrc.org/uem/lca/lca-define.html).

<u>1.2.3. Quantifying Health Benefits from Biomass Co-firing</u>

Coal-fired power plants emit harmful air pollutants including PM, SO_2, and NO_x which are main causes of respiratory disease, heart disease, stroke and premature mortality (U.S. EPA 2004). Recent epidemiological studies have shown that high levels of PM are closely correlated with substantial adverse health effect such as acute respiratory infections and mortality (Chen et al. 2000; Sastry 2002; Tham et al. 2009). Long-term exposure to the combustion-related PM and the SO_2-related air pollution could lead to cardiopulmonary and lung cancer (Viswanathan et al. 2006). The biomass co-firing can reduce harmful air pollutants emissions. The research questions are:

- *How much can biomass co-firing in Utah reduce emissions of air pollutants?*
- *What are the economic benefits of biomass co-firing in this?*

This is the first study to investigate and quantify the benefit of reducing air pollution from the biomass co-firing.

1.3. Organization of the Research

This study is structured as follows. Chapter 1 provides a general introduction to biomass co-firing in coal-fired power plants and discusses the research objectives. Chapter 2 explores the physical feasibility and the production potential of the biomass co-firing in Utah. Chapter 2 discusses the feasibility of the biomass co-firing using the transportation model and calculates the levelized cost of the biomass co-firing to produce electricity in Utah. Chapter 3 reviews the previous studies on GHG emission reductions and biomass co-firing. This chapter examines the economic gains of reduction of GHG emissions. Chapter 4 examines the benefit of improving human health from biomass co-firing. These chapters discuss the implication of reducing PM emissions and, in turn, the health benefits associated with it. A benefit-cost ratio is calculated using the information from Chapters 2, 3, and 4 in Chapter 5. Benefit-Cost analyses with various scenarios are conducted to see if the biomass co-firing is economically feasible in Utah in the near future. Lastly, Chapter 6 draws conclusions of the study and outlines future studies.

CHAPTER 2

FEASIBILITY AND COST OF BIOMASS COFIRING IN UTAH

Biomass co-firing is the use of biomass (crop residues, energy crops, logging residues, etc.) with coal to generate electricity in the same boiler. This research will consider only ***agricultural crop residues*** for the biomass. Biomass co-firing has been viewed as the potential low cost technology in reducing the GHG emissions (Battista et al. 2000) and air pollutants (Mann and Spath 2001). In this chapter, the physical feasibility and potential of biomass (crop residue) co-firing in Utah are discussed. In addition, this chapter derives the levelized cost of the biomass co-firing. The levelized cost is the total cost required by the energy generating system over its lifetime for producing electricity which includes initial investment, operation and maintenance cost, fuel cost, etc. and is discussed briefly later in this chapter.

2.1. Why Biomass?

Burning coal remains the most cost effective way of producing electricity. In the U.S., 42% of net generation came from coal (25% from natural gas and 19% from nuclear) in 2011, while renewable resources except hydro power only account for about 5%. In Utah, 82% of net generation came from coal (13% from natural gas and 2% from renewable sources excluding hydroelectric) in 2011 (U.S. EIA 2011) (Table 1).

Biomass is any organic material made from plants or animals. Biomass resources include agricultural and forestry residues, municipal solid wastes, industrial wastes, terrestrial and aquatic crops grown solely for energy purposes. In general, biomass has low heat content and high transaction costs, and thus electricity producers may not have the necessary incentives to switch from coal to biomass fuels (Nogee et al. 1999). Even so, there are at least two reasons to consider biomass as a substitute of coal to generate electricity.

Table 1. Net Generation by Fuel Types (thousand GWh)

		2001	2005	2009	2011
U.S.	All Fuels	3,737 (100%)	4,055 (100%)	3,950 (100%)	4,106 (100%)
	Coal	1,904 (51%)	2,013 (50%)	1,756 (44%)	1,734 (42%)
	Petroleum	125 (3%)	122 (3%)	39 (1%)	28 (1%)
	Natural gas	639 (17%)	761 (19%)	921 (23%)	1,017 (25%)
	Nuclear	769 (21%)	782 (19%)	799 (20%)	790 (19%)
	Hydroelectric	217 (6%)	270 (7%)	273 (7%)	325 (8%)
	Other renewables	71 (2%)	87 (2%)	144 (4%)	195 (5%)
Utah	All Fuels	35.85(100%)	38.17(100%)	43.54 (100%)	40.52 (100%)
	Coal	36.38 (94%)	35.97 (94%)	35.33 (81%)	33.07 (82%)
	Petroleum	0.06 (0%)	0.04 (0%)	0.04 (0%)	0.05 (0%)
	Natural gas	1.45 (4%)	1.18 (3%)	6.44 (15%)	5.31 (13%)
	Nuclear	-	-	-	-
	Hydroelectric	0.51 (1%)	0.78 (2%)	0.84 (2%)	0.98 (2%)
	Other renewables	0.16 (0%)	0.19 (0%)	0.49 (1%)	0.92 (2%)

Source: EIA Electricity Data Browser (http://www.eia.gov/beta/enerdat)

First, energy security: the U.S. Energy Independence and Security Act of 2007 and the ACES of 2009 were enacted to move the U.S. towards greater energy independence and security with the aim to increase the production of clean renewable fuels. The United State Department of Energy (USDOE) is assisting government agencies in developing biomass energy projects to help the nation use more domestic renewable energy resources.

Second, coal-fired power plants are emitting CO_2, contributing to global warming. In 2010, the U.S. CO_2 emission was 5,706 million metric tons and fossil fuel combustion (energy use) is responsible for 94.4% of that (Table 2). Electricity generation was responsible for 39.6% (with transportation 30.6%, industrial 13.6%, and residential 6%) of the total CO_2 emission in 2010 (U.S. EPA 2012). Utah emitted 65.2 million metric tons of CO_2 in 2009 (Utah Geological Survey 2009). The results from Table 2 show that electricity generation accounted for 55% of total CO_2 emission of Utah in the year 2009. In this regard, CO_2 emission from electricity generation may be regulated in the near future under the series of the international negotiations.

Table 2. Recent Trends in CO_2 Emissions (million metric tons CO_2 Eq.)

	Source	2005		2009		2010[1]	
U.S.	Total CO_2 emission	6107.6	100%	5500.5	100%	5706.4	100%
	Fossil fuel combustion	5746.5	94%	5206.2	95%	5387.8	94%
	Electricity generation	**2402.1**	**39%**	**2146.4**	**39%**	**2258.4**	**40%**
	Transportation	1896.6	31%	1727.9	31%	1745.5	31%
	Industrial	816.4	13%	726.6	13%	777.8	14%
	Residential	357.9	6%	339.0	6%	340.2	6%
	Commercial	223.5	4%	224.6	4%	224.2	4%
	Other	361.1	6%	294.3	5%	318.6	6%
Utah	Total CO_2 emission	67.4	100%	65.2	100%		
	Fossil fuel combustion	67.4	100%	65.2	100%		
	Electricity generation	**36.2**	**54%**	**36.1**	**55%**		
	Transportation	16.6	25%	16.3	25%		
	Industrial	8.9	13%	6.6	10%		
	Residential	3.4	5%	3.8	6%		
	Commercial	2.3	3%	2.4	4%		

Source: EPA (2012) U.S. Greenhouse Gas Inventory Report, Table ES-2 (http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html); Utah Geological Survey, Table 8.2 (http://geology.utah.gov/emp/energydata/ghgdata.htm)
(http://www.eia.gov/state/state-energy-profiles-data.cfm?sid=UT#Environment)
[1] 2010 data for Utah are not available

The American Clean Energy and Security Act (ACES) of 2009 establishes emission caps that would reduce GHG emissions to 17% below 2005 levels in 2020, 42% below 2005 levels in 2030, and 83% below 2005 levels in 2050 (Center for Climate and Energy Solutions 2009). The ACES of 2009 aims are not only mitigating GHG emissions, but also reducing the U.S. reliance on foreign sources of energy. Burning biomass to generate electricity is one of options to reduce dependency of foreign energy sources. The regional Renewable Portfolio Standards (RPS) has emerged as a tool for promoting clean energy, renewable power supply.

By the end of 2009, 33 states and the District of Columbia had enacted RPS policies, ranging from 2% of the electricity supply in Iowa to 40% in Maine (U.S. EPA 2009a). Utah also established the voluntary RPS goal which aims to produce 20% of electric sales from renewable sources other than hydro-power by year 2025 (U.S. EPA 2009a). These policies were established with dual purposes of mitigating CO_2 emission, as well as enhancing national energy security by cutting the US dependency on foreign energy sources.

This chapter analyzes the physical feasibility and the production potential of biomass for electric power generation in Utah. The research goals for the chapter are: (i) investigating the potential of biomass co-firing in Utah, (ii) identifying the optimal biomass supply regions and a feedstock transportation pattern , and (iii) estimating the (additional) levelized costs of generating electricity when the biomass co-firing is mandatory.

2.2. Can Utah Supply Enough Biomass for Co-Firing?

The first research question is to examine if Utah can supply enough crop residues for the biomass co-firing. Crop production and crop residue availability are calculated to determine the potential of biomass to meet the demand of coal-fired power plants at various co-firing rates. The transportation model is developed to determine the transportation cost of biomass for co-firing in coal-fired power plants. The model identifies the optimal biomass supply locations with minimal transportation cost. Also, a levelized electricity generation cost (*LEC*) is computed to assess the cost competitiveness of crop residue co-firing with coal for electric power generation in Utah.

2.2.1. Biomass and Biomass Co-Firing

Biomass is any organic material made from plants or animals. Biomass resources include agricultural and forestry residues, municipal solid wastes, industrial wastes, energy crops (U.S.DOE/EERE 2012b). This research will consider only ***agricultural crop residues*** for the biomass. This is because the use of energy crops for electricity generation is yet to be practiced in Utah and it is hard to find the county level data on forest resources and the landfill biomass.

The primary technologies for the conversion of biomass to electricity production are direct combustion, co-firing, gasification, and pyrolysis (Centre for Energy 2012). Biomass co-firing refers to the simultaneous combustion of biomass along with coal in a power plant to generate electricity—which is considered as the technology for electric power generation in U.S. Since it uses the existing coal fired power plant, it is cost effective as well, plus this technology benefits the environment by mitigating emissions of CO_2 and the air pollutants (Battista et al. 2010).

2.2.2. Crop Production and Crop Residue Availability

Renewable resources for generating electricity are the one that helps Utah to meet their volunteer RPS goal. The biomass co-firing is one of options. Although Utah is the second driest state of the U.S. there are some niches of biomass production. The production of different crops (from irrigated croplands) in Utah counties (and Idaho) is shown in Table A-1 in Appendix A.

Agricultural crop residues are the plant parts, primarily stalks and leaves, left over after removal of the primary food or fiber product. Examples include corn stover (leaves, stalks, cobs, and husks), wheat straw, and barley straw. Grain production for the entire field crops were calculated from Agricultural Census 2007. Total quantities of crop residues available can be estimated by applying straw to grain ratio.[2] Table A-2 in Appendix A includes the total crop residues available in Utah (and Idaho).

2.2.3. Harvestable Crop Residues

Only some percentage of crop residues can potentially be collected for the biomass feedstock, others should be left in the field to enhance soil productivity, maintain soil nutrient

[2] Residue-to-grain ratio of 1.5:1.0 for wheat and barley, and 1.4:1 for oat, and stover to grain ratio of 1:1 for corn (Brown 2003; Heid 1984; Larson 1979a, 1979b)

availability, and prevent soil erosion. Soil type and fertility level, slope characteristics, tillage system, climate and crop rotations are site specific factors that can affect the crop removable rates (DiPardo 2000; Muang 2008).

National Resources Conservation Service (NRCS) guidelines for residue management recommend that at least 30 % crop residue needs to be in the field to control soil erosion. Thus, 70% of crop residue can be collected~~)~~. According to Ho (1985), 67% of the crop residues can be safely harvested without causing soil erosion problems. Nelson (2002), Nelson et al. (2004) and Perlack et al. (2005) derived the national estimates of average crop residue removal rates for corn and wheat. They show that the removal rates for corn were 33%, 54% and 68% respectively, under conventional tillage, reduced tillage and zero tillage systems. For wheat, the removal rates were 14%, 34% and 48%, respectively, under conventional tillage, reduced tillage and zero tillage scenarios. However, Hettenhaus et al. (2000) argues that on average about 50% to 60% of corn stover can be available depending on the regional slope characteristics. In the same way, Glassner, Hettenhaus, and Schechinger (1998) report that 76%~82% of corn stover can be harvested with current equipment and no-till farming, although 70% is the limit for commercial balers. Similarly, it has been estimated that about 50% of the wheat straw can be sustainably harvested for other uses (Kadam and McMillan 2003).

Since Lindstrom et al. (1981) results on crop removal rates have been cited by most of the previous studies listed above, this research also uses the crop removal rate from their study. They studied the crop residue production in the Corn Belt region and determined the amount of crop residue that could be removed from the field without causing any harmful effects on soil. They found that 60% of the residue can be safely removed under the conventional tillage assuming a 100% harvest efficiency of residue. With conservative and no tillage, more crop residue can be collected (Lindstrom et al. 1981). This research uses 60% removal rate. A total *harvestable crop residue* in Utah counties is given in Table 3 and also Table A-3 in Appendix A.

Table 3. Harvestable Crop Residue in Utah Counties (metric tons)[1]

Counties	Barley	Corn	Oats	Wheat
Utah				
Beaver	209	-	226	-
Box Elder	4,748	15,711	83	50,705
Cache	12,343	3,565	728	17,138
Carbon	-	1,208	181	-
Davis	94	2,811	69	2,732
Duchesne	505	4,892	278	-
Emery	-	-	122	-
Garfield	-	-	28	-
Grand	-	-	71	140
Iron	-	1,539	-	-
Juab	1,571	3,289	174	2,473
Millard	4,664	2,430	255	3,475
Morgan	959	377	203	631
Piute	-	-	14	-
Rich	454	-	-	70
Salt Lake	123	-	77	2,223
San Juan	-	-	-	241
Sanpete	1,658	150	412	72
Sevier	1,216	306	145	-
Tooele	438	-	-	-
Utah	980	3,155	360	-
Uintah	3,096	5,781	430	12,019
Wasatch	-	-	164	-
Wayne	263	-	306	-
Weber	389	702	74	3,816
Total	**33,710**	**45,917**	**4,398**	**95,735**

[1] Author's calculation

The heating value (or energy value, heat of combustion) of a substance is defined by the amount of heat released during the combustion with oxygen. It may be expressed with the quantity of energy units/volume of fuel, mostly MJ/kg.[3] Table 4 shows the higher heating value (HHV) of different crop residues. HHV numbers are collected from ECN Phyllis database that contains information on the composition of biomass and waste including HHV. As shown in Table 4 each crop residue has a different heating value that implies crop residues are not one-to-one substitutable. For example, oats residue has higher HHV than wheat straw, and thus 1 metric ton of oat residue is equivalent to 1.02 metric tons of wheat straws.

Harvestable crop residues need to be converted to wheat-straw-basis metric tons (or something else) so that each crop residue can be one-to-one substitutes and thus add them together to find <u>*total harvestable crop residues*</u> in each county. Total harvestable crop residue information is transferred to the transportation model which is discussed in the next section. Table 5 and also Table A-4 contain total harvestable crop residues in wheat-straw-tonnes.

Table 4. Higher Heating Value (HHV) of Different Crops (MJ/kg)

Crops Residue	HHV(MJ/kg)[a]	Million BTU/tonne[b]
Barley residue (straw)	17.54	16.62
Corn stover	18.48	17.52
Oats residue	19.62	18.60
Wheat straw	19.24	18.24

[a] ECN Phyllis Database (<u>http://www.ecn.nl/phyllis/</u>) – average of multiple experiments results in the database; For comparison, average HHV of **Utah coal** (based on Utah geological survey, Table 2.24a) is **27.09MJ/kg** or 25.67 Million BTU/metric ton

[b] Author's calculation using the following conversion factors: 1 metric tons = 1.1023 tons and 947.8 BTU/MJ and 907.185 kg/ton.

[3] The joule (symbol J) is a unit of energy or amount of heat. By definition, it is equal to the energy to produce one watt of power for one second. Thus, 3.6 MJ is equal to 1 kWh.

Table 5. Harvestable Crop Residue in Utah Counties (wheat-straw-metric tons)

Counties	Barley	Corn	Oats	Wheat	**Total**
Utah					
Beaver	190		230	-	420
Box Elder	4,328	15,091	85	50,705	70,209
Cache	11,252	3,424	742	17,138	32,557
Carbon	-	1,160	184	-	1,344
Davis	86	2,700	70	2,732	5,588
Duchesne	460	4,699	283	-	5,442
Emery	-	-	125	-	125
Garfield	-	-	29	-	29
Grand	-	-	72	140	212
Iron	-	1,478			1,478
Juab	1,432	3,159	177	2,473	7,242
Millard	4,252	2,334	260	3,475	10,321
Morgan	874	362	207	631	2,073
Piute	-	-	14	-	14
Rich	414	-	-	70	484
Salt Lake	113	-	78	2,223	2,414
San Juan	-	-	-	241	241
Sanpete	1,511	144	420	72	2,148
Sevier	1,109	294	148	-	1,551
Tooele	399	-	-	-	399
Utah	894	3,030	367	-	4,291
Uintah	2,822	5,552	439	12,019	20,833
Wasatch	-	-	167	-	167
Wayne	240	-	312	-	552
Weber	354	675	76	3,816	4,921
Total	**30,730**	**44,102**	**4,485**	**95,735**	**175,055**

2.3. Transportation Model

Transportation of biomass to power plants is one of the major barriers in making biomass co-firing feasible. This is because, unlike coal, biomass resources are not concentrated in a particular region. In order to acquire sufficient amount of biomass for co-firing, it requires collection from different parts of the Utah and Idaho. The dispersed nature of biomass availability is responsible for higher transportation costs which ultimately increases the production cost of power plants.

The amount of biomass used in the power plants and the transportation cost of biomass in Utah are simulated using a transportation model. The transportation model identifies the biomass supply regions that minimize the transportation cost for transporting biomass to different power plants. The model is given by:

$$
\begin{aligned}
&\min_{x_{ij}} && \sum_{i=1}^{M}\sum_{j=1}^{N} c_{ij}x_{ij} \\
&\text{s.t.} && \sum_{j=1}^{N} x_{ij} \le s_i \quad \forall i \\
(1)\quad & && \sum_{j=1}^{N} x_{dm,j} \le s_{dm} \\
& && \sum_{i=1}^{M} x_{ij} \ge d_j \quad \forall j \\
& && x_{ij} \ge 0, \quad \forall i, j \quad ,
\end{aligned}
$$

where, i = (possible) biomass production regions (counties), dm is dummy production region[4], j = power plants, x_{ij} = amount of biomass transported from i to j, c_{ij} = unit transportation cost from i to j, $\underline{s_i}$ = biomass supply available in the region i and d_j = biomass demand from the power plant j. Note that d_j is dependent upon the exogenously determined biomass co-firing rates, 5%, 10%, and 15%.

The transportation model in equation (1) decides which power plants co-fire biomass to minimize the total transporting cost. The model in equation (1) is easily expanded to add price of

[4] Dummy production region that meets biomass demand of all the power plants should be added to construct empirical model. This is because (in Utah) there exists excess demand of biomass all the time. The production (or supply) capacity of dummy regions is calculated as $s_{dm} = \sum_j d_j - \sum_i s_i$

biomass (incentive to farmers) to modify the objective function, which is the total cost of the biomass co-firing, as in equation (2):

$$(2) \qquad \min_{x_{ij}} \quad p\sum_{i}^{M}\sum_{j}^{N} x_{ij} + \sum_{i=1}^{M}\sum_{j=1}^{N} c_{ij}x_{ij} \; ,$$

where, p = price of biomass.

2.3.1. Transportation Distance and Cost

Transportation cost, c_{ij}, is the cost required to transport crop residue from the supply regions to the power plants. One of the key elements of transportation cost is the distance between supply regions and power plants. The distance was calculated using the Google map assuming the biomass is transported using the highways and major roads. First, the center of each supply region (county) is identified where crop residues might be transported and stored, mainly the county seat or the city close to the major highway is used as the center of supply region. For example, Logan is used as the center of Cache County because it is the county seat of Cache County. Second, existing coal-fired power plants are identified which are scattered around Utah as shown in Figure B-1 in Appendix B. Third, the distance from the center of the county to the power plant is measured by the Google direction search. The distances between potential supply regions and power plants of Utah are shown in Table B-2 in Appendix B.

The second part of the transportation cost is a hauling cost. Based on an approach by French (1960) as described in McCarl et al. (2000), the hauling cost per ton of biomass residues are calculated as shown in equation (3):

$$(3) \qquad hc = \frac{2cpm \cdot dst + fx}{sz} \; ,$$

where, *hc* = hauling cost, *cpm* = (unit) cost per mile, *dst* = distance, *fx* = fixed cost for loading, and *sz* = loading size. Hauling cost parameters[5] are given by: *cpm* = $1.38/mile, *fx* = $173.2, and *sz* = 20 tons, respectively. Based on these figures, the per ton transportation cost, c_{ij}, is reported in Table B-2 in Appendix B.

2.3.2. Biomass Requirements by Power Plants

The annual biomass requirement for the 100-MW power plant is calculated as follows. Because 100-MW power plant's annual energy requirement is seven trillion BTUs (McCarl et al. 2000), 5% biomass co-firing implies that it requires 350,000 million BTUs.[6] Using the HHV number in Table 5, 100-MW power plant needs 19,189 metric tons of wheat residues.[7] Similarly, at 10% and 15% co-firing rate, 100-MW power plant requires 38,377 and 57,566 metric tons of wheat residues, respectively. Table 6 contains the calculation results. By using the same calculation, the crop residue requirements for the more than 100 MW-capacity power plant can be calculated. Currently there are eight coal-fired power plants in operation (Table B-1 in Appendix B for generation capacity for each power plant). This study estimates the quantity of biomass residue required for different co-firing rates. Table 7 shows the biomass demand of different power plants of Utah at different co-firing rates.

Table 6. Annual Crop Residue Requirements for 100 MW Power Plant[1]

	5% co-firing	10% co-firing	15% co-firing
Wheat-straw-metric tons	19,189	38,377	57,566

[1]Author's Calculation

[5] Hauling cost parameters are obtained from Kerstetter and Lyons (2001) and inflated to 2011 values using producer price index.
[6] 7,000,000,000,000 BTUs × 5% = 350,000,000,000 BTUs = 350,000 million BTUs
[7] 350,000 million BTUs/18.24 million BTUs/metric tons = 19,189 metric tons

Table 7. Biomass Requirement by Power Plants (wheat-straw-metric tons)[1]

Power Plants	5% co-firing	10% co-firing	15% co-firing
Carbon	36,267	72,534	108,802
Smelter	34,924	69,848	104,772
Deseret	8,251	16,503	24,754
Huntington	191,123	382,235	573,357
Hunter	282,464	564,927	847,390
Bonanza	95,946	191,891	287,836
Intermountain	314,701	629,402	944,103
Sunnyside	11,149	22,298	33,447

[1]Author's Calculation

2.3.3. Results of Transportation Model

The transportation model in equation (1) is run with the harvestable crop residues, annual biomass requirements, and the unit transportation cost. Since, the demand and supply equation in the model need to be balanced, a Dummy County is added in the model which supplies the remaining biomass needed by the power plants. Table 8 shows the result under 5% co-firing scenario.

As shown in Table 8, the transportation model suggests that crop residues in Utah can only support a few power plants near supply regions, Carbon, Deseret and Smelter power plants. Hunter and Huntington power plants do not have the necessary biomass supply (less than 1% of total biomass requirements). The Bonanza power plant is supplied with 11% of feedstock requirement and Intermountain power plant with 25% and Sunnyside power plant with 16% of their total feedstock requirement.

Table 8. Transporting Biomass – Utah only, 5% Co-firing (wheat-straw-metric tons)

From \To	Bonanza	Carbon	Deseret	Hunter	Hntngtn	InterMT	Smelter	Sunny
Beaver						420		
Box Elder		31,780	2,932			35,497		
Cache							32,557	
Carbon								1,216
Davis						3,222	2,366	
Duchesne	5,422							
Emery				125				
Garfield						29		
Grand								212
Iron						1,478		
Juab						7,242		
Millard						10,321		
Morgan		2,073						
Piute						14		
Rich	484							
Salt Lake		2,414						
San Juan								241
San Pete					2,148			
Sevier				1,551				
Tooele			399					
Utah						20,833		
Uintah	4,921							
Wasatch								167
Wayne				552				
Weber			4,921					
Total	10,217	36,266	8,521	2,227	2,148	79057	34,923	1,836
% of requirement	11%	100%	100%	0.7%	1%	25%	100%	16%

Thus, to make biomass co-firing feasible for all power plants in Utah, it is essential to transport biomass from other regions outside of Utah. As Idaho does not have a large coal-fired power plant, neighboring Idaho counties may be used as potential biomass supply regions. Thirteen southern Idaho counties, with plenty of crop residues available, are included in the model. Other neighboring counties in Nevada, Arizona, Colorado, and Wyoming are not considered either because they do not produce enough biomass (Nevada and Wyoming) or coal-fired power plants already exist (Arizona and Colorado).

Using similar processes and assumptions from Table 5, crop residues available from Idaho are calculated (Table 9). Transportation costs are computed using the distance between counties and power plants (Tables B-2 and B-3 in Appendix B). Transportation distance and the unit transportation cost are shown in Table B-2 and Table B-3 in Appendix B. Results from the transportation model including neighboring Idaho counties are reported in Table 10 at 5% co-firing scenario.

The results in Table 10 clearly show that, in cooperation of Idaho, the biomass co-firing is physically feasible for all the power plants in Utah at a 5% co-firing ratio. For comparison purposes, the feasibility of biomass results at 10 % and 15% co-firing ratios are given in Table C-1 and Table C-2 in Appendix C.

Table 9. Crop Residue Available in Southern Idaho Counties (wheat-straw-metric tons)

Counties	Barley	Corn	Oats	Wheat	**Total**
Bannock	6,163	-	120	20,331	**26,614**
Bear Lake	5,281	-	100	1,397	**6,779**
Caribou	50,837	4,732	282	139,618	**195,468**
Cassia	31,178	-	385	35,507	**67,071**
Elmore	4,069	14,635	-	23,054	**41,759**
Franklin	7,286	1,491	332	15,423	**24,533**
Gooding	4,050	28,525	503	7,024	**40,103**
Jerome	26,659	8,969	-	28,387	**64,014**
Lincoln	5,667	6,400	141	20,131	**32,340**
Minidoka	55,328	16,047	203	85,018	**156,597**
Oneida	2,219	-	786	8,537	**11,542**
Power	2,424	10,083	-	112,477	**124,984**
Twin Falls	42,941	31,745	390	60,122	**135,198**
Total	**244,102**	**122,628**	**3,244**	**557,029**	**927,002**

Table 10. Transportation Model Result - 5% Co-firing (wheat-straw-metric tons)

From \To	Bonanza	Carbon	Deseret	Hunter	Hntngtn	InterMT	Smelter	Sunny
Beaver						420		
Box Elder				70,209				
Cache				5,038			27,520	
Carbon				1,344				
Davis							5,588	
Duchesne	5,442							
Emery				125				
Garfield						29		
Grand				212				
Iron						1,478		
Juab						7,242		
Millard						10,321		
Morgan		2,073						
Piute				14				
Rich	484							
Salt Lake		2,414						
San Juan				241				
San Pete					2,148			
Sevier				1,551				
Tooele			399					
Utah						20,833		
Uintah	4,291							
Wasatch	167							
Wayne				552				
Weber				4,921				
Bannock						26,614		
Bear Lake	6,779							
Cassia		4278		5,469		175,152		10,569
Caribou	67,071							
Elmore								
Franklin						24,533		
Gooding								
Jerome					64,014			
Lincoln	6,722	25,617						
Minidoka				41,574	115,023			
Oneida				11,542				
Power				124,984				
Twin Falls			7,423			31714		
Total Requirement	90,956	34,381	7,822	267,775	181,185	298,337	33,108	10,569
From UT	10,384	4,486	399	84,205	2,148	40,323	33,108	10,569
From ID	80,572	29,895	7,423	183,570	179,037	258,014	-	10,569
Total(UT+ID)	90,956	34,381	7,822	267,775	181,185	298,337	33,108	10,569
% of requirement	100%	100%	100%	100%	100%	100%	100%	100%

2.4. Cost of Biomass Co-firing

The cost of electricity generation using the biomass co-firing might be more expensive than using coal. In this section, the (additional) cost of biomass-co-firing is calculated.

2.4.1. Levelized Cost of Electricity Generation

The cost of electricity generation, typically $/MWh, is calculated based on the initial capital and investment (building a power plant and a boiler), operating and maintenance costs (O&M), and fuel costs. Because the life of power plants is usually 20~40 years (Branker, Pathak, and Pearce 2011), the levelized cost over time is used. A total levelized cost is computed by:

(4) $$LEC_0 = \frac{\left(\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}\right)}{\left(\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}\right)},$$

where, LEC = (average lifetime) levelized electricity generation cost, I_t = investment expenditures in the year t (usually when $t = 0$), M_t = operations and maintenance expenditures in the year t, F_t = fuel (coal) cost in the year t, E_t = electricity generation in the year t, r = discount rate, and n = life of the power plant.

Table 11 shows the U.S. average levelized cost of power plants. According to EIA (2012)[8], the estimated LEC of conventional coal-fired power plants is minimum $91/MWh, average $98/MWh, and maximum $114/MWh. Table 12 contains regional variation in levelized cost of power plants.

[8] EIA (2012) Levelized Cost of New Generation Resources in the Annual Energy Outlook 2012, (http://www.eia.gov/forecasts/aeo/electricity_generation.cfm)

Table 11. U.S. Average Levelized Cost of Power Plants ($/MWh)[1]

Technology	Capacity Factor (%)[2]	Levelized Capital Cost	Fixed O&M	Variable O&M (+ Fuel)	Transmission Investment	Total
Conventional coal	85	64.9	4.0	27.5	1.2	97.7
Advanced coal [3]	85	74.1	6.6	29.1	1.2	110.9
Advanced coal with CCS [4]	85	91.8	9.3	36.4	1.2	138.8

[1] Source: EIA (2012) Annual Energy Outlook 2012 with Projections to 2035

[2] Capacity factor = ratio of the actual output of a power plant over a period of time and its potential output if it had operated at full capacity the entire time.

[3] Advanced coal = new technologies to reduce the environmental impact of coal, e.g., gasification

[4] CCS = carbon capture and storage technology

Table 12. Regional Variation in Levelized Cost of Power Plants ($/MWh)[1]

Technology	Minimum	Average	Maximum
Conventional coal	90.5	97.7	114.3
Advanced coal [2]	102.5	110.9	124.0
Advanced coal with CCS [3]	127.7	138.8	158.2

[1] Source: EIA (2012) Annual Energy Outlook 2012 with Projections to 2035

[2] Advanced coal = new technologies to reduce the environmental impact of coal, e.g., gasification

[3] CCS = carbon capture and storage technology

2.4.2 Levelized Cost of Biomass Co-firing

The capital costs required for co-firing projects are usually lower than those of establishing new power plants or other renewable energy projects such as wind, solar and geothermal due to the fact that co-firing systems can be done on existing infrastructure of coal power plants (Hughes 2000; Livingston 2005). Costs related to co-firing (adapting coal-based power plant to co-firing) can be divided into a few groups:

- Capital costs – modification cost of boiler,

- Fuel costs – cost of biomass acquiring, saving coal cost and
- Additional operation and maintenance cost

The following section discusses these costs in detail. For the biomass co-firing, the levelized electricity generation cost may be given by,

$$LEC_1 = \frac{\left(\sum_{t=1}^{n} \frac{I_t + I_t^B + M_t + F_t + B_t - sF_t}{(1+r)^t} \right)}{\left(\sum_{t=1}^{n} \frac{E_t}{(1+r)^t} \right)} \, , \tag{5}$$

where I_t^B = cost of modifying the existing boiler, B_t = cost of biomass procurement which is the sum of biomass purchase and the biomass transportation cost, and sF_t = coal cost saving from the biomass co-firing. Thus, the *additional LEC* is $\left(\sum_{t=1}^{n} \frac{I_t^B + B_t - sF_t}{(1+r)^t} \right) / \left(\sum_{t=1}^{n} \frac{E_t}{(1+r)^t} \right)$.

2.4.2.1. Modification of Boilers

Boilers need to be modified to introduce co-firing biomass with coal. The capital cost to set up a co-firing capability divide into two classes, depending on whether the biomass is blended with coal or fired separately from the coal. Blending requires no separate flow and injection path for the biomass and is usually lower in cost, i.e., on the order of $50,000/MW~$100,000/MW. The separate system requires costs $175,000/MW~$200,000/MW (Hughes 2000). Note that these costs are expressed per unit of power capacity ***on biomass***, not on total capacity of the power plant. For example, at 5% co-firing rate, biomass is responsible for producing 5MW electricity from 100-MW power plant. That is, the cost required for modification of broiler is for 5MW capacity of biomass not for the 100-MW capacity of the power plant.

Hence, a 100-MW boiler with 5% co-firing requires $0.5 million investment for blending system and $1 million investment for separate feed system to modify the boiler or $5/Kw[9] and $10/kW[10] for blending and separate feed system, respectively. Boiler modification cost per electricity generation unit assuming 280 days and 24 hours operation is given by $0.04/MWh and $0.09/MWh, respectively (Table 13) for 5% biomass co-firing assuming 30-year lifetime of the system with 4.5% discount rate. A 4.5% discount rate is selected as the recommendation of the Office of Management and Budget (OMB 2009).[11]

Table 13. Boiler Modification Cost ($/MWh)[1]

	Co-firing Scenarios		
	5% ($/MWh)	10% ($/MWh)	15% ($/MWh)
Blending System	$0.04	$0.09	$0.13
Separate Feed System	$0.09	$0.17	$0.26

[1] Assuming 30-year lifetime with 4.5% discount rate

2.4.2.2. Biomass Procurement Cost

One of the most sensitive factors in biomass co-firing is the cost of biomass fuel. Although the crop residues which are by-products and nominally free at the point of its generation, the costs of transportation and handling increase its effective costs per unit of energy to the extent, that it exceeds that of the coal (Baxter 2005). The biomass fuel cost can be

[9] $100k/MW × 5 MW = $500k for blending system; $200k/MW × 5 MW = $1,000k for separate feed system

[10] $500k/100MW = $5/kW and $1 million/100MW = $10/kW.

[11] "Discount rates reflect simply the particular use of interest rates to find the earlier value of expected returns" Zebre et al. (2002). $P = F/(1+r)^T$ where is P is the resent value, F is the future value and r is the discount rate. Recommended discount rates for 2010 are available at OMB Circular No. A-94 at (http://www.whitehouse.gov/sites/default/files/omb/assets/memoranda_2010/m10-07.pdf)

estimated using the transportation model given in equation (1). The biomass fuel cost in power plant *j* is given by

$$B_j = \frac{p\sum_{i}^{M} x_{ij} + \sum_{i=1}^{M} c_{ij} x_{ij}}{E_j} \quad , \tag{6}$$

where, B_j = cost of biomass procurement in power plant *j*, p = price of biomass, c_{ij} = unit transportation cost, and x_{ij} is the biomass transported from county *i* to power plant *j*.

Table 14 shows the biomass procurement cost in $/MWh at 5% co-firing from the transportation model with various biomass prices scenarios. Similarly, biomass fuel cost at 10% and 15 % are shown in Table C-3 and Table C-4 in Appendix C. Note that biomass fuel costs differ by power plant~~s~~ locations.

Table 14. Biomass Fuel Cost at 5% Co-firing ($/MWh)

	Biomass Price Scenarios			
	0	$10/ton	$20/ton	$30/ton
Bonanza	$1.37	$1.66	$1.94	$2.23
Carbon	$1.31	$1.59	$1.88	$2.16
Deseret	$1.27	$1.56	$1.85	$2.13
Hunter	$1.41	$1.69	$1.98	$2.26
Huntington	$1.44	$1.72	$1.80	$2.29
Intermountain	$1.39	$1.68	$1.93	$2.25
Smelter	$0.58	$0.87	$1.16	$1.44
Sunnyside	$1.42	$1.70	$1.99	$2.27
Average	$1.27	$1.56	$1.82	$2.13

2.4.2.3. Operation and Maintenance Cost

Operation-based costs are mainly personnel costs and maintenance cost. Usually biomass has higher operation costs than coal because of different biomass properties in comparison with coal, i.e., example, lower energy density. Higher volumes of biomass are required in comparison with coal because of the lower energy density of biomass that increases the handling and transportation cost of biomass. The O&M costs usually remain constant irrespective of the actual amount of electricity generated, but some are dependent on it, e.g. lubricants and chemicals used in the generation process (Baxter 2005). In this study, the *additional* O&M cost is estimated to be $0.02/MWh based on Cuellar (2012).

2.4.2.4. Saving Coal Cost

According to Utah Department of Natural Resources (2010), Utah power plants purchased 17 million short tons of coal in year 2008 from Utah, Wyoming and Colorado. In total, power plants in Utah spent $487 million for coal in 2008. Net generation in 2008 was 37,332 GWh. Thus, coal cost is calculated as $13.04/MWh. This research used $37.22/ton as the coal price which is the average price of coal delivered to the end use sector in 2010 (U.S. EIA 2011).

In doing so, the biomass co-firing uses 19,189 wheat-straw-tonnes of biomass and would save 13,635 tons of coal[12] for 100-MW power plant, which is $507,495.[13] Equivalently, it is $0.76/MWh.

2.4.2.5. Additional Levelized Cost of Biomass Co-firing Power Plant

Additional cost for 5% co-firing is now calculated for each power plant such that additional investment of boiler modification + cost of biomass purchasing and transporting + additional O&M cost – saving coal cost. Table 15 contains the results of additional levelized cost of biomass co-firing for the different power plants.

[12] 7,000,000,000,000 BTUs/25.67 million BTUs/ton = 272,692 tons of coal for 100 MW power plant. 5% biomass co-firing can save 272,692×5% = 13,635 tons of coal

[13] 13,635 tons of coal × $37.22/ton = $507,495

Table 15. Additional Cost of 5% Biomass Co-firing ($/MWh)[1]

	Biomass Price Scenarios			
	0	$10/ton	$20/ton	$30/ton
Bonanza	$0.67	$0.96	$1.24	$1.53
Carbon	$0.61	$0.89	$1.18	$1.46
Deseret	$0.57	$0.86	$1.15	$1.43
Hunter	$0.71	$0.99	$1.28	$1.56
Huntington	$0.74	$1.02	$1.10	$1.59
Intermountain	$0.69	$0.98	$1.23	$1.55
Smelter	-$0.12	$0.17	$0.46	$0.74
Sunnyside	$0.72	$1.00	$1.29	$1.57
Average	$0.57	$0.86	$1.12	$1.43

[1] Assuming blending system

The results from Table 15 show that additional levelized cost of biomass co-firing for different power plants ranges from $0.46/MWh~$1.29/MWh assuming the biomass price is $20/ton. The additional levelized cost for Smelter power plant is as low as $0.46/MWh comparing to other power plants. This is because Smelter power plant receives the biomass feedstock from the nearby Cache County. Bonanza, Hunter, and Sunnyside power plants receive most of their biomass feedstock from counties of Idaho, and thus the additional levelized costs are much higher than Smelter power plant.

Similarly additional costs of biomass co-firing with blending system at 10% and at 15 % co-firing are given in Table C-5 and Table C-6 in Appendix C. Note that Bonanza and Hunter power plants do not receive sufficient biomass to meet their demand at 10 % co-firing and Bonanza, Hunter and Huntington power plants do not receive sufficient biomass to satisfy their requirement at 15% co-firing rate. The additional costs of biomass co-firing are not listed for these power plants in Table C-5 and Table C-6 and not discussed.

The additional burden for different sectors is calculated using the additional cost of 5% biomass co-firing using numbers in Table 15. In year 2010, the residential sector in Utah consumed 8,834 GWh of electricity; commercial sector consumed 10,368 GWh, industrial sector used 8,808 GWh, and transportation sector utilized 38 GWh (UGS 2011). The additional burden is calculated assuming each sector consumes the same amount of electricity (Table 16).[14] As shown in Table 16, the total additional cost of biomass ranges from $18.82 million to $42.84 million depending on biomass prices. The current prevailing biomass price is $20/ton (Gallagher et al. 2003; Rankin 2012a; Rankin 2012b). The total additional cost of 5% biomass co-firing is estimated to be $34.84 million (Table 16).

Table 16. Additional Cost of 5% Biomass Co-firing by Sectors (million dollars)

	Biomass prices			
Sectors	$0	$10.00	$20.00	$30.00
Residential	5.93	8.45	10.98	13.49
Commercial	6.96	9.92	12.88	15.84
Industrial	5.91	8.43	10.94	13.46
Transportation	0.02	0.03	0.04	0.05
Total	18.82	26.83	34.84	42.84

2.5. Results and Discussion

The results from the transportation model suggest that it is essential to include southern Idaho counties to make biomass co-firing feasible for all of coal-fired power plants in Utah. The result in Table 10 shows that 5% biomass co-firing is feasible for all the power plants in Utah

[14] Additional cost of biomass co-firing by sector = Additional cost of generation * electricity consumption by sector in 2010.

with the cooperation of Idaho. Unfortunately, only a few power plants are feasible at 10% and 15% biomass co-firing.

Table 14 shows the biomass fuel cost in $/MWh for the different power plants at 5% co-firing scenario. The results suggest that the biomass fuel cost depends on the location of power plants and varies from $1.16/MWh~$1.99/MWh, assuming $20/ton of biomass price. These costs are the additional burden to use the biomass in the production of electricity. Including cost of the boiler modification, additional O&M cost, and saving coal cost, the additional levelized cost of 5% biomass co-firing with the $20/ton of biomass is given by $1.12/MWh on average (Table 15). Total (additional) cost of biomass co-firing is calculated as $34.84 million (Table 16) assuming $20/ton of biomass.

One caveat should be mentioned. The numbers and parameters used in the derivation of the additional cost for the biomass co-firing are not deterministic. In other words, crop residue production is stochastic, cost parameters in transportation model are not fixed, coal price varies, and the discount rate might be higher or lower, and thus the additional cost to Utah household is uncertain. The range analysis should be performed and derive a sort of distribution of the additional cost.

CHAPTER 3

GREENHOUSE GAS EMISSION AND BIOMASS CO-FIRING IN UTAH

Co-firing biomass with coal reduces GHG emissions (Battista, Hughes, and Tillman. 2000). Biomass co-firing has been thought as one of the efficient options for reducing GHG emissions in coal based power generation. Hughes and Tillman (1998) confirm that the biomass co-firing reduces GHG emissions. Displacing coal by biomass and preventing production of methane from biomass decomposition are the two ways of reducing GHG emission (Hughes and Tillman 1998). This chapter investigates the effect on greenhouse emissions due to co-firing biomass with coal.

3.1. Introduction

Climate change is a serious environmental threat. Increase in anthropogenic GHG concentration in the atmosphere is the major cause of this change (U.K. DECC 2010). International efforts to reduce GHG emissions and stabilize GHG concentration can be summarized in the series of international negotiations such as the Kyoto Protocol in 1997 and the Copenhagen Accord in 2009.

The United Nations Framework Convention on Climate Change (UNFCCC) is an international environmental treaty, which came into effect in 1994 with the goal of achieving the stabilization of GHG concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system. Its Kyoto Protocol was adopted in Kyoto, Japan in 1997 which entered into force in 2005; sharing the objective of the Convention to stabilize atmospheric concentrations of GHG and enabling such a global response to climate change. The major feature of the Kyoto Protocol is that “Annex I Party has a binding commitment to limit or reduce GHG emissions” (UNFCCC 2008). Under the Kyoto Protocol, the

U.S. is required to reduce its emission by 7% from its 1990 level by the year 2012 (UNFCCC 2008).[15] Similarly according to Copenhagen Accord, the U.S. should reduce 17% of its GHG emission below 2005 levels by 2020, which can be the serious burden of the US economy (UNFCCC 2009). The American Clean Energy and Security Act (ACES) of 2009 establishes emission caps that would reduce GHG emissions to 17% below 2005 levels in 2020, 42% below 2005 levels in 2030, and 83% below 2005 levels in 2050 (Center for Climate and Energy Solutions 2009) .

Although coal-fired power plants only accounted for 45% of US electricity in 2010, it was responsible for 81% of total U.S. CO_2 emissions in 2010 (EIP 2011). In the U.S., the coal-fired power plants emitted 1.9 billion tons of CO_2 in 2009 (U.S. EIA 2009). In Utah, the coal-fired power plants emit 35.52 million metric tons of CO_2 (U.S. EIA 2010). Scientists, economists and policy makers are searching for the least cost technologies to reduce GHG emissions. Battista et al. (2000) demonstrated that the biomass co-firing is the one of lowest cost methods for generation green power and reducing GHG emission. They reported that 7% biomass co-firing at Steward Station power plant in Ohio reduced SO_2 emission by 7%. Mann and Spath (2001) showed that the use biomass for electricity generation lessened CO_2 and NO_x emission by 2% and SO_2 emission by 3% at 5% co-firing rate. De and Assadi (2009) also concluded that the biomass co-firing with coal in generating electricity is a prospective and an effective way for reducing GHG emissions.

3.2. How Biomass Co-Firing Reduce GHG Emission?

Numerous studies, for example, Hughes and Tillman (1998), McCarl et al. (2000), Demirbas (2003), and Qin et al. (2006) indicated that the biomass co-firing reduces CO_2

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[15] The U.S. has not ratified the Kyoto Protocol (UNFCCC-Status of Ratification of the Kyoto Protocol, available at http://unfccc.int/kyoto_protocol/status_of_ratification/items/2613.php).

emissions by absorbing CO_2 during growth (photosynthesis) and emitting it at the time of combustion. Biomass is considered nearly a zero net CO_2 emission fuel source as it emits the same amount of CO_2 which they absorb during growth (Demirbas 2003).

A *life cycle assessment* (LCA) is the way to quantify the GHG emission effect from the biomass co-firing. The LCA was created as "a valuable decision-support tool for both policy makers and industry in assessing the cradle-to-grave impacts of a product or process" (Global Development Research Center 2004). Global Development Research Center (2004) specifies the LCA as "the assessment includes the entire life cycle of the product or service, encompassing, extracting and processing raw materials; manufacturing, transportation and distribution; use, re-use, maintenance; recycling, and final disposal."

Most of the research on bio-energy production processes in the U.S. uses a LCA to quantify the overall environment impacts associated with a product or service. For example, Qin et al. (2006) used the LCA approach to examine the competitiveness of switchgrass as a biomass resource for power generation. Mann and Spath (2001) also employed the LCA approach to a coal-fired power system that co-fires wood residue capturing all processes necessary for the operation of the power plant, including raw material extraction, feed preparation, transportation, and waste disposal and recycling. Analysts from the U.S. National Bioenergy Center at National Renewable Energy Laboratory (NREL) also applied the LCA to determine the environmental impacts of biomass conversion technologies, using a cradle-to-grave approach that includes biomass feedstock growth, harvest, conversion, and product use (U.S. DOE/EERE 2003).

In this study, findings of Mann and Spath (2001), Sebastian et al. (2007), Tillman (2001), and U.S. DOE/EERE (2000) are used to estimate CO_2 emission reduction from replacing coal with biomass in the electricity generation (Table 17). As shown in Table 17, CO_2 emission may decrease by 2% (Mann and Spath 2001) to 6% (U.S. DOE/EERE 2000).

Table 17. CO_2 Emission Reduction at 5% Biomass Co-firing

Sources	Emission Reduction	Emission Reduction in Utah[a]
Mann and Spath (2001)	2.0%	0.71 million tons
Sebastian el al. (2007)	5.3%	1.88 million tons
U.S. DOE/EERE (2000)	6.0%	2.13 million tons

[a] Utah CO_2 emission in 2010 = 35.52 million metric tons of CO_2

3.3. GHG Emissions and Economic Benefit of Biomass Co-firing in Utah

CO_2 emission from coal-fired power plants in Utah is estimated to be 35.52 million metric tons of CO_2 in the year 2010 (US EIA 2010c). The last column of Table 17 shows that 5% biomass co-firing may reduce CO_2 emission in Utah by 0.71~2.13 million metric tons of CO_2. The economic benefit of reduction in CO_2 emission can be quantified assuming Utah can sell these reductions as the carbon credits in the carbon trading markets such as Chicago Climate Exchange (CCX) or European Climate Exchange (ECX). Annual economic benefits from carbon trading are dependent upon the carbon price in the market. According to the Intercontinental Exchange (2012) the carbon trading price was $7.40/ton of CO_2 in the CCX in the year 2007 and the current price of CO_2 in the ECX is about 13 Euro (= $16) as of September 2012 (Kossoy and Ambrosi 2010). The carbon prices may rise up to $20/ton~$36/ton in the year 2020 according to Synapse Energy Economics, Inc. (2011).

Economic benefits from carbon trading are calculated based on CO_2 emission reduction in Table 17 and plausible carbon prices in the trading market discussed above. Table 18 contains the results. As shown in Table 18, economic benefits depend on the carbon price. Economic benefits range $5.26 million to $86.65 million. A moderate economic benefit estimate would be $30.12 million. The economic benefit rises to $37.65 million in the near future (year 2020) with $20/ton of CO_2 as forecast by Synapse Energy Economics, Inc. (2011).

Table 18. Economic Benefit from CO_2 Trading (million dollars)

	CO_2 price			
Emission Reduction	\$7.40	\$16.00	\$20.00	\$36.00
Mann and Spath (2011)	5.26	11.37	14.21	25.57
Sebastian el al. (2007)	13.93	**30.12**	37.65	67.77
U.S. DOE/EERE (2000)	15.77	34.10	52.55	86.65

3.4. Results and Discussion

The estimates from Mann and Spath (2001), Sebastian et al. (2007), and U.S. DOE/EERE (2000) studies given in Table 17 are used to calculate the amount of CO_2 emission reduction from the 5% biomass co-firing. Results show that CO_2 emission would be decreased by 2%~6% at 5% biomass co-firing due to the fact that biomass is nearly a zero CO_2 emission fuel. Based on 2010 emission record in Utah, 5% biomass co-firing might reduce 0.71~2.13 million metric tons of CO_2 and, in turn, bring the annual economic benefit of \$11.37~\$34.10 million assuming \$16/ton of CO_2 in the emissions trading market. The total benefit increases to \$14.21~\$52.55 million with \$20/ton of CO_2 in the near future (year 2020) as projected by Synapse Energy Economics, Inc. (2011). This is possible only if the power plants are able to sell CO_2 credits from the biomass co-firing.

The biomass co-firing may also improve the public health from the fact that the biomass co-firing reduces PM emission which affects the human health negatively. It is discussed in the next chapter.

CHAPTER 4

BIOMASS CO-FIRING AND PUBLIC HEATH

4.1. Introduction

The biomass co-firing has multiple benefits as described in the previous chapters, which are (i) achieving a regional RPS goal (chapter 2), (ii) reducing GHG emissions (chapter 3), and (iii) reducing harmful air pollutants such as particulate matters (PM) (this chapter). Many previous studies associated with biomass co-firing have focused on the feasibility and potential of biomass co-firing and implications of greenhouse gas emissions, i.e., benefits (i) and (ii); for instance, McCarl et al. (2000), English et al. (2004), Ismayilova (2007), Muang (2008), and De and Assadi (2009).

It is rare, however, to investigate and *quantify* the benefit of reducing PM emission. This chapter attempts to measure the (monetary) value of reducing PM emissions in terms of improving human health or avoiding adverse health incidents. These benefits are understood as the co-benefit (positive externality) of the biomass co-firing.

4.2. Particulate Matter and Human Health

Coal-fired power plants directly emit PM as well as other harmful air pollutants such as SO_2 and NO_x, which undergo chemical reactions to form fine particles in the atmosphere. These emissions increase the ambient concentration of PM less than 2.5 microns in diameter (PM25) and in the atmosphere over hundreds miles downwind of the power plants which depends upon the direction of the wind and the surrounding geography (Penney, Bell, and Balbus 2009).

Fine particles can affect the heart and lungs and cause serious health effects. When PM25 particles inhaled by people, some of them deposit along the respiratory tract, while others penetrate deeply into the lung where they can enter the bloodstream. These particles aggravate the severity of chronic lung diseases and impair airway functions, and cause inflammation of lung tissue which results in the release of chemicals that impact heart functions and leads to changes in blood chemistry that produces clots which can cause heart attacks (U.S. EPA 2012).

According to U.S. EPA (2009b), exposure to PM emitted from coal-fired power plants is responsible for causing cardiovascular including heart attacks and its associated mortality; also a cause of hospital admissions for breathing problems, respiratory illness such as asthma; and is linked to other adverse respiratory, reproductive, developmental and cancer outcomes. Recent epidemiological studies have shown that high levels of PM are closely correlated with substantial adverse health effects such as acute respiratory infections and mortality in the short-term (Chen et al. 2000; Sastry 2002; Tham et al. 2009). Long-term exposure to the combustion-related PM and the SO_2-related air pollution could lead to cardiopulmonary and lung cancer (Viswanathan et al. 2006).

Dockery, Schwartz, and Spengler (1992), Pope (2000), and Pope, Burnett, and Thun (2002) quantify the effects of chronic exposure of PM and conclude that exposure to PM25 has been consistently linked with increased mortality from cardiopulmonary diseases, lung cancer and numerous other respiratory illnesses and associated morbidity. Pope (2000) and Pope et al. (2002) also find that a 10μg/m^3 increase in ambient PM25 concentration was associated with approximately a 4% increased risk of all-causes of mortality, a 6% increased risk of cardiopulmonary mortality, and a 8% increased risk of lung cancer mortality.

4.3. Econometric Model

To measure the co-benefit of the biomass co-firing the following damage equation is introduced:

(7) $$D = f(e, \mathbf{x}) + \varepsilon\ ,$$

where, $D(e)$ is the (monetary) health damage from PM25 emission including mortality, acute respiratory diseases (asthma, bronchitis), heart attack and work day loss. [16] The variable e is the PM25 emission and $\mathbf{x}$ is a vector of other factors to affect the human health, e.g., population density, personal income, and weather conditions (e.g., wind speed and temperature) in a region where the power plant located. It is expected that the sign of PM25 is positive which implies more emission causes more health damage.

4.4. Data

To estimate equation (7), the health damage, PM25 emission and other relevant data are required. This section explains how these data were compiled.

4.4.1. Health Damage

The health damage due to PM25 emitted from coal-fired power plants is collected from *Death and Disease from Power Plant* prepared by The Clean Air Task Force (2010).[17] The impact on human health, total health damage, is the sum of monetary expenses or estimated monetary losses due to the health damages from PM25. Abt Associates (2010) report how to estimate and calculate these monetary expenses or losses from the human health damages caused by the air pollutants, especially from PM.

Abt Associates (2010) performed multiple steps for calculating monetary damages linked with PM25 emissions. First, PM25 emissions are calculated from the different electricity

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[16] The health damages include mortality, acute bronchitis, heart attacks, asthma attacks, chronic bronchitis, asthma related emergency room visits, cardiovascular related hospital admission, respiratory related hospital admission, and also the acute illness and symptoms not requiring hospital admission such as lower respiratory system problems, upper respiratory system problems, minor restricted activity days and work loss days.

[17] Death and Disease from Power Plant. Additional Resources: Data Annex (CATF 2010); http://www.catf.us/fossil/problems/power_plants/existing/

generation units, and, in turn, the impacts on ambient air quality were calculated. Second, using the epidemiological studies and literature to quantify the effect of PM25, adverse health impacts and number of incidents are estimated. Once the numbers of adverse health impacts are estimated, the economic damages associated these incidents are computed. For example, the mortality is evaluated for loss of $7.3 million, chronic bronchitis costs $440,000, and asthma ER visit evaluated for the loss of $370. Table 19 contains averages of the health damage in the U.S. Table D-1 in Appendix D contains the total of the health damage estimates over the US states.

Figure D-1 in Appendix D represents national mortality effects from existing power plants and their geographical distribution. Figure D-1 is taken from the Clean Air Task Force (CATF) study on the impacts on human health caused by the fine particles air pollution emitted by roughly 500 power plants in the U.S. As shown in Figure D-1, those areas with the higher concentration of coal-fired power plants (indicated by black dots on the map) clearly bear a disproportionate share of the aggregate burden of adverse impacts.

Table 19. Health Damage due to PM25 Emission in the U.S. (million dollars)

Health Damage	Average	St. Dev.	Max	Median	Min
Mortality	218.31	250.02	2,029.93	128.72	2.27
Acute Bronchitis	0.02	0.02	0.16	0.01	0
Heart Attacks	5.06	5.78	48.7	3.02	0.05
Asthma Attacks	0.03	0.03	0.23	0.01	0
Chronic Bronchitis	8.07	9.17	73.25	4.73	0.1
Asthma ER Visits	0.01	0.01	0.09	0.01	0
Cardio Hosp Adm	0.41	0.48	3.87	0.24	0
Resp Hosp Adm	0.10	0.11	0.92	0.06	0
LRS[1]	0.01	0.01	0.09	0.01	0
MRAD[2]	1.34	1.52	12.07	0.79	0.02
URS[3]	0.01	0.01	0.1	0.01	0
WLD[4]	0.33	0.38	3.06	0.2	0

Source: Data Annex (http://www.catf.us/fossil/problems/power_plants/existing/)

[1] LRS = Lower Respiratory System Problems, [2] MRAD = Minor Restricted Activity Days, [3] URS = Upper Respiratory System Problems, and [4] WLD = Work Loss Days

4.4.2. PM25 Emission

PM25 emission data for each power plant are not available publicly and therefore, it needs to be estimated. Here is how to estimate the PM25 emission data. First, net generation and the name plate capacity for state are identified from the U.S. EIA database[18] and the capacity of each power plant is obtained from Source Watch Data.[19] Also, the net electricity generation and the net power plant capacity of the U.S. for 2010 are obtained from Electric Power with Annual Data (U.S. EIA 2010b).[20]

Net days of operation of the power plant, day_j, is calculated with the use of net electricity generation and the nameplate capacity as in equation (8).

(8) $$day_j = \frac{elec_j}{24cpct_j},$$

where, day_j = operation days for jth state, $elec_j$ = net electricity generation in jth state, and $cpct_j$ = nameplate capacity of the jth state.

On average, all the power plant operated 280 days in 2010. Using the results from equation (8), net generation in each power plant i in the state j, $elec_{ij}$, is calculated using equation (9).

(9) $$elec_{ij} = cpct_{ij} \cdot day_j \cdot 24$$

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[18] "Nameplate Capacity is equal to Design Capacity for which the plant was built and is the volume of ethanol that can be produced during a period of 12 months under normal operating conditions" U.S. EIA-819 (Monthly Oxygenate Report). Q: What is Nameplate Capacity?
Existing Nameplate and Net Summer Capacity by Energy Source, Producer Type and State (EIA-860) (http://www.eia.gov/electricity/data/state/)

[19] State level Power plant capacity data
(http://www.sourcewatch.org/index.php?title=Category:Existing_coal_plants_in_Utah)
(http://www.eia.gov/survey/faqs/oxygenate.html#q5).

[20] 1990-2010 Net Generation by State by Type of Producer by Energy Source (EIA-906, EIA-920, and EIA-923) (http://www.eia.gov/electricity/data/state/)

where, $elec_{ij}$ = net generation of ith power plant in jth state, $cpct_{ij}$ = the nameplate capacity of ith power plant in jth state. PM25 emission in each power plant now can be estimated as follows:

(10) $$e_{ij} = 9.2 \cdot elec_{ij}$$

where, e_{ij} = PM25 emission from ith power plant in jth state, and 9.2 (kg/MWh) is PM25 emission coefficient from Mann and Spath (2001). Table 20 summarizes the total health damage due to PM25 emission estimates over regions.

Table 20. Regional Health Damage due to PM25 Emission (million dollars)

Regions	Total Health Damage	Number of Power Plants	Health Damage per Power Plant	St. Dev.	CV	Max	Med	Min
East South Central	1,509.6	34	44.4	29.9	67.3	109.1	34.5	2.1
Rocky Mountain	1,329.0	30	44.3	47.2	106.5	146.5	19.3	2.2
West South Central	2,002.6	31	64.6	45.5	70.4	233.1	51.1	17.7
Pacific	124.0	4	31.0	35.4	114.2	78.3	21.4	2.8
New England	134.1	9	14.9	14.8	99.3	50.4	8.4	0.8
South Atlantic	3,405.6	88	38.7	37.9	97.9	166.0	24.2	1.8
East North Central	3,914.0	103	38.0	35.7	93.9	163.7	26.4	0.7
West North Central	1,938.8	74	26.2	28.5	108.8	129.7	13.6	0.8
Mid Atlantic	1,176.0	40	29.4	33.6	114.3	137.9	17.1	0.7
Utah	344.6	6	57.4	41.4	82.1	102.1	46.6	3.6

Regions: New England = CT, ME, MA, NH; Mid Atlantic = NJ, NY, PA; East North Central = IL, IN, MI, OH, WI; West North Central = IA, KS, MN, MO, NE, ND, SD; South Atlantic = DE, FL, GA, MD, NC, SC, VA, WV; East South Central = AL, KY, MS, TN; West South Central = AR, LA, OK, TX; Mountain (base region) = AZ, CO, MT, NV, NM, UT, WY; Pacific = CA, OR, WA

4.4.3. Other Explanatory Variables

Per capita income, population density, and weather variables such as average temperature and average wind speed, are included in the regression model because these factors may affect the public health impact. Per capita income was obtained from the U.S. Bureau of Economic Analysis. Population density was collected from the State and County Quick Facts in the U.S. Census Bureau Average temperature and average wind speed were collected from the Weather History, Weather Underground. Table 21 contains the U.S. level basic statistics of all the data. Note that other explanatory variables are based on county level where the power plants are located.

Table 21. Other Explanatory Variables – County Level Where Power Plants Located

U.S.	Population Density[1] (per sq miles)	Per Capita Income[2] (dollars)	Average Temperature[3] (Fahrenheit)	Average Wind Speed[3] (miles per hour)
Average	423.80	35,080	55.39	6.53
Std. Dev.	902.65	6,658	6.67	2.01
CV	212.99	18.98	12.05	30.78
Maximum	9,999.90	76,362	73.00	13.00
Median	132.30	33,922	55.00	7.00
Minimum	1.70	22,492	41.50	1.00

[1] County level population densities are collected from the QuickFacts in the U.S. Census Bureau (2012a) (http://quickfacts.census.gov/qfd/index.html).

[2] Per capita income is collected from the US BEA (2012)

[3] Average temperature and average wind speed are collected from Weather History, Weather Underground (http://www.wunderground.com/history/)

4.5. Results and Discussion

4.5.1. Estimation

Preliminarily, the scatter plot was created to see if there was the meaningful relationship between PM25 emission and total health damage (Figure 1). As shown in Figure 1, there exists a strong positive relationship indicating that more PM25 emission causes more health damage. The scatter plot in Figure 1 shows that there may exist a heteroscedasticity problem.[21]

To quantify the health benefit from the biomass co-firing, three log-log regression models are specified as in Table 22 and Table 23 (Models 1 to 2) and Table D-2 (Model 3). Model 1 includes PM and other explanatory variables such as population density, per capita income, average temperature and average wind speed to observe whether these parameters have any effects on the health damage. Model 2 includes aggregate regional dummies while Model 3 includes state dummies. Both Model 2 and Model 3 capture any state or regional level variability in the health damage because of the use of state and regional dummies.

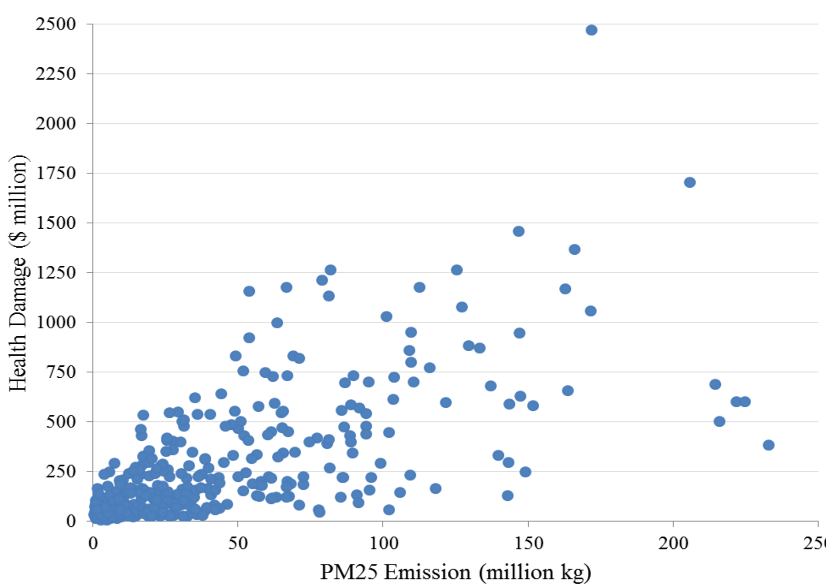

Figure 1. Scatter Diagram for PM25 Emission and Health Damage in 2010

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[21] These scatter plot reveals an appropriate linear relationship between X and the Y, but more importantly it also reveals a statistical condition referred to as heteroscedasticity (that is, nonconstant variation in Y damage over the values of X). For a heteroscedastic data set, the variation in Y differs depending on the value of X {Engineering Statistics Handbook-1.3.3.26.9. Scatter Plot: Variation of Y Does Depend on X (heteroscedastic)}. Scatter plot also helps in guessing the square error plot which is used for interpreting heteroscedasticity.

Because the health damage and PM25 emission data are based on cross-sectional units, individual counties in the U.S., there might exist the heteroscedasticity problem as shown in Figure 1. Breusch-Pagan (BP) test is performed with OLS estimates. The BP test rejects the homoscedasticity hypothesis for Models 1 (see notes below Tables 22) but fails to reject the homoscedasticity hypothesis for Model 2 and 3 (see notes below Tables 23 and D-2 in Appendix D).

4.5.2. Regression Results

Regression results are reported in Tables 22, 23, and D-2 in Appendix D. As shown in Model 1, 2, and 3, PM25 emissions have a positive and statistically significant effect on the health damage. The health damage has the positive relationship with population density which is expected; the more people in the region, the more will be affected by PM25 emission and concentration, and thus the more health damage. Average wind speed has the negative effect which implies that a strong wind disperse the PM25 emissions quickly and lessens concentrations, and thus reduces health damage. The average temperature has the negative effect. This is because the excessive outside temperature restricts people in going outside, thus the estimated results have the negative sign.

All three models in Table 22, and 23 (Models 1 to 2), and Table D-2 (Model 3) in Appendix D have the similar estimates for PM25 emission, 0.65~0.67. These estimates are interpreted as elasticity of the health damage with respect to the PM25 emission (log-log model). In other words, the public health would be improved by 0.65%~0.67%, or the monetary heath damage would be decreased by 0.65%~0.67%, when PM25 emissions were reduced by 1%.

Table 22 Health Damage Regression Results of Model 1 (Log-Log Model)

Health Damage	Coef.	Robust Std. Err.[1]	T-statistic
PM25 Emission	0.6697****	0.039	17.36
Pop Density	0.1878****	0.037	5.12
Per Capita Income	-0.4299	0.429	-1
Average Temperature	-1.5589***	0.646	-2.41
Average Wind Speed	-0.4252****	0.143	-2.97
Constant	13.4695***	6.367	2.12
R^2	0.5347		
F	70.12	Prob > F = 0.000	
No. of Obs.	356		

**** 1%, *** 5%, ** 10%, and * 15% significance level[1]

[1]The standard errors are biased when heteroscedasticity is present. Test for heteroscedasticity: Breusch-Pagan test χ^2 =16.18 (P-value = 0.0001). To fix the problem robust standard errors are used.

Table 23. Health Damage Regression Results of Model 2 (Log-Log Model)

Health Damage	Coef.	Robust Std. Err.	T-statistic
PM25 Emission	0.6549****	0.030	21.44
Pop Density	0.0336	0.039	0.87
Per Capita Income	0.1584	0.377	0.42
Average Temperature	-1.1953*	0.809	-1.48
Average Wind Speed	-0.1682	0.150	-1.12
New England[2]	0.1288	0.437	0.29
Mid Atlantic	1.1801****	0.178	6.64
East North	1.3238****	0.159	8.33
West North	0.6614****	0.150	4.4
South Atlantic	1.1655****	0.165	7.07
East South	1.3187****	0.176	7.5
West South	0.4989***	0.237	2.11
Pacific	-1.2766****	0.195	-6.53
Constant	5.2681	6.459	0.82
R^2	0.6649		
F	80.82	Prob > F = 0.00	
No. of Obs.	356		

**** 1%, *** 5%, ** 10%, and * 15% significance level

[1]The standard errors are biased when heteroscedasticity is present. Test for heteroscedasticity: Breusch-Pagan test χ^2 =1.15 (P-value = 0.283). In Model 3 heteroscedasticity is not present; however, robust standard errors are used.

[2]Regional dummies: New England=CT, ME, MA, NH; Mid Atlantic=NJ, NY, PA; East North Central=IL, IN, MI, OH, WI; West North Central=IA, KS, MN, MO, NE, ND, SD; South Atlantic= DE, FL, GA, MD, NC, SC, VA, WV; East South Central=AL, KY, MS, TN; West South Central=AR, LA, OK, TX; Pacific=CA, OR, WA; Mountain (base region which was left out)=AZ, CO, MT, NV, NM, UT, WY

4.6. Economic Benefit from Reducing PM Emission

The regression of the human health on PM25 emission shows that in U.S. decreases in 1% of PM25 emission improves the human health by 0.65%~0.67% in value. This might not be the same for Utah because the power plants in Utah are not located in the populated regions and the damage in health depends upon the location of power plants, plume direction, population density, geological characteristics, etc. The elasticities in the regression model are for the U.S. and thus the economic benefit from reducing PM emission in Utah might be lower than the U.S. average. The estimates in regression models should be interpreted with caution.

Findings of Mann and Spath (2001), and Electric Power Research Institute (2003) are used to estimate PM emission reduction from replacing coal with biomass in the electricity generation (Table 24). As shown in Table 24, PM emission may decrease by 3% (Mann and Spath 2001) to 4.3% (Electric Power Research Institute 2003).

Table 24. PM Emission Reduction at 5% Biomass Co-firing

Sources	Emission Reduction
Mann and Spath (2001)	3.0%
Electric Power Research Institute (2003)	4.3%

Table 25. Economic Benefit of PM Emission Reduction from 5% Co-firing (million dollars)

Emission Reduction	Elasticities	
Potential	0.65	0.67
Low.PM (3%)	6.72	6.93
Medium.PM (3.65%)[a]	8.18	8.43
High.PM (4.3%)	9.63	9.93

[a] average between 3% and 4.3%

Based on Mann and Spath (2001) and Electric Power Research Institute (2003) studies shown in Table 24, 5% biomass co-firing reduces PM25 emission by 3%~4.3%, and thus it improves the human health by 1.95%~2.79% and 2.01%~2.88%, respectively. The annual economic benefits from PM emission reduction from biomass co-firing are estimated to be $6.72 million~$9.93 million (Table 25).

4.7. Conclusion

Coal-fired power plants are major PM25 emitter. PM25 is a major pollutant that causes serious adverse impacts on human health. The regression results illustrate that the biomass co-firing can improve the public health in reducing PM25 emission from the coal based power plants. The health damage is reduced by 0.65%~0.67% with 1% reduction in PM emission, equivalently, 5% biomass co-firing improves the human health by $6.72~$9.93 million. Note that these estimates might not be the precise economic benefit from the biomass co-firing in Utah because elasticities estimated in the regression are expected to be lower in Utah due to the fact that most of power plants in Utah are located in open areas.

CHAPTER 5

BENEFIT COST ANALYSIS

5.1. Introduction

Chapters 2, 3, and 4 discussed the additional cost of the biomass co-firing and economic benefits from the biomass co-firing including GHG and PM emission reduction. Benefit-Cost analysis is conducted to examine if the biomass co-firing in Utah is economically feasible under the various circumstances. Scenarios for benefit-cost analysis are constructed based on three components, i.e., biomass price, carbon price and amount of emission reduction from the biomass co-firing. A total of 36 scenarios are formed with three biomass prices ($10, $20 and $30), four carbon prices ($7.4, $16, $20, and $36), three emission reduction combinations [CO_2 emission reduction-PM emission reduction; 2%~3% (low), 5.3%~3.7% (medium), and 6%%~4.3% (high)]. Table 27 summarizes all of these scenarios.

Table 26. Construction of Scenarios for Benefit-Cost Analysis

Biomass Prices[a]	Carbon Prices[b]	Emission Reduction[c] (5% Biomass Co-firing)		
			CO_2	PM
$10/ton	$7.4/ton	Low	2.0%	3.0%
$20/ton	$16/ton	Medium	5.3%	3.7%
$30/ton	$20/ton	High	6.0%	4.3%
	$36/ton			

[a] Based on Gallagher et al. (2003), Rankin (2012a), and Rankin (2012b).
[b] Based on CCX and ECX historical price records (ICE 2012), and Synapse Energy Economic, Inc. (2011)
[c] Based on Mann and Spath (2001), Sebastian et al. (2007), and U.S. DOE/EERE (2000)

5.1.1. Additional Cost of Biomass Co-firing

Table 27 presents the additional costs of the biomass co-firing with various biomass prices using results in chapter two (also Table 16). The additional costs of the biomass co-firing are distributed to various economic sectors depending upon their electricity consumptions. Table 27 shows that the total additional costs of the biomass co-firing range from $26.82 million to 42.84 million. The current biomass (crop residue) price is about $20/ton (Gallagher et. al. 2003; Rankin 2012a; Rankin 2012b) and thus the most plausible estimate of the additional cost of the biomass co-firing would be $34.84 million. The additional cost of the biomass co-firing on residential areas is estimated to be $10.98 million (Table 27) which is equivalent to be $12.76/household assuming the number of household in Utah is 860,000 (U.S. Census of Bureau 2012b).

Table 27. Additional Cost of 5% Biomass Co-firing (million dollars)

	Sector				
Biomass Prices	Residential	Commercial	Industrial	Transportation	Total
$10/ton	8.45	9.92	8.43	0.03	26.82
$20/ton	10.98	12.88	10.94	0.04	**34.84**
$30/ton	13.5	15.84	13.46	0.05	42.84

5.1.2. Economic Benefit of Biomass Co-firing

Economic benefits from the biomass co-firing under various scenarios are summarized in Table 29 using results from chapters three and four. Economic benefits from the biomass co-firing are dependent upon carbon prices in the trading market and the amount of emission reduction from the biomass co-firing. With low CO_2 and PM emission reduction scenario (see Table 26) and the low carbon price ($7.40/ton of CO_2), the economic benefit is estimated to be only $12.19 million (Table 28). The economic benefit rises to $21.14 million when the carbon price reaches \$20/ton of CO_2 (Table 28). The economic benefit increases to \$22.36~\$76.20 million with the medium emission reduction scenario (see Table 27) and rises even more with the high emission reduction scenario. The current carbon price in the ECX is around \$16/ton of CO_2 and thus the most plausible estimate of the economic benefit from the biomass co-firing would be \$38.55 million. In the year 2020, the carbon price is expected to increase up to \$20~\$36/ton of CO_2 (Synapse Energy Economics, Inc. 2011) depending on energy consumptions, government policies and legislation, and international negotiations. Some other studies, for example, US EPA (2008),[22] forecasts the carbon price even higher than \$60/ton of CO_2. The economic benefit rises to \$46.08 million with \$20/ton of CO_2 with the medium emission reduction scenario (Table 28).

Table 28. Economic Benefits from 5% Biomass Co-firing (million dollars)

Emission Reduction Potential	CO_2 price			
	\$7.40	\$16.00	\$20.00	\$36.00
Low.CO_2	5.26	11.37	14.21	25.57
Low.PM	6.93	6.93	6.93	6.93
Low.Total	**12.19**	**18.29**	**21.14**	**32.50**
Medium.CO_2	13.93	30.12	37.65	67.77
Medium.PM	8.43	8.43	8.43	8.43
Medium.Total	**22.36**	**38.55**	**46.08**	**76.20**
High.CO_2	15.77	34.10	42.62	76.72
High.PM	9.93	9.93	9.93	9.93
High.Total	**25.70**	**44.03**	**52.55**	**86.65**

5.2. Benefit/Cost Ratio and Economic Feasibility

Benefit/Cost ratio of the biomass co-firing with various emission reduction scenarios (low, medium, and high) at different biomass and carbon prices are shown in Table 29. The biomass co-firing is economically feasible when the benefit cost ratio is greater than 1. That is

[22] EPA (2008) *Analysis of the Lieberman-Warner Climate Security Act of 2008 – S. 2191 in 110th Congress*. Available at http://www.epa.gov/climatechange/economics/economicanalyses.html

highlighted in grey in Table 29. As shown in Table 29, the five percent biomass co-firing is economically feasible with high carbon prices, low biomass prices and high emission reduction potential (southeast corner of Table 29).

It is noteworthy that two key factors to make the biomass co-firing economically feasible are the emission reduction potential and the carbon price. If the biomass co-firing has the low emission reduction potential, it may not be economically feasible in general. If the biomass co-firing has the medium and high emission reduction potential, it would be economically feasible with moderate carbon prices (≈ \$16/ton of CO_2). The most plausible estimate of the benefit cost ratio would be 1.107 assuming the medium emission reduction potential with biomass price of \$20/ton and carbon price of \$16/ton of CO_2.

Table 29. Benefit/Cost Ratio of 5% Biomass Co-firing*

Emission Reduction Potential	Biomass Prices	CO_2 Price			
		\$7.40	\$16.00	\$20.00	\$36.00
Low	\$30	0.284	0.427	0.493	0.759
Low	\$20	0.350	0.525	0.607	0.933
Low	\$10	0.454	0.682	0.788	1.212
Medium	\$30	0.522	0.900	1.076	1.779
Medium	\$20	0.642	$\boxed{1.107}$	1.323	2.188
Medium	\$10	0.834	1.437	1.718	2.841
High	\$30	0.600	1.028	1.227	2.023
High	\$20	0.738	1.264	1.509	2.488
High	\$10	0.958	1.641	1.959	3.230

* Biomass co-firing is economically feasible when B/C ratio is greater than 1 that is in grey cell.

CHAPTER 6

CONCLUSION AND FUTURE STUDIES

National energy security, climate change and global warming, and environmental concerns are major factors that drive the nation's interests of using biomass for energy production, especially in generating electricity. This research examines economic implications of co-firing agricultural residues with coal to produce electricity in Utah. Agricultural crop residues such as corn stover, and barley, oats and wheat straw are considered as the potential feedstock for the biomass co-firing in coal-fired power plants.

A transportation model was built to examine the physical feasibility of biomass supply in Utah. As discussed in Chapter 2, Utah may not supply enough biomass feedstock for all of the coal-fired power plants in the state. Without making any further adjustment the biomass co-firing seems less feasible in Utah. One policy recommendation is to include southern Idaho counties. It is plausible option because southern Idaho provides plentiful biomass and there is no coal-fired power plant in southern Idaho. Once these counties were included in the transportation model, all of Utah coal-fired power plants have sufficient biomass supply at 5% co-firing rate.

The results in Chapter 2 suggest that the biomass fuel cost depends on the location of power plants and varies from \$1.16/MWh~\$1.99/MWh, assuming \$20/ton of biomass price. These costs are the additional burden to use the biomass in the production of electricity. Including cost of the boiler modification, additional O&M cost and saving coal cost, the additional levelized cost of the 5% biomass co-firing with the \$20/tons of biomass is given by \$1.12/MWh on average (Table 15). The additional costs of the biomass co-firing are distributed to various sectors depending upon their electricity consumptions. The total additional cost of the biomass co-firing is estimated to be \$34.83 million.

Meanwhile, 5% biomass co-firing brings the economic benefits from reducing GHG emission (Chapter 3) and PM emission (Chapter 4). Numerous studies indicate that the biomass co-firing reduces CO_2 emissions by absorbing CO_2 during growth (photosynthesis) of biomass feedstock and emitting it at the time of combustion. The biomass is considered a near zero net CO_2 emission fuel source. It brings a benefit of $5.26 million from CO_2 emission reduction and carbon trading with the price of $7.40/ton of CO_2 and low emission reduction potential of the biomass co-firing (Table 28). The biomass co-firing brings a benefit of $76.72 million from CO_2 emission reduction and carbon trading with the price of $36/ton of CO_2 and high emission reduction potential (Table 28).

The biomass co-firing also reduces PM emission which causes negative impacts on human health, especially causing cardiovascular and respiratory illness. The regression of the human health on PM25 emission shows that decreases in 1% of PM25 emission in U.S. improves the human health by 0.65%~0.67% in value. This might not be the case for Utah because most of health damages from PM25 occur in the populated Eastern state of the U.S. The economic benefit ranges from $6.93~$9.93 million (Table 28) depending upon the emission reduction potential. In total, the economic benefit is estimated to be $12.19~$86.65 million. The most plausible estimate of the economic benefit is given by $38.55 million with the medium emission reduction potential, moderate carbon price (≈ $16/ton of CO_2) and biomass price (≈ $20/ton).

Two key factors to make the biomass co-firing economically feasible are the emission reduction potential and the carbon price. If the biomass co-firing has the low emission reduction potential, it may not be economically feasible in general. If the biomass co-firing has the medium and high emission reduction potential, it would be economically feasible with moderate carbon prices. The most plausible estimate of the benefit cost ratio would be 1.107 assuming the medium emission reduction potential with biomass price of $20/ton and carbon price of $16/ton of CO_2.

In presenting this research, several limitations should be mentioned. First, the results in this research might not be extended to other states because the biomass purchase and transportation cost will differs with the state. The transportation cost might be less or higher in other state according to the availability of biomass niches and supply regions. Second, benefits and costs of the biomass co-firing are subject to change because some of the parameters vary with the state and some of the parameters fluctuate with international market. For example, the price of coal, power plant operation days vary with the state while the price of CO_2 fluctuates with the international market. The range analysis or simulation with the various parameters would reveal the distribution of benefits and costs of the biomass co-firing.

In addition, all the parameters are kept to be consistent in year 2010 value but the extension of the value to the near future may not be proportional and thus should be done with caution. Another limitation of this research is that it assumes that all the farmers participated in this program which may not be possible. It will depend on the incentive provided, or price of biomass.

The biomass co-firing may boost the rural economy (by providing an added opportunity for farmers) which is not discussed here due to the complication of the inter-industry relationship. Also, the biomass co-firing may cut back the production of coal mining sector which is not included here. Similarly, this research doesn’t include the negative effect of biomass co-firing to the other sectors which are currently utilizing these biomass resources for example; cattle raising farms, hay making industries etc. These topics would be the future study. In addition, cost comparisons with other renewable energy sources should be done to achieve the regional RPS to promote the decision making processes.

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APPENDICES

Appendix A Crop Residue Availability

Crop production data of Utah and Idaho are reported in Table A-1. Crop production data are obtained from the USDA/NASS, Census of Agriculture 2007. Table 26 Field Crops: 2007 and 2002 available at http://www.agcensus.usda.gov/Publications/2007/Full_Report/Volume_1,_Chapter_1_State_Level/Utah/.

Agricultural crop residues are the plant parts, primarily stalks and leaves, left over after removal of the primary food or fiber product. Examples include corn stover (leaves, stalks, cobs, and husks), wheat straw, and barley straw. Total quantities of crop residues available can be estimated by applying straw to grain ratio. Table A-2 shows the total crop residues available in Utah and Idaho.

Table A-3 contains the harvestable crop reside in Utah and Idaho counties assuming 50% of crop residues removal rate. As shown in Table 3 each crop residue has a different heating value which implies that they are not one-to-one substitutable. Harvestable crop residues are converted to wheat-basis metric tons so that each crop residue can be one-to-one substitutes. Table A-4 contains total harvestable crop residues in wheat-basis metric tons.

Table A-1. Crop (Grains) Production in Utah and Idaho (metric tons)

Counties	Barley	Corn	Oat	Wheat
Utah				
Beaver	232	-	269	-
Box Elder	5,276	26,185	99	56,339
Cache	13,714	5,942	867	19,043
Carbon	-	2,013	215	-
Davis	105	4,686	82	3,036
Duchesne	561	8,153	331	-
Emery	-	-	146	-
Garfield	-	-	34	-
Grand	-	-	84	156
Iron	-	2,565	-	-
Juab	1,745	5,482	207	2,748
Millard	5,183	4,051	303	3,861
Morgan	1,065	628	241	701
Piute	-	-	17	-
Rich	504	-	-	78
Salt Lake	137	-	91	2,470
San Juan	-	-	-	267
Sanpete	1,842	250	490	80
Sevier	1,352	510	173	-
Tooele	486	-	-	-
Utah	1,089	5,258	429	-
Uintah	3,440	9,635	512	13,355
Wasatch	-	-	195	-
Wayne	293	-	364	-
Weber	432	1,171	89	4,240
Utah Total	**37,455**	**76,528**	**5,236**	**106,372**
Idaho				
Bannock	7,512	-	140	22,590
Bear Lake	6,436	-	117	1,553
Caribou	38,000	-	450	39,453
Cassia	61,960	8,212	329	155,131
Elmore	4,959	25,396	-	25,616
Franklin	8,880	2,588	388	17,137
Gooding	4,936	49,497	588	7,804
Jerome	32,492	15,563	-	31,541
Lincoln	6,907	11,105	165	22,368
Minidoka	67,434	27,845	237	94,465
Oneida	2,705	-	917	9,486
Power	2,954	17,497	-	124,975
Twin Falls	52,336	55,084	455	66,802
Idaho Total	**297,512**	**212,785**	**3,787**	**618,921**
Total	**334,967**	**289,312**	**9,022**	**725,293**

Source: Ag Census 2007, Table 26, Utah and Idaho.

The grain in bushels has been converted into tones where 1bushel = .022 tonne for barley, 1 bushel= .027 tonne for wheat, 1 bushel= .025 for corn and 1bushel= .015 for oat. Source: Conversion Calculators, Rayglen Commodities Inc. (http://www.rayglen.com/conversioncalc.aspx)

Table A-2. Crop Residues in Utah and Idaho[*](metric tons)

Counties	Barley	Corn	Oats	Wheat
Utah	-	-	-	-
Beaver	348		376	-
Box Elder	7,913	26,185	138	84,508
Cache	20,571	5,942	1,213	28,564
Carbon	-	2,013	302	-
Davis	157	4,686	114	4,554
Duchesne	841	8,153	463	-
Emery	-	-	204	-
Garfield	-	-	47	-
Grand	-	-	118	234
Iron	-	2,565	-	-
Juab	2,618	5,482	290	4,122
Millard	7,774	4,051	424	5,791
Morgan	1,598	628	338	1,051
Piute	-	-	24	-
Rich	757	-	-	117
Salt Lake	206	-	128	3,705
San Juan	-	-	-	401
Sanpete	2,763	250	686	121
Sevier	2,027	510	242	-
Tooele	729	-	-	-
Utah	1,634	5,258	600	-
Uintah	5,160	9,635	717	20,032
Wasatch	-	-	273	-
Wayne	439	-	509	-
Weber	648	1,171	124	6,360
Utah Total	**56,183**	**76,528**	**7,330**	**159,558**
Idaho	-	-	-	-
Bannock	11,268	-	196	33,885
Bear Lake	9,655	-	164	2,329
Caribou	92,940	8,212	461	232,696
Cassia	57,000	-	630	59,179
Elmore	7,439	25,396	-	38,424
Franklin	13,321	2,588	543	25,705
Gooding	7,405	49,497	823	11,707
Jerome	48,737	15,563	-	47,312
Lincoln	10,361	11,105	231	33,552
Minidoka	101,151	27,845	332	141,697
Oneida	4,057	-	1,284	14,229
Power	4,431	17,497	-	187,462
Twin Falls	78,504	55,084	638	100,204
Idaho Total	**446,269**	**212,785**	**5,301**	**928,381**
Total	**502,451**	**289,312**	**12,631**	**1,087,940**

[*] Author's calculation using residue-to-grain ratio of 1.5:1 for wheat and barley, 1:1 for corn, and 1.4:1 for oats

Table A-3. Harvestable Crop Residues in Utah and Idaho[*](metric tons)

Counties	Barley	Corn	Oats	Wheat
Utah				
Beaver	209	-	226	-
Box Elder	4,748	15,711	83	50,705
Cache	12,343	3,565	728	17,138
Carbon	-	1,208	181	-
Davis	94	2,811	69	2,732
Duchesne	505	4,892	278	-
Emery	-	-	122	-
Garfield	-	-	28	-
Grand	-	-	71	140
Iron	-	1,539	-	-
Juab	1,571	3,289	174	2,473
Millard	4,664	2,430	255	3,475
Morgan	959	377	203	631
Piute	-	-	14	-
Rich	454	-	-	70
Salt Lake	123	-	77	2,223
San Juan	-	-	-	241
Sanpete	1,658	150	412	72
Sevier	1,216	306	145	-
Tooele	438	-	-	-
Utah	980	3,155	360	-
Uintah	3,096	5,781	430	12,019
Wasatch	-	-	164	-
Wayne	263	-	306	-
Weber	389	702	74	3,816
Utah Total	**33,710**	**45,917**	**4,398**	**95,735**
Idaho	-	-	-	-
Bannock	6,761	-	118	20,331
Bear Lake	5,793	-	98	1,397
Caribou	34,200	-	378	35,507
Cassia	55,764	4,927	276	139,618
Elmore	4,464	15,237	-	23,054
Franklin	7,992	1,553	326	15,423
Gooding	4,443	29,698	494	7,024
Jerome	29,242	9,338	-	28,387
Lincoln	6,217	6,663	139	20,131
Minidoka	60,691	16,707	199	85,018
Oneida	2,434	-	771	8,537
Power	2,659	10,498	-	112,477
Twin Falls	47,103	33,050	383	60,122
Idaho Total	**267,761**	**127,671**	**3,181**	**557,029**
Total	**301,471**	**173,587**	**7,579**	**652,764**

[*] Author's calculation assuming 60% crop residue removal rate for all crops residue

Table A-4. Harvestable Crop Residue in Utah Counties (wheat-straw-metric tons)

Counties	Barley	Corn	Oats	Wheat	**Total**
Utah	-	-	-	-	-
Beaver	190		230		420
Box Elder	4,328	15,091	85	50,705	70,209
Cache	11,252	3,424	742	17,138	32,557
Carbon	-	1,160	184	-	1,344
Davis	86	2,700	70	2,732	5,588
Duchesne	460	4,699	283	-	5,442
Emery	-	-	125	-	125
Garfield	-	-	29	-	29
Grand	-	-	72	140	212
Iron	-	1,478	-	-	1,478
Juab	1,432	3,159	177	2,473	7,242
Millard	4,252	2,334	260	3,475	10,321
Morgan	874	362	207	631	2,073
Piute	-	-	14	-	14
Rich	414	-	-	70	484
Salt Lake	113	-	78	2,223	2,414
San Juan	-	-	-	241	241
Sanpete	1,511	144	420	72	2,148
Sevier	1,109	294	148	-	1,551
Tooele	399	-	-	-	399
Utah	894	3,030	367	-	4,291
Uintah	2,822	5,552	439	12,019	20,833
Wasatch	-	-	167	-	167
Wayne	240	-	312	-	552
Weber	354	675	76	3,816	4,921
Utah Total	**30,730**	**44,102**	**4,485**	**95,735**	**175,055**
Idaho					
Bannock	6,163	-	120	20,331	**26,614**
Bear Lake	5,281	-	100	1,397	**6,779**
Caribou	50,837	4,732	282	139,618	**195,468**
Cassia	31,178	-	385	35,507	**67,071**
Elmore	4,069	14,635	-	23,054	**41,759**
Franklin	7,286	1,491	332	15,423	**24,533**
Gooding	4,050	28,525	503	7,024	**40,103**
Jerome	26,659	8,969	-	28,387	**64,014**
Lincoln	5,667	6,400	141	20,131	**32,340**
Minidoka	55,328	16,047	203	85,018	**156,597**
Oneida	2,219	-	786	8,537	**11,542**
Power	2,424	10,083	-	112,477	**124,984**
Twin Falls	42,941	31,745	390	60,122	**135,198**
Idaho Total	**244,102**	**122,628**	**3,244**	**557,029**	**927,002**
Total	**274,832**	**166,730**	**7,729**	**652,764**	**1,102,057**

Appendix B Coal-Fired Power Plants in Utah and Transportation Cost

In Utah, there exist 8 coal-fired power plants. See Figure B-1 and Table B-1 for profiles of each power plant.

As described in Section 2.3.1, to construct the transportation model in equation (1), distances between each county and power plants need be measured. The transportation distance in the study is calculated by using the Google map. First, the center of each county is identified where crop residues might be transported, mainly county seat. Second, the distance from the center of the county to the power plant is measured using the Google direction search. The distance between potential supply regions and power plants of Utah are shown in Table B-2.

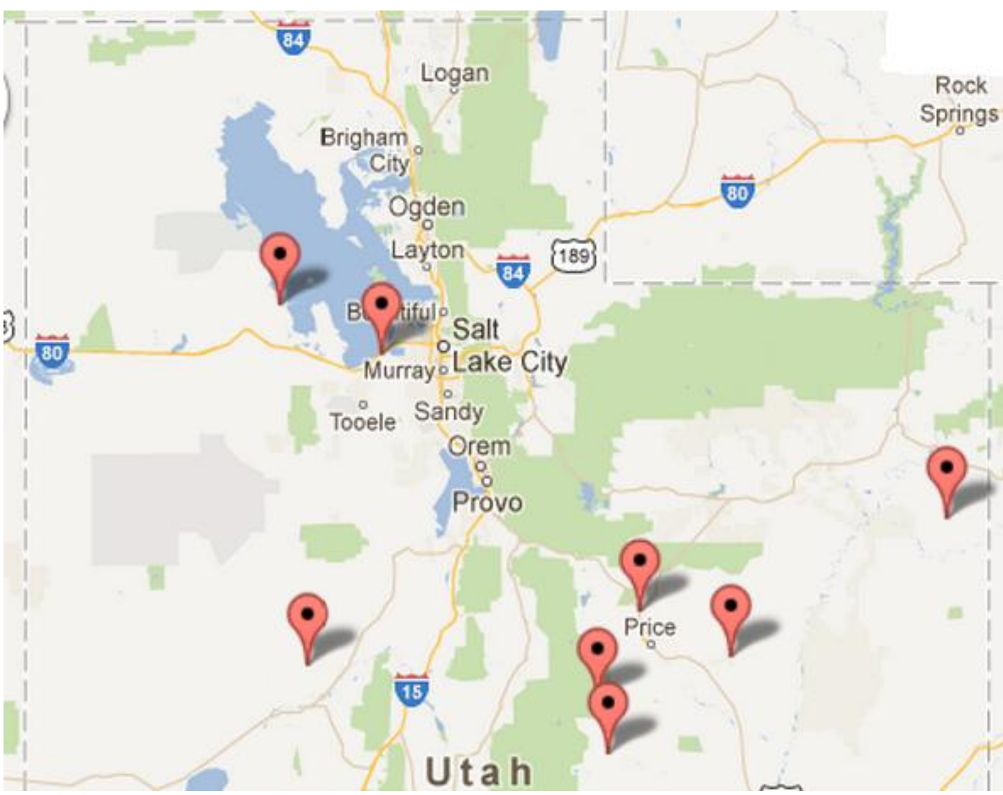


Figure B-1. Location of Coal-Fired Power Plants in Utah

Table B-1. Coal-Fired Power Plants in Utah

	Location	Capacity (MW)
Bonanza	Vernal, UT 84078	500
Carbon	Helper, UT 84526	189
Deseret	Tooele, UT 84074	43
Hunter	Castle Dale, UT 84513	1,472
Huntington	Huntington, UT 84528	996
Intermountain	Delta, UT 84624	1,640
Smelter	Magana, UT 84044	182
Sunnyside	Sunnyside, UT 84539	58.1

Assumption: Net Operation Days = 280 (Equation 8)

Table B-3 shows the unit transportation cost from supply regions to power plants in Utah using equation (2): $hc = \frac{2cpm \cdot dst + fx}{sz}$ where *hc* = hauling cost, *cpm* = (unit) cost per mile, *dst* = distance, *fx* = fixed cost for loading, and *sz* = loading size. Hauling cost parameters are given by: *cpm* = $1.38/mile, *fx* = $173.2, and *sz* = 20 tons, respectively.

Table B-2. Distance from Supply Region to Power Plants in Utah (miles)

Counties	Bonanza	Carbon	Deseret	Hunter	Huntington	InterMT	Smelter	Sunny
Beaver	333	199	249	143	163	98	206	234
Box Elder	274	177	126	221	203	201	87	212
Cache	285	188	182	232	215	212	92	223
Carbon	151	17	138	39	34	155	132	19
Davis	236	139	88	183	165	163	43	174
Duchesne	64	82	210	126	122	220	165	79
Emery	201	67	231	23	43	130	185	80
Garfield	343	205	228	167	176	132	253	257
Grand	198	75	239	80	97	189	195	58
Iron	392	258	309	202	222	158	263	287
Juab	224	90	140	97	77	46	95	125
Millard	276	142	150	142	126	12	119	177
Morgan	215	150	100	195	177	175	60	187
Rich	276	171	210	133	142	115	210	224
Piute	208	209	168	236	236	216	123	227
Salt Lake	204	108	60	153	135	133	20	144
San Juan	263	180	345	186	197	294	299	163
Sanpete	227	93	173	82	62	81	127	129
Sevier	266	131	219	88	108	96	173	173
Tooele	239	141	31	186	168	128	18	177
Utah	57	80	208	124	120	218	163	116
Uintah	213	99	81	144	126	91	49	135
Wasatch	128	96	77	134	124	120	54	116
Wayne	250	116	254	72	92	129	208	129
Weber	240	143	92	187	169	167	53	178
Bannock	346	248	198	292	275	271	158	283
Bear Lake	260	259	208	303	285	282	168	294
Cassia	377	280	229	324	307	304	190	294
Caribou	301	254	203	297	280	277	164	289
Elmore	500	403	352	447	429	427	313	438
Franklin	306	215	164	259	242	238	125	250
Gooding	449	352	301	396	378	376	262	387
Jerome	430	331	282	375	259	355	242	366
Lincoln	382	324	274	369	351	349	234	360
Minidoka	395	300	247	343	324	323	207	334
Oneida	311	215	164	259	241	239	124	250
Power	394	297	249	341	323	321	206	332
Twin Falls	438	341	270	385	367	364	251	376

Table B-3. Unit Transportation Cost from Supply Region to Power Plants ($/ton)

Counties	Bonanza	Carbon	Deseret	Hunter	Huntington	InterMT	Smelter	Sunnyside
Beaver	54.77	36.22	43.14	28.46	31.23	22.23	37.19	41.06
BoxElder	46.60	33.17	26.11	39.26	36.77	36.49	20.7	38.02
Cache	48.13	34.69	33.86	40.79	38.43	38.02	21.4	39.54
Carbon	29.57	11.01	27.77	14.06	13.36	30.12	26.94	11.29
Davis	41.34	27.91	20.84	34.00	31.51	31.23	14.61	32.75
Duchesne	17.52	20.01	37.74	26.11	25.55	39.12	31.51	19.60
Emery	36.49	17.94	40.65	11.84	14.61	26.66	34.28	19.74
Garfield	56.16	37.05	40.23	31.78	33.03	26.94	43.70	44.25
Grand	36.08	19.04	41.76	19.74	22.09	34.83	35.66	16.69
Iron	62.95	44.39	51.45	36.63	39.40	30.54	45.08	48.4
Juab	39.68	21.12	28.05	22.09	19.32	15.07	21.81	25.97
Millard	46.88	28.32	29.43	28.32	26.11	10.37	25.14	33.17
Morgan	38.43	29.43	22.51	35.66	33.17	32.89	16.97	34.55
Piute	46.88	32.34	37.74	27.08	28.32	24.58	37.74	39.68
Rich	37.46	37.60	31.92	41.34	41.34	38.57	25.69	40.09
Salt Lake	36.91	23.61	16.97	29.85	27.35	27.08	11.43	28.60
San Juan	45.08	33.58	56.44	34.42	35.94	49.37	50.07	31.23
Sanpete	40.09	21.54	32.62	20.01	17.24	19.87	26.24	26.52
Sevier	45.50	26.8	38.99	20.84	23.61	21.95	32.62	32.62
Tooele	41.76	28.18	12.95	34.42	31.92	26.38	11.15	33.17
Uintah	16.55	19.74	37.46	25.83	25.28	38.85	31.23	24.72
Utah	38.16	22.37	19.87	28.6	26.11	21.26	15.44	27.35
Wasatch	26.38	21.95	19.32	27.21	25.83	25.28	16.13	24.72
Wayne	43.28	24.72	43.83	18.63	21.40	26.52	37.46	26.52
Weber	41.89	28.46	21.40	34.55	32.06	31.78	16.00	33.31
Bannock	56.57	43.00	36.08	49.1	46.74	46.19	30.54	47.85
Bear Lake	44.66	44.53	37.46	50.62	48.13	47.71	31.92	49.37
Cassia	60.87	47.43	40.37	53.53	51.17	50.76	34.97	49.37
Caribou	50.34	43.83	36.77	49.79	47.43	47.02	31.37	48.68
Elmore	77.90	64.47	57.41	70.56	68.07	67.79	52.00	69.32
Franklin	51.04	38.43	31.37	44.53	42.17	41.62	25.97	43.28
Gooding	70.84	57.41	50.34	63.5	61.01	60.73	44.94	62.25
Jerome	68.21	54.50	47.71	60.59	44.53	57.82	42.17	59.34
Lincoln	61.56	53.53	46.60	59.76	57.27	56.99	41.06	58.51
Minidoka	63.36	50.20	42.86	56.16	53.53	53.39	37.32	54.91
Oneida	51.73	38.43	31.37	44.53	42.03	41.76	25.83	43.28
Power	63.22	49.79	43.14	55.88	53.39	53.11	37.19	54.64
Twin Falls	69.32	55.88	46.05	61.98	59.48	59.07	43.42	60.73

Appendix C Transportation Model Results

Table C-1 includes results from the transportation model in equation (1) with 10% co-firing scenario. Three of 8 coal-fired power plants, Bonanza, Hunter, and Huntington, may not have enough biomass supply. Tables C-1 and C-2 contain the results of transportation model in equation (1) at 10% and 15% co-firing scenarios. Transportation model is run in GAMS with BDMLP solver.

Table C-1. Transportation Model Result - 10% Co-firing (wheat-straw-metric tons)

From \To	Bonanza	Carbon	Deseret	Hunter	Hntngtn	InterMT	Smelter	Sunny
Beaver						420		
Box Elder						70,209		
Cache							32,557	
Carbon								1,344
Davis							5,588	
Duchesne	5,442							
Emery				125				
Garfield						29		
Grand								212
Iron						1,478		
Juab						7,242		
Millard						10,321		
Morgan		2,073						
Piute						14		
Rich	484							
Salt Lake		2,414						
San Juan								
San Pete					2,148			241
Sevier				1,551				
Tooele			399					
Utah						20,833		
Uintah	4,291							
Wasatch						167		
Wayne				552				
Weber						4,921		
Bannock						26,614		
Bear Lake	6,779							
Cassia						174,968		20,501
Caribou						67,071		
Elmore						41,759		
Franklin						24,533		
Gooding						40,103		
Jerome					64,014			
Lincoln		32,340						
Minidoka					124,894		31,703	
Oneida						11,542		
Power		35,709			81,191	8,084		
Twin Falls			16,104			119,094		
From UT	10,217	4,487	399	2,228	2,148	115,634	38,145	1,797
From ID	6,779	68,049	16,104	-	270,099	513,768	31,703	20,501
Total (UT+ID)	16,996	72,536	16,503	2,228	272,247	629,402	69,848	22,298
Total Requirement	191,891	72,535	16,503	382,246	564,927	629,402	69,848	22,298
% of requirement	9%	100%	100%	0%	71%	100%	100%	100%

Table C-2. Transportation Model Result - 15% Co-firing (wheat-straw-metric tons)

From \To	Bonanza	Carbon	Deseret	Hunter	Hntngtn	InterMT	Smelter	Sunny
Beaver						420		
Box Elder		70,209						
Cache							32,557	
Carbon								1,344
Davis							5,588	
Duchesne	5,442							
Emery				125				
Garfield						29		
Grand								212
Iron						1,478		
Juab						7,242		
Millard						10,321		
Morgan		2,073						
Piute						14		
Rich	484							
Salt Lake		2,414						
San Juan								
San Pete					2,148			241
Sevier				1,551				
Tooele			399					
Utah						20,833		
Uintah	4,291							
Wasatch		167						
Wayne				552				
Weber		1,601				3,320		
Bannock						26,614		
Bear Lake	6,779							
Cassia						163,819		31,649
Caribou						67,071		
Elmore						41,759		
Franklin						24,533		
Gooding						40,103		
Jerome					64,014			
Lincoln		32,340						
Minidoka						89,970	66,627	
Oneida						11,542		
Power						124,984		
Twin Falls			24,355			110,843		
From UT	10,217	76,464	399	2,228	2,148	43,657	38,145	1,797
From ID	6,779	32,340	24,355	-	64,014	701,238	66,627	31,649
Total(UT+ID)	16,996	108,804	24,754	2,228	66,162	744,895	104,772	33,446
Total Requirement	287,836	108,802	24,754	847,391	573,370	944,103	104,772	33,446
% of requirement	6%	100%	100%	0%	12%	79%	100%	100%

Table C-3. Biomass Fuel Cost at 10% Co-firing ($ per MWh)

	Biomass Price Scenarios			
	0	$10/ton	$20/ton	$30/ton
Bonanza*	-	-	-	-
Carbon	$2.65	$3.19	$3.73	$4.27
Deseret	$2.65	$1.47	$1.74	$2.01
Hunter*	-	-	-	-
Huntington	$2.52	$2.99	$3.46	$3.93
Intermountain	$2.60	$3.14	$3.68	$4.23
Smelter	$1.38	$1.92	$2.47	$3.01
Sunnyside	$2.51	$3.05	$3.60	$4.14

* Bonanza and Hunter Power plant receive only 9% and less than 1% biomass, respectively at 10 % co-firing scenario. This is why biomass fuel cost for both power plants is very low.

Table C-4. Biomass Fuel Cost at 15% Co-firing ($ per MWh)

	Biomass Price Scenarios			
	0	$10/ton	$20/ton	$30/ton
Bonanza*	-	-	-	-
Carbon	$3.85	$4.66	$5.48	$6.29
Deseret	$3.69	$4.51	$5.32	$6.13
Hunter*	-	-	-	-
Huntington*	-	-	-	-
Intermountain	$3.46	$4.14	$4.83	$5.52
Smelter	$2.50	$3.32	$4.13	$4.94
Sunnyside	$3.85	$4.66	$5.47	$6.29

* Bonanza, Huntington and Hunter Power plant receive only 6%, 11% and less than 1% biomass, respectively at 15 % co-firing scenario. This is why biomass fuel cost for these power plants are very low.

Table C-5. Additional Cost of Biomass Co-firing at 10% Co-firing ($/MWh)

	Biomass Price Scenarios			
	0	$10/ton	$20/ton	$30/ton
Bonanza*	-	-	-	-
Carbon	$1.95	$2.49	$3.03	$3.57
Deseret	$1.75	$2.29	$2.84	$3.38
Hunter*	-	-	-	-
Huntington	$1.83	$2.30	$2.77	$3.24
Intermountain	$1.91	$2.45	$2.99	$3.53
Smelter	$0.69	$1.23	$1.77	$2.31
Sunnyside	$1.82	$2.36	$2.90	$3.44

* Bonanza, Huntington and Hunter Power plant receive only 9% and less than 1% biomass, respectively at 10 % co-firing scenario. This is why biomass fuel cost for both power plants is very low.

Table C-6. Additional Cost of Biomass Co-firing at 15% Co-firing ($/MWh)

	Biomass Price Scenarios			
	0	$10/ton	$20/ton	$30/ton
Bonanza*	-	-	-	-
Carbon	$3.16	$3.97	$4.78	$5.59
Deseret	$3.00	$3.81	$4.62	$5.44
Hunter*	-	-	-	-
Huntington*	-	-	-	-
Intermountain	$2.76	$3.45	$4.14	$4.83
Smelter	$1.81	$2.62	$3.43	$4.24
Sunnyside	$3.15	$3.97	$4.78	$5.59

* Bonanza, Huntington and Hunter Power plant receive only 6%, 12% and less than 1% biomass, respectively at 15% co-firing scenario. This is why biomass fuel cost for these power plants are very low.

Appendix D Health Damage Impact Regression Results

Total health damage data collected from *Death and Disease from Power Plant* prepared by The Clean Air Task Force (2010) are reported in Table D-1.

Table D-1. Total Health Damage (million dollars)

State	Mortality (Pope)	Acute Bronchitis	Heart Attacks	Asthma Attacks
Alabama	2,368.43	0.20	50.02	0.28
Arizona	568.50	0.05	13.08	0.07
Arkansas	1,093.77	0.09	24.32	0.13
California	6.26	0.00	0.14	0.00
Colorado	705.10	0.07	16.08	0.09
Connecticut	60.58	0.00	1.65	0.01
Delaware	723.28	0.06	18.56	0.08
Florida	1,549.99	0.12	31.27	0.17
Georgia	5,720.97	0.50	119.64	0.69
Illinois	3,990.73	0.35	92.72	0.48
Indiana	8,938.23	0.76	206.41	1.06
Iowa	1,709.51	0.15	40.12	0.20
Kansas	620.29	0.06	14.25	0.08
Kentucky	4,797.90	0.40	108.82	0.55
Louisiana	338.57	0.03	7.08	0.04
Maine	24.00	0.00	0.64	0.00
Maryland	1,396.28	0.12	35.07	0.16
Massachusetts	338.87	0.03	9.35	0.04
Michigan	6,883.51	0.56	165.86	0.79
Minnesota	1,530.59	0.13	36.68	0.19
Mississippi	503.19	0.04	10.27	0.06
Missouri	3,879.94	0.34	89.26	0.47
Montana	276.25	0.02	6.42	0.03
Nebraska	432.05	0.04	10.01	0.05
Nevada	99.37	0.01	2.29	0.01
New Hampshire	67.11	0.01	1.81	0.01
New Mexico	576.75	0.05	13.05	0.08
New Jersey	952.21	0.08	24.90	0.11
New York	1,282.94	0.10	33.86	0.14
North Carolina	4,258.09	0.36	96.30	0.50
North Dakota	1,912.19	0.17	44.03	0.23
Ohio	7,475.58	0.60	-	0.83
Oklahoma	1,544.94	0.14	35.16	0.19
Oregon	25.60	0.00	0.56	0.00
Pennsylvania	5,763.86	0.46	145.29	0.64
South Carolina	2,088.61	0.18	44.58	0.25
South Dakota	76.15	0.01	1.75	0.01
Tennessee	3,375.94	0.28	73.76	0.39
Texas	2,758.32	0.26	61.67	0.36
Utah	319.78	0.04	7.34	0.05
Virginia	2,777.66	0.23	64.21	0.32
Washington	39.32	0.00	0.88	0.01
West Virginia	5,063.41	0.40	121.14	0.56
Wisconsin	2,429.47	0.21	57.91	0.29
Wyoming	579.38	0.06	13.32	0.08

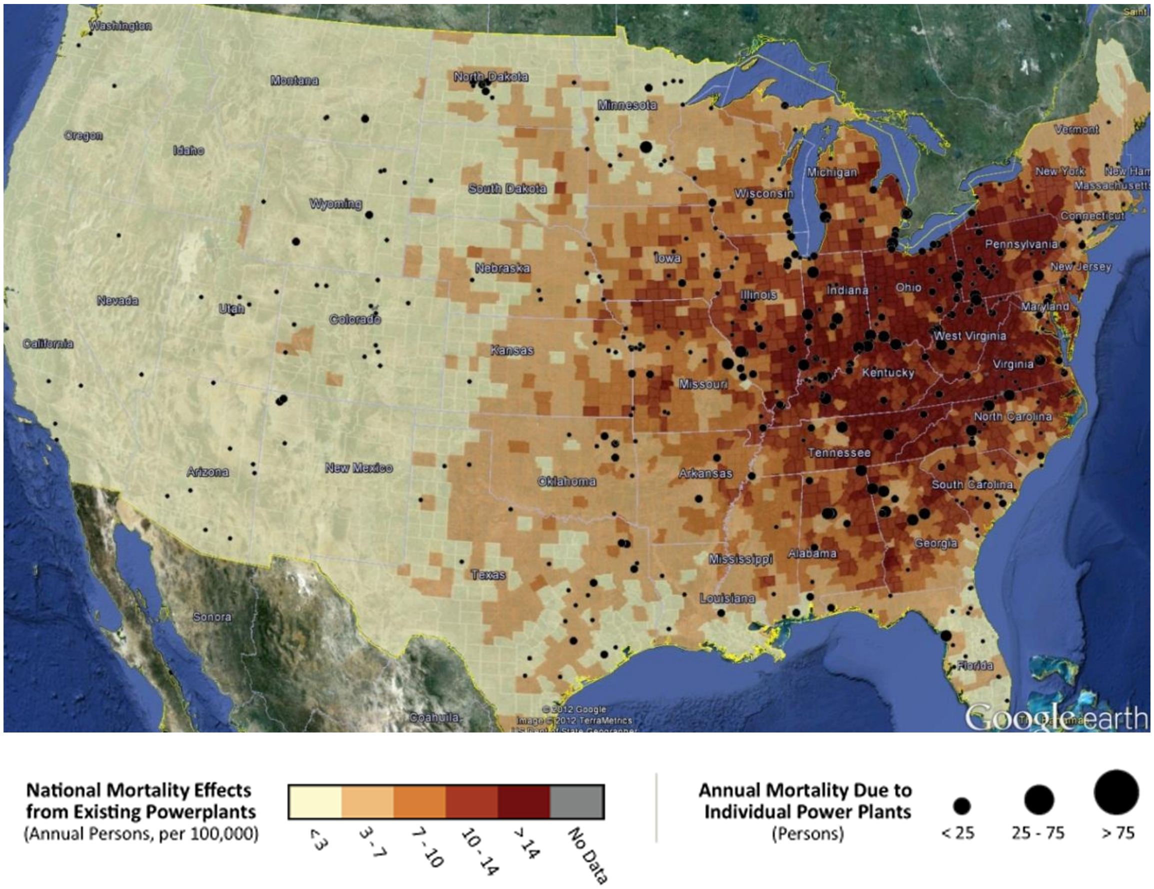
Total Health Damage, Cont'd. (million dollars)

State	Chronic Bronchitis	Asthma ER Visits	Cardio Hosp Adm	Respiratory Hosp Adm
Alabama	87.25	0.12	4.40	1.02
Arizona	22.28	0.03	1.04	0.25
Arkansas	40.22	0.06	2.00	0.48
California	0.27	0.00	0.01	0.00
Colorado	28.47	0.03	1.27	0.30
Connecticut	2.25	0.00	0.13	0.03
Delaware	26.83	0.03	1.48	0.35
Florida	55.05	0.07	2.92	0.65
Georgia	214.44	0.30	10.68	2.46
Illinois	148.86	0.21	7.42	1.80
Indiana	330.48	0.46	16.61	4.00
Iowa	64.13	0.09	3.20	0.77
Kansas	23.47	0.03	1.16	0.28
Kentucky	175.25	0.23	8.98	2.12
Louisiana	12.67	0.02	0.62	0.15
Maine	0.88	0.00	0.05	0.01
Maryland	51.69	0.05	2.82	0.66
Massachusetts	12.72	0.01	0.72	0.17
Michigan	250.22	0.31	13.12	3.13
Minnesota	58.47	0.08	2.90	0.70
Mississippi	18.49	0.03	0.92	0.21
Missouri	144.59	0.21	7.15	1.74
Montana	10.49	0.01	0.52	0.12
Nebraska	16.42	0.02	0.81	0.19
Nevada	3.98	0.00	0.18	0.04
New Hampshire	2.50	0.00	0.14	0.03
New Mexico	22.77	0.03	1.06	0.25
New Jersey	35.30	0.03	1.95	0.46
New York	47.00	0.04	2.63	0.62
North Carolina	158.40	0.19	8.26	1.91
North Dakota	71.83	0.10	3.58	0.85
Ohio	268.50	0.32	14.28	3.37
Oklahoma	57.98	0.09	2.87	0.69
Oregon	1.05	0.00	0.04	0.01
Pennsylvania	207.93	0.21	11.52	2.70
South Carolina	77.42	0.10	3.94	0.90
South Dakota	2.88	0.00	0.14	0.03
Tennessee	123.52	0.16	6.34	1.47
Texas	107.74	0.15	5.19	1.23
Utah	13.75	0.01	0.56	0.14
Virginia	103.34	0.12	5.44	1.26
Washington	1.68	0.00	0.06	0.01
West Virginia	182.50	0.20	9.86	2.29
Wisconsin	90.71	0.13	4.58	1.11
Wyoming	23.51	0.03	1.05	0.25

Total Health Damage, Cont'd. (million dollars)

State	LRS	MRAD	URS	WLD
Alabama	0.11	14.51	0.13	3.37
Arizona	0.03	3.74	0.03	0.91
Arkansas	0.05	6.69	0.06	1.58
California	0.00	0.05	0.00	0.01
Colorado	0.04	4.82	0.04	1.16
Connecticut	0.00	0.37	0.00	0.10
Delaware	0.03	4.43	0.04	1.23
Florida	0.07	8.95	0.08	2.00
Georgia	0.26	35.88	0.31	8.37
Illinois	0.18	24.79	0.22	6.10
Indiana	0.40	54.94	0.48	13.48
Iowa	0.08	10.66	0.09	2.58
Kansas	0.03	3.91	0.03	0.92
Kentucky	0.21	29.01	0.25	7.03
Louisiana	0.02	2.13	0.02	0.48
Maine	0.00	0.14	0.00	0.04
Maryland	0.06	8.55	0.07	2.31
Massachusetts	0.01	2.09	0.02	0.58
Michigan	0.30	41.31	0.35	10.45
Minnesota	0.07	9.74	0.08	2.40
Mississippi	0.02	3.09	0.03	0.69
Missouri	0.18	24.10	0.21	5.82
Montana	0.01	1.75	0.02	0.42
Nebraska	0.02	2.74	0.02	0.65
Nevada	0.01	0.67	0.01	0.17
New Hampshire	0.00	0.41	0.00	0.11
New Mexico	0.03	3.83	0.03	0.91
New Jersey	0.04	5.85	0.05	1.65
New York	0.05	7.73	0.06	2.06
North Carolina	0.19	26.31	0.23	6.58
North Dakota	0.09	11.94	0.10	2.85
Ohio	0.31	44.18	0.37	11.11
Oklahoma	0.07	9.67	0.08	2.28
Oregon	0.00	0.18	0.00	0.05
Pennsylvania	0.24	34.15	0.29	8.99
South Carolina	0.09	12.91	0.11	3.06
South Dakota	0.00	0.48	0.00	0.11
Tennessee	0.15	20.45	0.18	4.86
Texas	0.14	18.19	0.16	4.26
Utah	0.02	2.37	0.02	0.57
Virginia	0.12	17.22	0.15	4.45
Washington	0.00	0.28	0.00	0.07
West Virginia	0.21	30.03	0.25	7.66
Wisconsin	0.11	15.07	0.13	3.74
Wyoming	0.03	3.99	0.04	0.97

where, LRS = Lower Respiratory System Problems, MRAD = Minor Restricted Activity Days, URS = Upper Respiratory System Problems, and WLD = Work Loss Days



Source: Figure 2 CATF (2010), http://www.catf.us/fossil/problems/power_plants/existing/

Figure D-1. National Mortality Effects from Existing Power Plants

Table D-2. Health Damage Regression Results of Model 3 (Log-Log Model)

Health Damage	Coef.	Robust Std. Err.	T-statistic
PM25 Emission	0.6728****	0.033	20.51
Population Density	0.0278****	0.422	0.66
Per Capita Income	0.0692****	0.372	0.19
Avg. Temperature	-0.2934****	1.506	0.19
Avg. Wind Speed	-0.0953****	0.151	-0.63
AL[1]	1.4882****	0.449	3.31
AZ	0.3032****	0.516	0.59
AR	1.3280****	0.442	3
CA	-1.4283****	0.478	-2.99
CO	0.2991****	0.330	0.91
CT	-0.1339****	0.784	-0.17
DE	2.6172****	0.347	7.55
FL	0.5002****	0.561	0.89
GA	1.7594****	0.429	4.1
IL	0.9106 ****	0.366	2.49
IN	1.9098****	0.342	5.58
IA	1.0181****	0.331	3.07
KS	0.4941****	0.366	1.35
KY	1.5240****	0.375	4.06
LA	-0.2562****	0.670	-0.38
ME	1.7761****	1.465	1.21
MD	1.3205****	0.494	2.67
MA	0.6104****	0.770	0.79
MI	1.9469****	0.337	5.78
MN	1.0873****	0.363	3.25
MS	1.2031****	0.489	1.59
MO	1.1443****	0.395	2.85
MT	0.0514****	0.282	2.4
NE	0.4016****	0.314	1.14
NV	1.0137****	1.134	0.44
NH	0.0953****	1.064	0.09
NM	0.5785****	1.135	0.35
NJ	2.0395****	0.416	4.55
NY	1.4281****	0.405	3.39
NC	1.2068****	0.418	2.38
ND	1.2952****	0.352	4.79
OH	1.7416****	0.351	5.02
OK	1.2701****	0.583	1.61
OR	-0.5924****	0.388	-1.86
PA	1.4079****	0.330	4.46
SC	1.4798****	0.473	2.63
SD	0.4769****	0.472	1.34
TN	1.9347****	0.470	3.46
TX	0.6950****	0.524	0.62

VA	1.7697****	0.404	3.82
WA	-0.7427****	0.290	-2.93
WV	1.7193****	0.349	4.75
WI	1.6443****	0.347	4.99
WY	0.7529****	0.424	1.82
Constant	6.4314****	8.193	-0.02
R^2	0.7505****		
F	152.88****	Prob>F =0.00	
No. of Obs.	356********		

**** 1%, *** 5%, ** 10%, and * 15% significance level

[1]The standard errors are biased when heteroscedasticity is present. Test for heteroscedasticity: Breusch-Pagan test χ^2 =0.39 (P-value = 0.53); To fix the problem robust standard errors are used.

[2]State dummies: CT, ME, MA, NH, NJ, NY, PA, IL, IN, MI, OH, WI, IA, KS, MN, MO, NE, ND, SD, DE, FL, GA, MD, NC, SC, VA, WV, AL, KY, MS, TN, AR, LA, OK, TX, CA, OR, WA, AZ, CO, MT, NV, NM, WY (UT base region which was left out)