ECONOMICS OF BIOMASS FUELS FOR ELECTRICITY PRODUCTION: A CASE STUDY WITH CROP RESIDUES

A Dissertation

by

THEIN AYE MAUNG

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

DOCTOR OF PHILOSOPHY

August 2008

Major Subject: Agricultural Economics

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Chair of Committee,	Bruce A. McCarl
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Head of Department,	John P. Nichols

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ABSTRACT

Economics of Biomass Fuels for Electricity Production: A Case Study with Crop Residues. (August 2008)

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In the United Sates and around the world, electric power plants are among the biggest sources of greenhouse gas emissions which the Intergovernmental Panel on Climate Change argued was the main cause of climate change and global warming. This dissertation explores the factors which may induce electricity producers to use biomass fuels for power generation and thereby mitigate the impact of greenhouse gas emissions. Analyses in this dissertation suggest that there are two important factors which will play a major role in determining the future degree of bioelectricity production: the price of coal and the future price of carbon emissions. Using The Forest and Agricultural Sector Optimization Model—Green House Gas version (FASOMGHG) in a case study examining the competitiveness of crop residues, this dissertation finds that crop residues currently cost much more than coal as an electricity generation feedstock because they have lower heat content and higher production /hauling costs. For them to become cost competitive with coal, the combined costs of production and hauling must be cut by more than half or the coal price needs to rise. In particular, for crop residues to have any role in electricity generation either the price of coal has to increase to about $43 per ton or the carbon equivalent price must rise to about $15 per ton.

The simulation results also show that crop residues with higher heat content such as wheat residues will have greater opportunities in bioelectricity production than the residues with lower heat content. In addition, the analysis shows that improvements in crop yield do not have much impact on bioelectricity production. However, the energy recovery efficiency does have significant positive impact on the bioelectricity desirability but again only if the carbon equivalent price rises substantially. The analysis

also shows the desirability of cofiring biomass as opposed to 100% replacement because this reduces haling costs and increases the efficiency of heat recovery.

In terms of policy implications, imposing carbon emission restrictions could be an important step in inducing electric power producers to include biofuels in their fuel-mix power generation portfolios and achieve significant greenhouse gas emission reductions.

DEDICATION

To my family

ACKNOWLEDGEMENTS

I would like to thank my committee chair, Dr. Bruce McCarl for his guidance and support throughout the course of this research. I would also like to thank Dr. David Bessler for guiding me through using the Time Series Forecasting Methodology, and Dr. Joe Outlaw and Mahmoud El-Halwagi for their valuable comments. I would like to extend my gratitude to Dr. Jerry Cornforth for helping me with various issues that I encountered with the FASOM while researching this dissertation.

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1. INTRODUCTION

More than a century ago the U.S. relied on energy from wood and other biofuel resources for almost all of its energy needs. The demand for wood was so great that by the end of 19th century a wood shortage was emerging. However the shortage did not become a crisis as wood reliance began to diminish with a switch to fossil fuels. By 1940, only 20 percent of US energy came from biofuels.[1] Reliance dropped even further during the 50's, 60's and early 70's. Increased interest in biofuels arose in the late 70's stimulated by rising oil prices during the "energy crisis", with biofuels seen as a way to protect against rising fossil fuel prices[2] and the political insecurity of foreign energy supply. Biofuel related concerns and interest subsided following the sharp, mid 80's, oil price decline. Nevertheless, the pleas for promotion of biofuels remained and were even emphasized (Radetzki, 1997). Today with recent oil price rises, issues regarding Middle East stability and concerns for climate change, interests to use biofuels are again on the rise (Kolstad, 2000). Climate change concerns are stimulating interest as EPA (2006) indicates that combustion of fossil fuel is considered to be the largest contributing factor to the atmospheric release of greenhouse gases, which the Intergovernmental Panel on Climate Change (IPCC) argued was the main cause of global warming.

Biofuels are generally derived from biomass and that most prominently arises from agriculture and forestry. Use of biofuels can play an important role in reducing greenhouse gas emissions because biomass based biofuels recycle atmospheric carbon, first absorbing it through photosynthesis then later releasing it through combustion. This reduces greenhouse gas (GHG) emissions relative to fossil fuel use which draw carbon from the ground and release it to the atmosphere creating a net addition and hence reduce greenhouse gas contributions to global warming. This dissertation will only focus on biomass for power generation.

This dissertation follows the style of the *American Journal of Agricultural Economics*.

[1] Source: Sharing Sustainable Solutions (Date unknown).
[2] Increases in fossil fuel prices during the 70's were interpreted by many observers as importantly caused by depletion (Radetzki, 1997).

1.1 Research Objectives and Methodology

The goal of this dissertation is to investigate and understand the economics of biofuels for electricity generation as a contribution to the economic analysis of climate change and global warming mitigation. In particular this dissertation strives to enhance the understanding of current and future roles of bioelectricity production as a mechanism for reducing net greenhouse gas emissions. In pursuing this goal this dissertation has three primary objectives: 1) to analyze the prospects for the use of biomass fired electricity generation including current market opportunities and barriers, and transaction costs and market structure, 2) to examine the influence on bioelectricity market penetration of factors such as price of fossil fuels, vintage and capital turnover rate for fossil and nuclear power plants, power generation technologies and electricity demand growth, and 3) to estimate costs of crop residue production and evaluate its relative economic competitiveness for electricity generation in a case study setting. In terms of methodology, the Forest and Agricultural Sector Optimization Model—Green House Gas version (FASOMGHG) will be used to simulate future market scenarios for bioelectricity production from crop residues. FASOMGHG will be discussed later in detail.

1.2 Organization

The dissertation is organized as follows. Section 1 provides an introduction to biomass fuels for power production and discusses the goals of this study. Section 2 overviews the literature on the economics of biomass fuels. Issues and problems related to biomass fuels and bioelectricity generation are also discussed. Section 3 explores various factors which will influence the future market penetration of bioelectricity production. Section 4 and the following sections empirically study the feasibility of crop residues for bioelectricity production using FASOMGHG. Methods for harvesting, production and cost evaluation of crop residues are also described in section 4. Section 5 reports the amount of residue available for power generation, residue density, hauling distance and delivered cost estimates. Section 6 simulates future bioelectricity production for the case of crop residues employing FASOMGHG under various alternative scenarios. Simulation results are interpreted and then conclusions are provided.

2. ECONOMICS OF BIOMASS FUELS FOR POWER GENERATION

2.1 Background on Biomass Fuels

Biofuels as defined herein are any fuels that derive from agricultural and forestry (AF) biomass. There are many forms of AF biomass that can be used to create energy. Biomass can be used in creating electric power, heat, ethanol or biodiesel. Biomass fuels typically used for fueling electric power plants or heat producing processes include the following:

- Agricultural crop residues ─ corn stover, wheat straw, sugar cane bagasse, rice straw and husks etc.
- Forest residues ─ logging residues and salvageable dead wood along with milling residues.
- Energy crops ─ switchgrass, willow and poplar.
- Urban wood wastes ─ wood pallets and products of demolition.
- Animal manure and associated methane emissions.

Liquid fuels arising from biomass include,

- Bioalcohols ─ ethanol produced from corn and sugarcane, and methanol produced from wood, and
- Biologically produced oils ─ biodiesel produced from vegetable oil and animal fats.

Since biomass feedstocks for biofuel production are the products or by-products of agriculture and forestry (AF), the AF sectors will play a very important role in the set of biofuel production possibilities and in subsequent reductions in GHG net emissions (Schneider and McCarl, 2003).[3]

2.1.1 Current Market Status of Biomass

This dissertation will only focus on biomass for power generation. Biomass power has a number of attributes. The biomass feedstock is renewable; it is low in sulfur and

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[3] For more information on the reduction of net GHG emissions see McCarl and Schneider (1999 & 2000).

mercury. Its combustion generally adds less net carbon dioxide to the atmosphere than do fossil fuels. Biomass is currently used as feedstock for the supply of about 3% of total U.S. energy consumption. In 2002, the U.S. commercial biomass fueled electricity generation amounted to about 9,733 megawatts (MW) installed capacity, being the single largest source of non-hydro renewable electricity (Department of Energy, 2004). At present, residues from agriculture and forestry processing operations are the largest power related biomass sources. In terms of residues used, most are used to generate electricity or process heat in cogeneration systems (combined heat and power production) at industrial sites or municipal district heating facilities (Larson, 1993). Bagasse, and milling residues are the most common commercially industrial site feedstocks with little use of other biomass feedstocks to generate electricity.

Biomass-based energy is generally not economically competitive with conventional fossil fuel-based energy. According to Hall and Scrase (1998), biomass fuels are bulky often with high water content. Fuel quality may not be predictable. Physical handling of the material can be challenging. Hauling can be expensive. These characteristics drive up the cost of biomass energy, as additional land, labor and equipment is required for feedstock planting, harvesting, transport, storage and processing compared to conventional fuels. Moreover, biomass-based power plants are relatively small in size, and they tend have high capital cost. Hence, relative to electricity generated from coal or natural gas, biomass-based power is more expensive on average. Given the current economic situation, feasible forms of biomass tend to be those in which feedstock is and industrial by product (generally bagasse and milling residue) generated at the same site where electricity generation system is located. For instance, most existing biomass-based power plants are located or built where biomass feedstock is cheaply available or incurs disposal costs, such as in sugar milling, wood product and paper industries (Shakya, 2000). Biomass-based electric plants have also flourished in the areas where electricity is more expensive than the national average electricity price (Graham et. al., 1996; Shakya, 2000).

Another feasible option currently in use is to co-fire biomass feedstock with coal in power generating plants. This happens for several reasons

- The capital costs for co-firing are less than those associated with standalone biomass power projects.
- Co-firing projects capitalize on existing generating stations and can be operated at the plant's discretion. Hence the risks related with co-firing projects are rather low (Hughes, 2000).

To make biomass fuels competitive with fossil fuels, monetization of the environmental attributes of biomass power (for instance, GHG emission reductions) would be required, i.e. suppose one had to pay for emissions or was able to sell emission reductions, then there would be an extra benefit from using biomass fuels relative to fossil fuels. McCarl et al. (2004) show that the existence of a substantial carbon equivalent price applied to net emissions would make biomass fuels competitive and enter the market in substantial amounts. Namely at low carbon prices, they find that biomass fuels are not competitive.

2.2 Rationales and Incentives for Using Biomass

2.2.1 Climate Change

Concerns for climate change dominate the current environmental agenda as evidenced by the increased in published articles, symposia, workshops, and other scientific forums dealing with this issue (Adams, 1989). Climate change is one of the most serious environmental threats facing the world today. Rising global temperatures will bring changes in weather patterns, rising sea levels and increased frequency and intensity of extreme weather events. The effects will be felt (or are already felt) here in the U.S. and internationally, there may be severe problems for people in regions that are particularly vulnerable to change. The main human influence on global climate is likely to be emissions of greenhouse gases (GHG) such as carbon dioxide (CO_2), methane (CH_4) and other gases. At present, about 6.5 billion metric tons of CO_2 is emitted globally each year, mostly through burning coal, oil and gas for energy.[4] The U.S. alone accounts for about 24 percent of global CO_2 emissions.[5]

Power plants are among the biggest sources of GHG emissions in the U.S. Currently, the electric power sector emits about 38 percent of the total U.S. CO_2 emissions from all sources (EPA, 2006). Burning coal produces more CO_2 than any other method of generating electricity, with coal used to generate more than half of the electricity in the U.S (see Table 2.1). To reduce CO_2 emissions from electricity generation, one solution is to switch to renewable energy sources, such as biomass, solar and wind. Biomass accounts for only about 1.5 percent of net electricity generation (Table 2.1). The potential use of biomass for generating power can be increased from the current level of 1.5 percent, if some of the fossil fuels used in power plants are replaced with biomass feedstock. In turn by replacing fossil fuels with biomass fuels, GHG emissions from fossil-fired power plants can be reduced.

2.2.2 National Energy Security

Energy security generally focuses on the threat of sudden supply disruptions. In the U.S., concerns over energy security reached a peak during the 1970s, when the nation's economy struggled to overcome the negative economic impacts of the "energy crisis", experiencing inflation, high unemployment and low GDP growth. Today, energy security has again become an important public issue amid concerns about high energy prices, shortage and disruptions in oil and gas supplies due to competing global demands and terrorist attacks. Disruptions of energy supply could also occur due to extreme weather conditions and political factors. Over the past decades, energy security concerns were mainly determined by oil security concerns. But, most recently this traditional concept of supply security is being expanded to include other energy sources such as natural gas (Bielecki, 2002). For example, Europe relies on Russia for about a third of its natural gas supplies. As a result of the recent dispute between Russia and Ukraine over natural gas supplies, the flow of natural gas among European nations is disrupted. This

[4] Source: Department for Environment, Food and Rural Affairs (2005).
[5] Source: Energy Information Administration (2005a).

disruption in gas supplies has aroused energy security concerns in Europe (Simons, 2006).

Most of the natural gas consumed in the U.S. is produced domestically. At present, about 82 percent of the natural gas consumed in the U.S. is produced within the country. Canada provides about 15 percent, with 3 percent imported as liquefied natural gas (LNG) from other countries.[6] In contrast, only about 30 percent of crude oil is produced domestically, with 70 percent imported from foreign nations.[7] Hence, U.S. energy security will continue to be determined mostly by the security of foreign crude oil. However, with constant threats from terrorist attacks, and unforeseen geopolitical and severe weather events, the risks of disruption to existing energy supplies are high regardless of fuel sources. To reduce supply disruptions, a key factor in global energy security is diversification (Simons, 2006). Increased supply diversity from renewables and alternative fuels could play an important role in promoting national energy security interests. In 2005, petroleum crude oil accounted for only about three percent of electricity generation in the U.S. (see Table 2.1). In order to diversify fuel supplies and achieve national energy security objectives, biomass and other renewables should be used to replace petroleum crude oil and other fossil fuels for electricity generation. By doing so, not only energy security objectives can be achieved but also GHG emission reductions.

[6] Source: Energy Information Administration (2005b).
[7] Source: Energy Information Administration (2005c).

Table 2.1 Percent of Net Electricity Generation by Different Fuel Sources, 1990 and 2005

Fuel Type\Year	1990 (%)	2005 (%)
Coal	52.65	50.04
Natural Gas	12.31	18.67
Nuclear	19.05	19.39
Petroleum	4.18	3.03
Hydro	9.67	6.59
Biomass[8]	1.51	1.54
Geothermal	0.51	0.38
Solar	0.01	0.01
Wind	0.09	0.36

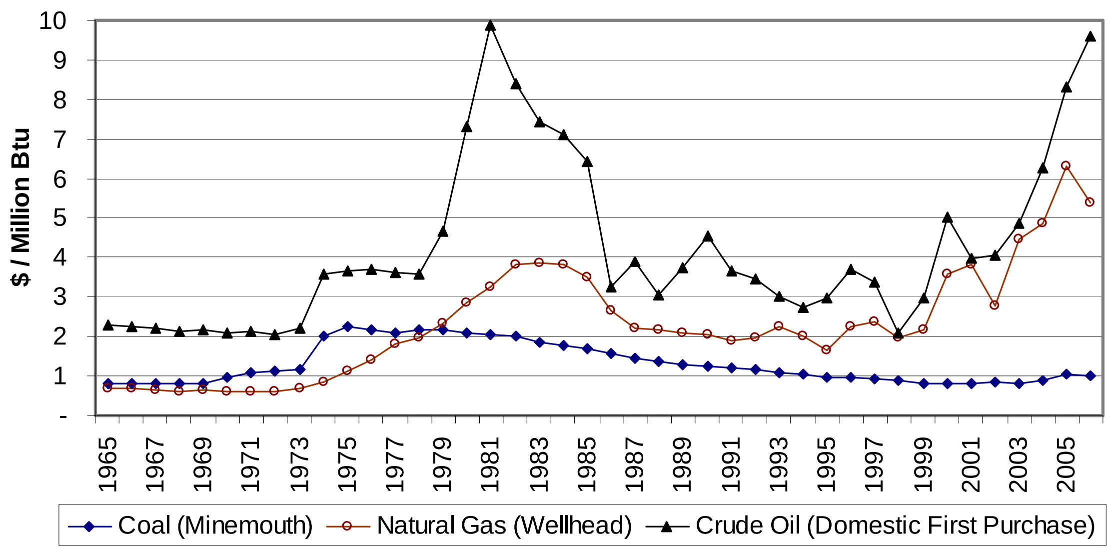
Source: Energy Information Administration (2006a)

2.2.3 Higher Fossil Fuel Prices

Historically, natural gas and petroleum prices in real dollar term have been extremely volatile compared with the real price of coal (Figure 2.1). Due to the energy crisis in the 1970s, both natural gas and petroleum prices went up. Consequently, the price of coal also increased in the 1970s because of the demand shift from oil and gas to coal in electric power sectors. After the crisis, the real coal price has gradually started to decline to the pre-1970 level as shown in Figure 2.1. Its average real price hovers around $1 per million Btu. On the other hand, since the early 2000 the real price of natural gas and crude oil has been increasing significantly which is quite similar to the price-rising pattern of the 1970s. Would electric power producers shift toward coal again in response to recent rising costs for natural gas and petroleum?

[8] Biomass includes wood, wood waste, sludge waste, black liquor, municipal solid waste, landfill gas, tires, agricultural byproducts and other biomass.

According to the Energy Information Administration (2007a), coal will continue to be the dominant fuel used for electricity generation in the foreseeable future due to its low cost. Because of the possibility of induced inter-fuel substitution among fossil fuels as their prices change (Sweeney, 1984); the market potential of biomass fuels for electricity generation would likely depend on the future costs of carbon emission reductions. Higher carbon abatement costs in the future could discourage the use of fossil fuels for electricity generation. Schneider and McCarl (2003) argue that the higher the cost of carbon emission reduction (i.e., the higher the future external costs of GHG emissions into the atmosphere); the more competitive the biomass fuels will be in generating electricity.



Note: All units are converted into dollars per million Btu using respective heat contents.

Source: Energy Information Administration (2006b, 2006c and 2006d)

Figure 2.1 Average Annual Real Fossil Fuel Prices, 1965 to 2006

2.3 Government Support, Policy Choices and Incentives

Electric power plants emit large quantities of CO_2, SO_2 (sulfur dioxide) and NO_X (nitrous oxide) that contribute to three major environmental problems: acid rain, urban air quality, and global climate change. The emissions of these pollutants result in negative externalities[9] which are often viewed as examples of market failure. In the case of the electricity market, market failure occurs because the market price of electricity does not reflect the true cost of generating electricity, i.e. the market price fails to include pollution costs. The effects of externality and market failure can be seen in Figure 2.2, which depicts the electricity market. The demand for electricity is shown by the demand curve D, and marginal private cost of producing electricity is denoted as MPC. Since both the cost of pollution and the cost of generating electricity are considered by the society, the marginal social cost (MSC) will include both of these costs.

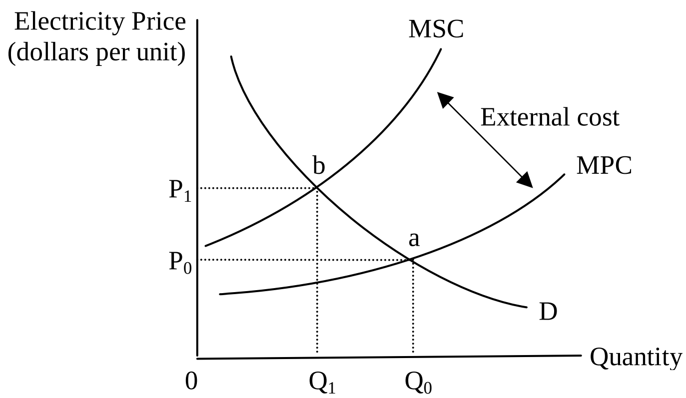


Figure 2.2 The Effect of an Externality on the Demand for Electricity
Modified from Tietenberg (2006)

[9] Externalities occur when one person's actions affect another person's well-being and the relevant costs and benefits are not reflected in market prices.

In a competitive market setting, if the electric sector faces no emission control, it will produce Q_0 amount of electricity at price P_0. But, a resource allocation is inefficient at the point “a”, because the societal costs of pollution are not considered. Therefore, market failure occurs. As long as this external cost exists, the electric industry will be reluctant to allocate its resources and operate its plant to maximize social welfare at the point “b”. To correct the market imperfections due to external costs, some sort of outside intervention is needed. In this case, the government can help internalize the external costs by using different policy options. The current electricity prices in the U.S. or other countries could fall somewhere between P_0 and P_1, depending on which environmental policy options are employed. For example, as a result of more stringent carbon emission regulations, electricity prices in Europe could be higher than the prices in the U.S.

If the current electricity prices were to reach P_1 then electricity generated by biomass would have become cost competitive with the electricity generated by fossil fuels, since all the external costs of pollution are fully internalized at the point “b”. The competitiveness of biomass fuels for power generation will critically depend on the implementation of government’s environmental policies which internalize external costs. Currently available policy options used to promote biomass and other renewables throughout the U.S. and other nations are described below.

2.3.1 Public Utility Regulatory Policies Act

The Public Utility Regulatory Policies Act (PURPA) was a law passed in 1978 by the U.S. Congress as part of the National Energy Act. It was passed in response to the unstable energy climate of the late 1970s and was meant to encourage a shift from fossil energy to renewables. According to Joskow (2003), Title I of PURPA required states to determine whether they would introduce new pricing mechanisms to encourage more efficient utilization of electricity. Title II of PURPA obligated electric utilities to purchase power from cogeneration plants and small power production facilities using renewable and waste fuels. PURPA created a market for independent power (i.e. non-utility) producers requiring electric utilities to purchase surplus electricity from these non-utility producers at a price equal to the utilities' avoided cost[10] of producing electricity (see Bain et al., 2003). As a result of passing PURPA, Bain et al. (1998) have indicated that the period from 1973 to the present has shown a dramatic increase in biomass energy use, especially in thermal and electrical applications of wood residues. The wood processing and pulp and paper sectors became about 70% self-sufficient in energy in this period.

However, some power purchase agreements that were negotiated under PURPA in the 1980’s are no longer available today due to high avoided cost rates which result in significant costs to consumers as electric utilities passed through the costs of PURPA power (Darmstadter, 2001). Because of high avoided costs, a number of plants have closed as their power contracts come up for renewal. These plants could be competitive in today’s environment using low cost waste and residue fuels if their efficiency were much higher. This has been demonstrated in the Hawaii sugar industry where the sugar mill power plants operate for a major part of the year as combined heat and power (CHP) installations (Overend, 1997; Bain et al., 1998). In any case, under PURPA, electric utilities were encouraged to invest in efficient boiler technologies that resulted in a competitive rate of power generation. For instance, Overend (1997) and Bain et al. (1998) suggested that low-pressure boilers were systematically replaced by higher-pressure boiler systems of larger capacity in the period 1960 through 1980 as a result of PURPA.

2.3.2 Renewable Portfolio Standard

A Renewable Portfolio Standard (RPS) is a policy developed by the Clinton administration during 1999 that requires a retail electricity supplier to include in its electricity generation portfolio, a certain amount of electricity from renewable energy resources. Retail suppliers can meet this obligation by either owning renewable energy facilities which produce their own renewable power or purchasing power from eligible

[10] Avoided cost is the cost the utility would have incurred had it supplied the power itself or obtained it from another source. Avoided cost is simply the price at which an electric utility purchases the output of an independent power producer.

generators. The RPS policy is generally designed to increase the contribution of renewable energy to the electricity supply mix and its goal is to ensure that some minimum percentage of generation originates with non-hydro renewable energy sources (Darmstadter, 2001; Wiser et al., 2005). It also establishes numeric targets for renewable energy supply and applies those targets to retail electricity suppliers. Penalties will be imposed on those suppliers who fail to meet their renewable energy purchase obligations.

To add flexibility and reduce the cost of meeting the requirement, tradable renewable energy certificates (TRECs), also known as green certificates or renewable energy production credits (REPC), can be used by the suppliers to track and verify RPS compliance (Langnissa and Wiser, 2003). A TREC is created whenever a unit of renewable energy is generated. This is purely a financial product and can be traded separately from the underlying electricity generation; much like tradable emissions permits (Mozumdera and Maratheb, 2004; Wiser et al., 2005). The main difference between RPS and PURPA is that RPS allows electricity suppliers flexibility in how to meet specific targets for the supply of renewable energy. It is expected that an RPS will lead to strong motivations for cost reduction. Langnissa and Wiser (2003) have argued that RPS policies have been established by legislation in 10 U.S. states, and in Australia, Austria, Belgium, Italy, and the United Kingdom, but little experience has been gained with the actual operation of the policy. Nonetheless, they have pointed out that emerging experience from the state of Texas demonstrates that a well-crafted and implemented RPS can deliver on its promise of strong and cost-effective support for renewable energy with a minimum of ongoing administrative intervention by the government.

2.3.3 System Benefit Charge

According to National Renewable Energy Laboratory (Aabakken, 2006), a System Benefit Charge (SBC) is a small fee added to a customer’s electricity bill used to fund programs that benefit the public, such as low-income energy assistance, energy efficiency, and renewable energy. SBC is a way to collect funds from electric customers and support renewable energy projects. There are 15 states with SBCs through which a portion of the money will be used to support renewable resources. Together, these states will collect about $4 billion in funds to support renewable resources between 1998 and 2017. SBC funding has supported the development of 707 MW of generating capacity (see Aabakken, 2006).

2.4 Emergence of Green Power Markets

Green power refers to all form of electricity produced from renewable energy sources. In order to increase green power capacity, a market for green power needs to emerge. At present, the green market has been relatively small. Increasing environmental and energy security concerns are main reasons for the development of green markets. Green power marketing takes advantage of environmentally conscious customers who are willing to purchase and pay a premium for electricity supplied by renewable energy sources (Wiser and Pickle, 1997). A small number of U.S. utilities in regulated electricity markets began offering green power options to their customers in the early 1990s. Since then, these green products have become more prevalent, both from utilities and in states that have introduced competition into their retail electricity markets. Currently, about 600 utilities or 20% of utilities nationally offer green power programs to customers in 34 states (see Bird and Swezey, 2006).

As indicated in Bird et al. (2002), green power market programs can provide renewable energy developers with access to an additional revenue stream to cover the above-market costs of generating electricity from renewable sources. These programs allow customers to buy some portion of their power supply as renewable energy at a higher price. Consumers can also support renewable energy development through TREC purchases regardless of whether they have access to a green power product from their retail power supplier and without having to switch to an alternative electricity supplier. At present, a few dozen companies actively market TRECs to residential or business customers throughout the U.S (see Bird and Swezey, 2006).

Wiser and Pickle (1997) argue that green power has offered new market opportunities for renewables, causing some to suggest that public policies supporting these technologies will no longer be needed. But, because renewable energy provides public goods, few customers will voluntarily purchase green power and most will instead free ride on others' participation. Since the benefits of a public good cannot be captured solely by the purchasing customer, economic theory suggests that consumers have incentives to free ride the benefits of the public good rather than contribute to it. If individual consumers free ride on rather than contribute to public goods, then they may be unwilling to pay a premium for green power. This situation constitutes a market failure and is often a rationale for government intervention (Rader and Norgaard, 1996; Wiser and Pickle, 1997).

Bird et al. (2002) indicate that the market penetration rate for green power in the U.S. is about 1%, i.e. only about 1% of utility customers participate in green power programs. There has been little growth in green power sales to residential customers in competitive markets in the U.S. Most recent growth has been fueled by green power sales to large, non-residential customers, partnerships between marketers and utilities, and sales of TRECs that do not require customers to switch suppliers. In contrast, about 13% of residential customers in Netherlands have chosen green power. The relative success of the Dutch market can be explained, in part, by aggressive marketing campaigns by utilities and marketers, a restructuring policy that has allowed early access to retail green power suppliers and tax exemptions for green power purchases (see Bird et al., 2002).

In order to reach a higher market penetration rate, green power would have to be aggressively marketed in the U.S. Policies and incentive programs set up to boost the market for renewables also will play a key role in the development and success of the markets. However, the ultimate success of green markets rests on consumers' willingness to pay for green electricity and the ability of power providers to offer the availability and benefits of green power options to customers.

2.5 Barriers to Biomass Power Generation

The key challenges facing biomass for electricity generation are to commercialize high efficiency generating plant and to secure sustainable supplies of relatively low cost biomass feedstock. As indicated in studies (see Office of Technology Assessment, 1995;

Sathaye and Bouille, 2001), a key barrier to the development of bio-energy markets is the "chicken and egg" problem. For example, farmers cannot afford to grow and supply biomass feedstock in a sustainable way unless electric power conversion facilities are in place to purchase it. Power conversion facilities cannot be built unless biomass feedstock is constantly available and end-use market is ready. An end-use market is difficult to develop without assured supplies of the feedstock. Due to the lack of infrastructure development and integration at all these levels, the potential market growth for biomass power has not been able to realize. There are many barriers that currently and potentially impede the development of supply and demand markets for biomass feedstock. These barriers include technological barriers and institutional barriers.

2.5.1 Overcoming Technological Barriers

To overcome the technological barriers, two systems of technologies need to be developed. (1) On the biomass supply side, technologies for biomass feedstock supply systems need to be improved, and (2) on the demand side, the biomass power-generation technologies also need to be developed and improved from the current situation.

(1) Technologies for biomass feedstock supply systems

Technological advancement in the following systems will bring down the cost of biomass feedstock supply[11]:

- Production ─ cost reductions are needed through increases in yields or input efficiency.
- Harvest and Collection ─ a new form of bulk harvesting and collection systems is needed in order to decrease the cost of harvesting and collection.
- Storage ─ improvements are needed in the areas of feedstock quality and monitoring, dry storage systems, and wet storage systems.

[11] Source: Department of Energy (2003).

- Reprocessing ─ technical barriers such as low bulk density, combustibility, and variability in physical and chemical characteristics among others impede the ability to deliver high-quality, low-cost biomass.

(2) Biomass power-generation technologies

The cost of power generation from biomass can be greatly reduced if the conversion technologies are developed and improved for the following generation systems[12]:

- Conventional steam cycle plant ─ biomass is burned in an excess of air to produce heat which is in turn used to raise high pressure steam in a boiler. Many types of biomass contain alkali metal species: sodium, potassium, and calcium. And the combustion products of these species, chlorides, silicates, etc. can form deposits on heat transfer surfaces reducing heat transfer, and thus, overall plant efficiency.
- Gasification ─ biomass can be converted to a clean-burning gas that can be used to power gas turbines. In the longer term, gasification technologies hold the most promise for the next generation power generation efficiency improvements from combined cycles and fuel cells.
- Co-firing ─ biomass can replace a portion of the coal used to produce power in an existing power plant. But, when biomass is co-fired with coal (even in small percentages), alkali species can change the properties of the resulting mixed ash, which can have a significant impact on the coal plant’s operating and maintenance costs or even operability.
- Pyrolysis ─ biomass is heated rapidly in a high-temperature, oxygen-free environment, converting it into a liquid fuel (bio-oil) as well as other products. The bio-oil can then be used to generate heat and electricity by combustion in boilers, engines and turbines.

On the supply side, biomass energy systems have as a technical barrier the cost of producing, transporting, preparing and processing biomass feedstock. To be

[12] Sources: European Network of Energy Agencies (Date unknown), Pioneer Valley Renewable Energy Collaborative (2007), and Bain et al. (2003).

economically competitive, new production technologies and methods must be developed. Bain et al. (2003) point out that harvesting, preparation, transportation, and feeding of a variety of biomass feedstocks that are suitable for power production must be demonstrated, and new methods developed for reducing costs and energy requirements must be verified. This will reduce the delivered cost of feedstock to the power facility to a level more competitive with fossil fuels as well as increase the return to the farmer producing the biomass.

On the demand side, current biopower generation systems suffer from poor efficiencies (see Wiltsee, 2000). To improve the efficiencies of power generation, technologies described above need to be developed and improved. The development of power generation technologies will significantly reduce biomass power generation costs. As discussed in Bain et al. (2003), the advancement of biomass power generation technologies can be impeded by barriers that do not involve technical issues. Technological progress that improves performance or increases system efficiency can give opportunities to deployment. However, market growth ultimately depends on overcoming the institutional challenges.

2.5.2 Overcoming Institutional Barriers

In order to successfully create bioenergy markets and to implement biopower technologies, institutional issues such as regulatory, financial, infrastructural, and perceptual have to be overcome (Costello and Finnell, 1998). The regulations in the U.S. that control the emission of pollutants such as SO_2 and NO_X are rapidly tightening under a variety of cap and trading schemes. These regulations may work as a potential blessing to biopower because technologies such as co-firing may improve electric utilities' emissions profiles in SO_2 and NO_X (Bain et al., 2003). In the future, it appears likely that regulations to restrict carbon emissions will come into effect through the Kyoto Protocol in the form of tradable carbon permits as more people become involved in fighting against global warming caused by the increasing concentration of GHG in our atmosphere. This potential regulation of carbon emissions will be of advantageous for biomass fuels to be cost competitive with fossil fuels.

The main concern for firms entering into new biomass businesses and offering biomass feedstock products to the marketplace is financing. Given the uncertainty and policy dependent nature of biomass market conditions, new firms will incur a significant amount of entrance costs. As suggested in Costello and Finnell (1998) capital and financial markets generally perceive the deployment of new emerging biopower generation technologies as involving more risk than established technologies such as coal-fired power generation technologies. The higher the risk, the higher the rate of return demanded on capital thus impacting the rate of investment in these new emerging technologies (Costello and Finnell, 1998; Sathaye and Bouille, 2001). Due to the perceived uncertainty and risk, most private entities such as commercial banks and others are not willing to provide loans or funds to invest in biomass related businesses that could be financially viable and in addition, reduce carbon emissions. Hence, they constitute failures of capital and financial markets that must be overcome to reach the level of economic potential (Sathaye and Bouille, 2001). In contrast to private institutions, who are primarily concerned about the risk-adjusted financial return, Sathaye and Bouille (2001) argue that government institutions are expected to provide funding to evaluate desirability of investments in a wider context of the well-being of the whole society, including costs and benefits that some entities impose on others. The future success and survivability of biopower industry will likely depend on the government stringent policies aim at reducing carbon emissions from coal-fired power plants.

In the U.S., sophisticated infrastructures have already been developed for the supply and distribution of conventional fossil fuels such as coal and natural gas. For instance, coal and natural gas can be gathered and transported efficiently via developed railroad systems and pipelines. But, similar infrastructures do not exist for the supply and distribution of biomass feedstock. As mentioned in Bain et al. (2003), currently biomass feedstock supplies are dominated by low cost residues streams consisting of materials generated by industries that process biomass for fiber or food uses such as paper mills, lumber mills, sugar mills, etc. Other economic activities like agriculture, urban construction and demolition, waste generation also dominate the supplies of biomass. In the future, a dedicated feedstock supply system based on crops such as poplar, willow and switchgrass could dramatically expand the availability of biomass for energy generations. Developing a sustainable biomass feedstock reserve program of these woody crops and perennial grasses could help remove some infrastructural barriers related to the cost and supply of feedstocks (Costello and Finnell, 1998). Another problem associated with the supply technology infrastructure concerns the distance for the economic collection and transportation of fuel, since collection and transportation of biomass feedstocks to processing points and generators is costly and limits feedstocks for most projects to within a 50-mile radius (Bain et al., 2003).

The public's perception that biomass technology is not a green energy source can limit the acceptance of biomass power projects. According to Oregon Biomass Market Assessment Report[13], public tends to see burning biomass as producing emissions and view wind and solar as cleaner, more preferred technologies. In addition, for wood biomass there are concerns among publics that excessive forest thinning might have a negative impact on wildlife habits and on soil and water quality. These unfavorable perceptions are due to a lack of understanding of the overall benefits of biomass technologies and could incur significant amount of costs and risks to any development of biomass program. Furthermore, the report from Oregon Biomass Market Assessment asserts that the fossil fuel industry has a strong and effective lobbying effort to gain political support; the biomass industry is relatively weak in comparison. In order to overcome the negative perceptions held by the public about the biomass technology, considerable education efforts and demonstration will be required to inform them about the benefits of biomass energy.

2.6 Economics of Demand and Supply for Biomass Feedstocks

The potential for market penetration of biofuels for electricity generation will depend on the development of biofuel markets at different levels of production processes. In

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[13]Source: Energy Trust of Oregon (Date unknown).

general, farmer's supply (S_{FB}) and electric industry's demand (D_{IB}) functions for biofuels can be written as follows:

$$S_{FB} = f(\overset{+}{P}_B, \overset{?}{P}_{Fossil}\ \overset{-}{P}_{Alter}, \overset{-}{P}_{Landuse}, \overset{+}{Tech}_{\Pr od}, \overset{+}{Sub}_{FB}) \tag{2.1}$$

$$D_{IB} = f(\overset{-}{P}_B, \overset{+}{P}_{Fossil}, \overset{+}{Tax}_{Fossil}, \overset{?}{Tech}_{Conver}, \overset{+}{Poly}, \overset{+}{G}_E) \tag{2.2}$$

Negative and positive signs indicate the relationships between dependent (left-hand side variables) and independent variables (right-hand side variables). P_B is the price of biofuel. It will be positively related to the S_{FB}, but negatively related to the D_{IB}. On the supply side, P_{Fossil} represents the price of oil and natural gas which are used as inputs in the production of agricultural outputs such as biofuels. The one-to-one relationship between P_{Fossil} and S_{FB} and is undetermined. P_{Alter} captures the price of the best alternative use of the biomass as feed or erosion control in the case of crop residues. The higher P_{Alter}, the lower the S_{FB}. $P_{Landuse}$ is the opportunity cost of using farm lands for biomass fuel production. As $P_{Landuse}$ rises, the S_{FB} will decline. $Tech_{Prod}$ is denoted as the rate of technological improvement in the production of biomass crops. As technology improves, the S_{FB} will increase. Sub_{FB} is the farm subsidies provided by the government to support biofuel industry. The higher Sub_{FB}, the higher the S_{FB}.

On the demand side, P_{Fossil} captures the price of alternative fuels such as coal, oil and gas. The higher P_{Fossil}, the more competitive is the biofuels and the higher the D_{IB}. Tax_{Fossil} represents the external costs of using fossil fuels imposed on power producers. It is assumed to be positively related to the D_{IB}. $Tech_{Conver}$ is denoted as the rate of technological improvement in fuel conversions. For instance, improvement in biomass conversion technology will reduce conversion costs and enhance the efficiency of biomass power generation. The one-to-one relationship between $Tech_{Conver}$ and D_{IB} and is undetermined. *Poly* is a policy variable which requires power producers to include in its electricity generation portfolio, a certain amount of electricity from biomass or other renewable energy resources. *Poly* is assumed to have a positive impact on the D_{IB}. And finally, G_E is defined as growth in power energy sectors due to economic and population growth. It is assumed to be positively related to the D_{IB}.

2.7 Economics of Biomass Fuel Production

The whole process of biomass feedstock production is shown in Figure 2.3. Biomass feedstocks are produced and priced at two levels: farm level and industry level. At the farm level, biomass feedstocks are produced, harvested and collected. Harvest and collection includes gathering and removing biomass feedstocks from farm land. The price of feedstocks at the farm level (P_{BFL} in Figure 2.4) includes harvest and collection costs plus the net return to the farmer. Before burning them in the power plant, biomass feedstocks have to be picked up at the farm gate, transported and preprocessed. Preprocessing may include one or a combination of several size reduction, fractionation, sorting, and densification (Sokhansanj and Fenton, 2006). Thus, the price of bio-feedstock at the industry level (P_{BIL} in Figure 2.4) includes farm level costs (i.e. P_{BFL}) plus transportation, processing and storage costs and some net return to the feedstock supplier[14] (Sokhansanj et al., 2003). The difference between biofuel prices at the industry and farm levels (i.e. $P_{BIL} - P_{BFL}$) reflects transaction costs that firms must pay to acquire biofuels for electricity generation. Presently, due to high transaction costs, the price of bio-feedstock at the industry level is assumed to be higher than the price of fossil fuels such as coal (i.e. $P_{BIL} > P_C$ in Figure 2.4).

Biomass Production → Harvest and Collection → Transport → Preprocessing → Power Plant

Figure 2.3 Biomass Feedstock Production Process

[14] Feedstock suppliers responsible for procuring the required amount of biomass for power generation act as a middleman between farmers and power producers.

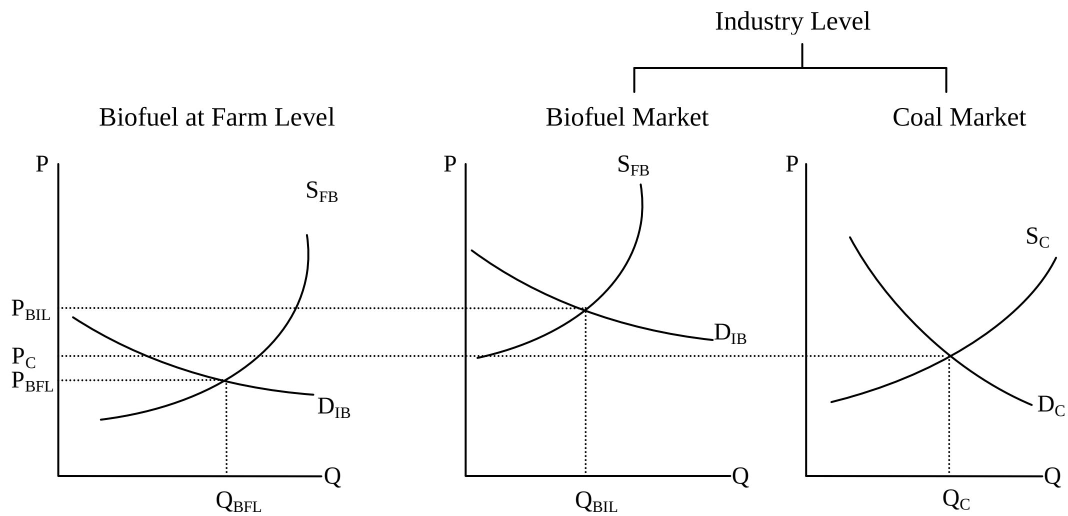


Figure 2.4 Bio-feedstock Prices at the Farm and Industry Levels as Compared to Coal Market Price

2.8 Transaction Costs

One of the key requirements for making biomass fuels competitive is to narrow the gap between P_{BIL} and P_{BFL}, that is to minimize the transaction costs. Transportation costs could comprise a significant portion of transaction costs because of the low bulk density of biomass. As distance traveled increases between bio-feedstock producers and biopower generators, so will the transportation costs. In order to minimize the costs of transportation, both parties must locate near each other. Reducing the costs of collection, processing and storage are also important in making biomass feedstocks competitive and in developing efficient infrastructure capable of supplying large quantities of feedstocks to biopower facilities. Any future reductions in these transaction costs would depend on the advancement in the efficiencies of biomass harvesting, collection, transport and processing technologies.

2.9 Market Structure

Overall market structure for electric power industry is described in the following Figure 2.5. Farmers are responsible for growing and producing the required amount of feedstocks that biopower producers need for electricity generation. On the other hand, biopower producers purchase the necessary feedstocks which need to be processed before burning them in the boilers for electricity generation. This section will only focus on the relationships between farmers and biopower producers.

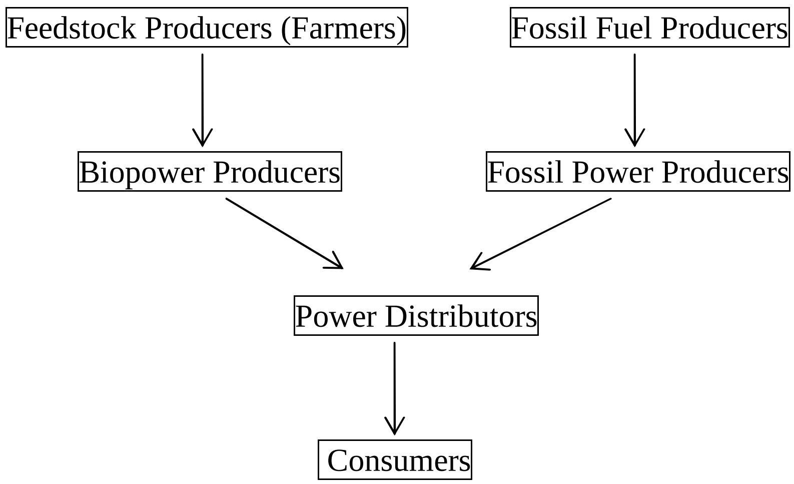


Figure 2.5 Market Structure for Electric Power Industry

Reducing transaction costs[15] will play an important role in the structuring of bio-feedstock and biopower industries. The transactions between these industries can be organized in three ways: spot markets, contracts or vertical integration. Should the transactions between farmers and biopower producers be governed by spot markets for the purpose of minimizing firms' internal structural costs? Or should they be governed by long-term contracts or vertical integration? It has been shown that (Williamson, 1985; Joskow, 1985 and 1988) increasing the degree of asset specificity leads to longer term contracts: with a very low degree of asset specificity a market-based governance structure (i.e. a spot market) is preferable; however, with a high degree of asset

[15] Transaction costs within firms include costs of negotiating, writing contracts, monitoring, enforcing, and breaching contracts.

specificity long-term contracts or vertical integration is preferable because the hold-up problem (i.e. the possibility of ex post opportunistic behavior) might arise. There are four different types of relationship-specific investment (Williamson, 1983; Joskow, 1988) which is helpful for identifying and measuring the degree of asset specificity. They are:

Site specificity: seller and buyer are in close physical proximity to each other, reflecting ex ante decisions to minimize inventory, transportation and processing costs. For instance, coal power plant and coal mine are deliberately located next to each other to minimize costs.

Physical asset specificity: when one or both parties make investments in machinery and equipment that are specific to a certain transaction and which have lower values in alternative uses. For instance, the efficiency of boilers in a coal power plant can be increased if they are designed to burn a specific type of coal. But this implies that they are less efficient if they burn coal with differing heat, sulfur and moisture content.

Dedicated assets: general investments by an input supplier in capital to meet the demands of a specific buyer. If the contract is terminated prematurely, it would leave the supplier with significant excess capacity. For instance, the coal mine would not be built but for the promise of purchases from the nearby power plant.

Human-capital asset specificity: the accumulation of knowledge and expertise that is valuable specifically to a particular transaction. Specific knowledge and skills and information accumulated over a period of time by operating in a coal-fired power plant or a coal mine can be described as an example of human-capital asset specificity. These accumulated knowledge and skill may have little value outside of this economic relationship.

Relationships between farmers and biopower producers may be characterized by a high degree of site specificity, since they must locate near each other to minimize transaction costs especially transportation costs. In addition, the biopower technology may be characterized by a high degree of physical asset specificity. As mentioned in Choinière (2004), the quality of biofeedstocks could vary from one place to another due to the quality of soil, cropping practices, and the climate and altitude in which they are grown. The efficiency of biopower plants can be increased if they are designed to burn a specific type of bio-feedstock. However, they will be less efficient if bio-feedstock with differing energy, moisture and nutrient contents is used. Thus, biopower producers would need greater specialization in biopower generation technologies and this means a high degree of physical asset specificity on the generator's investment (see Choinière, 2004).

Most investments required for developing a new biomass industry may be characterized as dedicated assets. As indicated in Choinière (2004), farmers are not likely to begin production of biomass crops such as switchgrass and willow without the assurance that a biopower facility will be built to procure those crops, and biopower producers are not likely to construct a power facility without the assurance that farmers will produce the required crops. Once an agreement is reached between farmers and biopower producers to develop the project, farmers may have to dedicate all their physical and human assets to the production of biomass crops that have little value to any other users than the producers of biopower. Moreover, any knowledge and skills gained in the production of these crops may have little value to other industries outside of the transactions. Hence, investments made in the biomass industry may also have a high degree of human-capital asset specificity.

Due to the presence of relationship specific investments, the degree of asset specificity will be high between bio-feedstock producers and biopower generators as discussed above. This suggests that for these industries vertical integration or long term contracts will be preferred to spot markets. However, according to Choinière (2004), uncertainty in agricultural production due to changes in weather and growing conditions, and uncertainty in markets for biomass resources suggest that it may be difficult to develop a contract which allows for the adjustment of bio-feedstock price that accounts for the various forms of uncertainty. To induce farmer participation in the biomass industry, biopower generators should offer contracts designed to protect farmers from exposing to risks. By offering the right contracts which align with the interests of farmers, biopower producers can not only protect their investments, but also assure adequate supply of feedstock (Choinière, 2004).

Because of the uncertainty and high transaction costs, research findings from Choinière (2004) suggest that currently biopower industry may not be profitable. In any case, because society as a whole can benefit from improved environmental conditions such as reductions in air pollution and GHG emissions, the government should support the industry by using various policy measures. Farmers can also benefit from an increase in their income because of a new developing bio-feedstock industry.

2.10 Policy Options

As suggested in equations (2.1) and (2.2), the competitiveness of bio-feedstock industry may depend on government policy choices. Figure 2.6 illustrates the impact of two policy options (a subsidy given to farmers for feedstock production and a carbon tax imposed on coal suppliers) on the bio-feedstock market. A farm subsidy will reduce the costs of feedstock production and shift the farm feedstock supply curve downward (i.e. from S_{FB} to S'_{FB} in Figure 2.6a and b). This will result in a decrease in bio-feedstock price and an increase in quantity of feedstock supplied both at the farm level and at the industry level. As shown in Figure 2.6a and b, the feedstock price will drop from P_{BFL} to P'_{BFL} at the farm level and from P_{BIL} to P'_{BIL} at the industry level. Quantity of feedstock supplied will increase from Q_{BFL} to Q'_{BFL} at the farm level and from Q_{BIL} to Q'_{BIL} at the industry level.

Again, differences between P_{BIL} and P_{BFL} (without subsidy), and P'_{BIL} and P'_{BFL} (with subsidy) reflect transaction costs that power firms must incur to obtain the required feedstock to generate electricity. It is assumed in Figure 2.6b, that a certain amount of government's farm subsidy could make the bio-feedstock price drop to a point where it is equal to the market price of coal (i.e. $P'_{BIL} = P_C$). A carbon tax imposed on coal suppliers will increase the costs of coal production and shift the coal supply curve upward (i.e. from S_C to S'_C in Figure 2.6c). This will result in an increase in coal price from P_C to P'_C and a decrease in the quantity of coal supplied from Q_C to Q'_C. It is assumed that because the government imposes carbon tax on coal suppliers, the price of coal will rise to a point where it is equal to the unsubsidized market price of feedstock (i.e. $P'_C = P_{BIL}$ in Figure 2.6b).

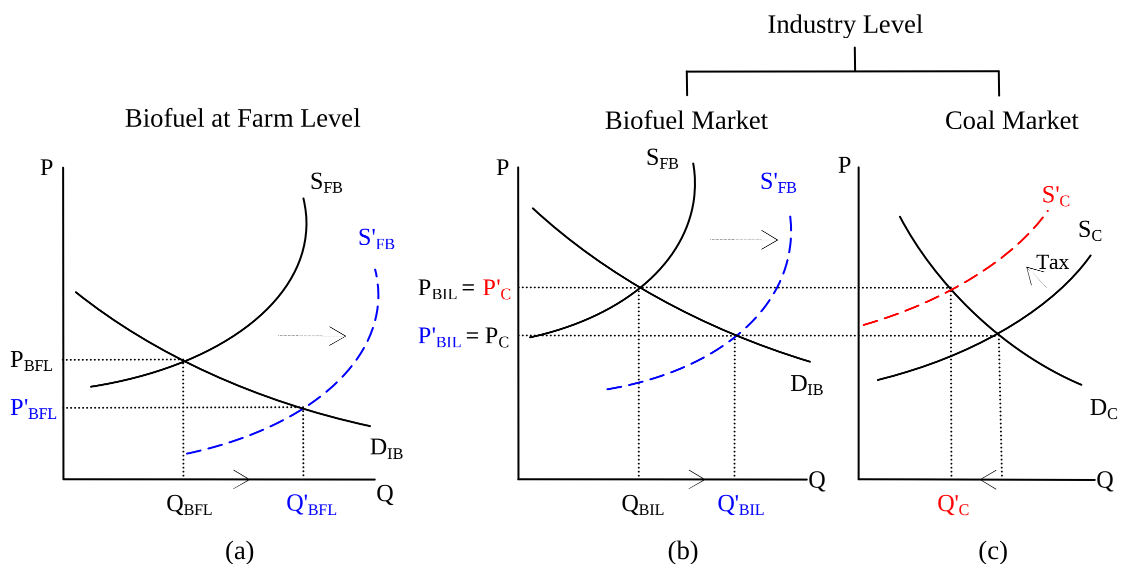


Figure 2.6 The Impacts of Farm Subsidy and Carbon Tax on Bio-feedstock Market

Both policy options will make bio-feedstock economically competitive with coal. A subsidy will make both the farmer and the biopower producer better off because of a reduction in the feedstock price and an increase in the quantity of feedstock supplied. But, the government will be worse off in terms of revenue. On the other hand, a carbon tax imposed on coal suppliers will make bio-feedstock more cost competitive and increase the government's revenue. But, coal producers and fossil power generators will be worse off as the price of coal rises and the quantity of coal supplied dwindles. Another option the government can use is to enforce a policy such as RPS (Renewable Portfolio Standard) which requires power producers to generate a certain amount of electricity from renewable energy resources.

2.11 Improvement in Feedstock Production and Conversion Technologies

Technological improvement in feedstock production at the farm level will increase feedstock yield as shown in equation (2.1) above. This will shift the farm's feedstock supply curve (S_{FB}) to right and result in a decrease in feedstock price and an increase in quantity of feedstock supplied. On the demand side, as suggested in equation (2.2) above, improvement in fuel conversion technology may or may not affect the demand for feedstock (D_{IB}), as power generators have opportunities to choose between either bio- or fossil-fuels for electricity generation. Given that fossil-fuel conversion technology is more developed and efficient than biomass conversion technology, power generators will not have incentives to choose biofuels for power generation, unless carbon emissions are highly restricted. This implies that future technological development in biopower industry will not only depend on the government which use various policy measures to promote biopower and to restrict carbon emissions, but also on the public awareness of negative consequences of global climate change.

2.12 Summary

Today, the main reason that stimulates the interest of using biofuels for electricity generation is concerns for global warming and climate change. National energy security may not be an important factor in inducing the use of biofuels for power generation, since petroleum crude oil only accounts for 3% of the U.S. electricity generation and most of the required fuels used to generate electricity are available within the country. Due to the possibility of inter-fuel substitutions among various fuel sources in electric sectors, increase in oil and natural gas prices also may not be an important factor in motivating power generators to switch to biomass.

As indicated, there are various technological and institutional barriers that prevent biofuels from entering the fuel-supply chains for power generation. The costs of overcoming these barriers would be tremendously high, making biofuels for power generation economically uncompetitive. Because biomass and other renewable power industries provide public goods, their economic survivability will depend on governmental support through subsidy and other policy measures such as PURPA, RPS and SBC as discussed above. Consumers' willingness to pay will also play an important role in creating niche markets (the so-called green power markets) for biomass and other renewable energy.

For biofuels to become cost competitive with fossil fuels, transaction costs between and within firms must be significantly reduced. Incentives to reduce biofuel transaction costs and to increase biofuels' share in electricity production need to be created. These incentives may come from government restrictions to regulate GHG emissions which may take effect through Kyoto Protocol in the form carbon trading. Using various literatures, this section provides background information on biofuels for electricity generation. Economics of biofuels is discussed in details which help facilitate the understanding of biofuel market status in electricity generation.

3. FACTORS INFLUENCING BIOELECTRICITY GENERATION

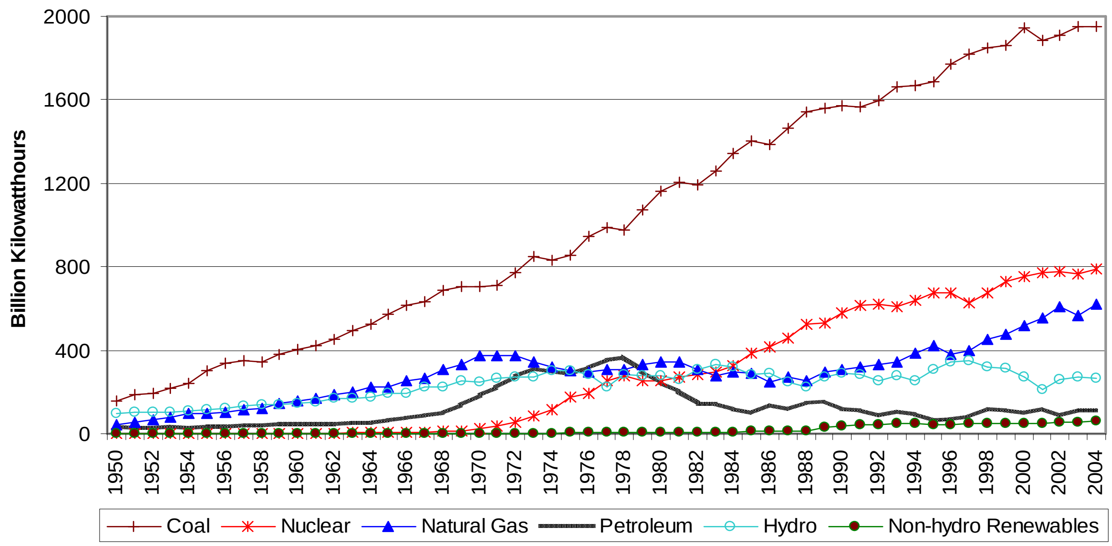
To determine what role biofuels can play in the future of electric power generation, one needs to explore the influence of a number of factors including: the price of fossil fuels, the rate of turnover for existing fossil power plants, electricity demand growth, and changes in technologies which could facilitate the use of biomass as fuels for electricity generation.

3.1 Electricity Generation Using Various Fuel Sources

In recent years, the largest share of US electricity generation has been from coal (Figure 3.1). Net electricity generation from coal was about 155 billion kilowatt hours (kWh) in 1950. By 2004, it had increased to about 1,954 billion kWh. Generation from nuclear and natural gas has also increased as indicated in the figure. On the other hand, the use of petroleum to generate electricity reached its peak in 1978, about 365 billion kWh but has fallen since due to the energy crisis in the 1970s and subsequently concerns over the costs and future supply of petroleum. Figure 3.1 also indicates that electricity generated by using biomass fuels has been small. From 2000 to 2004 (see Table 3.1), average electricity generation from biomass was only about 29 billion kWh as compared to about 1,929 billion kWh from coal.

3.2 Challenges from Fossil Fuels and Nuclear

Currently, biofuels for power production face serious challenges from fossil and other fuels. The future costs of carbon emission reductions will likely help shape the changes in fuel mix used to generate electricity. Power producers could be induced to include or use more biomass and other renewable and less carbon-intensive fuels in their fuel mix portfolios as costs of carbon emission rise. Various fuel scenarios are discussed below.



Source: Energy Information Administration (2006e)

Figure 3.1 Historical U.S. Electric Power Sector Electricity Net Generation by Fuel Type in Billion Kilowatt-hours, 1950-2004

Table 3.1 Electric Power Industry's Electricity Net Generation from Various Fuel Sources (in Billion Kilowatt-hours)

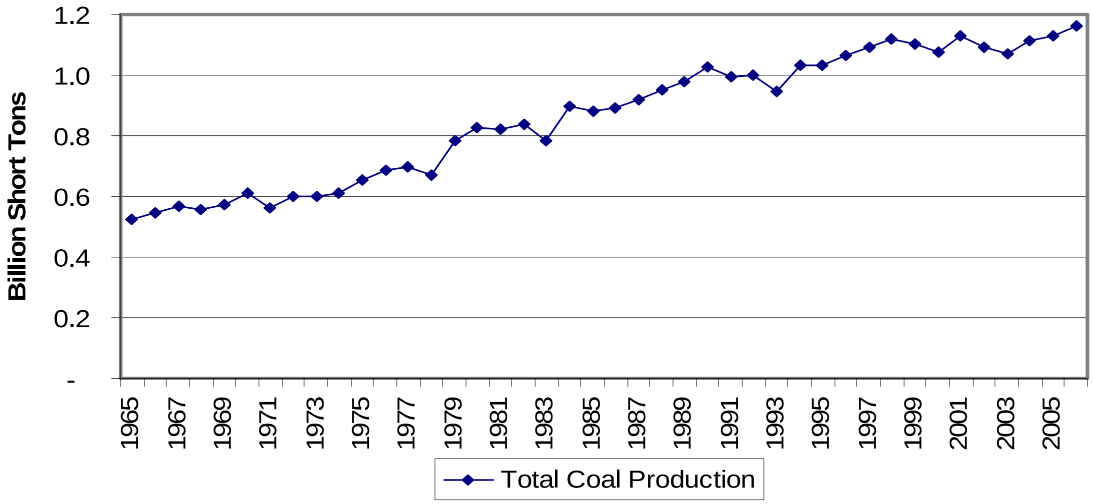
Year	Coal	Nuclear	Natural Gas	Hydro	Petro-leum	Biomass	Geo-thermal	Wind	Solar
2000	1,943.11	753.89	517.98	271.34	105.19	29.22	14.09	5.59	0.49
2001	1,882.83	768.83	554.94	213.75	119.15	27.78	13.74	6.74	0.54
2002	1,910.61	780.06	607.68	260.49	89.73	29.19	14.49	10.35	0.55
2003	1,952.71	763.73	567.30	271.51	113.70	30.37	14.42	11.19	0.53
2004	1,953.97	788.56	618.60	264.50	112.48	29.35	14.36	14.15	0.58

Source: Energy Information Administration (2006e)

3.2.1 The Case of Coal

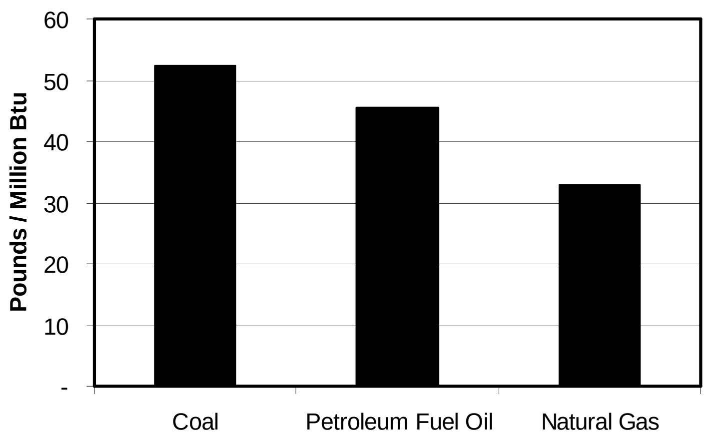
Today, electricity generation consumes more than 90% of the coal produced in the U.S. Coal production has increased tremendously over the past two decades (Figure 3.2). Increasing productivity in mining ensures that coal will likely remain cost competitive with other fuels. However, the problem with coal is that it contains the highest amount of carbon per unit of useful energy (see Figure 3.3). At present, the single largest source of carbon dioxide (CO_2) emissions comes from the coal use in the electric power industry (EPA, 2006). Table 3.2 shows that CO_2 emissions from coal-fired power plants have been rising. The increase in CO_2 emissions is especially pronounced after the oil price shocks of the 1970s, as electric power producers switched to coal from oil. The increasing atmospheric CO_2 content is a major global warming concern. Coal-fired power plants also emit a substantial amount of sulfur dioxide (SO_2) and nitrogen oxide (N_2O), both of which can produce acid rain and other pollutants which can harm the environment.

The current market price of coal does not reflect the costs of carbon emissions. The coal price could have been much higher if these external costs were taken into account in the price scheme. Because of the existence of externality problems, carbon emission abatement costs will not be accounted for in the market price of coal until the government is willing to impose stringent environmental regulations aimed at curbing GHG emissions. The future role of biomass for electricity production is still uncertain due to the uncertainties in government’s environmental policies and other factors discussed below.



Source: Energy Information Administration (2006b)

Figure 3.2 Annual U.S. Total Coal Production in Billion Short Tons, 1965-2006



Source: Royal Academy of Engineering (2004)

Figure 3.3 Carbon Content of Fossil Fuels

Table 3.2 Historical CO_2 Emissions from Electric Power Sector Energy Consumption (in Million Metric Tons CO_2)

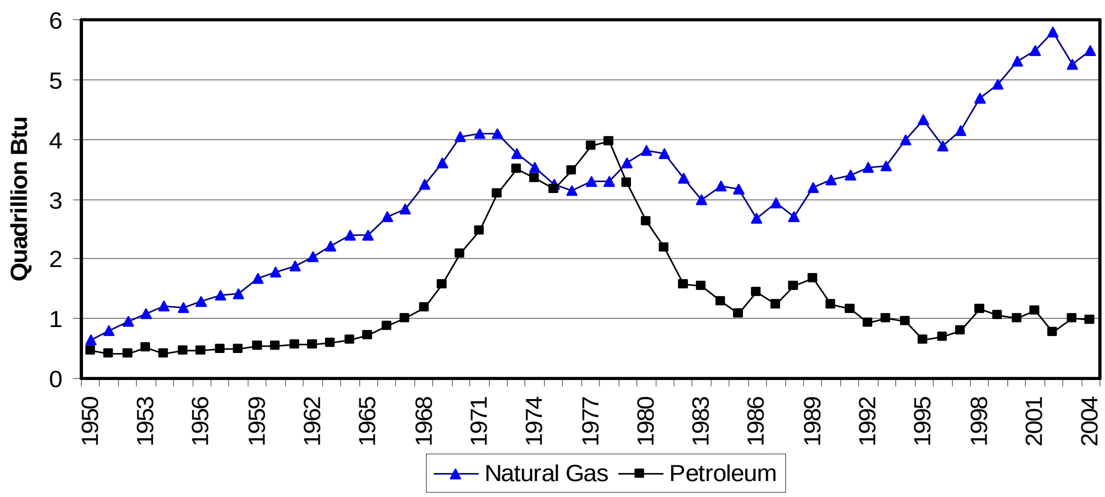
Fuel	1950-59	1960-69	1970-79	1980-89	1990-99
Coal	2,950.03	5,239.66	8,343.89	13,090.14	16,542.71
Natural Gas	613.44	1,329.50	1,902.48	1,680.86	2,109.97
Petroleum	364.03	642.03	2,516.26	1,266.52	846.43

Source: Energy Information Administration (2006f)

3.2.2 The Role of Natural Gas and Petroleum in Electricity Generation

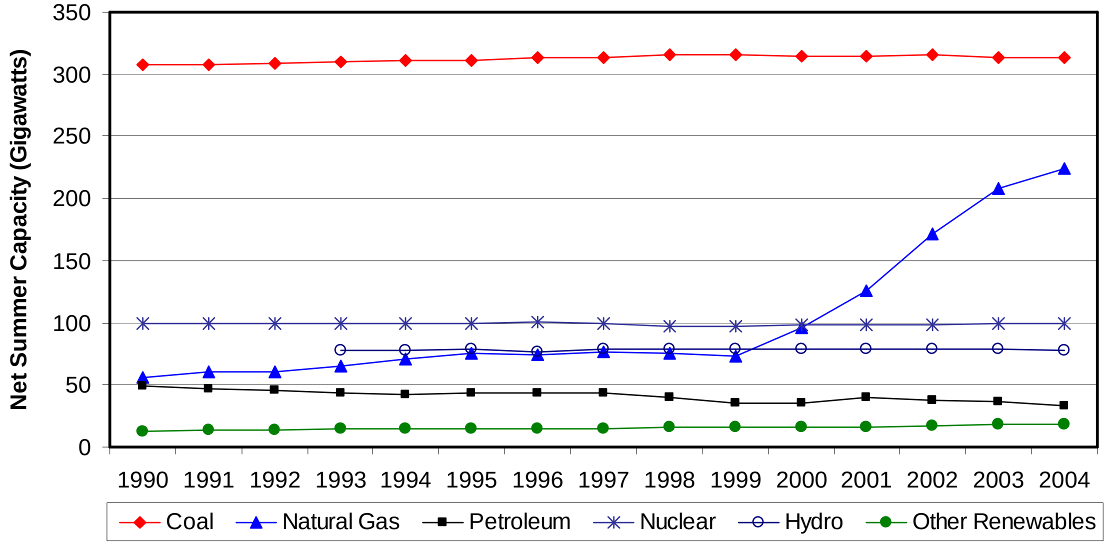
As seen in Figure 3.3, natural gas is the least carbon-intensive fossil fuel. In terms of per unit of useful energy, combustion of natural gas results in 42% less CO_2 emissions than coal and 29% less than petroleum (Sandor, 1999). Significant reductions in CO_2 emissions can be made through fuel switching from coal to natural gas. Figure 3.4 indicates that natural gas consumption in the electric sector has been on the rise since the late 1980s, while the petroleum consumption has declined significantly since the late 1970s. In fact, natural gas has become the fuel of choice for today's new power plants. Beginning in the 1990s, the combination of lower prices, reduced capital cost and improved efficiency has made natural gas the economic choice for new generating capacity in most regions of the U.S. (Ellerman, 1996). As illustrated in Figure 3.5, since the early 1990s gas-fired generating capacity has been increasing. This increase in gas-fired generating capacity is especially intense during the periods of 2000-2004. In contrast, the figure shows that electricity generating capacity from all other fuel sources remains relatively stable. In terms of both the additional capacity in megawatt (MW) and the number of additional generating units, Table 3.3 indicates that gas-fired power generation has surpassed coal-fired electricity generation in significant amount in both periods of 1995-1999 and 2000-2004. Only 17 coal-fired generating units are added during the entire periods of 1995-2004 with total summer capacity of 3,351MW. In addition, the table shows that petroleum does not add much capacity to the electric generating units during the entire period.

Besides its use for generating power, natural gas has many other competing uses in the industrial, residential and commercial sectors. Industry is the biggest user of natural gas, accounting for more than 30% of natural gas consumption across all sectors. Natural gas has a multitude of industrial uses, including providing the base ingredients for such varied products as plastic, fertilizer, anti-freeze, and fabrics. In the residential and commercial sectors, natural gas is mainly used for heating purposes. If the demand for natural gas goes up in all sectors of the economy, the price of natural gas will certainly increase. A future increase (or decrease) in the capacity of gas-fired power generating units will likely depend on the future costs of burning natural gas in power plants.



Source: Energy Information Administration (2006c and 2006d)

Figure 3.4 Annual Consumption of Natural Gas and Petroleum Fuel Oil by Electric Power Sector in Quadrillion Btu, 1950-2004



Source: Energy Information Administration (2003 and 2005d)

Figure 3.5 Historical Electric Power Generating Capacity by Fuel Source, 1990-2004

Table 3.3 Capacity Additions at U.S. Electric Industries, 1995-1999 and 2000-2004, by Fuel Type

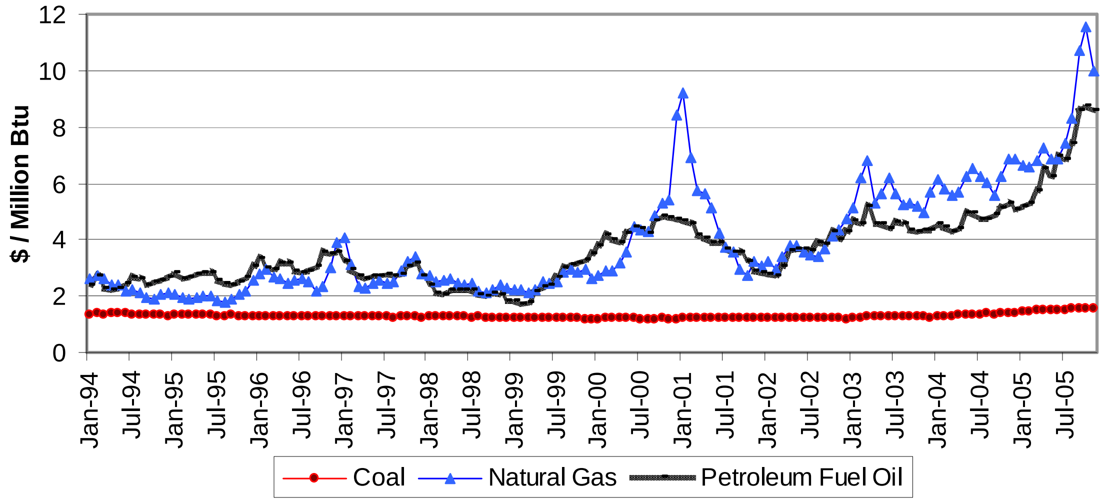
	1995 to 1999		**2000 to 2004**	
Fuel Type	***Capacity (MW)***	***Number of units***	***Capacity(MW)***	***Number of units***
Coal	2,702	10	649	7
Gas	10,919	147	130,971	1,176
Petroleum	1,804	228	1,703	534

Source: Energy Information Administration (1995-2002, 2003a, 2004a, and 2005d)

3.2.3 Costs of Natural Gas and Petroleum at Electric Utilities

Figure 3.6 compares average monthly costs of fossil fuels at the U.S. electric utilities in nominal U.S. dollars. For some electric industries, natural gas and petroleum fuel oil are substitutes. Although declining in number, these energy users are able to switch back and forth between these fuels quickly, depending upon which is cheaper (Brown, 2003). Rising oil costs push these energy users toward natural gas, and falling oil costs attracts them back to the fuel oil. Consequently, Figure 3.6 indicates that average monthly costs of petroleum fuel oil and natural gas have tended to track each other over long periods of time.

History tells us that supply shocks will be the important factor that determines the future demand for natural gas in electric power sector. For instance, due to the oil shortage during the energy crisis of 1970s, demands for fuels in the electric sector has shifted toward coal, the fuel experiencing the smallest price increase and away from oil and gas; fuels experiencing the greatest price increase (Sweeney, 1984). Recently, average costs of both gas and oil delivered to electric utilities have been on the rise, while average costs of coal still remain stable. High natural gas and oil costs could discourage the construction of new gas- and oil-fired power plants. Unless carbon abatement costs rise significantly, coal could potentially remain an attractive option for power generators because of its supply stability and low costs.



Source: Energy Information Administration (1996-2006)

Figure 3.6 Comparison of Average Monthly Costs of Fossil Fuel at Electric Utilities in Nominal Dollars per Million Btu, Jan/1994 - Nov/2005

3.2.4 The Role of Nuclear in Power Production

The future competitiveness of biomass fuels for electricity generation will also depend on the current development of nuclear power generation. Nuclear electricity production started to grow rapidly after the oil price shocks of the 1970s. In 1973, only about 83 billion kWh of nuclear power was produced. But by 2004, it had grown to about 789 billion kWh, a nine fold increase from 1973 (see Figure 3.1). Although nuclear power generation has increased substantially during the past two decades, EIA data[16] suggests that no new nuclear power plants have been placed in order since the 1979 Three Mile Island accident. Most of the existing nuclear power generating units were added to the plants during the 1970s and 1980s (see Figure 3.7). The increase in nuclear power generation could be due to the increased utilization of existing old nuclear power generating units operating at a higher capacity. Figure 3.8 shows that the annual average

[16] Source: Energy Information Administration (2007b).

capacity factor[17] of all U.S. nuclear power plants increased from 54% in 1973 to about 91% in 2004. The high capacity factor of more than 90% indicates that most of the nuclear power plants operating today are used to their fullest capacity.

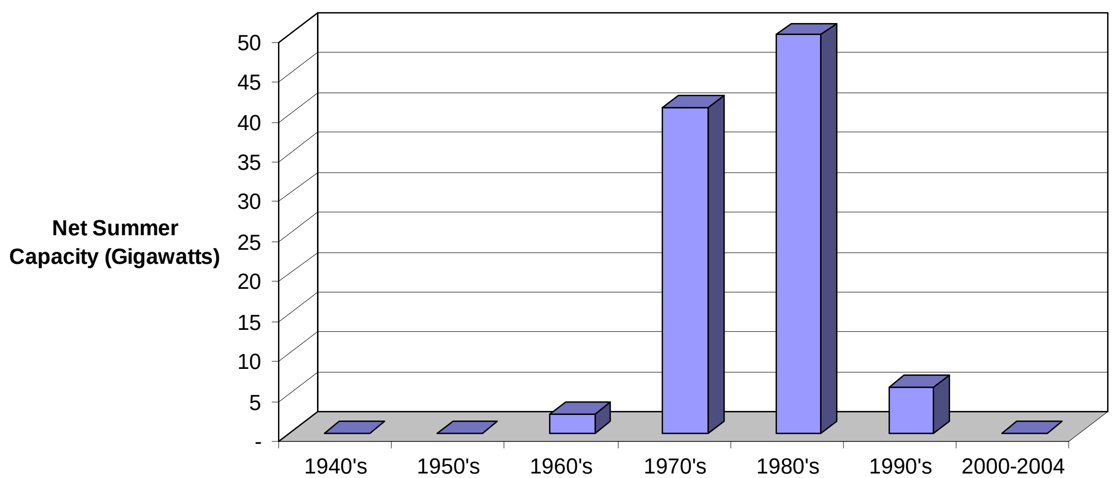
At present, there are about 103 operable nuclear generating units in the U.S. Most of them are more than 20 years old as suggested in Figure 3.7. EIA (2006g) predicts that all existing nuclear power plants are expected to continue operating through 2030. Would new nuclear plants be built to replace the old ones expected to retire in the future? The potential growth for nuclear power could be constrained by the following four issues (see Gielecki and Hewlett, 1994; Ansolabehere et al., 2003):

- Costs – nuclear power plants are the most expensive to build. It has higher overall lifetime costs compared to coal and natural gas.
- Safety – nuclear power has perceived adverse safety, environmental, and health effects, heightened by the 1979 Three Mile Island and 1986 Chernobyl reactor accidents. There is also growing concern about the safe and secure transportation of nuclear materials and the security of nuclear facilities from terrorist attack.
- Proliferation – nuclear power entails potential security risks, notably the possible misuse of commercial or associated nuclear facilities and operations to acquire technology or materials as a precursor to the acquisition of a nuclear weapons capability.
- Waste disposal – nuclear power has unresolved challenges in long-term management of radioactive wastes. Disposing of the spent fuel or high level radioactive waste from nuclear plants is both a costly problem and a major obstacle to the further development of nuclear power.

Unless the above four problems are resolved, the future development of nuclear power is still uncertain. Unlike coal, natural gas and petroleum, the advantage of nuclear power is that it does not emit much carbon into the atmosphere in the process of

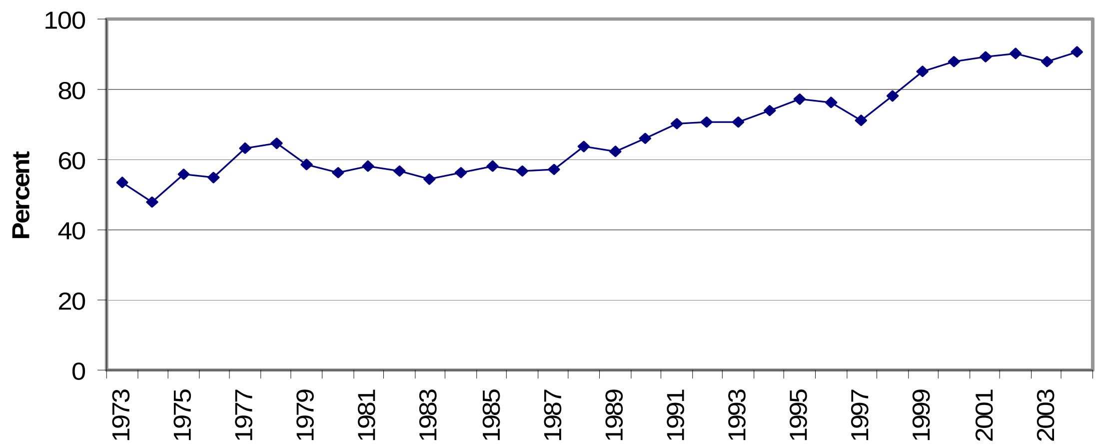
[17] "Capacity factor is defined as the ratio of the amount of actual electricity produced in a given period to the amount of electricity that could have been produced if the unit operated at its full rated capacity for 100 percent of the period" (Gielecki and Hewlett, 1994).

generating electricity. Like biomass power, nuclear power could become competitive with fossil-based power if the costs of carbon emissions increase in the future (see Ansolabehere et al., 2003). Assuming that the social costs of carbon emissions have been internalized, the question is then “Could nuclear power become competitive with biomass power?” There is no doubt that biomass power has a clear advantage over nuclear power in the issues of safety, proliferation and waste disposal. Whether or not nuclear power could become competitive with biomass power in the future will depend on how these issues are handled.



Source: Energy Information Administration (2004b)

Figure 3.7 Existing Nuclear Power Generating Capacity by Vintage



Source: Energy Information Administration (2006h)

Figure 3.8 Average Annual Capacity Factor of Nuclear Power Plants, 1973-2004

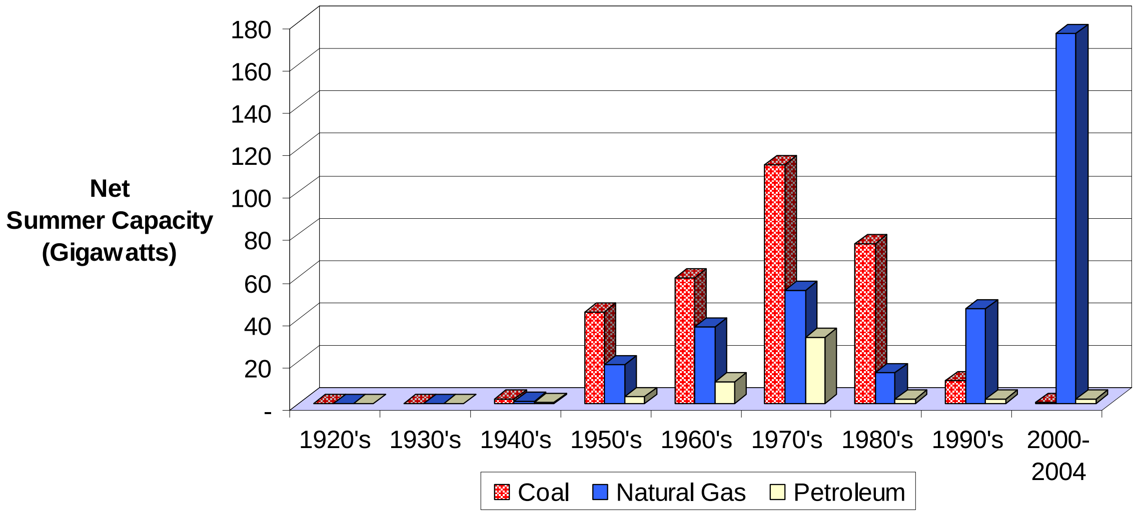
3.3 Analysis of Vintage and Capital Turnover of Fossil Power Plants

The typical average economic lifetime of electric power plants is 40 to 60 years and these power plants will need to be replaced or renovated extensively when they reach the end of their useful life. In order to reduce carbon emissions and enhance environmental quality, old capital needs to turn over rapidly. There are more than 1,000 large fossil-fired power generating units operating in the U.S. with a total combined capacity of over 450 gigawatts (GW). The total annual carbon emissions from these plants exceed 2 billion tons (Dahowski and Dooley, 2004). The range of vintages for these existing electric generating units spans the period from 1940 to 2004. Figure 3.9 depicts the U.S.'s fossil-fired power generation capacity for the electric utility and non-utility sectors[18] by unit vintage and fuel type. It shows that most coal-fired power plants operating today were built throughout the 1950s-1980s. The plant sizes ranges from 10 MW per unit to 1,300 MW per unit over that time period. A large portion of existing

[18]The electric utility sector consists of privately and publicly owned establishments that generate, transmit, distribute, or sell electricity primarily for use by the public. Non-utility power producers are not included in the electric sector. In the electric non-utility sector, electricity is generated by end-users, or small power and independent power producers to supply electricity for industrial, commercial, and military operations, or sales to electric utilities.

coal-fired power plants is more than 30 years old (see for weighted average age) and is still capable of operating for many years to come. Moreover, these plants have fairly high capacity factors and the investments in SO_2, N_2O and other emissions controls that many owners have already made in these plants suggest that they (owners) have significant interest in keeping them operating for decades to come (Dahowski and Dooley, 2004). Furthermore, empirical studies (see Maloney, 1988 and Nelson et. al., 1993) have shown that environmental regulations could create an incentive for firms to delay the retirement of old power plants because these plants receive the grandfather rights. Hence, the capital turnover rate for existing old coal-fired power plants is likely to be slow unless the government makes serious commitments to reducing carbon emissions. It is interesting to see in Table 3.4 that the weighted average age of natural gas-fired power plants has been declining since 2000. This is due to an increasingly large number of gas-fired generating units being added between 2000 and 2004 (as illustrated in Figure 3.9), bringing down their weighted average age. In contrast, since the 1970s energy crisis, very few large oil-fired power plants (especially for those which use residual fuel oil, RFO) have been constructed and most of them are becoming obsolete as suggested in Table 3.4.

Recently, as climate change and global warming have become such an important issue, increases in carbon abatement costs in the near future will likely make old and inefficient fossil power plants retire early. This will be especially true for coal- and oil-fired power plants as their maintenance costs will increase along with their age and rising pollution and carbon abatement costs. This could offer an opportunity to increase biomass contribution in electricity generation.



Source: Energy Information Administration (2004b)

Figure 3.9 U.S. Electric Utility's Existing Generating Capacity in 2004 by Unit Vintage and Fuel Type

Table 3.4 Weighted Average Age of Electric Power Generating Units

Year	Coal	Natural Gas	Nuclear	RFO	DFO	Hydro
1992	20.39	22.88	11.68	22.25	18.27	29.35
1996	24.18	25.62	15.35	26.33	23.00	33.34
2000	27.40	25.30	18.79	30.64	25.94	35.98
2004	31.50	13.66	23.29	33.04	26.98	40.88

Note: RFO is defined as Residual Fuel Oil and DFO is denoted as Distillate Fuel Oil. Age is weighted by generating capacity.

Source: Energy Information Administration (1992-2004)

3.4 Technologies for Electricity Generation

The technologies for using fossil fuels to generate electricity are well established. At present, steam turbines, internal combustion engines, gas combustion turbines, water turbines, and wind turbines are the most common methods to generate electricity. Following Hansen (1998), a list of the major technologies for using fossil fuels to generate electricity is given below:

- Pulverized coal firing with steam cycle
- Fluidized bed combustion with steam cycle
- Oil or gas fired boiler with steam cycle
- Oil or gas fired gas turbine
- Combined cycle (CC) with gas and steam turbine
- Pressurized fluidized bed combustion with combined cycle
- Integrated coal gasification with combined cycle (IGCC)

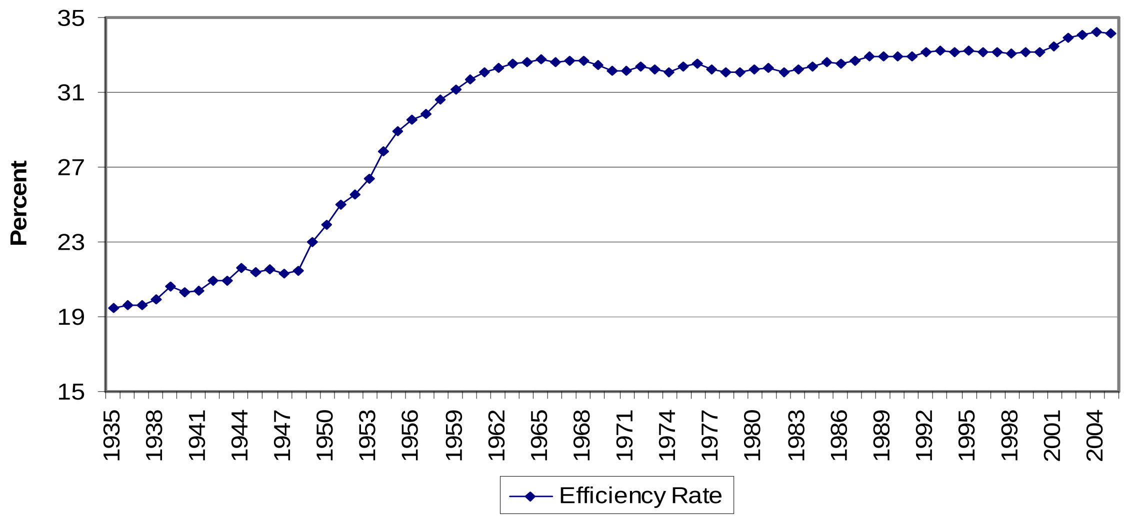
Most of the electricity in the U.S. is produced in steam turbines. Fossil fuel is burned in a furnace to generate pressurized high temperature steam. The pressurized steam is then expanded through a turbine that turns a generator to produce electricity. The steam exhausted from a turbine is then cooled in a condenser and returned to a boiler to begin the cycle once again (Joskow, 1987). The primary measure of the efficiency of an electric power plant's operation is its heat rate which is defined as the amount of Btu's fuel energy input required to produce a kilowatt hour (kWh) of electricity. The lower the heat rate is, the greater the power plant's efficiency. As fossil-fired power plants gain more efficiency, CO_2 emissions can be reduced since less amount fossil fuel input is used to produce the same amount of electric power.

The heat rate can be converted to an efficiency factor by taking the ratio of the heat equivalent value of a kWh to the heat rate of the plant (Thompson et al., 1977). For example, the ratio of the heat equivalent value of 3,412 Btu/kWh to a heat rate of 10,107 Btu/kWh can be calculated and translated into an operating efficiency of 34%, the U.S. average efficiency for fossil-fired power plants. An operating efficiency of 34% means that for every 100 Btu of energy that go into a power plant, only 34 Btu is converted to usable electrical energy. Historically, Figure 3.10 shows that the average efficiency rate of fossil power plants has been increasing. It is interesting to see from the figure that the rise in average efficiency rate is especially sharp during the periods of 1950 to 1970. Since then, the efficiency rate has stayed relatively stable. Today, gas-fired combined cycle technology is the overwhelming choice for new power generating units. Compared with coal and nuclear power generating technologies, gas-fired combined cycle plants offer extremely high efficiency, low capital costs and shorter construction lead times (see Table 3.5). The operating efficiency of combined cycle units is now approaching 60%.[19] Because of the efficiency improvements and low capital costs of gas-fired power generating technologies, virtually all new generating capacity being added today is gas-fired, as seen in Figure 3.9.

The future market penetration of biomass fuels for electricity generation will not only depend on developments in biomass generation technologies, but also on reductions in fuel and capital costs. As mentioned, there are four classes of technologies for the conversion of biomass for electricity generation: direct combustion, co-firing, gasification and pyrolysis. Similar to most conventional fossil-fired power plants, most of today's biomass power plants are direct combustion systems which use steam generation technology to produce electricity. Biomass power plants can be in the 10-100 MW range compared with coal-fired power plants which can be anywhere in the range of 100-1500 MW. According to NREL (2000), the heat rate for biomass power plants may range from 12,000-20,000 Btu/kWh, with average operating efficiency of about 22%. Overnight constructions costs for a 100MW bio-power plant in the U.S. could cost as much as $1,700 per kilowatt (NEA/IEA, 2005). Due to their small sizes and low efficiency, and the uncertainty over the availability of biomass fuels, biomass-fired power plants tend to incur more costs and risks than fossil-fired power plants. At present, the most feasible and lowest cost option is to cofire biomass with coal in existing boilers, as capital costs and risks associated with co-firing plants are rather low compared with those of standalone biomass power plants (Hughes, 2000; and Bain and

[19] Source: Fueling the Future (Date unknown).

Overend, 2002). The future market for biomass power and thus biomass fuels will depend on how present power generation technologies evolve over time.



Source: see APPENDIX I

Figure 3.10 Average Operating Efficiency Rate of Fossil Power Plants

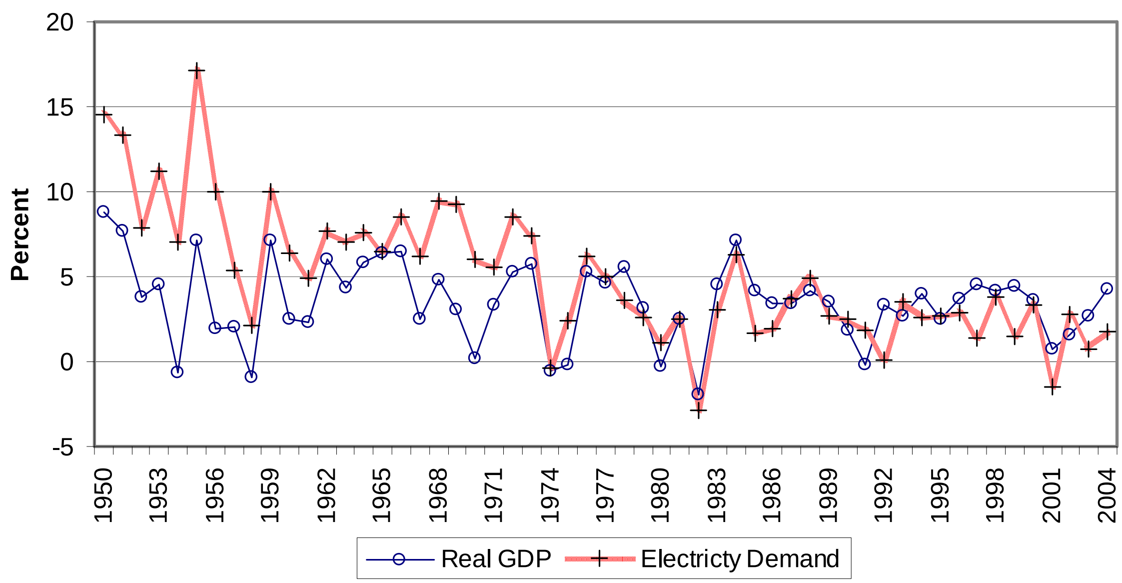
Table 3.5 Comparisons of Costs and Efficiency Rate between Fossil and Nuclear Power

Type	Gas (CC)	Coal	Nuclear
Construction Time (Years)	2	4	5
Overnight Construction Costs (2002 $/kilowatt)	500	1,300	2,000
Heat Rate (Btu/kWh)	7,200	9,300	10,400
Efficiency (%)	47	37	33

Note: These values are based on the power plants with 1,000 MW capacities.
Source: Ansolabehere et al. (2003)

3.5 Electricity Demand Growth

The annual U.S. electricity demand growth had been the highest before the oil crisis began in the early 1970s. From 1950 to 1973, an average annual growth rate for electricity was about 8.3%, while from 1974 to 1997; it was only about 2.6%. During the recent period of 1998-2004, the average growth rate was even lower, less than 2% per year as suggested in Figure 3.11. The most important factor that contributes to the slower growth rates in electricity demand has been lower economic growth. Figure 3.11 shows that historically there has been a strong correlation between economic growth measured by real GDP and electricity demand growth. The faster the economy grows, the higher the growth rate of electricity demand (see National Research Council, 1986; Schurr et al., 1990).



Source: see APPENDIX I

Figure 3.11 Comparison of Annual Changes in Electricity Demand Growth and Economic Growth, 1950-2004

3.5.1 Estimating the Demand for Electricity

Electricity demand is influenced by several other factors like the number of consumers, price of electricity, price of fossil fuels, changes in technologies and environmental regulations etc. Based on Mitchell et al. (1986), a simple electricity demand model that includes explanatory variables representing all of the major determinants of total electricity consumption can be written as:

$$ED = \alpha \times EP^{a} \times XP^{b} \times GDP^{c} \times NCON^{d} \times TECH^{f} \times \varepsilon^{u}$$

where *ED* is total electricity demand in the U.S. *EP* is an average real electricity price. *XP* is denoted as the real price of the alternative fuel such as natural gas. *GDP* is a gross domestic product measured in real U.S. dollars and is used as a proxy for an income or economic growth. *NCON* is defined as the number of electricity customers. *TECH* is a technological variable such as an average efficiency rate of power production in the U.S. α is a constant; a, b, c, d, and f are elasticities; and u is a random error. Historical annual data from 1932 to 2005 are used to estimate the above model. Details of data description are provided in APPENDIX I. Using a simple OLS method, the model is estimated and the results are presented in Table 3.6. The model has a serial correlation problem which is corrected using an iterative Cochrane-Orcutt procedure.

The results are more or less consistent with the literature (see Taylor, 1975; Bohi, 1981; Beierlin et al., 1981; Mitchell et al., 1986). The table shows that statistically the GDP variable is highly significant in explaining the impact of economic growth on the demand for electricity. All variables in the table have the expected signs. The negative sign of real electricity price suggests that consumers will use less electricity if the price of electricity goes up. On the other hand, the positive sign of real natural gas price implies that natural gas and electricity may be substitutes. As the price of natural gas increases, consumers may switch to electricity for heating and other purposes. The real price of crude oil does not explain well on the consumers' demand for electricity, as the variable is statistically insignificant. Increases in real oil price may lead to increases in the price all other petroleum products, which as a whole stand for a substantial portion of expenditures. This would result in a significant decrease in real income. The negative income effect could outweigh the positive substitution effect for a negative net effect (Beierlin et al., 1981). This could explain why the real crude oil price variable has a negative sign. The technological variable, efficiency rate of power generation, is also statistically insignificant in explaining the demand growth for electricity. But it does have an expected positive sign which may indicate that improvements in power generating technologies would result in the decline of real price of electricity which induces more electricity consumption.

Table 3.6 Electricity Demand Model Coefficient Estimates

Independent Variable	**Coefficient**	**T-Ratio**	**P-Value**
Constant	-0.46	-0.50	0.62
Electricity Price	-0.46	-6.37	0.00
Natural Gas price	0.05	2.66	0.01
Crude Oil Price	-0.01	-1.02	0.31
GDP	0.58	8.04	0.00
Number of Consumers	0.90	5.74	0.00
Efficiency Rate	0.14	0.76	0.45
R^2	0.99		
Durbin-Watson	2.04		

The total number of power consumers (*NCON*) is used instead of the total number of population to estimate the model. Table 3.6 shows that the variable is significantly and positively related to the electricity demand. Increase in total population may have little impact on the overall demand growth for electricity.[20] It is the increase in total number of electricity consumers that matters. China the most populated country in the world can be used as a good example. Did increase in total population in China induce an overall increase in the demand for electricity? An increasing number of Chinese consumers, helped by economic growth and rising income levels, are the main factor that explains tremendous rise in Chinese energy consumption. In a sense, GDP growth combined with the increase in number of power consumers would help explain the model better.

3.5.2 Forecasting the Demand for Electricity

Based on the cointegration method, the demand for electricity is forecasted using the recursive estimation and chain rule forecasting (see Chaisantikulawat, 1995 for the details of methodology). All the data and variables used for forecasting are exactly the same as above. Forecasted results from the period of 2004 to 2015 are presented and compared with the forecasted values of EIA (2007a) in Table 3.7. As can be seen from the table, the two forecasted results are quite similar to each other. Our results suggest that as much as 56 GW generating capacity would have to be added between 2005 and 2015 to meet the electricity demand. EIA results imply that about 68 GW generating capacity would be needed between the same periods of time. Both results show that annual electricity growth rate is below 2% per year. The future increase in electricity consumption will undoubtedly link to economic growth as indicated in Figure 3.11 and Table 3.6. But, the big related question is: Would the future demand for “bioelectricity” grow as consumers’ wealth increases? This could depend on the costs of purchasing bioelectricity in the future. And bioelectricity could become cost competitive with electricity generated by fossil fuels, only if future costs of carbon emissions rise significantly (shown in the next section). In the end, it all boils down to concerns for climate change and global warming that stimulate the interests of bioelectricity production.

[20] The model is also tested with the total population variable which is found to be statistically insignificant.

Table 3.7 Results for Forecasting the Demand for Electricity (in Billion Kilowatt-hours), 2004 to 2015

Year	Time Series Based	EIA (Reference Case)
2004	3,720.79	3,548.22
2005	3,768.65	3,660.01
2006	3,816.13	3,693.65
2007	3,863.41	3,757.16
2008	3,910.70	3,836.23
2009	3,958.17	3,891.28
2010	4,006.01	3,953.43
2011	4,054.42	4,014.42
2012	4,103.56	4,081.77
2013	4,153.62	4,138.47
2014	4,204.76	4,194.40
2015	4,257.12	4,251.35

3.6 Summary

Most of the world's electricity is generated by using fossil fuels such as coal, natural gas and petroleum fuel oil. Burning fossil fuels remains the most cost effective way of producing electricity at least for now. In the U.S., fossil fuels account for about 70% of the fuels used for electricity generation, while biomass only accounts for about 1%. The electric power sector in the U.S. is a major source of CO_2 emissions which contribute to global climate change. A substantial amount of CO_2 emissions could be reduced if the electric sector uses biomass and other renewables to generate electricity. However, electricity producers may not have incentives to switch from fossil fuels to biomass fuels due to their low heat content and high transaction costs. The question we are interested in is: how do we make biomass fuels economically competitive with fossil fuels in electric power sectors?

This section explores the factors which may influence the market penetration of biomass fuels for power generation. There are two important factors which will influence market penetration of biofuels for power generation: 1) the price of coal, and 2) the future price of carbon emissions. Because of the extreme price fluctuations of oil and gas, coal has always been seen as an attractive option by some power generators. Since historically the price of coal has been stable as it has less competitive uses and is abundantly available locally. The downside of using coal is that among fossil fuels, it contains the highest amount of carbon and other pollutants such as sulfur and nitrous oxide which contribute to global warming and regional air pollution. Any increases in coal and other fossil fuel prices in the future would likely come from regulations to restrict carbon emissions. Similar to sulfur dioxide (SO_2) permit trading system in the U.S., the future market price of carbon will likely evolve through local and global trading on GHG emissions.

Issues related to the capital turnover for existing fossil power plants and electric power generation technologies are also discussed in this section. Most coal- and oil-fired power plants are more than 30 years old and the speed at which they turnover or retire will likely depend on how strict carbon emission regulations are. Increasing costs of carbon emission reductions will likely make old and inefficient power plants retire early. Compared to fossil power plants, current stand-alone biomass power plants are smaller in size; tend to have higher capital costs and lower rate of operating efficiency. Any future technological improvements in biomass power generation will likely come from demonstrations with co-firing power generation technologies of coal and biomass.

If carbon emission reductions are to be strictly enforced in the future, nuclear power could potentially become competitive with biomass power because of its low carbon emission status. Future expansion of biomass power will likely rest on cost issues. However, nuclear power expansion will not only depend on cost issues, but on the issues of safety and waste disposal. Eventually, any electric power expansions will significantly depend on economic growth. Restrictions on carbon emissions will likely intensify fuel diversification in power generation, making biomass and other renewables become an established part of power generation portfolios.

4. AGRICULTURAL CROP RESIDUES FOR POWER GENERATION: IS IT FEASIBLE?

This section reviews the literature on crop residue studies and examines the economics of crop residue collection and usage for electricity generation. The Forest and Agricultural Sector Optimization Model-Green House Gas version (FASOMGHG) is also described in details. Following the section, the availability of crop residues is estimated nationally and by regions in FASOMGHG — considering how much crop residues can be removed based on tillage systems and land types without exacerbating soil erosion. Delivered costs of crop residues which include costs of harvesting, processing and hauling or transporting are also estimated and compared with delivered costs of coal. FASOMGHG is then employed to simulate the future market conditions of bioelectricity production using crop residues under various alternative scenarios.

4.1 Effects of Crop Residue Removal on Soil Erosion and Organic Matter

Not all agricultural crop residues are available for energy production, because some must remain in the field for soil erosion control, maintenance of soil organic matter[21] (SOM) and maintenance/enhancement of soil carbon (C). Moreover, surface crop residues reflect light and protect soil from high temperatures and evaporative losses (Sauer et al., 1996).

4.1.1 Relationships between Crop Residue Removal, Soil Erosion, SOM Concentration and Carbon Emissions

The value of crop residues for erosion control and soil fertility maintenance has been well documented for all agricultural regions in the U.S. (Larson, 1979). Residues control erosion by reducing the impact of wind and water on soil particles. Erosion would increase significantly if crop residues were totally removed. In turn increased erosion would reduce soil fertility by carrying away nutrients in the soil sediments and deplete

[21] SOM plays a crucial role in the development and maintenance of fertility through the cycling, retention, and the supply of plant nutrients, and in the creation and maintenance of soil structure (Swift, 2001).

the soil organic carbon (SOC) pool (Holt, 1979; Lal, 2003; Pimentel et al., 1981). Lal et al. (1998) estimated that soil erosion by water leads to an emission of 15 million metric ton (MMT) of C per year from the U.S. soils. Thus, reducing emissions of GHG from agriculture is related to increasing and protecting SOM concentration (Jarecki and Lal, 2003).

Removal of crop residue has a rather small direct impact of crop residue removal on SOM concentration. According to studies (see Campbell et al., 1991; Balesdent and Balabane, 1996; Gale and Cambardella, 2000; Flessa et al., 2000; Wilhelm et al., 2004), only a small portion of the residues added to soil are converted to SOM. Roots contribute most of the SOM, because roots have a slower decay rate, are well-placed within the soil and are continually dying and discharging materials in soil. Aboveground crop residues take on importance as they diminish soil erosion which protects SOM concentration.

4.1.2 Tillage Effects on SOM Concentration, Carbon Emissions and Residue Removal

Soil tillage practices affect the concentration of SOM. The influence of tillage on SOM dynamics is also well documented (Paustian et al., 1997; Lal, 2001; Jarecki and Lal, 2003). Immediately after plowing the exposure of SOM or SOC to oxidization cause large losses of CO_2 released into the atmosphere (Reicosky and Lindstrom, 1993; Al-Kaisi, 2001). There are different levels of tillage intensity and these are often grouped into two classes: conservation tillage (no tillage or reduced tillage) and conventional tillage. Conservation tillage reduces the frequency and intensity of tillage, retains crop residues as mulch on the soil surface, reduces the risks of runoff and soil erosion, increases the SOC content of the surface soil, and reduces CO_2 emissions (Lal and Kimble, 1997; Reicosky, 1999; Al-Kaisi and Yin, 2005). Moreover, conservation tillage with residue cover usually results in less soil erosion than conventional tillage, highlighting the importance of tillage-residue interaction when assessing the effects of residues on soils (Benoit and Lindstrom, 1987; Andrews, 2006).

Hooker et al. (2005) show that removing corn residues under conservation tillage system does not affect SOC storage, however when conventional tillage system is employed, removing corn residues negatively affects SOC storage. So, the specific quantities of residue that could be safely removed without affecting soil erosion and SOC concentration vary with tillage management practices. Greater amounts are available with conservation tillage than with conventional tillage. A study of the U.S. Corn Belt indicates that by shifting from conventional tillage to conservation tillage, the recoverable residues could be increased significantly (Lindstrom et al., 1979; Hall et al., 1993). Although conservation tillage systems have advantage over conventional tillage systems, historically conventional tillage systems are more commonly practiced (Uri, 1999). This could be due to the uncertainties associated with adopting a conservation tillage practice which requires investment in physical and human capital. In addition, conservation tillage usually leads to lower yields in early years before soil nutrients build up. The lost profit in these years is sunk because it cannot be recovered by reverting back to conventional tillage. Given the uncertainties and the lost profits, a farmer may be reluctant to adopt conservation tillage (Kurkalova et al., 2006). Conservation tillage systems are more often practiced in the area where farmlands are highly erodable (see Uri, 1999).

4.1.3 Harvestable Crop Residues for Energy Generation

The maximum amount of crop residue which can be removed without affecting soil erosion depends on many site specific factors such as soil type and fertility level, slope characteristics, tillage system, climate and crops. Moreover, the opportunity cost of using residues has to be considered in the residue removal decision making process. Generally, USDA, National Resources Conservation Service (NRCS) recommends that about 30 percent residue cover is adequate to control soil erosion. Most studies have centered on the removal of corn stover. Calculations have been made for the U.S. Corn Belt on the amount of residues needed to bring erosion below the soil loss tolerance level.[22] According to Hall et al. (1993), the fraction of residues that can be removed with conventional tillage practices averages 35 percent for the Corn Belt as a whole. Nelson (2002) and McAloon et al. (2000) indicate that the actual amount of corn stover that could be removed ranges from 20% to about 30% of the total based on the need for adequate soil cover to control erosion.

Hettenhaus et al. (2000) argued that on average about 50% to 60% of corn stover was likely to be available depending on the regional slope characteristics. Haq (2002) suggested that depending on the State, about 30% to 40% of agricultural residues could be removed from the soil. Campbell et al. (1979) calculated the crop residues needed for water erosion control in six southern states which include Alabama, Georgia, Mississippi, North and South Carolina, and Virginia. In four of six states, 60% of the crop residues were needed for water erosion control. About 90% of the residues were required for water erosion control in Alabama and Mississippi. Recently, Perlack et al. (2005) derived the national estimates of average crop residue removal rates for corn and wheat based on various tillage scenarios. They showed that the removal rates for corn were 33 percent, 54 percent and 68 percent respectively under conventional tillage, reduced tillage and zero tillage systems. For wheat, the removal rates were 14 percent, 34 percent and 48 percent respectively under conventional tillage, reduced tillage and zero tillage scenarios. These results are consistent with the finding of Lindstrom et al. (1979), which indicates that by shifting from conventional tillage to conservation tillage, the removable rate of residue could be increased significantly. On the other hand, in their recent review, Mann et al. (2002) did not give recommendation of harvestable residue, recognizing research is still needed to project long-term effects of residue harvest on soil and water quality, SOC dynamics and storage etc. (also see Wilhelm et al., 2004).

[22] Soil loss tolerance level is defined by the USDA as the maximum level of soil erosion that will permit high crop production to be maintained economically and indefinitely.

4.2 Method of Estimation, Assumptions and Data Need

4.2.1 Crop Residue Production

For the residues, six crops will be considered: corn, sorghum, wheat, oats, barley and rice. Following Nelson et al. (2004), the quantities of residues that can be removed for energy generation or other purposes can be estimated as,

$$R_{rem} = R_{prod} - R_{min} \tag{4.1}$$

R_{rem} is the quantities of residues that can be removed from agricultural lands. R_{prod} is the amount of residue produced. It can be calculated as follows,

$$R_{prod} = Grain\ Yield \times Weight \times SGR$$

where total residue production is measured in wet tons. *Grain Yield* is the weighted average yield of grain crop in bushels per acre. Grain yield data for *Weight* is the weight of grain in tons per bushel which can be converted from pounds per bushel. *SGR* is defined as a straw-to-grain ratio. For instance, *SGR* for rice is about 1.5 which means for every kilogram of rice yield, the yield of straw is 1.5 kilogram. To compute the residue production (R_{prod}) data for crop yield, weight and *SGR* will be needed. Both grain yield and weight data for the six crops were obtained from the USDA/NASS (2001). The yield data are based on the year 2001. While the data for *SGR* were collected from the following literature: Tyner et al. (1979) and Lal (2005). The values of *SGR*, weight and related moisture content for the six crops are reported in Table 4.1. To give an example, for a wheat grain yield of 140 bushels/acre, total amount of wheat residues produced is 6.3 wet tons per acre [140(bushel/acre)×60(pounds/bushel)×(1/2000) (tons/lb)×1.5].

Finally, R_{min} is denoted as the minimum amount of residue that must be retained in the field each year to protect soil erosion. Developing a single national estimate of the minimum amount of residue that must remain on the ground to maintain soil sustainability is rather challenging, as one will require detail knowledge in the area of soil fertility, soil erosion, land characteristics and tillage and cropping systems. Residue maintenance requirements are most properly estimated at the individual field level with models such as Revised Universal Soil Loss Equation (RUSLE) used together with the

Soil Conditioning Index (SCI) tool (Perlack et al., 2005). But, as suggested in Perlack et al., (2005), using this approach to compute a national estimate would require actual data from hundreds of thousands of specific locations. Fortunately, Nelson (2002) and Nelson et al. (2004) developed a methodology for making a national estimate that reflected the RUSLE/SCI modeling approach in that it considered soils, rainfall, crop rotation and tillage choices in determining the amount of residue required to minimize erosion to tolerance levels.

Based on the approach of Nelson (2002) and Nelson et al. (2004), Perlack et al., (2005) derived the national estimates of average crop residue removal rates for corn and wheat under three tillage scenarios – conventional tillage, reduced tillage and zero tillage. As mentioned in the section above, the removal rates for corn were 33 percent, 54 percent and 68 percent respectively under conventional tillage, reduced tillage and zero tillage scenarios and for wheat they were 14 percent, 34 percent and 48 percent respectively. By using these national estimates of residue removal rates, R_{min} were computed for corn and wheat. For the remaining four crops – sorghum, barley, oats and rice, the same removal rates of wheat were used to compute R_{min}. Research in this dissertation is conducted at a national level. The total quantities of crop residues available in each State are estimated using grain production, straw to grain ratio, weight, and moisture content.

Table 4.1 Straw to Grain Ratio, Weight and Moisture Content of Six Crops

Crop	Straw to Grain Ratio	Grain Weight (Pounds/bushel)	Moisture Content (%)
Corn	1.0 : 1	56	12.0
Wheat	1.5 : 1	60	8.9
Barley	1.5 : 1	48	10.3
Oats	1.0 : 1	32	10.3
Sorghum	1.0 : 1	56	10.0
Rice	1.0 : 1	45	15.0

Sources: Tyner et al. (1979), Lal (2005), and Sami et al. (2001)

4.2.2 On Farm Production Cost

Before delivering biomass residues to electric power plants, they first have to be harvested and collected. Harvest and collection includes gathering and removing crop residues from field. The harvest and collection method is a three-step procedure which can be illustrated with the following Figure 4.1 (Department of Energy, 2003).

$\boxed{\text{Cut and Windrow}} \rightarrow \boxed{\text{Bale and Package}} \rightarrow \boxed{\text{Move to Field Edge for Storage}}$

Figure 4.1 Procedure for On-farm Harvesting and Collection of Crop Residues

First, grains are harvested and the biomass residues are cut and/or shredded. Cutting and/or shredding may be necessary because some of the biomass plant will be in stalks anchored to the ground after grain harvesting. The anchored pieces of biomass are difficult to cut and bale in a single operation. Large pieces of biomass would make better bales but shredding followed by spreading will accelerate field drying (Sokhansanj and Turhollow, 2002). The spread biomass may need to be windrowed depending on the situation to facilitate baling. Second, a baler (either self-pull or pulled by a tractor) picks up the residues, compacts and packages the residues in a bale. Bales can be in the form of either rounds or squares. Large round bales are applied in the analysis, because round bales are widely used in existing haying operations and they are popular on most U.S. farms (Sokhansanj and Fenton, 2006). Finally, bales are moved to the field edge or road side for temporary storage. The stacks of collected biomass at the road side will be picked up and transported to their destination.

Using an engineering-economic approach, Turhollow et al. (1998) estimated in-field costs for collection and movement to field edge of corn and small grain residues. Based on different crop residue yield assumptions, they showed that on average (weighted by the yield), it would cost about $15.91 per ton for corn residues and $10.42 per ton for small grain residues to be collected and removed to the field edge. The in-field operation costs include the costs of mowing, raking, baling, moving to road side, and twining. Similarly, by employing an engineering-economic approach, Sokhansanj and Turhollow (2002) estimated the cost of collecting corn stover to be around $14.1 per ton. This covers shredding, baling, stacking and twining costs. Perlack and Turhollow (2002) calculated corn stover collections costs (which include baling, moving bales to storage, stacking bales and storage) for an ethanol conversion facility. They showed that on average it would cost about $24.47 per ton to collect and store corn stover.[23] Summers (2001) estimated that rice straw removal costs were about $ 17.69 per ton for on-field operations which include swathing, raking, baling and moving to road side. He also showed that storage and grinding operations would add more costs to the rice straw, about $13.54 per ton. Following the study of Turhollow et al. (1998), in this dissertation on-farm collection costs are assumed to be fixed and equal to $15.91 per ton for corn and sorghum residues and $10.42 per ton for small grains such as wheat, barley and oats. For rice residues, collection costs are assumed to be $ 17.69 per ton as suggested in Summers (2001). In addition, based on Summers (2001), storage and processing costs of $13.54 per ton will be assumed. These on-farm collection costs, storage and processing costs, and transportation costs (discussed below) will be incorporated into the FASOMGHG.

4.2.3 Transportation Cost

Transportation is a key segment of the biomass feedstock supply system industry. Biomass may be transported by truck on existing roads or by trains and barges on existing rail networks and waterways (Department of Energy, 2003). It is assumed that biomass is transported to a power plant by truck, since truck transport is generally well developed and is usually the cheapest mode of transport but it becomes expensive as travel distance increases (Sokhansanj and Fenton, 2006). Transportation costs which cover the distance from the farm gate to the plant gate are an important part of total costs. They are increasing function of distance and depend on the yield and density of crop residues, the size of biomass power plant and a given truck-hauling rate (Gallagher

[23] Transport cost from the storage area to ethanol conversion facility is excluded.

et al., 2003). The cost of transporting biomass is often the factor that limits the size of a power plant. Larger power plants can benefit from economies of scale and lower unit capital costs. However, the dispersed nature of biomass residues, and relatively low efficiencies of available conversion systems have tended to limit the size of existing electricity producing plants to a maximum size of 100-150 megawatt (MW) (Larson, 1993).

Following McCarl et al. (2000), the power plant size in this study is assumed to be a 100 MW plant which requires seven trillion BTUs (7 TBTUs) of feedstock per year. Based on an approach by French (1960) as described in McCarl et al. (2000), transportation costs (*TC*) per ton of biomass residues are calculated as follows:

$$TC = \frac{Fixed\ Cost + (2 \times \overline{D} \times Cost\ per\ Mile)}{Loadsize}, \text{ where} \tag{4.2}$$

$$\overline{D} = 0.4714 \times \sqrt{\frac{M}{(640 \times Den \times Yld)}}$$

Given a square grid system of roads as described in French (1960), $\overline{D}$ is denoted as an average hauling distance in mile(s) which depends on a 100 MW power plant requirement of *M* tons of biomass (equivalent to 7 TBTUs of feedstock), the density (*Den* in %) of biomass residue production and a harvestable residue yield (*Yld*) in ton(s) per acre. The factor "640" represents the number of acres in a square mile. The required *M* tons or 7 TBTUs of biomass crop residues can be computed using higher heating value (HHV) of each crop residue (see Table 4.2). All crop residues are assumed to have moisture content and all units are based on the wet matter content. The density of each crop residue in percent is calculated by dividing total harvested acres of each crop by total land area in acres. *Fixed Cost* includes loading and unloading costs and the cost of operating a truck. The number "2" represents round trip and *Cost per Mile* is a cost for each mile of the trip. *Loadsize* is an average load size of a truck load in weight hauled.

Fixed Cost and *Cost per Mile* are assumed to be \$90 and \$2.20 respectively.[24] Finally, *Loadsize* of a truck is assumed to be 20 tons.

Table 4.2 Higher Heating Value (HHV) for Crop Residues

Crop Residues	HHV (Million Btu/ton)
Corn stover	9.23
Wheat straw	15.06
Barley straw	14.88
Oat straw	14.88
Rice straw	13.07
Sorghum stalk	13.24

Sources: Sami et al. (2001) and Optimum Population Trust (2006)

4.3 Model Description

All of the above aforementioned method of estimation, assumptions and data are incorporated into the Forest and Agricultural Sector Optimization Model—Green House Gas version (FASOMGHG). It is a dynamic, nonlinear programming model of the forest and agricultural sectors in the U.S. The model simulates the allocation of land over time to competing activities in both the forest and agricultural sectors and the resultant consequences for the commodity markets supplied by these lands and, importantly for policy purposes underlying the development of this model, the net greenhouse gas (GHG) emissions. The model was developed to evaluate the welfare and market impacts of public policies that cause land transfers between the sectors and alterations of activities within the sectors.

[24] Fixed cost and cost per mile are obtained by Dr. Jerry Cornforth's personal communication with Dr. Shahab Sokhansanj, Agricultural Engineer, Environmental Sciences Division of Oak Ridge National Laboratory.

To date, FASOMGHG has been used to examine the effects of GHG mitigation policy, climate change impacts, public timber harvest policy, federal farm program policy, biofuel prospects, and pulpwood production by agriculture. It can also aid in the appraisal of a wider range of forest and agricultural sector policies. FASOMGHG is an outgrowth of a number of previous lines of work (see details in Adams et al., 2005). One of the primary roots of FASOMGHG involves efforts by McCarl and colleagues to use sector modeling to appraise the economic and environmental implications of environmental and agricultural policy-related developments within the agricultural sector.

4.3.1 Overall FASOMGHG Model Structure

Operationally, FASOMGHG is a dynamic, nonlinear, price endogenous, mathematical programming model. It is dynamic in that it solves for the simultaneous multi-market, multi-period equilibrium across all agricultural and forest product markets, for all time periods, and thus for the inter-temporal, inter-sectoral land market equilibrium.

FASOMGHG is nonlinear in that it contains and solves a nonlinear objective function to maximize net market surplus, represented by the area under the product demand function (an aggregate measure of consumer welfare) less the area under factor supply curves (an aggregate measure of producer costs). The resultant objective function value is consumers' plus producers' surplus. FASOMGHG is price-endogenous because the prices of the products produced and the factors used in the two sectors are determined in the model solution. Finally, FASOMGHG is a mathematical programming model because it uses numerical optimization techniques to find the multi-market price and quantity vectors that simultaneously maximize the value of an objective function, subject to a set of constraints and associated right-hand-side (RHS) values that characterize: the transformation of resources into products over time; initial and terminal conditions; the availability of fixed resources; generation of GHG net emissions; and policy constraints.

Since the objective function of FASOMGHG depicts maximization of the net present value of producers' and consumers' surpluses, associated with production and price formation in competitive markets over time for both agricultural and forest products, the first-order (Kuhn-Tucker) conditions for the choice variables in the model provide a set of optimization rules for economic agents to follow, leading to the establishment of a competitive equilibrium. Because these choices occur over time, the optimizing nature of the model holds that producers and consumers' have perfect foresight (the assumption that agents are rational and respond with the best information they have available at the time) regarding future demand, yields, technologies, and prices. In other words, choices made at the beginning of the projection period are based on correct expectations of what the model predicts will occur in the future. Thus, FASOMGHG incorporates expectations of future prices. Farmers and timberland owners are able to foresee the consequences of their behavior (when they plant trees or crops) on future agricultural product and stumpage prices and incorporate that information into their behavior.

FASOMGHG is typically run as a 100-year model depicting land use, land transfers, and other resource allocations between and within the agricultural and forest sectors in the U.S. The two sectors are linked through land transfer activities and constraints. Given the modeling of multiyear timber production, FASOMGHG needs to handle economic returns over time. This is done by solving for multiple interlinked market equilibria in adjacent five year periods for the model duration, rather than for just one single period (as would be the case in a static equilibrium model). Hence, the model solution portrays a multi-period equilibrium on a five year time step basis. The results from FASOMGHG yield a dynamic simulation of prices, production, management, consumption, and GHG effects within these two sectors under the scenario depicted in the model data.

FASOMGHG reflects the mobility of the land resource between the forest and agriculture sectors subject to controls for land quality/growing conditions, investments needed to mobilize land, and hurdle costs consistent with observed behavior. The land quality factors generally restrict some lands to only be in forest, due to topography or soil characteristics. Likewise, the growing conditions render some lands unsuitable for forest uses at all, particularly in the drier plains areas of the country, and would thus be suitable only for some agricultural uses. The investments to mobilize land from forest to agriculture generally involve stump clearing, leveling, etc. of forested lands and result in a three step depiction of land transformation processes. The hurdle costs reflect costs to move land between uses.

FASOMGHG also reflects movement of commodities between the forest and agriculture sectors, largely in the form of biofuels and short rotation woody crops. In particular, agriculturally produced short rotation poplar can be chipped and move into pulp and paper production processes and milling residues, pulp logs and in some cases logging residues can move between sectors as raw material sources for finished products made in the other sector. All agricultural sector models, where great heterogeneity of growing conditions, resource quality, market conditions, and management skills are present, must deal with aggregation and calibration. The aggregation problem involves treating groups of producers operating over aggregated resource sets as homogeneous units. The calibration problem involves dealing with spatially disaggregate producers who are entrants in a single market but receive different prices.

4.3.2 Forest Sector Portion of FASOMGHG

The key forest sector features involved with forest harvest and stand establishment, wood products manufacturing and demand, domestic wood product transport, international trade in wood products, forest land resources and non-wood inputs. Forest production occurs in 9 of the 11 regions used in FASOMGHG. While timber production is represented in all 9 of these regions, the major producing regions are the Pacific Northwest (west of the Cascade Mountain Range), the South Central and the South East. National Forest timber and Canadian production are also represented but with exogenous harvest levels. FASOMGHG incorporates price dependent demand relations for softwood lumber, softwood plywood, hardwood lumber, oriented strand board (OSB) and a number of fiber products. The relations for non-fiber products were derived by aggregating the Timber Assessment Market Model (TAMM) annual demand relations.

Demand relations for the 14 classes of primary fiber products were derived from the North American Pulp and Paper Model (NAPAP).

The basic set of FASOMGHG relations comes from the TAMM-NAPAP base case as described in the 2000 Resources Planning Act (RPA) Timber Assessment (Haynes, 2003). The solid-wood demand relations are linear, except for hardwood lumber that uses a constant elasticity form. All of the fiber products demand curves are of the constant elasticity form. These curves shift over time following the TAMM and NAPAP procedures. Alternative projection scenarios that would influence the inter-temporal development of demand (e.g., changes in the projections of macroeconomic activity or price trends of substitute goods) require re-derivation of the FASOMGHG demand curves by making an appropriate TAMM-NAPAP run and extracting then re-aggregating new demand relations. The demand curves for the final consumption of timber products are incorporated into FASOMGHG at a national level. In addition, the forest manufacturing sector utilizes many products as intermediate inputs all on a regional basis. Similarly both international and interregional trades are specified on a regional basis. FASOMGHG thus generates wood product prices at both the regional and national levels. Goods flow from regions into national demand at a cost equal to the historically observed price difference.

As mentioned above, FASOMGHG is designed to depict activity over a long time period, approaching 100 years in its current form. A related issue is the number of explicit time periods that should be reflected within this total 100 year horizon. In the original FASOM version (Adams et al. 1996), time was represented in ten year intervals. Experience with subsequent model analysis sometimes suggested that ten year intervals were too long. This was particularly true in terms of harvest rotations in the South which can be as short as 20 years. Restricting rotations to ten year intervals like 20 or 30 or 40 years was constraining. As a consequence FASOMGHG is set up based on a five year time step allowing portrayal of Southern harvest options at 20, 25 and 30 year periods. Naturally there is a trade-off in the model between the number of explicit time periods (given a 100-year projection period) and model size.

The possibility of planting trees with a rotation length which would carry them beyond the explicit model time frame necessitates valuation of the standing inventory existing in the terminal projection period. The mechanism reflecting the value of inventory involves specification of terminal conditions that represent the projected net present value for all time periods beyond the end of the model projection. Terminal conditions are resolved by computing the potential future even-flow of harvest from the terminal inventory and valuing this harvest using appropriate prices from downward sloping product demand curves and forested stands associated timber management and production costs. Terminal period inventories are valued in both of the forest and agricultural sectors assuming perpetual, steady state management following the last year of the time horizon. Demand relations for forestry in all periods beyond the end of the projection were taken to be the same as those in the final period. Thus terminal period prices, costs and revenues vary with level of output.

Forestry activities in FASOMGHG are assumed identical in each year of a five year period as are activities in forest manufacturing and harvest. These cases were treated as if they generated constant costs and returns during each year of a five year period (running from year 0 to year 4). Thus, forest returns in each explicit period were treated as a continuing annual series of five equal amounts discounted to the start of each period under the assumption that the same level of returns arise in each year of the period. In the terminal period returns arising in all subsequent years (beyond the end of the projection) were treated as an infinite annuity.

The principal decision variables in the forestry portion of FASOMGHG include the harvest and management of existing and newly afforested timberland, production of manufactured products, levels of manufactured product demand, interregional transportation of logs and products, and aggregate shipments from producing regions. The forestry portion of FASOMGHG objective function involves maximization of the discounted sum of producers' and consumers' surplus, less the costs of timber supplies that vary with volume harvested, less the costs of volume-sensitive non-wood inputs, transportation, manufacturing inputs, and forest management.

4.3.3 Agricultural Sector Portion of FASOMGHG

FASOMGHG contains an adaptation of the Agricultural Sector Model (ASM) (Chang et al) and the ASMGHG variant (Schneider, McCarl and Schneider) as a submodel. The whole model of ASM and its GHG version are included as a submodel in FASOMGHG appearing in each explicit time period. This agricultural sector submodel: 1) depicts crop and livestock production and agricultural processing using key land, water, labor, and forage inputs as well as product trade; 2) simulates the effects of changes in agricultural resources and market conditions on prices, quantities produced, consumers' and producers' surplus, exports, imports, and processing; 3) considers production, processing, domestic consumption, imports, exports, and input procurement; and 4) distinguishes between primary and secondary commodities, with primary commodities being those directly produced by farms and secondary commodities being those involving processing. [25]

For agricultural production the US is disaggregated into either 63 or 11 geographical subregions depending on time period. Each subregion possesses different endowments of land, labor, irrigation water and animal unit month (AUM) grazing, as well as crop and livestock yields. The supply sector allocates these regional factors across a set of regional crop and livestock budgets and a set of processing budgets which use commodities as inputs. There are more than 1200 production possibilities (budgets) representing agricultural production in each time period. These include field crop, livestock, and biofuel feedstock production. The field crop variables are also divided into irrigated and dryland production according to the irrigation water and production possibilities available in each region. There are also import supply functions from the rest of the world for a number of commodities. The demand sector of the model is

[25] There are 56 primary agricultural commodities that depict the majority of total agricultural production, land use and economic value. They can be grouped into crops, livestock and biofuels related commodities. The FASOMGHG agricultural submodel incorporates processing of primary commodities into secondary commodities that are created by processing. These commodities are chosen based on their linkages to agriculture. Some primary commodities are inputs to processing activities yielding these secondary commodities. Certain secondary products (by-products) are in turn inputs to agricultural livestock production or feed blending. These can be broken into crop, livestock and biofuels related items.

constituted by the intermediate use of all the primary and secondary commodities, domestic consumption, and exports.

Secondary commodities are produced by processing variables. They include soybean crushing, corn wet-milling, potato processing, sweetener manufacturing, mixing of various livestock and poultry feeds, and the conversion of livestock and milk into consumable meat and dairy products. The processing cost is generally calculated as the difference between its price and the costs of the primary commodity inputs. Primary and secondary commodities are consumed at the national level according to constant elasticity demand functions. The areas under these demand functions represent total willingness to pay for agricultural products. The difference between total willingness to pay and production and processing costs is equal to the sum of producers' and consumers' surpluses. Maximization of the sum of these surpluses constitutes the agricultural sector objective function.

Demand and supply components are updated between time periods by means of projected growth rates in yield, processing efficiency, domestic demand, exports, and imports. The agricultural related land use decision simulated in FASOMGHG is that, in each period, owners of agricultural land can decide: 1) whether to keep an acre of land in agricultural production or change land use to afforestation; 2) what crop/livestock mix to plant/rear/harvest, if the land stays in agriculture; and 3) what type of timber management to select, if the land is to be planted in trees. These decisions are made entirely on the basis of relative profitability of land in its various competing alternative uses over the life-span of the foreseeable choices.

Like the forest sector model, the agricultural sector model is assumed to represent typical activity during each year of a five year period. Thus, agricultural returns in each period excepting the last one were treated as if they were a continuing annual series of five equal amounts discounted to the first period's dollars. Because agricultural land values in any use reflect the present value of an infinite stream of future net returns, it is theoretically inappropriate to ignore land values at the end of our finite projection period. One has to value agricultural land in continuing agricultural use beyond the explicit model time periods. If this is not done the model would simply transform agriculture lands into forestry to capture net returns beyond the explicit model time horizon. Terminal conditions in forestry are handled as constant perpetual. In the agricultural sector, activity in the last period is treated as if it continues forever. Hence, in the last period the returns were treated as if they were an infinite annuity.

4.3.4 GHG Accounting in FASOMGHG

GHGs, generally in the form of carbon, can be sequestered in soils, standing trees, other vegetation, and in wood products. Sequestration refers to storage of the GHGs for more than one year. As a consequence, the sequestration definition used in the model for standing vegetation is limited to carbon storage in trees, understory and litter within both forests and plantations of woody biomass feedstocks (poplar and willow) but excludes, for instance, carbon stored in annually cultivated crops. FASOMGHG accounts for changes in agricultural and forestry sector related net GHG emissions within a number of categories. These categories can be classified into broad categories of those involved with forest, agriculture, and biofuel feedstocks. These items are strongly interactive within model solutions. For example, land moving from agriculture to forestry will change (a) agricultural sequestration and emissions, (b) sequestration gains from afforestation, (c) emissions from forest management related fuel usage, and (d) eventual sequestration of carbon within wood products. Thus, the implications of GHG management-induced alterations span widely across activities within the model.

The multi-GHG impact of the agricultural and forestry sectors and possible manipulation of the atmospheric levels of these gases introduces multi-dimensional trade-offs between model variables, net GHG emissions, and the climate change implications thereof. In order to consider these trade-offs, the GHG emissions needed to be placed on a common footing. This is done through adoption of the 100-year global warming potential (GWP) concept and conversion of all gases to a carbon or carbon dioxide equivalent basis. GWPs compare the abilities of different GHGs to trap heat in the atmosphere and allow one to convert emissions of various GHGs into a common measure, which allows for aggregating the radiative impacts of various GHGs into a single measure denominated in CO2 or C equivalents.

FASOMGHG quantifies GHG emissions produced in the forestry and agricultural sectors. These emissions primarily arise from fossil fuel-related processes (e.g., energy consumption), livestock production, fertilization, and rice cultivation. FASOMGHG depicts positive credits for sequestration, but when the amount of carbon sequestered is reduced by harvesting forests or changing land uses, this in effect corresponds to an emission of the sequestered carbon and is thus penalized as a GHG emission debit. FASOMGHG can grant credits for activities which cause an offsetting reduction in GHG emissions by sources outside the model. These credits arise via the use of agricultural commodities as biofuel feedstocks for the production of three different types of energy. The energy types are: electricity fueled by agricultural energy crops, forest milling residues, or forest logs, ethanol from corn or agricultural energy crops, and diesel from oils derived from agricultural sources. The basic argument for granting credits for such activities involves the concept of carbon recycling[26].

FASOMGHG does not try to determine GHG prices endogenously. Rather it recognizes that the GHG prices will be exogenous to the agricultural and forestry sectors and takes a fixed GHG price on a carbon equivalent basis. This is a reasonable assumption given that approximately 84% of the U.S. GHG emissions arise in the energy sector, so it is clear that the energy sector will play the primary role in price determination. FASOMGHG operates with an exogenously specified trajectory for carbon equivalent GHG prices by five year period. It is initially run with a zero carbon equivalent price. In turn the resultant GHG trajectory from that run is be used as the baseline in subsequent runs. This implies that FASOMGHG does not give mitigation

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[26] As agricultural or forest biomass grows, it absorbs carbon dioxide from the atmosphere through photosynthesis. The carbon removed from the atmosphere in this way is sequestered in standing biomass. In turn, when the biomass is harvested and turned into energy through combustion or chemical processes, the sequestered carbon is emitted and thereby returns to the atmosphere in the form of carbon dioxide. This basically means that the net effect on atmospheric carbon of growing biomass as a fuel source that is subsequently combusted is zero. In contrast, when fossil fuels are used to generate energy, the carbon that has been stored in below-ground pools (and presumably would remain there forever were it not for its use as a fuel source) and is emitted to the atmosphere this leads to a net increase in atmospheric carbon concentration. Therefore, the substitution of biofuel feedstocks for fossil fuels can be viewed as decreasing the net carbon emissions.

credit for tillage changes, adoption of practices, afforestation, and other forest management manipulations that are observed in the absence of a GHG incentive program. Any GHG changes that occur in the baseline are considered business as-usual (or BAU) changes to which GHG effects induced by a policy can be compared to gauge the effectiveness of the policy.

Within the forest and agricultural sectors, there are numerous management alternatives to reduce net GHG emissions below baseline levels. These are referred to as mitigation options in FASOMGHG. GHG emissions can be reduced by using forest and agricultural mitigation strategies, and biofuel production as agriculture and forestry can offset energy-related emissions by providing bio-feedstocks that can be used in energy production processes. The potential biofuel related management possibilities that are inherent in the structure of FASOMGHG are the production of ethanol as a replacement for gasoline through the conversion of corn, sugar cane, switchgrass, poplar and willow, the generation of electricity through use of milling residues, harvested wood, switchgrass, poplar and/or willow as feedstocks as a substitute for coal and the production of biodiesel from soybeans or corn, for use in transportation fuel.

Because FASOMGHG is a multi-period model, the net GHG mitigation contributions of modeled activity over time were needed to consider in the model. Different strategies were used to reflect these dynamic contributions depending on whether the activity of interest was sequestration, emissions reduction, or biofuel offsets. Here the cumulative amounts of sequestration or emissions incurred during each model time period were used in the model. Consequently, sequestration is modeled in terms of cumulative tons of carbon sequestered over time. For sequestration activity, the model yields non-uniform quantities over time due to the generally accepted scientific premise that carbon sequestered in ecosystem approaches steady state equilibrium under any management alternative. For emissions and biofuel offsets, the cumulative amounts incurred in this and all previous time periods are reflected in each time period reflecting change in total climatic forcing.

4.3.5 Crop Production in FASOMGHG Regions

Geographically, FASOMGHG regions cover forest and agricultural activities across the U.S. The crop production set is defined at the 63 region level and currently there are more than 1200 production possibilities. Yields, costs and input usage rates vary by region. These include major field crop production, livestock production, and biofuel feedstock production. Also, they are defined across multiple land types (wet land, low erodible crop land, medium erodible crop land, and severely erodible crop land), irrigation possibilities (irrigated and non-irrigated), fertilization alternatives (three alternatives – base fertilization then 15% and 30% reductions from the base) and tillage alternatives (three alternatives – conventional, reduced and zero). Yield, water use, and erosion data for these alternatives are defined based on runs of the EPIC (Erosion Productivity Impact Calculator) crop growth simulator.

For the purpose of simplifying our analyses, all the yield and crop residue production data based on different land types, irrigation possibilities and tillage alternatives are aggregated and broken down from 63 subregions into 11 market regions for agricultural sector coverage as shown in the Table 4.3. Research in this dissertation will be conducted at the 11 region level. The 11-region breakdown reflects the existence of regions for which there is agricultural activity but no forestry, and vice versa. Forestry production occurs in nine of the 11 production regions, but agricultural sector activity cannot be reasonably condensed to only these nine regions. For instance, the Northern Plains (NP) and Southwest (SW) regions reflect important differences in agricultural characteristics, but no forestry activity is included in either region. Likewise, there are important differences in the two Pacific Northwest regions (PNWW, PNWE) for forestry, but only the PNWE region is considered a significant producer of the agricultural commodities tracked in the model.

Table 4.3 Definitions of 11 Regions in FASOMGHG

Key	Region	States/Subregions
NE	Northeast	Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, West Virginia
LS	Lake States	Michigan, Minnesota, Wisconsin
CB	Corn Belt	All regions in Illinois, Indiana, Iowa, Missouri, Ohio
GP	Great Plains	Kansas, Nebraska, North Dakota, South Dakota
SE	Southeast	Virginia, North Carolina, South Carolina, Georgia, Florida
SC	South Central	Alabama, Arkansas, Kentucky, Louisiana, Mississippi, Eastern Oklahoma, Tennessee, Eastern Texas
SW	Southwest	Western and Central Oklahoma, All of Texas but the Eastern Part – Texas High Plains, Texas Rolling Plains, Texas Central Blacklands, Texas Edwards Plateau, Texas Coastal Bend, Texas South, Texas Trans Pecos
RM	Rocky Mountains	Arizona, Colorado, Idaho, Montana, Eastern Oregon, Nevada, New Mexico, Utah, Eastern Washington, Wyoming
PSW	Pacific Southwest	All regions in California
PNWE	Pacific Northwest – East side	Oregon and Washington, east of the Cascade mountain range
PNWW	Pacific Northwest – West side	Oregon and Washington, west of the Cascade mountain range

5. ANALYSIS OF CROP RESIDUE PROSPECTS

Besides their uses in energy generation, crop residues have an important role in soil erosion control and maintenance of soil organic matter. As discussed above, the amount of crop residues which can be removed for energy generation will depend on many factors such as soil type and fertility level, slope characteristics and tillage system. Based on the studies of Nelson (2002), Nelson et al. (2004) and Perlack et al. (2005), the amount of removal crop residues is established in FASOMGHG. In addition, following a method by French (1960) as described in McCarl et al. (2000), residue density, hauling distance and hauling cost are estimated in FASOMGHG. Furthermore, crop residue delivered costs which include harvesting, processing, storage and hauling costs are also be computed.

5.1 Characteristics of Crop Residue Supply

The supply of crop residues for electricity generation will rest on a number of factors which are described below.

5.1.1 Availability of Crop Residues for Power Generation

All estimated results are aggregated from 63 sub-regions into 10 agricultural regions27 as defined in FASOMGHG. Using equation (4.1), the amount of removable crop residues available for energy generation is estimated in FASOMGHG based on different land types, irrigation possibilities, and fertilization and tillage alternatives. These estimated aggregated results of removable crop residues in the 10 agricultural regions for six crops are shown in Table 5.1. Total amount of harvestable crop residues in million tons are obtained by multiplying the amount of removable crop residues in tons per acre with total harvested acres of each crop in each region (see Table 5.2 and Table 5.3). Table 5.3 shows that nationally about 156 million tons of crop residues are available with 68% of them coming from the CB and GP regions and 93% of them are accounted for by corn and wheat residues. The table also shows that about 116 million tons of corn

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[27] One region (PNWW) is ignored because it is not agriculturally significant in FASOMGHG.

residues and 30 million tons of wheat residues can be harvested nationally and are enough to supply 217 100MW power plants.[28]

5.1.2 Average Density and Distance of Crop Residues

One of the main factors that influence the spread between farm level costs and industry level (delivered plant) costs is the density of residue (Gallagher et al., 2003). Lower crop residue density will result in higher distance traveled between farm land and delivered plant. This in turn will result in higher transportation costs as indicated by equation (4.2). The density of crop residue in each region (in percent) can be obtained by dividing total harvested acres of each crop in each region by total land area of that region in acres. The estimated results of crop residue density reported in Table 5.4 are aggregated from 63 sub-regions into 10 agricultural regions as defined in FASOMGHG. As expected, the table shows that corn residues are densely concentrated in CB region, while wheat, sorghum and barley residues are highly concentrated in the GP region.

Average hauling distance between farm land and bioenergy plants (see equation (4.2) is a function of density, yield and required tons of crop residues (which contains recoverable BTUS equivalent to 7 TBTUs for a 100 MW power plant) . The estimated aggregated results for average hauling distance, for the 10 agricultural regions in FASOMGHG, and various cofire (5%, 10%, 15% and 20%) and fire alone (100%) scenarios, are displayed in Table 5.5 and Table 5.6 for corn and wheat residues respectively (see APPENDIX II for sorghum, oats, barley and rice residue results). Data in the tables suggest that as cofiring ratios increase i.e. as a 100 MW power plant consumes more and more crop residues for power generation, average hauling distance increases at an increasing rate since residues will have to be collected from longer distances[29]. Table 5.5 indicates that among the 10 agricultural regions, the CB has the lowest average hauling distance for corn residues, because the concentration (density) of corn residues is the highest there. Similarly in Table 5.6, GP has the lowest average

[28] Here we are making the assumptions that crop residues are costless and that a 100 MW power plant requires 7 TBTUs equivalent of crop residues each year for power generation. By using HHVs and the required tons of corn and wheat residues for a 100 MW power plant, the number of 100MW power plants can be calculated.

[29] The distance is based on the square system as described in French (1960).

hauling distance for wheat residues as the concentration of wheat residues is the highest in that region.

Table 5.1 Weighted Average Yield of Removable Crop Residues (in Tons/Acre)

Region	Corn	Wheat	Sorghum	Barley	Oats	Rice
NE	1.30	1.08	1.11	0.61	0.36	-
LS	1.52	0.64	-	0.42	0.34	-
CB	1.85	1.16	1.11	0.63	0.47	0.20
GP	1.59	0.58	0.93	0.43	0.35	-
SE	1.37	0.87	0.76	0.58	0.33	-
SC	1.61	0.86	1.05	0.64	0.26	0.40
SW	1.27	0.49	0.52	0.30	0.19	0.41
RM	1.59	0.53	0.53	0.56	0.33	-
PSW	1.67	0.82	0.48	0.40	0.31	0.59
PNWE	1.86	0.42	-	0.45	0.38	-

Note: For definitions of regions, see Table 4.3.

Table 5.2 Total Harvested Acres (in Million Acres)

Region	Corn	Wheat	Sorghum	Barley	Oats	Rice
NE	2.35	0.55	0.01	0.17	0.22	-
LS	10.70	2.49	-	0.19	0.46	-
CB	33.69	2.78	0.30	-	0.28	0.21
GP	14.91	20.92	4.33	1.54	0.47	-
SE	1.44	1.04	0.05	0.07	0.09	-
SC	2.77	2.14	0.52	0.01	0.00	2.43
SW	1.59	6.89	3.00	-	0.17	0.20
RM	1.27	8.00	0.37	1.66	0.15	-
PSW	0.16	0.46	-	0.11	0.03	0.47
PNWE	0.07	3.21	-	0.52	0.04	-

Note: For definitions of regions, see Table 4.3.

Table 5.3 Total Removable Crop Residues (in Million Tons)

Region	Corn	Wheat	Sorghum	Barley	Oats	Rice	Total
NE	3.07	0.59	0.01	0.10	0.08	-	3.86
LS	16.21	1.58	-	0.08	0.15	-	18.03
CB	62.19	3.23	0.33	-	0.13	0.04	65.92
GP	23.65	12.16	4.03	0.66	0.16	-	40.66
SE	1.98	0.90	0.03	0.04	0.03	-	2.98
SC	4.46	1.84	0.55	0.01	0.00	0.98	7.83
SW	2.03	3.36	1.55	-	0.03	0.08	7.06
RM	2.03	4.23	0.19	0.93	0.05	-	7.43
PSW	0.27	0.38	-	0.04	0.01	0.28	0.97
PNWE	0.14	1.35	-	0.23	0.01	-	1.73
Total	116.02	29.62	6.70	2.09	0.66	1.38	156.47

Note: For definitions of regions, see Table 4.3.

Table 5.4 Weighted Average Crop Residue Density (in %)

Region	Corn	Wheat	Sorghum	Barley	Oats	Rice
NE	3.29	0.42	0.34	1.48	1.42	-
LS	7.36	1.21	-	0.08	0.27	-
CB	20.82	2.12	0.27	-	0.15	0.08
GP	9.38	12.68	5.43	2.26	0.24	-
SE	0.93	0.61	0.07	0.07	0.05	-
SC	1.61	1.11	0.20	-	-	2.23
SW	0.65	4.35	1.61	-	0.07	0.50
RM	0.51	2.08	0.08	0.46	0.03	-
PSW	0.09	0.17	0.19	0.09	0.03	0.10
PNWE	0.01	1.33	-	0.25	0.01	-

Note: For definitions of regions, see Table 4.3.

Table 5.5 Average Hauling Distance for Corn Residues (in Miles)

Region	Cofire5%	Cofire10%	Cofire15%	Cofire20%	Fire100%
NE	13.12	18.38	22.72	26.47	78.39
LS	8.13	11.40	14.09	16.41	48.60
CB	4.38	6.14	7.59	8.84	26.18
GP	7.04	9.86	12.19	14.20	42.06
SE	24.02	33.66	41.60	48.46	143.52
SC	16.87	23.65	29.23	34.05	100.84
SW	29.89	41.89	51.76	60.30	178.60
RM	30.14	42.24	52.20	60.81	180.10
PSW	70.08	98.23	121.39	141.42	418.84
PNWE	199.41	279.48	345.39	402.36	-

Note: For definitions of regions, see Table 4.3.

Table 5.6 Average Hauling Distance for Wheat Residues (in Miles)

Region	Cofire5%	Cofire10%	Cofire15%	Cofire20%	Fire100%
NE	31.47	44.10	54.50	63.49	188.05
LS	24.27	34.02	42.04	48.98	145.06
CB	13.53	18.97	23.44	27.31	80.88
GP	7.83	10.98	13.57	15.81	46.81
SE	29.15	40.86	50.50	58.83	174.23
SC	21.68	30.38	37.55	43.74	129.55
SW	14.59	20.45	25.27	29.44	87.20
RM	20.25	28.38	35.08	40.86	121.03
PSW	56.55	79.26	97.95	114.10	337.95
PNWE	28.42	39.83	49.22	57.34	169.82

Note: For definitions of regions, see Table 4.3.

5.1.3 Hauling Cost

Average crop residue density and subsequently hauling distance will be important in determining average hauling cost between the supply point and the demand point of crop residues, as indicated in equation (4.2). The estimated average hauling costs for the 10 agricultural regions based on cofiring and fire alone ratios are shown in Table 5.7. As mentioned above, among the 10 agricultural regions, CB has the highest corn residue density which means the hauling distance between farm land and delivered plant in that region will be the lowest. This will yield the lowest hauling cost for corn residues in CB as shown in the table below. The same thing can be said about wheat and other residues (see Table 5.8) for wheat residues and the tables for other residues are provided in APPENDIX II). In PNWE, on average it would cost about $72 per ton for cofiring power plants to acquire corn residues as the concentration of corn residues is the lowest in that region and power generators would have to travel greater distances to collect corn residues. In addition, it would not be feasible at all to fire corn residues alone (100%) in a power plant in that region because the cost of hauling would be prohibitively high. Obviously, hauling cost for crop residues will be lower in a region where residue concentration is high than in a region which has a low concentration of residues.

5.1.4 Total Crop Residue Production Cost

Flaim and Hertzmark (1981) estimated that on average the total cost of crop residues delivered to electric utility would be about $34.33 per ton which included costs of harvesting, storing and hauling. Turhollow et al. (1998) assessed the delivered costs of corn and small grain residues to be around $21.79 per ton and $16.3 per ton respectively. Their delivered costs included harvesting and hauling costs[30], but storage and processing costs were ignored in their study. In the same way, Sokhansanj and Turhollow (2002) evaluated harvesting and hauling costs[31] of corn stover to be around $19.6 per ton, but they did not take storage and processing costs into consideration in their evaluation. Perlack and Turhollow (2002) showed that on average corn stover could be collected, stored and hauled[32] for about $45.83 per ton using conventional equipment for ethanol conversion facilities of different sizes.

[30] The hauling cost was assumed to be fixed at $5.88 per ton.
[31] Their estimated hauling cost was around $5.53 per ton.
[32] The calculated average hauling cost and hauling distance in their study are about $9.18 per ton and 38 miles respectively.

Table 5.7 Average Hauling Cost for Corn Residues (in Dollars/Ton)

Region	Cofire5%	Cofire10%	Cofire15%	Cofire20%	Fire100%
NE	7.39	8.54	9.50	10.32	21.74
LS	6.29	7.01	7.60	8.11	15.19
CB	5.46	5.85	6.17	6.44	10.26
GP	6.05	6.67	7.18	7.62	13.75
SE	9.78	11.90	13.65	15.16	36.07
SC	8.21	9.70	10.93	11.99	26.68
SW	11.07	13.71	15.89	17.77	43.79
RM	11.13	13.79	15.98	17.88	44.12
PSW	19.92	26.11	31.21	35.61	96.64
PNWE	48.37	65.99	80.49	93.02	-

Note: For definitions of regions, see Table 4.3.

Table 5.8 Average Hauling Cost for Wheat Residues (in Dollars/Ton)

Region	Cofire5%	Cofire10%	Cofire15%	Cofire20%	Fire100%
NE	11.42	14.20	16.49	18.47	45.87
LS	9.84	11.98	13.75	15.27	36.41
CB	7.48	8.67	9.66	10.51	22.29
GP	6.22	6.92	7.48	7.98	14.80
SE	10.91	13.49	15.61	17.44	42.83
SC	9.27	11.18	12.76	14.12	33.00
SW	7.71	9.00	10.06	10.98	23.68
RM	8.96	10.74	12.22	13.49	31.13
PSW	16.94	21.94	26.05	29.60	78.85
PNWE	10.75	13.26	15.33	17.11	41.86

Note: For definitions of regions, see Table 4.3.

In this dissertation, costs of harvesting and collecting, storing and processing based on the literature (as discussed above) are used along with the estimated hauling costs and the farmer payments[33] in 10 FASOMGHG regions to derive the estimates for average crop residue delivered costs in dollars[34] per ton which are reported in Table 5.9 and Table 5.10 for corn and wheat residues (the rest are available in APPENDIX II). As can be seen in the tables, our estimated results are more or less consistent with the literature. On average, it would cost about $50 per ton for a biomass-fire-alone 100MW power plant to acquire corn residues in CB. As for wheat residues with fire-alone option, it would cost about $49 per ton in GP. Cofiring crop residues with coal may be a better option for power generators as crop residues are cheaper with cofiring options than with fire-alone option as shown in the tables.

Table 5.9 Average Delivered Cost Estimates of Corn Residues (in Dollars/Ton)

Region	Cofire5%	Cofire10%	Cofire15%	Cofire20%	Fire100%
NE	46.83	47.99	48.94	49.77	61.19
LS	45.73	46.45	47.04	47.56	54.64
CB	44.91	45.30	45.62	45.89	49.71
GP	45.49	46.12	46.63	47.07	53.20
SE	49.23	51.35	53.10	54.61	75.52
SC	47.66	49.15	50.38	51.44	66.13
SW	50.52	53.16	55.33	57.21	83.24
RM	50.58	53.24	55.43	57.32	83.57
PSW	59.36	65.56	70.65	75.06	136.09
PNWE	87.82	105.43	119.93	132.47	-

Note: For definitions of regions, see Table 4.3.

[33] Based on Perlack and Turhollow (2002), farmer payments of $10 are assumed.
[34] Note all costs are based on 2004 dollars.

Table 5.10 Average Delivered Cost Estimates of Wheat Residues (in Dollars/Ton)

Region	Cofire5%	Cofire10%	Cofire15%	Cofire20%	Fire100%
NE	45.38	48.16	50.45	52.43	79.83
LS	43.80	45.94	47.71	49.23	70.37
CB	41.44	42.63	43.62	44.47	56.25
GP	40.18	40.87	41.44	41.94	48.76
SE	44.87	47.45	49.57	51.40	76.79
SC	43.23	45.14	46.72	48.08	66.96
SW	41.67	42.96	44.02	44.94	57.64
RM	42.91	44.70	46.18	47.45	65.09
PSW	50.90	55.90	60.01	63.56	112.81
PNWE	44.71	47.22	49.29	51.07	75.82

Note: For definitions of regions, see Table 4.3.

5.2 Cost Comparisons between Crop Residues and Fossil Fuels

In order to compare average delivered costs between crop residues and fossil fuels, all cost units in ton (or in cubic foot for natural gas) are converted into the same common energy units in million Btu (MMBtu) by employing higher heating values (HHVs) of the respective fuels. For instance, an average wheat residue delivered cost of $49 per ton can be converted into $3.25 per MMBtu by using the wheat residue HHV of 15.06 MMBtu per ton. The same thing can be done with fossil fuels by using their respective HHVs. All average delivered costs of coal, natural gas and crop residues converted from their respective units to a common unit in dollars per MMBtu are reported in the tables below.

Table 5.11 shows that coal prices have been stable and below $2 per million Btu in most of the regions. On the other hand, Table 5.12 reports that natural gas prices have been volatile, on average they have increased from $2.28 per million Btu in 1998 to about $8.13 per million Btu in 2005. As suggested in the tables below, crop residues are not cost competitive with coal for both cofiring and fire-alone options (see Table 5.13 and Table 5.14 for cost comparisons). Coal prices will have to rise much higher than the current level in order to make crop residues economically competitive. It may not be sensible to compare costs between natural gas and crop residues, as one is in a gaseous state and the other in a solid state. In addition, solid crop residues may not be able to substitute natural gas in a gas-fired power plant, unless gasification technologies were developed to directly convert solid crop residues into biogas which can be burned in the power plant. Even if these conversion technologies exist today, costs of converting solid residues into biogas could be extremely high.

Table 5.11 Average Cost of Coal Delivered to Electric Utilities (in Dollars/MMBtu)

Region	1998	2001	2004	2005
NE	1.65	1.63	1.78	2.15
LS	1.14	1.08	1.16	1.28
CB	1.22	1.15	1.18	1.32
GP	0.61	0.63	0.68	0.73
SE	1.80	1.96	2.27	2.71
SC	1.37	1.29	1.51	1.75
SW	0.88	0.96	1.06	1.04
RM	1.01	1.02	1.07	1.14
Pacific	1.12	0.95	1.00	1.07

Note: For definitions of regions, see Table 4.3.
Source: Data are derived from Energy Information Administration (1998, 2001, 2006i).

Table 5.12 Average Cost of Natural Gas Delivered to Electric Utilities (in Dollars/MMBtu)

Region	1998	2001	2004	2005
NE	2.59	4.22	6.60	9.31
LS	1.65	3.72	4.68	6.49
CB	2.39	5.06	6.48	8.83
GP	2.15	3.72	5.59	7.82
SE	2.31	4.41	6.34	8.65
SC	2.24	4.19	6.09	8.94
SW	2.24	4.34	5.91	7.91
RM	2.35	5.41	5.72	7.60
Pacific	2.58	8.62	5.73	7.65

Note: For definitions of regions, see Table 4.3.
Source: Data are derived from Energy Information Administration (1999, 2003b, 2005e, and 2006j).

Table 5.13 Average Delivered Cost Estimates of Corn Residues (in Dollars/MMBtu)

Region	Cofire5%	Cofire10%	Cofire15%	Cofire20%	Fire100%
NE	5.08	5.20	5.30	5.39	6.63
LS	4.96	5.03	5.10	5.15	5.92
CB	4.87	4.91	4.94	4.97	5.39
GP	4.93	5.00	5.05	5.10	5.77
SE	5.34	5.57	5.76	5.92	8.19
SC	5.17	5.33	5.46	5.58	7.17
SW	5.48	5.76	6.00	6.20	9.02
RM	5.48	5.77	6.01	6.21	9.06
PSW	6.43	7.11	7.66	8.14	14.75
PNWE	9.52	11.43	13.00	14.36	-

Note: For definitions of regions, see Table 4.3.

Table 5.14 Average Delivered Cost Estimates of Wheat Residues (in Dollars/MMBtu)

Region	Cofire5%	Cofire10%	Cofire15%	Cofire20%	Fire100%
NE	3.01	3.20	3.35	3.48	5.30
LS	2.91	3.05	3.17	3.27	4.67
CB	2.75	2.83	2.90	2.95	3.74
GP	2.67	2.71	2.75	2.79	3.24
SE	2.98	3.15	3.29	3.41	5.10
SC	2.87	3.00	3.10	3.19	4.45
SW	2.77	2.85	2.92	2.98	3.83
RM	2.85	2.97	3.07	3.15	4.32
PSW	3.38	3.71	3.99	4.22	7.49
PNWE	2.97	3.14	3.27	3.39	5.04

Note: For definitions of regions, see Table 4.3.

6. ANALYSIS OF FACTORS AFFECTING COST COMPETITIVENESS OF CROP RESIDUES

The future production of bioelectricity from crop residues would likely depend on various scenarios such as increases in the coal price and carbon abatement costs, reductions in residue production cost, and improvements in fuel conversion technologies and the quality of crop residues. FASOMGHG is employed to explore the future market conditions of crop residues for electricity generation under various scenario assumptions as discussed in the next section. At present, there are two main factors that affect economic competitiveness of crop residues for electricity production: low heat content and high production costs. Generally coal has a larger HHV of about 20 MMBtu per ton. The HHVs for corn and wheat residues are about 9 MMBtu per ton and 15 MMBtu per ton respectively. Due to its higher heat content, on average coal costs less than corn and wheat residues as shown in the tables above. Because wheat residues have higher heat content than corn residues, Table 5.13 and Table 5.14 show that average delivered costs of wheat residues are less than the average delivered costs of corn residues. The low heat content nature of crop residues makes them less likely to be cost-competitive with coal.

Another factor that may affect the cost competitiveness of crop residues is their high production costs such as harvesting, processing and transportation costs. Unlike coal which can be continuously mined, harvested, processed and transported via railroad in large quantities using highly developed technologies and sophisticated equipments, at present crop residues cannot be produced efficiently due to the lack of market development and development in production technologies and infrastructures. In addition, unlike coal, crop residues are not densely concentrated in a particular region or area. This means greater distances have to be covered to collect and transport residues and this would increase the cost of residue production tremendously. In order to make crop residues economically competitive with coal, their costs of production have to be reduced. Table 6.1 shows that wheat residues with cofiring options could become cost competitive with coal in some regions if we assume that the residue production costs can be reduced by at least 50%. Production costs for corn residues may have to be reduced by well above 50% to make corn residues cost competitive with coal (see Table 6.2).

Table 6.1 Average Delivered Cost Estimates of Wheat Residues (in Dollars/MMBtu), Assuming 50% Reduction in Production Costs

Region	Cofire5%	Cofire10%	Cofire15%	Cofire20%	Fire100%
NE	1.84	1.93	2.01	2.07	2.98
LS	1.79	1.86	1.92	1.97	2.67
CB	1.71	1.75	1.78	1.81	2.20
GP	1.67	1.69	1.71	1.72	1.95
SE	1.82	1.91	1.98	2.04	2.88
SC	1.77	1.83	1.88	1.93	2.56
SW	1.72	1.76	1.79	1.82	2.25
RM	1.76	1.82	1.87	1.91	2.49
PSW	2.02	2.19	2.32	2.44	4.08
PNWE	1.82	1.90	1.97	2.03	2.85

Note: For definitions of regions, see Table 4.3.

Table 6.2 Average Delivered Cost Estimates of Corn Residues (in Dollars/MMBtu), Assuming 50% Reduction in Production Costs

Region	Cofire5%	Cofire10%	Cofire15%	Cofire20%	Fire100%
NE	3.08	3.14	3.19	3.24	3.86
LS	3.02	3.06	3.09	3.12	3.50
CB	2.98	3.00	3.01	3.03	3.24
GP	3.01	3.04	3.07	3.09	3.43
SE	3.21	3.32	3.42	3.50	4.63
SC	3.12	3.21	3.27	3.33	4.13
SW	3.28	3.42	3.54	3.64	5.05
RM	3.28	3.43	3.55	3.65	5.07
PSW	3.76	4.09	4.37	4.61	7.92
PNWE	5.30	6.26	7.04	7.72	-

Note: For definitions of regions, see Table 4.3.

6.1 Future Market Scenarios of Crop Residues for Power Generation

FASOMGHG is used to analyze market potential for bioelectricity generated using crop residues. It is designed to simulate activity over a long period of time. In this dissertation, bioelectricity production is simulated from the year 2000 to the year 2045 in five year intervals. Both co-fire and fire-alone options are examined in the analyses. By incorporating various assumptions described above into FASOMGHG, the following scenarios are simulated over the period of 2000-2045:

1) Increase in coal prices
2) Increase in carbon dioxide (CO_2) equivalent prices
3) Changes in higher heating values(HHVs) of crop residues
4) Improvement in crop yield
5) Improvement in conversion efficiency of residues
6) Reduction in residue production costs
7) Changes in market penetration limits.

Under the first scenario, the impact of increase in coal prices on crop residues for power production is explored. In the second scenario, various levels of CO_2 prices are employed to examine their effect on bioelectricity production using crop residues. Third scenario detects the impact of changes in crop residue HHVs on biopower generation. Fourth scenario studies the effect of improvement in crop yield on the use of residues for power generation. Fifth scenario analyzes how improvement in fuel conversion efficiency rate affects bioelectricity production. Sixth scenario examines how decreases in residue production costs alter residue electricity generation. And final scenario looks at the impact of changes in the rate of market penetration constraints on bioelectricity production.

6.1.1 Coal Price Scenarios

By using alternative coal prices and constant CO_2 base price of zero in FASOMGHG, bioelectricity production is simulated over time and results are shown in Table 6.3. The table shows that coal price has to be above $40 per ton (equivalently $2 per million Btu

(MMBtu)) for wheat residues with cofiring options to have market potential. It also shows that fire-alone option is not feasible for any crop residues unless coal price reaches above $74.04 per ton (or $3.7 per MMBtu). As coal price increases, more and more power plants switch to wheat residues with 20% cofiring option. Corn, sorghum, barley, oats and rice residues do not have market potential in bioelectricity production as coal price rises.

6.1.2 Carbon Price Scenarios

A CO_2 equivalent price should ultimately reflect the future external cost of releasing GHG into the atmosphere. In the model, alternative CO_2 prices will be applied to CO_2, CH_4 (methane), and N_2O (nitrous oxide) emissions or offsets adjusted for their greenhouse gas or global warming potential (GWP)[35]. FASOMGHG is used to simulate future market scenarios for bioelectricity production with chosen CO_2 equivalent prices ranging from $0 to $100 per ton. In this section, the coal price is assumed to be unchanged with the base price of $24.68 per ton (or equivalently $1.23 per MMBtu). Simulated results are reported in Table 6.4 which shows that an increase in CO_2 price is tremendously important for crop residues to have potential in power generation. The table indicates that the CO_2 price has to be about $15 per ton for wheat residues with cofiring options to have electricity production potential. Similar to coal price scenarios above, wheat residues with 20% cofiring option will increasingly and significantly contribute to bioelectricity production as CO_2 price increases from $15 per ton to $50 per ton. When the CO_2 price reaches $100 per ton, bioelectricity producers would be willing to primarily use wheat residues for power generation as wheat residues with fire-alone option have become feasible. At that level of CO_2 price, corn residues with fire-alone option would also become attractive to biopower producers as can be seen in the table.

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[35] The GWP compares the radiative forcing of the various GHGs relative to CO_2 over a given time period (Cole et al., 1996). The 100-year GWP for CO_2 equals 1. Higher values for CH_4 (21) and N_2O (310) reflect a greater heat trapping ability (see Schneider and McCarl, 2003).

Table 6.3 Bioelectricity Production over Time under Alternative Coal Prices (in Number of 100MW Plants)

Coal Price	2000	2005	2010	2015	2020	2025	2030	2035	2040	2045
Coal $43.19										
Wheat (Cofire 5%, 10% and 15%)	-	2	10	11	16	23	26	32	19	26
Coal $49.36										
Wheat (Cofire 5%, 10% and 15%)	2	8	4	19	26	39	41	47	51	63
Wheat (Cofire 20%)	1	1	14	1	2	2	3	3	4	5
Coal $61.70										
Wheat (Cofire 10% and 15%)	-	-	2	4	6	14	32	36	75	84
Wheat (Cofire 20%)	2	12	19	27	38	44	29	29	17	29
Barley (Cofire 10%)	-	-	-	-	-	-	-	-	4	5
Coal $67.87										
Wheat (Cofire 10% and 15%)	-	-	3	7	8	6	14	14	13	23
Wheat (Cofire 20%)	2	12	19	27	36	51	47	51	93	97
Barley (Cofire 10%)	-	-	-	-	-	-	-	-	4	5
Coal $74.04										
Wheat (Cofire 15%)	-	-	-	4	8	6	6	9	-	-
Wheat (Cofire 20%)	2	12	24	31	35	51	55	56	107	123
Barley (Cofire 10%)	-	-	-	-	-	-	-	1	-	-

Table 6.4 Bioelectricity Production over Time under Alternative Carbon Prices (in Number of 100MW Plants)

Carbon Price	2000	2005	2010	2015	2020	2025	2030	2035	2040	2045
CO2 $10										
Wheat (Cofire 5% and 10%)	-	-	4	-	-	1	1	2	2	3
CO2 $15										
Wheat (Cofire 5%, 10% and 15%)	3	6	13	12	20	33	35	38	43	54
Wheat (Cofire 20%)	-	-	1	1	2	2	3	3	4	5
CO2 $30										
Wheat (Cofire 10% and 15%)	-	-	3	7	10	6	13	14	48	53
Wheat (Cofire 20%)	10	12	19	27	32	51	47	51	42	70
Barley (Cofire 10%)	-	-	-	-	-	-	-	-	4	5
CO2 $40										
Wheat (Cofire 15%)	-	-	-	-	-	-	6	7	-	-
Wheat (Cofire 20%)	10	12	24	35	46	57	53	57	107	128
Barley (Cofire 15% and 20%)	-	-	-	-	-	-	1	-	1	-
CO2 $50										
Corn (Cofire 20%)	-	-	-	-	-	-	5	-	-	-
Wheat (Cofire 15%)	-	-	-	-	-	-	3	-	-	-
Wheat (Cofire 20%)	12	13	24	35	43	61	60	68	109	127
Wheat (Fire-alone100%)	1	4	5	7	9	11	14	17	-	-
Barley (Cofire 15% and 20%)	-	-	-	-	-	-	1	-	1	-
Rice (Cofire 20%)	-	-	-	-	-	-	1	-	-	-

Table 6.4 (Continued)

Carbon Price	2000	2005	2010	2015	2020	2025	2030	2035	2040	2045
CO_2 $100										
Corn (Cofire 20%)	-	-	-	-	2	2	5	6	-	-
Corn (Fire-alone100%)	-	-	-	-	-	-	-	64	156	203
Sorghum (Fire-alone100%)	-	-	-	-	-	-	-	-	4	-
Wheat (Cofire 20%)	-	-	3	5	6	10	10	13	29	18
Wheat (Fire-alone100%)	11	13	25	29	43	66	69	77	81	110
Barley (Cofire 20%)	-	-	-	-	-	1	1	5	-	1
Rice (Cofire 20%)	-	-	-	-	-	-	-	1	3	-

6.1.3 Scenarios for Changes in Higher Heating Values

Table 6.3 and Table 6.4 show that wheat residues dominate most of the bioelectricity production as coal and CO_2 prices increase. This is due to the fact that wheat residue has a HHV of 15.06 MMBtu per ton which is much higher than that of corn (9.23 MMBtu per ton) and other residues (see Table 4.2 for all HHVs). Changes in crop residue HHVs can have great impact on the results of bioelectricity production. In this section, bioelectricity production results are obtained from simulating FASOMGHG, by assuming that all crop residues have the same HHV of 15.06 MMBtu per ton. The base price of coal is assumed to be constant, while CO_2 prices of $0 to $100 per ton are used in the simulation. Results are reported in Table 6.5 which shows that when all crop residues are assumed to have the same HHV, corn residues could potentially contribute to bioelectricity generation in substantial amount as CO_2 price rises. When CO_2 price reaches above $40 per ton, corn residue electricity production could surpass wheat residue's in both fire-alone and cofiring options. Findings here suggest that crop residues with larger HHVs are more likely to have market potential in bioelectricity production than the residues with lower HHVs.

6.1.4 Scenarios for Improvement in Crop Yield

Increase in the equivalent price of CO_2 would certainly make biofuels more cost competitive and induce farmers to improve their biofuel crop yields through the adoption of new technologies. Improvement in crop yield could increase the availability of crop residues and hence bring down the residue price. This would give biopower producers more incentives to use crop residues for electricity generation. Using various levels of CO_2 prices, this section simulates the effect of improvement in crop yield on bioelectricity production. The base price of coal is assumed to be constant. Two levels of yield improvement are simulated: an annual yield increase of 0.3% and of 0.6% respectively. Results are described in Figure 6.1 below which suggests that improvement in crop yield alone would not be sufficient to boost bioelectricity production. The CO_2 price will be an important factor in helping to induce bioelectricity production.

Table 6.5 Bioelectricity Production over Time under Alternative Carbon Prices with the Assumption That All Crop Residues Have the Same HHV (in Number of 100MW Plants)

Carbon Price	2000	2005	2010	2015	2020	2025	2030	2035	2040	2045
CO_2 \$10										
Wheat (Cofire 5% and 10%)	-	-	4	-	-	1	1	2	2	3
CO_2 \$15										
Corn (Cofire 5%, 10% and 15%)	1	1	3	2	11	21	10	11	34	30
Wheat (Cofire 5%, 10% and 15%)	2	5	11	10	13	29	35	38	44	54
Wheat (Cofire 20%)	-	-	1	1	2	2	3	3	4	5
CO_2 \$30										
Corn (Cofire 15%)	-	-	-	-	-	-	-	2	-	-
Corn (Cofire 20%)	8	10	16	28	36	28	34	39	60	56
Wheat (Cofire 10% and 15%)	-	-	3	7	10	6	7	9	48	55
Wheat (Cofire 20%)	2	2	3	4	12	35	38	41	24	41
Barley (Cofire 10% and 15%)	-	-	-	-	-	-	-	-	4	5
Rice (Cofire 15%)	-	-	-	-	-	1	1	1	3	3
CO_2 \$40										
Corn (Cofire 20%)	8	10	22	37	36	53	35	40	63	57
Wheat (Cofire 15%)	-	-	-	-	-	-	6	-	-	-
Wheat (Cofire 20%)	2	2	7	12	27	19	39	48	86	106
Barley (Cofire 20%)	-	-	-	-	-	-	-	-	1	-
Rice (Cofire 20%)	-	-	1	1	1	1	1	1	3	3

Table 6.5 (Continued)

Carbon Price	2000	2005	2010	2015	2020	2025	2030	2035	2040	2045
CO2 $50										
Corn (Cofire 20%)	2	2	8	21	15	21	13	15	53	41
Corn (Fire-alone 100%)	40	40	82	92	141	162	224	241	242	272
Wheat (Cofire 15%)	-	-	-	-	-	-	6	-	-	-
Wheat (Cofire 20%)	4	3	7	11	19	24	21	30	77	89
Wheat (Fire-alone 100%)	1	4	5	7	9	11	14	17	4	6
Barley (Cofire 15% and 20%)	-	-	-	-	-	-	1	-	1	1
Rice (Cofire 20%)	-	-	1	1	1	1	1	1	4	4
CO2 $100										
Corn (Cofire 20%)	-	-	-	1	4	6	9	18	-	-
Corn (Fire-alone 100%)	52	53	82	117	151	189	230	249	357	347
Wheat (Cofire 20%)	-	-	3	4	8	10	10	15	37	36
Wheat (Fire-alone 100%)	10	10	12	16	34	46	53	59	69	80
Barley (Cofire 20%)	-	-	-	-	-	1	1	3	-	2
Rice (Cofire 20%)	-	-	-	1	1	1	1	1	4	-
Rice (Fire-alone 100%)	-	-	-	-	-	-	-	-	-	2

As indicated in the figure, even with yield improvement assumptions, the CO_2 price must increase to about $15 per ton to have biopower producers generate electricity from crop residues. From the figure, we may generally conclude that higher crop yields would result in higher level of bioelectricity production over time given that CO_2 prices are at a lower level, i.e. when CO_2 prices are below $50 per ton. Overall results indicate that improvement in crop yield may not be an important factor in inducing more bioelectricity production from crop residues.

6.1.5 Scenarios for Production Cost Reductions

Reduction in the costs of bio-feedstock production is one of the important factors that make bio-feedstock economically competitive. Cost reductions can be accomplished by developing new and efficient technologies of harvesting, processing, and storage and transport systems. By employing various levels of cost reduction assumptions (i.e., 5% to 50% decrease in production costs) and of CO_2 prices, this section simulates the impact of cost reductions on bioelectricity generation and answers the question of by how many percentage would decrease in residue production costs has to be achieved (with and without CO_2 prices) for bioelectricity to have market potential. Results are depicted in Figure 6.2 which suggests that without any CO_2 price consideration; residue production costs must be reduced by at least 50% for crop residues to have any role in biopower production in the future.

With the CO_2 price of $5 per ton, electricity generation from crop residues will have market potential if production costs are reduced by at least 25% (not reported for this case). But, when the CO_2 price reaches $10 per ton, Figure 6.2 indicates that cost reductions of 5% to 50% will induce bioelectricity production. The figure clearly suggests that a higher percentage of residue production cost reduction will induce power producers to generate more bioelectricity from crop residues. A high percentage of cost reduction may not be as important when the CO_2 price rises to a significantly high level ($100 per ton or more), since at that high level of CO_2 price, power producers may be willing to pay more to acquire crop residues for electricity generation. In any case,

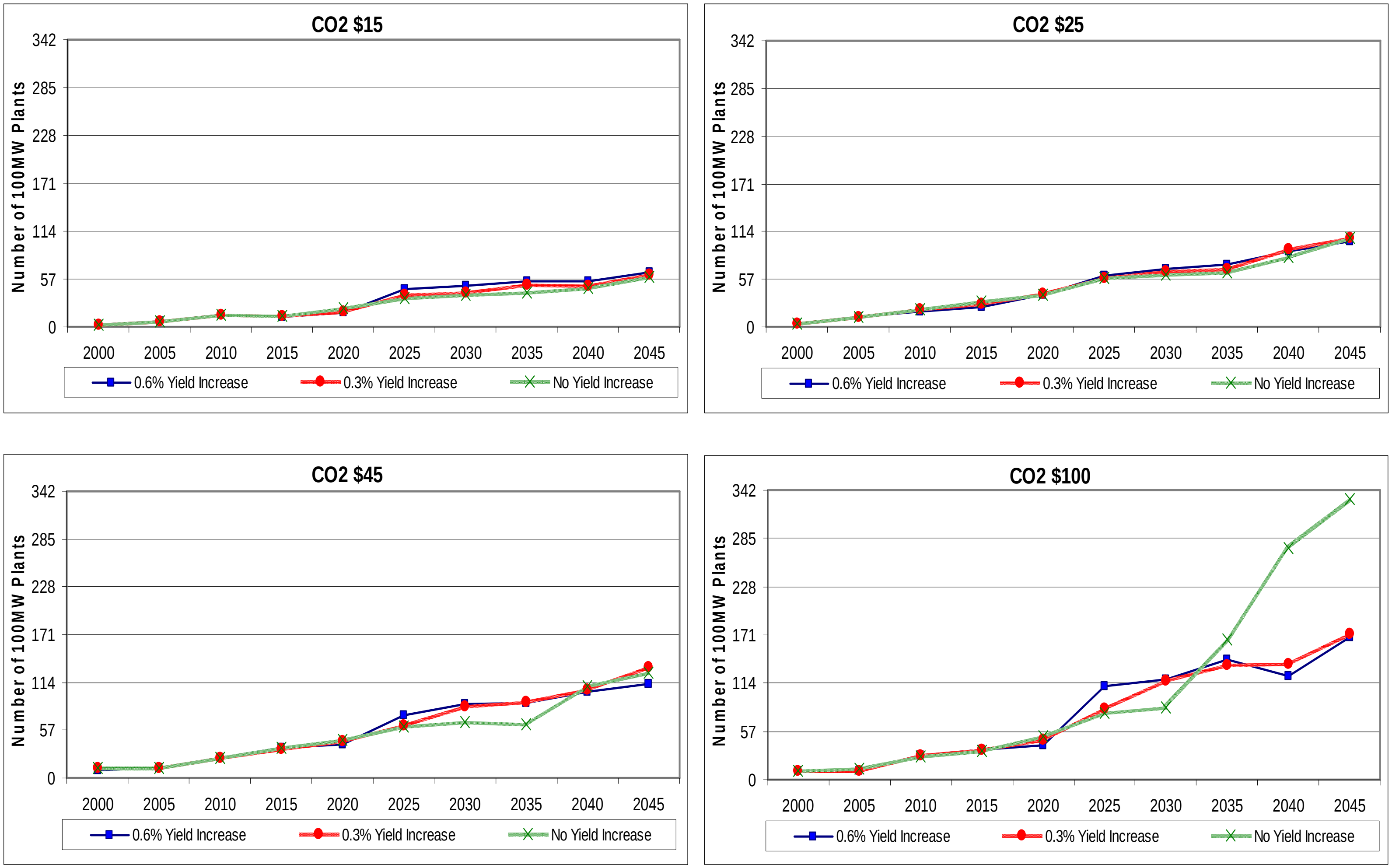


Figure 6.1 Total Bioelectricity Production (in Number of 100MW Plants) for Yield Improvement Scenarios

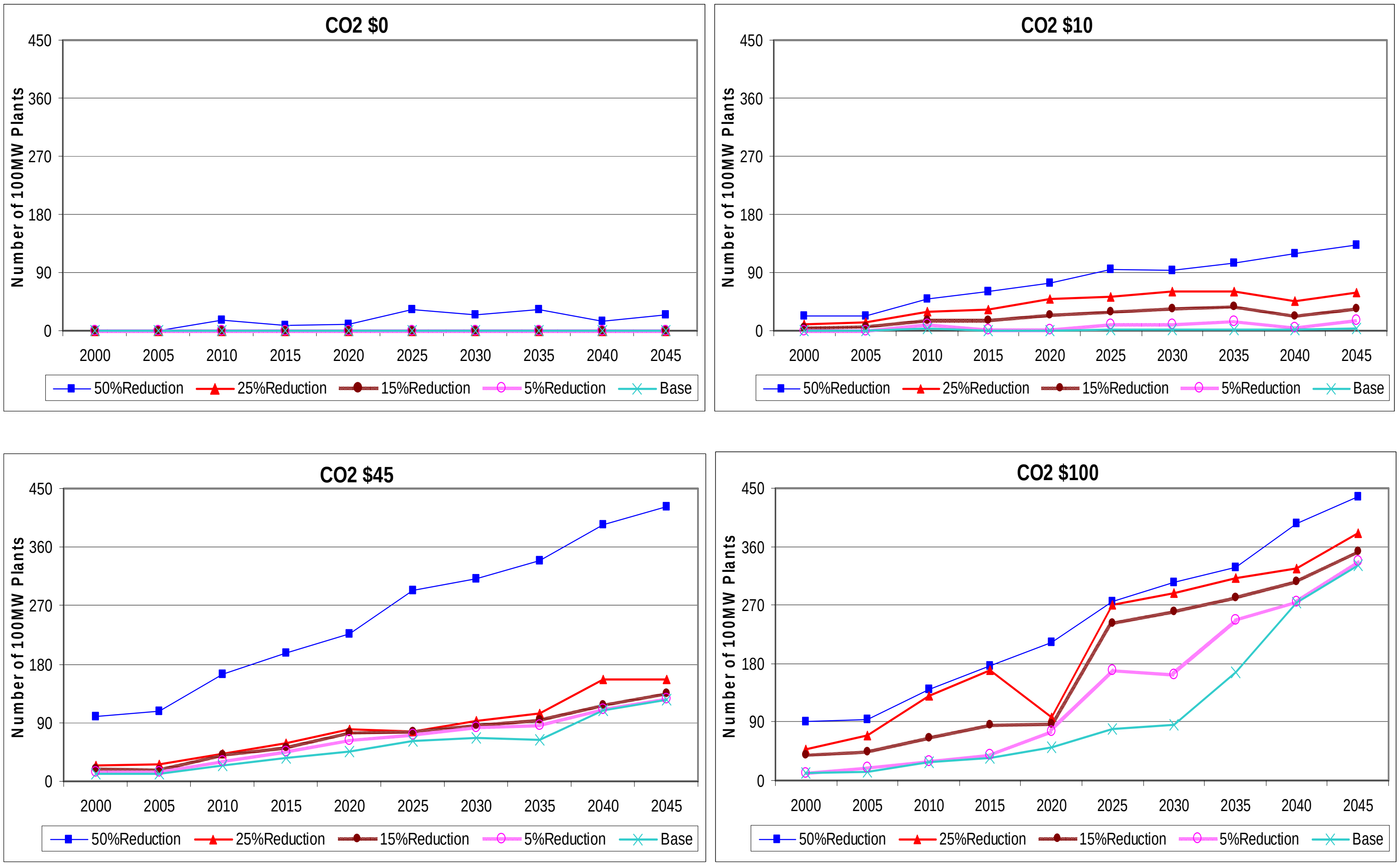


Figure 6.2 Total Bioelectricity Production (in Number of 100MW Plants) for Cost Reduction Scenarios

increase in CO_2 prices will be quite important for crop residues to have any future role for electricity generation, as cost reduction will be difficult to achieve without drastic technological improvements.

6.1.6 Scenarios for Improvement in Fuel Conversion Efficiency

This section simulates the effect of power plant's fuel conversion efficiency improvement on bioelectricity generation. Highly efficient power plants require less amount of Btu's fuel energy input to produce, say, a kilowatt hour (kWh) of electricity output. Increase in fuel conversion efficiency will reduce the cost of fuel input. It is assumed in the simulation that improvement in the fuel conversion efficiency of power plants can be attained at an annual rate of 1% per year. Simulated results are illustrated in Figure 6.3 which suggests that without any significant increase in CO_2 prices, improvement in the efficiency of fuel conversion alone may not be enough to induce potentially a higher level of bioelectricity production from crop residues. The figure shows that when the CO_2 price reaches at a substantially high level i.e., \$100 per ton or more, increase in the fuel conversion efficiency of power plants may be able to induce a higher level of bioelectricity production.

6.1.7 Market Penetration Limit Scenarios

In FASOMGHG, there is a maximum market penetration limit that constrains the amount of biofuel feedstock that can be used in generating electricity. The motivation for this constraint is that biofuel feedstocks can only be used in power generation if new (old) power plants are added (retrofitted) with biofuel generating capacities. The needs for these additional generating capacities will likely depend on the future demand growth for electricity. Based on the EIA's data on biomass energy consumption and forecasted values of electricity demand growth, market penetration limits are established in FASOMGHG for the 11 FASOM regions. This section looks at the impact of changes in the rate market penetration limits on bioelectricity production. Simulated results based on different levels of CO_2 prices are reported in Figure 6.4, where the rate of market penetration is assumed to change (i.e. increase/decrease) by 25% and 50% respectively.

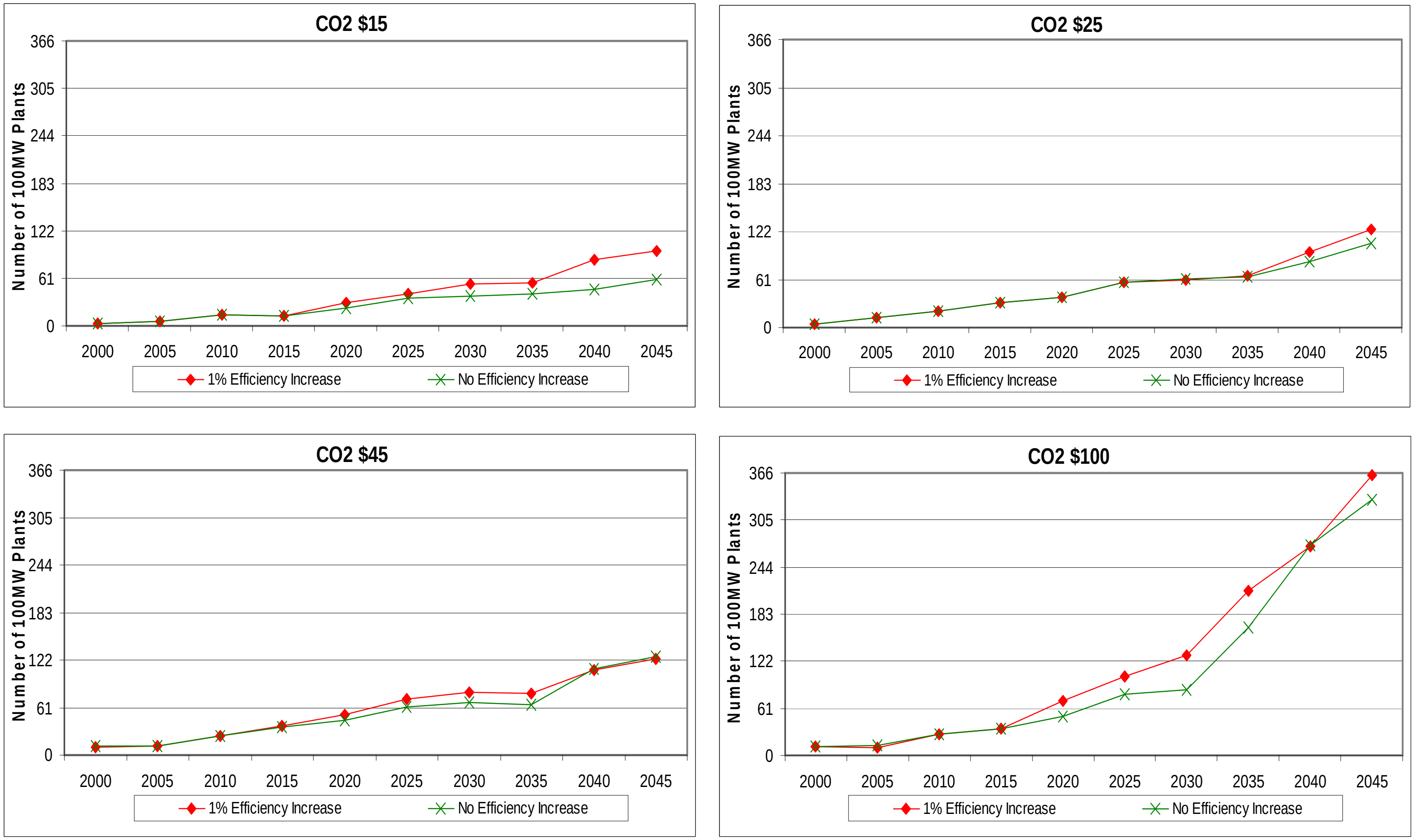


Figure 6.3 Total Bioelectricity Production (in Number of 100MW Plants) for Power Plant Fuel Efficiency Improvement Scenarios

At the national level, Figure 6.4 shows that changes in the assumptions of market penetration limits can bring big changes to the number of biopower plants that can penetrate the markets. If maximum market penetration limits are set at higher rates, the number of power plants that produce bioelectricity will certainly increase. The purpose of this section is to show that the results of bioelectricity production will be sensitive to changes in the assumptions of maximum market penetration limits in FASOMGHG. In any case, without any increase in CO_2 prices, market potentials for using crop residues in electricity generation are rather slim. Figure 6.4 shows that even with the assumptions of higher market penetration limit rates for bioelectricity production, CO_2 price has to be about $15 per ton for crop residues to have any chance in electricity production.

6.2 Impact on Consumer and Producer Welfare

Figure 6.5 illustrates the impact of increases in CO2 and coal prices on the welfare of U.S. consumers and producers36. The welfare is for agriculture only. The figure shows that as CO2 price increases, agricultural producers' welfare also increases, while consumers suffer from welfare losses. This is because agricultural producers can gain credits from carbon sequestration as CO2 price rises. Consumers' welfare declines due to the rise in agricultural commodity prices, the consequent of CO2 price increase. The rise in coal prices has similar impact on the welfare of agricultural producers and consumers as indicated in the figure. But, this impact is relatively small compared to the impact of CO2 price increase. Given different levels of CO2 prices, Figure 6.6 shows that consumers' welfare rises as crop yield increases. This is to be expected as increase in crop yield will bring down the price of agricultural commodities. On the other hand, agricultural producers do not gain from crop yield increase as shown in the figure. For agricultural crop residues, increases in HHVs, improvements in the efficiency of biopower generation and reductions in residue production costs bring little or no gains to the welfare of agricultural producers and consumers (not reported). This could suggest

[36] The consumer and producer welfare data in the figure are based on the average of annual consumer and producer welfare from 2000 to 2045.

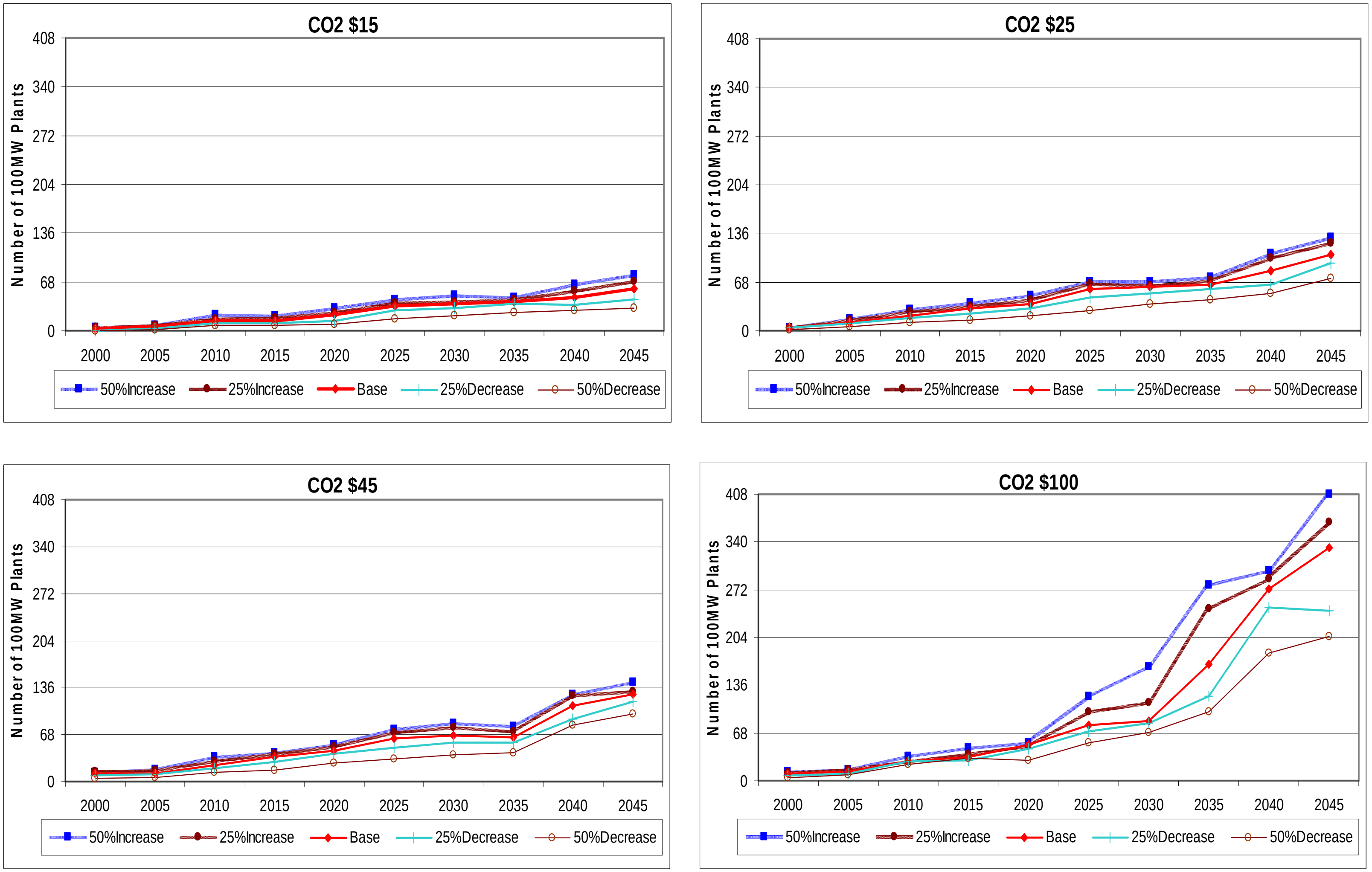
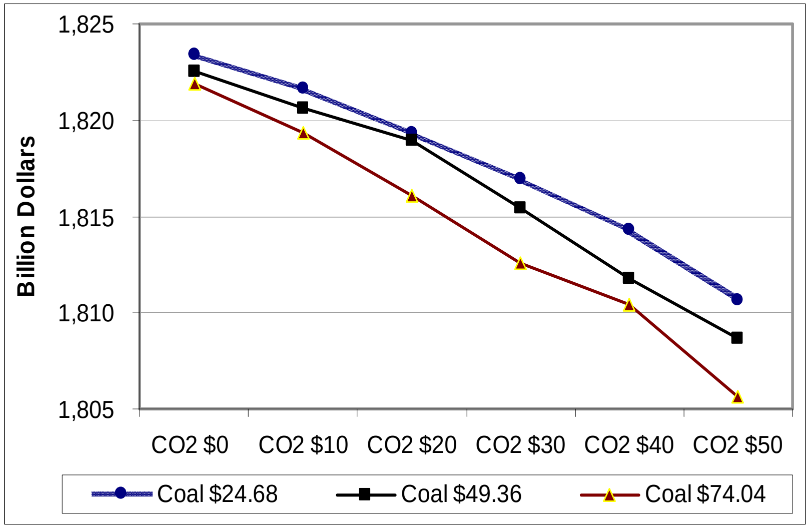
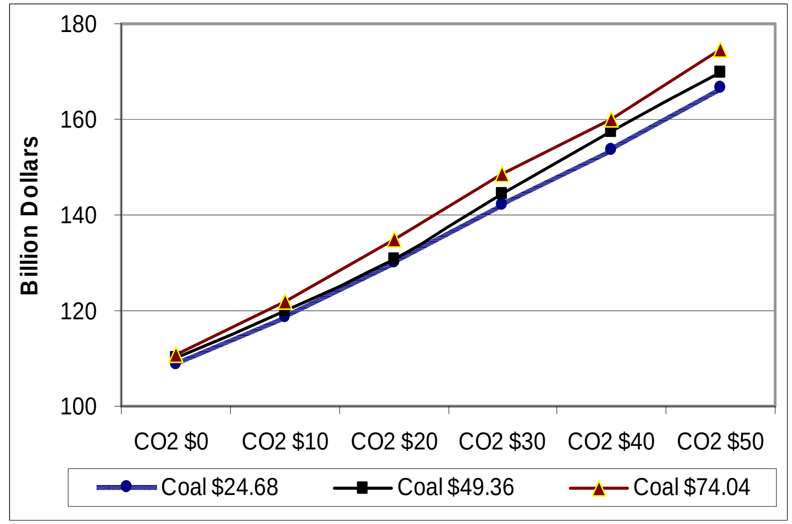


Figure 6.4 Total Bioelectricity Production (in Number of 100MW Plants) for Changes in the Rate of Market Penetration Limit Scenarios

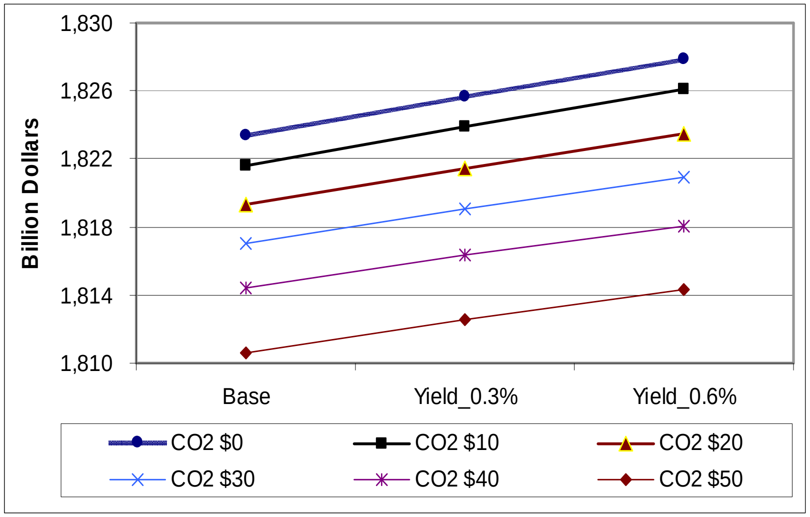


Consumer Welfare

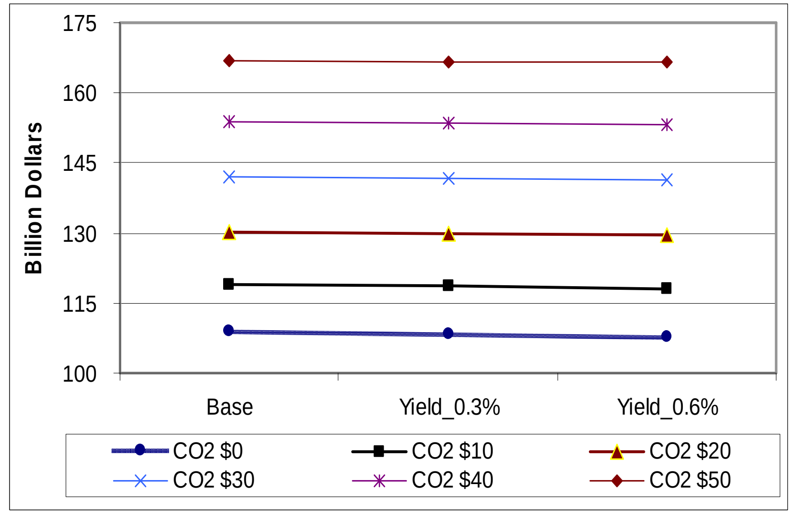


Producer welfare

Figure 6.5 Impact of Changes in Coal and Carbon Prices on Consumer and Producer Welfare



Consumer Welfare



Producer welfare

Figure 6.6 Impact of Changes in Yield Improvements on Consumer and Producer Welfare

that bioelectricity production from crop residues may not contribute much to the welfare of agricultural producers and consumers.

6.3 Results Summary and Conclusion

There are a number of factors which affect competitiveness of crop residues for power generation. The two most important factors are the higher heating values (HHVs) – the amount of recoverable energy and production costs. It has been shown that wheat residues with a HHV of 15.1 million Btu per ton cost much less to burn in power plants than corn residues with a lower HHV of 9.2 million Btu per ton. At a zero carbon price crop residues are not cost competitive with coal because coal has a larger HHV of about 20 million Btu per ton and consequently it will cost less for power producers to use coal than to use crop residues. High production costs are another factor that affects competitiveness of crop residues for power generation. Unlike coal, crop residues are limited in supply and critically in need of market development and improvement in production technologies and infrastructures. In order for crop residues to become cost competitive with coal, the results of this dissertation indicate that residue production costs have to be reduced by more than 50%. This will be a difficult task to achieve given the current market status of crop residues.

Integrating the social costs of GHG emissions into power production is a critical factor in making biopower economically competitive with coal and other fossil fuels. Social costs of GHG emissions are integrated in the Forest and Agricultural Sector Optimization Model—Green House Gas version (FASOMGHG) in the form of carbon dioxide (CO_2) equivalent prices. Using FASOMGHG, scenarios for bioelectricity production from crop residues are simulated and studied under alternative increases in coal and CO_2 equivalent prices, changes in HHVs, improvements in crop yield and fuel conversion efficiency rate, reductions in residue production costs and changes in the rate of market penetration limits.

Under alternative coal price scenarios, simulation results from FASOMGHG show that the coal price has to be well above $2 per million Btu or $40 per ton for wheat residues with cofiring options of 5%, 10% and 15% to have electricity production potential. Increase in coal prices induces more use of wheat residues as power producers switch to wheat residues with cofiring option of 20%. Corn, sorghum, barley, oats and rice residues do not have much potential in generating bioelectricity as coal price increases. Results also show that fire-alone option (100% firing with crop residues) is not feasible for any crop residues unless coal price surpasses well above \$3.7 per million Btu or \$74.04 per ton.

Because coal is abundantly available domestically in the U.S., scenarios for coal price increases do not appear to be realistic unless policy makers are willing to impose tax increase on coal production. As evidence of GHG emissions which cause global warming and climate change grows, global restrictions on GHG emissions have become tighter. Thus it appears that the external cost of carbon emissions (in the form of CO_2 equivalent prices in FASOMGHG) will likely rise in the near future. Under this price increase in the form of CO_2 equivalent prices, simulation results from FASOMGHG show that the price of CO_2 has to be about \$15 per ton for wheat residues with cofiring options to have potential in electricity generation. Similar to alternative coal price scenarios, higher CO_2 prices encourage more use of wheat residues as power producers switch from lower residue cofiring options to higher ones. Corn, sorghum, barley, oats and rice residues do not have potential in generating electricity when the CO_2 price is below \$50 per ton. But when it reaches \$100 per ton, corn and wheat residues with fire-alone options would become attractive to power generators. This is especially true for wheat residues, as at that level of carbon price wheat residues have become the main feedstock used in electricity generation.

It is interesting to see why corn residues, the most abundant residues in the U.S., do not account for much of the bioelectricity generation as the CO_2 equivalent price increases. This may be due to the fact that corn residues are assumed to have the lowest HHV among all crop residues in FASOMGHG. In contrast, wheat residues assumed to have the largest HHV in FASOMGHG are responsible for most of the bioelectricity generation as the CO_2 equivalent price increases. Results show that with the same level of HHV, corn residues will become competitive with wheat residues and contribute to bioelectricity production in tremendous amounts under higher CO_2 equivalent prices. Other residues such as sorghum, barley, oats and rice residues do not contribute much. These simulation results suggest that corn residues must have a larger HHV in order for them to become competitive with wheat residues in bioelectricity generation.

FASOMGHG simulation results in this section also show that improvements in crop yield and fuel conversion efficiency have positive impacts on bioelectricity production given that CO_2 equivalent price reaches at a certain level. The impact of reductions in residue production costs on bioelectricity generation is also tested in FASOMGHG. Results indicate that without any consideration of CO_2 equivalent price (i.e. when the CO_2 price is zero), residue production costs must be reduced by 50% for power producers to have incentives in using crop residues for bioelectricity generation. With the CO_2 price of $10 per ton, residue production cost reductions of 5% to 50% will induce bioelectricity production. When the CO_2 price reaches above $10 per ton, bioelectricity can be produced using crop residues without having to worry about reductions in residue production costs. Rising CO_2 prices together with falling residue production costs will undoubtedly bring bioelectricity production to a significantly high level. However, cost reductions may not be easy to achieve without significant developments in bio-feedstock markets. Hence, the future of bioelectricity production from crop residues will likely depend on the price of carbon emission reductions. Higher carbon prices will encourage more bioelectricity generation.

Another factor that can influence the level of bioelectricity production is the market penetration limits that constrain the amount of bio-feedstock used in electricity generation in FASOMGHG. The limits are set in the 11 FASOM regions based on the forecasted values of electricity demand and biomass consumption. As expected, FASOMGHG simulation results show that the higher the rate of market penetration limits is, the higher the production level of bioelectricity. Changes in the assumption of market penetration limits will certainly change the level of bioelectricity production. However, the overall outcome will not be affected. For instance, regardless of what assumption is made about market penetration limits, the CO_2 equivalent price still needs to reach about $15 per ton for bioelectricity to have market potential.

Based on all the FASOMGHG simulation results under various alternative scenarios as described above, the following conclusions can be made about crop residue bioelectricity production.

- Due to their low heat content and high transaction costs, crop residues cost much higher than coal to be used in electricity generation. For crop residues to become competitive with coal, their costs of production must be cut by more than half.
- Without future increase in coal or greenhouse gas emission prices, crop residues will not have any role in bioelectricity production.
- For crop residues to have future roles in bioelectricity production in the form of cofirings, either the price of coal has to increase to well above $2 per million Btu or the price of carbon must rise to about $15 per ton. The scenarios for power plants with crop residue fire-alone options will unlikely happen, unless either the coal price or the price of carbon or both rise to a significantly high level.
- Given that carbon equivalent price rises to a certain level, crop residues with higher heat content will have more potential in producing bioelectricity.
- If no external cost of carbon emissions is to be imposed in the future, then residue production costs must be reduced by about 50% to induce bioelectricity production from crop residues with cofiring options.
- Because delivered costs of crop residues are lower with cofiring options than with fire-alone option, and the share of bioelectricity production from cofiring crop residues with coal increases as external cost rises, the findings suggest that it is extremely likely that the future of bioelectricity markets will be developed from experiences with cofiring power generation technologies.

7. CONCLUSION

Today, increases in crude oil prices, interests in national energy security matters and concerns for climate change and global warming are main factors that drive the interests of using biofuels for energy production. In the case of biofuels for electricity generation, increases in fuel oil prices and concerns for energy security in the U.S. may not matter much in inducing electric producers to use biofuels. This is because fuel oil accounts for only 3% of the U.S. electricity generation and most of the required fuels used to generate electricity are available within the country. Also due to the possibility of inter-fuel substitutions among various fuel sources in electric sectors, any increases in oil and natural gas prices will induce power producers to switch other fuel sources especially coal which is abundantly available. Hence, we would argue that the only relevant explanation that stimulates the interests of using biofuels for power generation is concerns for climate change and global warming.

Climate change and global warming could pose serious environmental threats facing the world today. In the U.S. and other nations, the combustion of fossil fuels is considered to be the largest contributing factor to the atmospheric release of greenhouse gases, which the Intergovernmental Panel on Climate Change (IPCC) proclaimed was the main cause of climate change and global warming. Power plants are among the biggest sources of greenhouse gas emissions in the U.S. Currently, the electric power sector emits about 38 percent of the total U.S. CO_2 emissions from all sources. The problems that we are interested in exploring in this dissertation are: How do we create economic incentives to motivate power producers to use biofuels which can offset/mitigate greenhouse gas emissions? What are the existing economic barriers that prevent power producers from using biofuels? What would the future role of bioelectricity production be with the considerations of external cost of greenhouse gas or carbon emissions?

To answer above questions, this dissertation serves three purposes: 1) to examine the economics of biofuels for power generation through the use of literature and economic theory, 2) to determine the role of bioelectricity production by analyzing the influence of a number of factors, and 3) to simulate future market conditions of bioelectricity production under various alternative scenarios, using crop residues as a case study. FASOMGHG is employed for the purpose of simulation and analysis of crop residues for bioelectricity generation.

By reviewing the literature on various aspects of biofuels and by investigating the economics of biofuel production, this study found that biofuels used for electricity production have to overcome various technological and institutional barriers in order for them to become competitive with fossil fuels especially coal. This suggests that incentives need to be created to reduce high transaction costs incurred by these barriers. Because biopower industries provide public goods, their economic profitability will depend on supports from governmental institutions. Thus, the incentives created to reduce high transaction costs must come from the government's ability to support biofuel and biopower industries through farm subsidy and various other policy measures which include restrictions to mitigate greenhouse gas emissions.

This dissertation also shows that for biomass-fired power plants to become economically competitive with fossil-fired power plants three things must happen simultaneously 1) the operating efficiency in terms of heat revered from feedstocks must be enhanced; 2) their construction capital costs must be reduced and 3) the supply of biomass fuels must be assured. So long as these three conditions cannot be satisfied, biomass-fired power plants will likely have little success in competing against fossil-fired power plants. Due to their higher operating efficiency, lower construction lead times and capital costs, and the security of fuel supply, natural-gas-fired power plants have increased tremendously over the past decade in terms of both the number and the capacity. However, recently the price of natural gas has been increasing along with the price of oil. If history repeats itself, potential fuel switching from natural gas to coal will likely occur as coal has been historically seen as an attractive option because of its low cost. In the past, the relationship between carbon emissions and global warming had been a contentious issue. But, today as growing evidence suggests that increasing carbon emissions in our atmosphere cause global warming, tremendous efforts are being made to restrict carbon emissions from power plants. Hence, the future of coal-fired power is still in question. Analyses from this dissertation suggest that there are two main factors which will influence the market penetration of biofuels for power generation: the price of coal and the future price of carbon emissions.

This dissertation employs FASOMGHG to explore the future market conditions of bioelectricity production under various scenarios. Among different kinds of biomass fuels, crop residues are chosen as a case study. Simulation results from FASOMGHG suggest that it will cost much more for power producers to use crop residues than to use coal for power generation because crop residues have lower heat content and higher production costs than coal. Results also suggest that those crop residues with higher heat content such as wheat residues will have greater opportunities in bioelectricity production than the residues with lower heat content. These results may not only apply to crop residues, but also to other biomass fuels. In addition, results indicate that crop residues will have a role to play in generating electricity only if the price of coal or the future price of carbon emissions rises. In order for crop residues to have any role in cofiring, either the price of coal has to increase to above $2 per million Btu ($40 per ton) or the price of carbon must rise to about $15 per ton. Building a stand-alone crop-residue-fired power plant will not be feasible unless either the price of coal rises to above $3.7 per million Btu ($74.04 per ton) or the price of carbon increases to above $50 per ton.

Overall results suggest that the feasibility of using crop residues for power production will depend on the increase in the future price of carbon emissions. Any future developments in biomass fuel and bioelectricity markets will likely come from experiences in cofiring power generation industries, since this dissertation shows that it is cheaper for power producers to cofire biomass fuels such as crop residues with coal than to fire them alone in power plants. In terms of policy implications, imposing carbon emission restrictions will be a very important step in inducing electric power producers to use biomass fuels in their fuel mix portfolios. This could be the best way to foster the development of biofuel markets.

The findings herein are influenced by a number of assumptions that could be improved. Namely as the assumed harvesting, processing and storage costs and market penetration constraints could be improved and refined by further research. Moreover, costs of electricity generation from natural gas and nuclear power plants, and costs of underground carbon storage should be considered in future analyses.

The future of bioelectricity production will undoubtedly tie to the future of carbon emission restrictions and to the developments in the least carbon-intensive power generation technologies.

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APPENDIX I

DESCRIPTION OF DATA FOR ELECTRICITY DEMAND MODEL

a) Electricity Consumption

For the period of 1932 to 1948, electricity consumption data are obtained from various issues (1935-1950) of Statistical Abstract of the United States (available at http://www.census.gov/compendia/statab/ past_years.html). The rest of the data from 1949 to 2005are collected from EIA's Annual Energy Review Database (http://www.eia. doe.gov/emeu/aer/txt/stb0809.xls).

b) Electricity Retail Price and Number of Consumers

Annual average electricity retail price data are calculated by dividing annual electricity utility revenue (in billion dollars) by annual retail sales (in billion kilowatt hours). Both the revenue and sale data are obtained from various issues (1935-2007) of Statistical Abstract of the United States (available at http://www.census.gov/compendia/statab/ past_years.html). Data for the number of electricity consumers which include residential, commercial and industrial consumers are also collected from the various issues of Statistical Abstract of the United States.

c) GDP and CPI

Annual data for the nominal GDP (in billions of U.S. dollars) and CPI (in index 1982-1984=100) for all urban consumers all items are obtained from the web of Federal Reserve Bank of St. Louis (available at: http://research.stlouisfed.org/fred2). All nominal prices/GDP are converted to real prices/GDP by using CPI.

d) Natural Gas Price

Average natural gas wellhead price of marketed production is used in the estimation. The wellhead price data from 1932 to 2000 are obtained from Historical Natural Gas Annual 1930 through 2000 (available at: http://www.eia.doe.gov/oil_gas/natural_gas/ data_ publications/ historical_natural_gas_annual /hnga.html). The rest of the data from 2001 to 2005 are collected from EIA's Annual Energy Review Database (available at: http://www.eia. doe.gov/emeu/aer/natgas.html).

e) Crude Oil Price

For the period of 1932 to 1948, average crude oil price data are obtained from various issues (1935-1950) of Statistical Abstract of the United States. The rest of the data from 1949 to 2005are gathered from EIA's Annual Energy Review Database (available at: http://www.eia.doe.gov/emeu/aer/ petro.html).

f) Efficiency Rate

The efficiency rate of fossil power plants is computed by dividing heat content of electricity (3412 Btu per kilowatt-hour) by annual average heat rate (in Btu per Kilowatt-hour) of fossil power plants. The average heat rate is in turn calculated by dividing annual total consumption of fossil fuels (in million Btu) by annual total electricity net generation (in million kilowatt-hours). All the required data for the period of 1932 to 1948 are obtained from various issues (1935-1950) of Statistical Abstract of the United States. The rest are collected from EIA's Annual Energy Review Database (available at: http://www. eia.doe.gov/emeu/aer).

APPENDIX II

AVERAGE HAULING DISTANCE AND COST TABLES

Average Hauling Distance for Sorghum Residues (in miles)

Region	Cofire5%	Cofire10%	Cofire15%	Cofire20%	Fire100%
NE	39.01	54.68	67.57	78.72	233.15
LS	-	-	-	-	-
CB	43.41	60.84	75.18	87.58	259.40
GP	10.63	14.90	18.41	21.45	63.53
SE	104.84	146.94	181.59	211.55	626.55
SC	51.94	72.79	89.96	104.80	310.39
SW	26.19	36.70	45.36	52.84	156.49
RM	112.79	158.07	195.35	227.58	674.03
PSW	77.90	109.19	134.94	157.19	465.57
PNWE	-	-	-	-	-

Note: For definitions of regions, see Table 4.3.

Average Hauling Distance for Barley Residues (in miles)

Region	Cofire5%	Cofire10%	Cofire15%	Cofire20%	Fire100%
NE	22.46	31.48	38.90	45.32	134.22
LS	115.07	161.27	199.30	232.18	687.66
CB	-	-	-	-	-
GP	21.73	30.45	37.63	43.84	129.84
SE	105.12	147.32	182.07	212.10	628.18
SC	-	-	-	-	-
SW	-	-	-	-	-
RM	42.18	59.11	73.05	85.10	252.05
PSW	110.33	154.63	191.09	222.62	659.33
PNWE	64.04	89.75	110.92	129.21	382.69

Note: For definitions of regions, see Table 4.3.

Average Hauling Distance for Oats Residues (in miles)

Region	**Cofire5%**	**Cofire10%**	**Cofire15%**	**Cofire20%**	**Fire100%**
NE	29.90	41.91	51.79	60.34	178.70
LS	71.24	99.85	123.40	143.75	425.76
CB	80.79	113.24	139.94	163.03	482.84
GP	74.98	105.09	129.87	151.29	448.08
SE	175.22	245.58	303.49	353.56	-
SC	-	-	-	-	-
SW	185.63	260.17	321.52	374.56	-
RM	231.79	324.87	401.48	467.71	-
PSW	219.20	307.22	379.67	442.30	-
PNWE	423.67	593.79	733.82	854.87	-

Note: For definitions of regions, see Table 4.3.

Average Hauling Distance for Rice Residues (in miles)

Region	**Cofire5%**	**Cofire10%**	**Cofire15%**	**Cofire20%**	**Fire100%**
NE	-	-	-	-	-
LS	-	-	-	-	-
CB	196.66	275.62	340.62	396.81	1,175.25
GP	-	-	-	-	-
SE	-	-	-	-	-
SC	26.13	36.62	45.25	52.72	156.14
SW	54.62	76.55	94.60	110.20	326.40
RM	-	-	-	-	-
PSW	101.72	142.57	176.19	205.26	607.92
PNWE	-	-	-	-	-

Note: For definitions of regions, see Table 4.3.

Average Hauling Cost for Sorghum Residues (in dollars/ton)

Region	Cofire5%	Cofire10%	Cofire15%	Cofire20%	Fire100%
NE	13.08	16.53	19.37	21.82	55.79
LS	-	-	-	-	-
CB	14.05	17.88	21.04	23.77	61.57
GP	6.84	7.78	8.55	9.22	18.48
SE	27.57	36.83	44.45	51.04	142.34
SC	15.93	20.51	24.29	27.56	72.79
SW	10.26	12.57	14.48	16.12	38.93
RM	29.31	39.28	47.48	54.57	152.79
PSW	21.64	28.52	34.19	39.08	106.93
PNWE	-	-	-	-	-

Note: For definitions of regions, see Table 4.3.

Average Hauling Cost for Barley Residues (in dollars/ton)

Region	Cofire5%	Cofire10%	Cofire15%	Cofire20%	Fire100%
NE	9.44	11.42	13.06	14.47	34.03
LS	29.81	39.98	48.35	55.58	155.79
CB	-	-	-	-	-
GP	9.28	11.20	12.78	14.14	33.07
SE	27.63	36.91	44.55	51.16	142.70
SC	-	-	-	-	-
SW	-	-	-	-	-
RM	13.78	17.50	20.57	23.22	59.95
PSW	28.77	38.52	46.54	53.48	149.55
PNWE	18.59	24.24	28.90	32.93	88.69

Note: For definitions of regions, see Table 4.3.

Average Hauling Cost for Oats Residues (in dollars/ton)

Region	Cofire5%	Cofire10%	Cofire15%	Cofire20%	Fire100%
NE	11.08	13.72	15.89	17.77	43.81
LS	20.17	26.47	31.65	36.13	98.17
CB	22.27	29.41	35.29	40.37	110.73
GP	21.00	27.62	33.07	37.78	103.08
SE	43.05	58.53	71.27	82.28	-
SC	-	-	-	-	-
SW	45.34	61.74	75.23	86.90	-
RM	55.49	75.97	92.83	107.40	-
PSW	52.72	72.09	88.03	101.81	-
PNWE	97.71	135.13	165.94	192.57	-

Note: For definitions of regions, see Table 4.3.

Average Hauling Cost for Rice Residues (in dollars/ton)

Region	Cofire5%	Cofire10%	Cofire15%	Cofire20%	Fire100%
NE	-	-	-	-	-
LS	-	-	-	-	-
CB	47.76	65.14	79.44	91.80	263.05
GP	-	-	-	-	-
SE	-	-	-	-	-
SC	10.25	12.56	14.46	16.10	38.85
SW	16.52	21.34	25.31	28.75	76.31
RM	-	-	-	-	-
PSW	26.88	35.87	43.26	49.66	138.24
PNWE	-	-	-	-	-

Note: For definitions of regions, see Table 4.3.

Average Delivered Cost Estimates for Sorghum Residues (in dollars/ton)

Region	**Cofire5%**	**Cofire10%**	**Cofire15%**	**Cofire20%**	**Fire100%**
NE	52.53	55.97	58.81	61.26	95.24
LS	-	-	-	-	-
CB	53.50	57.33	60.49	63.21	101.01
GP	46.28	47.22	48.00	48.66	57.92
SE	67.01	76.27	83.90	90.49	181.79
SC	55.37	59.96	63.74	67.00	112.23
SW	49.71	52.02	53.92	55.57	78.37
RM	68.76	78.72	86.92	94.01	192.23
PSW	61.08	67.97	73.63	78.53	146.37
PNWE	-	-	-	-	-

Note: For definitions of regions, see Table 4.3.

Average Delivered Cost Estimates for Barley Residues (in dollars/ton)

Region	**Cofire5%**	**Cofire10%**	**Cofire15%**	**Cofire20%**	**Fire100%**
NE	43.40	45.38	47.02	48.43	67.99
LS	63.77	73.94	82.31	89.54	189.74
CB	-	-	-	-	-
GP	43.24	45.16	46.74	48.10	67.02
SE	61.58	70.87	78.51	85.12	176.66
SC	-	-	-	-	-
SW	-	-	-	-	-
RM	47.74	51.46	54.53	57.18	93.91
PSW	62.73	72.48	80.50	87.43	183.51
PNWE	52.55	58.20	62.86	66.89	122.65

Note: For definitions of regions, see Table 4.3.

Average Delivered Cost Estimates for Oats Residues (in dollars/ton)

Region	**Cofire5%**	**Cofire10%**	**Cofire15%**	**Cofire20%**	**Fire100%**
NE	45.04	47.68	49.85	51.73	77.77
LS	54.13	60.43	65.61	70.08	132.13
CB	56.23	63.37	69.25	74.32	144.68
GP	54.95	61.58	67.03	71.74	137.04
SE	77.01	92.49	105.23	116.24	-
SC	-	-	-	-	-
SW	79.30	95.70	109.19	120.86	-
RM	89.45	109.93	126.78	141.35	-
PSW	86.68	106.05	121.99	135.76	-
PNWE	131.67	169.09	199.90	226.53	-

Note: For definitions of regions, see Table 4.3.

Average Delivered Cost Estimates for Rice Residues (in dollars/ton)

Region	**Cofire5%**	**Cofire10%**	**Cofire15%**	**Cofire20%**	**Fire100%**
NE	-	-	-	-	-
LS	-	-	-	-	-
CB	88.99	106.37	120.67	133.03	304.28
GP	-	-	-	-	-
SE	-	-	-	-	-
SC	51.48	53.79	55.69	57.33	80.08
SW	57.75	62.57	66.54	69.98	117.54
RM	-	-	-	-	-
PSW	68.11	77.10	84.49	90.89	179.47
PNWE	-	-	-	-	-

Note: For definitions of regions, see Table 4.3.

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