4.0 ECONOMIC EVALUATION

The objectives of this activity were to determine cost and market penetration, selection of incentives, and regional economic impacts of coal-based fuel technologies. In addition, DOD's fuel mix was determined and a national energy portfolio constructed that minimizes energy price shock effects. Each of these activities is discussed in detail in the following sections.

4.1 Cost and Market Penetration of Coal-Based Fuel Technologies

4.1.1 Introduction

The United States is awash in coal and a plethora of technologies have been advanced to promote coal utilization as a means to avoid a dependence upon a foreign-controlled fuel source. The main problem is that, in many applications, coal-based fuels are simply not as easy and economical to use as oil-based fuels. The result is that the potential of these technologies has remained only a promise. Beginning in the 1970s, the prospect of greatly increased coal utilization seemed to be close to realization with expectations of oil prices rising to the margin of coal-based fuel technology viability. When oil prices did not achieve or maintain these levels, many technology development efforts refocused their attention on attaining economic viability through lowering costs. This task focuses upon those technologies that utilize coal-water mixtures (CWMs), with an emphasis upon micronized coal-water mixtures (MCWMs).

A motivation for developing boiler retrofit technologies stems from U.S. policy makers' desire to decrease dependence on foreign sources of energy. Dependence upon imported energy sources makes the U.S. vulnerable to an "oil price shock," such as that experienced from 1973 to 1974 and later during 1979 to 1980. Another motivation is to improve the international competitive position of the U.S. through developing technologies that utilize the country's coal resources at a cost lower than current domestic and imported energy supply sources.

A market penetration model was formulated that is based upon the optimal mix of a boiler retrofit technology adoption among a sample population of active boilers in the Pennsylvania counties of Cambria and Indiana. It was found that six of eighteen boilers are candidates for adopting the retrofit technology resulting in a total cost savings of $1.89 million annually. It was also found that the study region could likely be expanded to other adjacent counties since the actual mileage-dependent portion of the MCWM costs is small compared to all of the other costs.

An overview of boiler retrofit technology, background on the motivation for retrofitting, a brief survey of other technologies developed for utilization of CWMs, and factors affecting the economic feasibility of the technology has been presented in the Phase II Final Report (Miller et al., 2000). Reviews of oil price trends and the effects of divergent cost estimates on CWM economics are also presented in the Phase II Final Report (Miller et al., 2000). This information was instrumental in implementing the market penetration model presented here.

Section 4.1.2 defines and discusses the market penetration model approach and structure utilized in the study. The section begins with a review of the range of market penetration models available to provide the context and justification for selection of the nonlinear programming framework. The section concludes with a description of the model and its major components such as fuel production costs, transportation costs, retrofit costs, potential production sites, and the inventory of boilers that are retrofit candidates. Results and conclusions of the boiler retrofit market penetration model are presented in Section 4.1.3. The base case model results are presented followed by a sensitivity analysis of alternative siting and less than optimal number of boilers being retrofitted. Finally, conclusions are made regarding the impact of boiler retrofits in terms of increased coal sales to the industrial sector in Pennsylvania with extensions by analogy to the other coal-producing and industrial states of Ohio, Indiana, and Illinois.

4.1.2 Market Penetration Model Approach and Structure

Market penetration models have been ascribed to a wide set of methods directed toward predicting the likely future adoption or emplacement of products, services, or technologies within an economy (Bodington and Quinn, 1982). The models that have been developed and used in market penetration studies are tailored to fulfilling the objective of forecasting market share over time or estimating the potential, or equilibrium, market share. Models that forecast market share over time often must be explicitly defined with an estimate of the equilibrium market share toward which adoption proceeds. The types of models include:

- Diffusion models;
- Time series models;
- Econometric models;
- Historical analogy; and
- Optimization models.

A detailed description of these models can be found in Schaal (1995). The diffusion, time series, econometric, and historical analogy models rely upon first obtaining some estimate of the maximum market penetration of the technology. This crucial estimate of the maximum market share, or equilibrium optimal mix, then provides a 'force' toward which adoption would proceed. The method used in this study to predict market penetration of the retrofit technology is an optimization model solvable by nonlinear programming methods. The results derived from this model are then subjected to a sensitivity analysis to assess how the technology adoption fares when acceptance starts, or ends, at a level lower than the optimal level. The specific optimization model used is described in the next section.

4.1.2.1 Optimization Model

The type of market penetration model formulated in this study was based upon a partial equilibrium structure toward which the market share of the new technology (boiler retrofits) would trend. In this model, it is assumed that producers minimize their input costs to maximize profits. Within this context, those producers who own boilers seek to minimize their energy expenditures through minimizing their cost of steam production. The boiler retrofit technology represents an opportunity to further reduce costs by displacing fuel oil or natural gas with lower cost MCWM through the expenditure of a capital investment to allow use of the alternate fuel. Producers are assumed to adopt the boiler retrofit technology if the capital and variable costs of retrofitting are less than the current variable costs that would be displaced.

An illustration of a few of the relevant factors that would enter into a single boiler owner's decision to forgo or accept adoption of the boiler retrofit technology are shown in Figure 4.1.1. In this figure, the line that includes the segment **0B** represents the variable costs, mostly of the fuel being displaced that would be avoided if the boiler were retrofitted. However, if the boiler were retrofitted, fixed costs (line segment **0A**) and variable costs (line that includes segment **AB**) would be incurred. The slopes of **0A** and **0B** are composed primarily of the $/MM Btu price of MCWM and oil or gas respectively. Utilization is the ratio of actual boiler output, or load, to the maximum output that the boiler is capable of over a specified period of time, expressed as a percentage. In this analysis, utilization and costs are annualized.

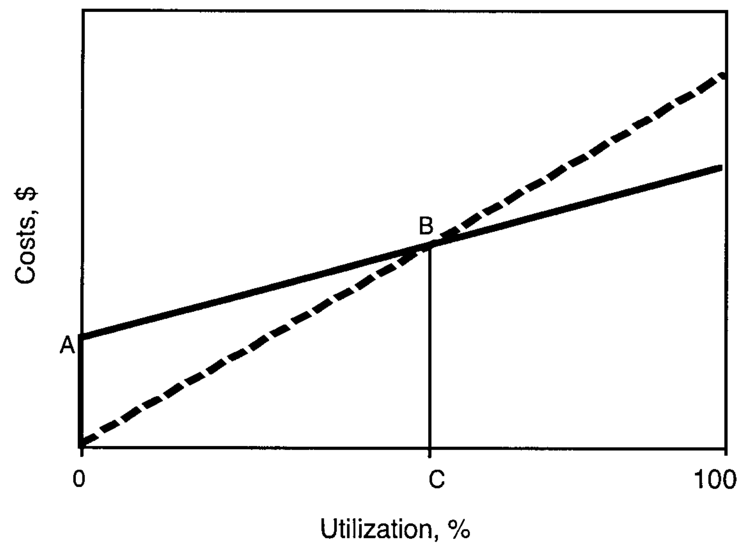

Figure 4.1.1 OPPORTUNITY COSTS OF RETROFITTING VERSUS BOILER UTILIZATION

If the combined fixed cost displacement and slope of retrofitting opportunity cost lines result in an intersection with the non-retrofit opportunity cost line, such as occurs at point **B** in Figure 4.1.1, then it is possible that the boiler owner's costs would be minimized by adopting the retrofit technology. The utilization at point **C** defines the breakeven point at which the boiler owner would be indifferent to adopting the retrofit technology on the basis of cost alone. If the boiler utilization is greater than **C** then the annualized costs of retrofitting are less than not retrofitting and the technology is adopted. If boiler utilization is less than **C** then the technology is not adopted.

Figure 4.1.1 is useful for demonstrating the decision rule of whether or not to adopt the technology on the basis of the single parameter of boiler utilization but it does not take into account other factors that enter into the model. For example, fixed costs consist primarily of the annualized capital charges necessary to retrofit the boiler. The magnitude of these retrofit costs vary non-linearly with the size of the boiler being considered. The slope of the retrofit cost line reflects the $/MM Btu per percent utilization for producing the MCWM and disposing of the ash products. The cost of MCWM is a variable since MCWM production is subject to economies of scale. Therefore, MCWM costs are dependent upon the total demands of all boiler owners in the region. This cost is further complicated by considering that multiple possible MCWM supply points occur throughout the region that could potentially supply the boilers that are dispersed geographically throughout the region. Supply points would therefore be chosen such to minimize both the costs of MCWM production and transportation.

The model considered here is a partial equilibrium analysis since it is assumed that there are no substitution effects on oil or natural gas prices due to their displacement by MCWM. Another assumption is that there would be no increase or decrease of the boiler utilization due to displacing the utilization of other types of boilers that may be in use at a site. A producer may own several different types of boilers at a single site and choose to operate the ones that provides the greatest competitive advantage at a particular point in time.

It was assumed that the specific costs that boiler owners consider when deciding whether or not to adopt the retrofit technology are:

- Total capital requirement (TCR) to effect the boiler retrofit;
- MCWM cost, f.o.b. mine (preparation plant location);
- Transportation costs for delivery of MCWM to the boiler;
- Incremental Operation & Maintenance (O&M) costs due to retrofitting; and
- Ash disposal costs.

4.1.2.2 Market Penetration Model Formulation

The model may be succinctly expressed as an optimization problem where the objective to minimize costs is subject to constraints that describe the interrelationship among variables and parameters. The model thus defined in a standardized form may then be solved using optimization software, such as GAMS (General Algebraic Modeling System), which utilizes standardized solution algorithms to determine the optimal objective function value (maximum or minimum) and the variable levels necessary to achieve this optimal state. The programming language chosen to compile the nonlinear programming model was GAMS release 2.5 (Brooke, et al., 1992).

An important constraint in the model is that each boiler owner annually demands a specific quantity of fuel to carry out his production process. The costs introduced in the previous section are dependent upon whether MCWM is selected for a particular boiler, the flows of fuel from each source to each boiler, and the aggregate demand for fuel at each source. The model is defined mathematically as:

$$\min z = \sum_{i=1}^{m}\sum_{j=1}^{n} FuelCost_{ij}x_{ij} + \sum_{i=1}^{m}\sum_{j=1}^{n} TCost_{ij}x_{ij} \tag{4.1.1}$$

Subject to:

$$\sum_{j=1}^{n} x_{ij} \le FS_i \qquad \text{for all } i \tag{4.1.2}$$

$$\sum_{i=1}^{m} x_{ij} = BQ_j \qquad \text{for all } j \tag{4.1.3}$$

$$PMCWSF_i = PMCWSF_i\left(K, \sum_{j=1}^{n} x_{ij}\right) \qquad \text{for all } i \text{ not oil or gas} \tag{4.1.4}$$

$$FuelCost_{ij} = PMCWSF_i + FuelFC_{ij} \qquad \text{for all } i \text{ and } j \tag{4.1.5}$$

Where:

z	= total annual fuel costs for all boilers in the region (objective), \$
i	= potential fuel supply points
j	= watertube boilers
$FuelCost_{ij}$	= total fuel cost from ith source to jth boiler less transportation cost, \$/MM Btu
x_{ij}	= annual flow of fuel from ith source to jth boiler, MM Btu
$TCost_{ij}$	= transportation cost from ith source to jth boiler, \$/MM Btu
FS_i	= total supply of fuel annually available at the ith source, MM Btu
BQ_j	= total fuel demanded by the jth boiler, MM Btu
$PMCWM_i$	= price of fuel at the ith source, \$/MM Btu
K	= MCWM cost curve constant
$FuelFC_{ij}$	= the annual fixed costs to supply the jth boiler from the ith source, \$/MM Btu

The objective function to be minimized, that of fuel costs to boiler owners, is defined by equation 4.1.1. The objective function is split into two parts in order to highlight the transportation cost framework that drives the selection of supply sites due to their geographical location relative to the boilers in the region. The variable $FuelCost_{ij}$ includes both fixed and variable costs on a \$/MM Btu measure. This is accomplished by assuming that boiler demands for fuel are the same during the year regardless of any other considerations.

The constraints are described in equations 4.1.2 through 4.1.5. The fuel supply constraint is defined in equation 4.1.2 which specifies that the total demand of all the boilers for fuel from a particular fuel source may not exceed the maximum amount available from that supply source. In keeping with the partial equilibrium structure of the model the fuel currently being fired by the boilers is set to an arbitrarily high level. Equation 4.1.3 specifies that the annual aggregate flow of fuel from each supply source to a particular boiler must equal that boiler's annual demand for fuel. Equation 4.1.4 specifies that the costs of producing MCWM at a particular supply source and is a function of a constant and the total demand for fuel from that particular supply source. Equation 4.1.5 provides an accounting of fuel costs.

A listing of the GAMS program that implements the market penetration model in detail is given in Appendix 4A.

4.1.2.3 Fuel Supply Costs

The production of fuels at each supply point is subject to economies of scale. It is assumed that MCWM production can recover coal fines from existing waste streams and prepare it for use by the retrofitted boilers. An overview of the MCWM production process is shown in Figure 4.1.2.

The cost model basis for MCWM fuel supply using this production arrangement has been estimated by Schaal and Gordon (1994). The MCWM Supply Cost Model is presented in Appendix 4B. Using the results from this work, the cost curve shown in Figure 4.1.3 was constructed.

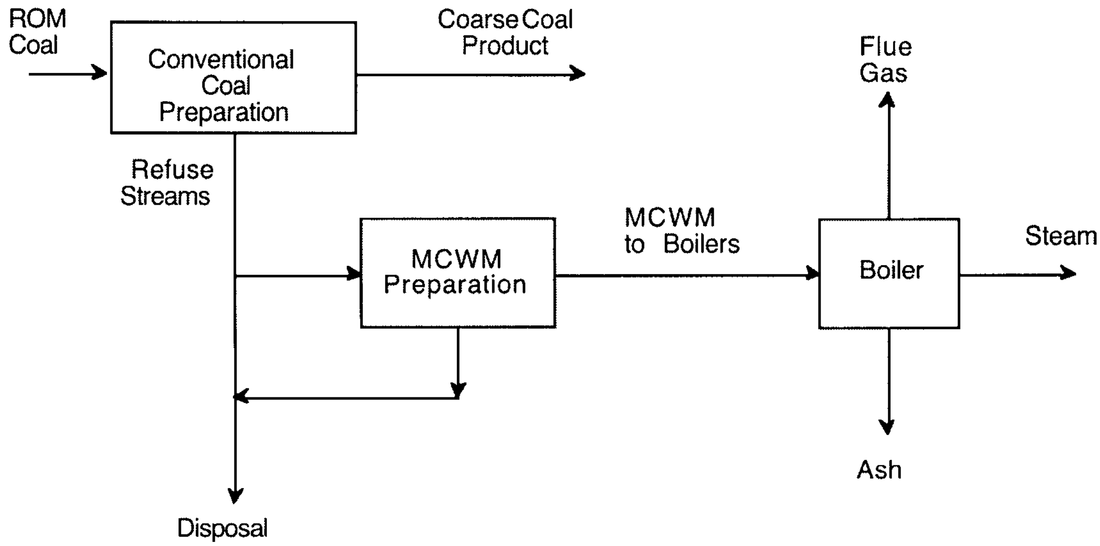

Figure 4.1.2 MCWM PRODUCTION AND UTILIZATION BLOCK FLOW DIAGRAM

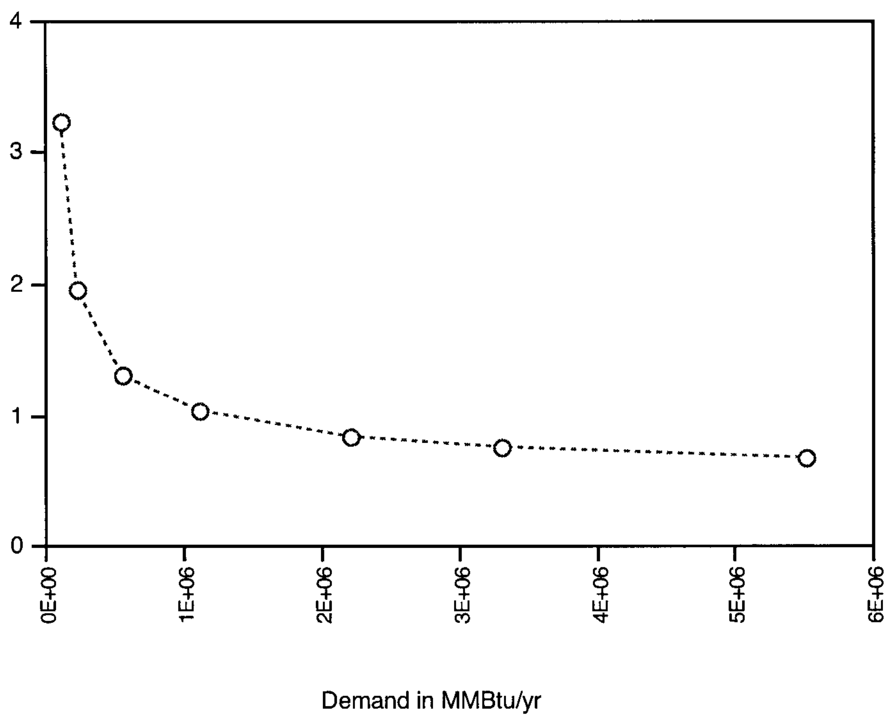

Figure 4.1.3 MCWM COST CURVE FOR A SINGLE SUPPLY POINT

A power function regression was estimated for the cost curve for Figure 4.1.3 with the resulting equation 4.1.6. Equation 4.1.6 is defined only for those supply points that are not oil or gas. The cost of supply for oil and gas was taken as the average fuel cost paid by the Pennsylvania industrial sector (Miller et al., 1994) or the actual fuel cost reported by the producer, if available.

$$PMCWSF_i = 0.6727 + 211561\left(\sum_{j=1}^{n} x_{ij}\right)^{-0.969} \quad \text{for all } i \text{ not oil or gas} \qquad (4.1.6)$$

4.1.2.4 Transportation Costs

The transportation costs for MCWM were determined through consultation with a local hauler of mine wastes using Department of Transportation (DOT) approved tank trucks (Punalla, 1994). The cost model derived from this conversation is given in equation 4.1.7.

$$T = \$0.168 \,/\, MMBtu + \$0.00373 \,/\, MMBtu \,/\, mile \qquad (4.1.7)$$

The fixed $/MM Btu cost is related to the fixed amount of time both the driver and tanker truck are required to spend to complete unloading of the fuel at the site. This fixed cost is included with the other fixed costs for operating the boiler with MCWM. The variable costs are expressed as $/MM Btu per mile. In the model, this variable cost is multiplied by the distance from the ith supply site to the jth boiler to obtain the transportation cost matrix.

4.1.2.5 Retrofit Technology Costs

The capital cost of the retrofit technology was estimated by EER for the Crane site's 25.2 MM Btu/h boiler (Miller et al., 2000). The standard method for scaling capital costs is to use the power factor method as shown in equation 4.1.8 (see Addy and Considine, 1994, for example). In this equation, C_2 is the desired cost at the new output level Q_2, and C_1 is the known cost at output level Q_1. The power factor, PF, reflects the economies of scale in construction which for boiler plants is usually taken as 0.75.

$$\frac{C_2}{C_1} = \left(\frac{Q_2}{Q_1}\right)^{PF} \qquad (4.1.8)$$

Anecdotal evidence exists that a portion of the cost estimate for converting the 25.2 MM Btu/h Crane boiler is not subject to scaling for boilers as large as 100 MM Btu/h (Miller et al., 2000). Given this information, a cost model was initially postulated that assumed that the 25.2 MM Btu/h capital cost to retrofit is subject to a graduated increasing percentage of costs subject to scaling. This approach yielded a linear cost curve. Refinements to this approach were made by incorporating more detailed information concerning how the individual cost components scale with increasing boiler size. This analysis is presented in Appendix 4C. Figure 4.1.4 shows the result of this work in estimating the total capital requirement (TCR) necessary to implement the boiler retrofit. The function that best describes this result is shown in equation 4.1.9. It can be observed from the TCR curve shown in the figure and equation, that the retrofit TCR increases at nearly a linear rate through much of the range of boiler sizes.

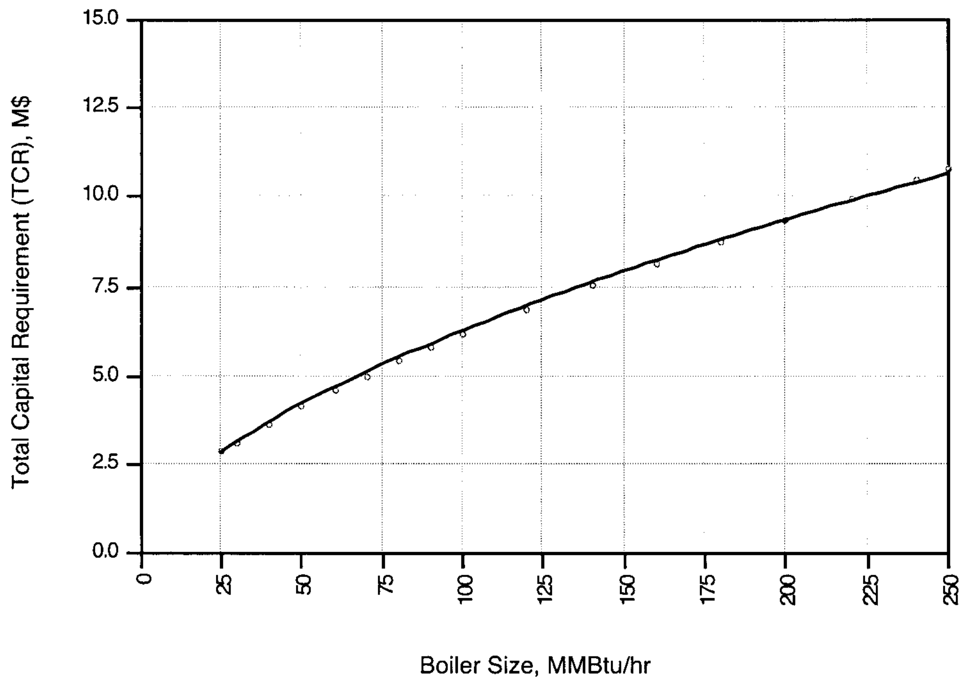

Figure 4.1.4 TOTAL CAPITAL REQUIREMENT VERSUS BOILER SIZE

$$TCR_j = 0.441 BoilerSize_j^{0.576} \qquad \text{for all } j \qquad (4.1.9)$$

Equation 4.1.9 provides the TCR needed retrofit each boiler in million dollars given the size of the boiler in MM Btu/h. This result is multiplied by the factor $73.582 per thousand dollars of TCR to provide an annualized capital cost given an interest rate of 4% amortized over 20 years. This annualized capital cost is then accounted for in the model by considering it as part of the fixed costs of operating a retrofitted boiler.

A consequence of investment in any new, or additional, technology is increased operating and maintenance (O&M) costs in excess of fuel costs. Standard cost estimation methodology calls for annually budgeting 4% of the initial capital investment to cover operating and maintenance costs that would occur over the life of a boiler. Two percent is a more likely factor in this case since: 1) retrofitting implies that a portion of the existing boiler plant will be removed, at some cost, resulting in reduced plant equipment requiring O&M expenditures; and 2) a large percentage of costs are attributable to civil and structural work, piping, tanks, etc., that are not particularly 'high tech' in nature.

4.1.2.6 Potential MCWM Supply Sites

A database of active Pennsylvania coal mines was compiled (Miller et al, 1994). His data is very useful in that it includes location, production levels, and coal quality. A review of Cambria and Indiana County coal mines showed that as many as eight could conceivably produce a MCWM of acceptable ash and sulfur levels. These mines and the pertinent data, are shown in Table 4.1.1. The data shown in this table can be used to help define the spatial distribution of potential MCWM supply sites relative to candidate boiler retrofits in the region.

4.1.2.7 Boiler Inventory

The chief problem with developing a market penetration model is that the population of boilers numbers is in the tens of thousands. Gathering and analyzing detailed information on this many boilers would be a formidable task. The approach taken then is narrowing the model space to include only those regions that have both a large industrial base and a significant coal industry already in place. The observation that the initial market for boiler retrofits is likely to be concentrated in a small area to allow economies of scale in fuel supply to be realized substantiates this approach.

Table 4.1.1 Cambria and Indiana County Premium Bituminous Coal Mines

Mine No.	Mine Name	Company	Lat. ° ' "	Long. ° ' "	Sulfur (%)	Ash (%)	Annual Output (tons)
1	Cambria Slope Mine No. 33	Beth Energy Mines Inc.	40 27 54	78 41 51	0.88	6.5	1,686,875
2	Greenwich 2-580 Portal	Div. of Pa. Mines	40 40 30	78 53 0	1.70	14.0	878,230
3	Greenwich 2-S. Portal	Div. of Pa. Mines	40 42 0	78 52 0	1.70	14.0	870,403
4	Westover Mine	K & J Coal Co., Inc.	40 41 45	78 38 30	1.00	7.0	258,030
5	Permit # 11803038	Cooney Bros. Coal Co.	40 14 50	78 45 31	1.40	12.5	188,760
6	No. 1 Portal	Tunnelton Mining	40 27 20	79 22 34	1.50	12.9	865,017
7	Tanoma Mine	Tanoma Mining Co.	40 46 0	79 2 45	0.85	6.5	485,980
8	Heshbon Mine	Florence Mining Co.	40 27 30	79 6 35	2.10	11.3	282,732

Source: Eduardo, 1994.

The states that best meet these conditions are Indiana, Illinois, Ohio, and Pennsylvania (Miller et al., 1994). These four states comprise the second tier, or rank, of states with large industrial sector total fuel use. The first tier states, consisting of Texas, Louisiana, and California, are of lesser interest, according to Gordon (see Miller et al., 1994), since the last two have no significant coal reserves and Texas' lignite deposits would be problematic for the boiler retrofit application. Among the second tier states, Pennsylvania has the advantage of being well known to the researchers. In addition, the sulfur content of Pennsylvania coal (and that in West Virginia that can be barged to many Pennsylvania customers) is generally lower, while the heating value is higher, than in the other three states.

4.1.2.8 Pennsylvania Inventory of Active Boilers

The effort to define the model space thus began by obtaining a current census database of industrial and commercial boilers located in Pennsylvania. The census was based upon data collected by the Pennsylvania Department of Labor & Industry (DL&I) and includes only those boilers that have been in active use within the past two years.

A review of the data revealed that the population of boilers in Pennsylvania is quite large, with a total of 66,262 boilers in active service throughout the state. The boiler database itself required about 13 megabytes (MB) of memory. The useable information on each boiler in the DL&I database included:

- Location;
- Equipment type;
- Manufacturer;
- Maximum allowable working pressure;
- Pennsylvania DL&I serial number; and
- National Board Number.

While the DL&I database represented the most authoritative source of information known regarding active boilers in the state, it lacked details such as fuel type(s), annual fuel consumption, size, utilization, and other data that were required to conduct a meaningful market penetration study. The approach, then, was to identify a concentration of possible boiler retrofit candidates located adjacent to, or co-located with, a concentration of useable coal reserves. The data provided by the DL&I were classified as to the particular type of boiler, or boilers, in use at each location. This allowed for a 'first-pass' sifting of the database to isolate a subset of boilers for further analysis that included only watertube boilers. A summary of the boiler census by boiler type is presented below in Table 4.1.2. The table shows that 6,936 boilers are of watertube design.

Table 4.1.2 Summary of Pennsylvania Boilers by Type

Boiler Type	Count	%
Cast Iron	30,760	46.4
Firetube	12,093	18.3
Watertube	6,936	10.5
Electric	4,228	6.4
Other	12,245	18.5
Total	66,262	100.0

The summary presented above should be treated with caution since the equipment type data field contained various non-standardized designations to denote the equipment type. Through a laborious process, the various indicators of boiler type were identified and standardized. In addition, the count includes boilers of all sizes and using all types of fuels.

4.1.2.9 Focus on Cambria and Indiana Counties

Two regions, corresponding to the Pittsburgh and Philadelphia metropolitan areas, encompass over 1,000 boilers each. The major drawbacks to retrofits in these areas are that the boilers in these areas would likely face greater physical space constraints and that the communities would likely provide a greater resistance to retrofit projects than elsewhere in the state. In addition, most of the bituminous coal is mined in the middle to western part of the state, with coal quality generally increasing towards the southwest.

The highest concentration of the remaining areas centers around the Cambria county region with a population of 311 boilers. A slightly larger study area was constructed by including the 151 boilers of Indiana county. The economy in this region historically has been dependent upon coal and has undergone a steady decline over the past two decades. Therefore, it is anticipated that the residents are more likely to accept, or even endorse, technologies that utilize coal-based fuels in an environmentally acceptable manner.

Another advantage of selecting the Cambria and Indiana counties areas is that the Pennsylvania Electric Company (Penelec) is currently engaged in a long-term test program to co-fire CWM with coal in a 32 MW (107 MM Btu/h) utility boiler. Battista (1994) reports some encouraging results from this project. The presence of a slurry preparation facility already configured to supply the coarser CWM for the utility boiler market should make it easier and more economical to supply MCWM for the industrial and commercial boiler market. Economies of scale would prevail and slurry demand would be leveled out by the utility markets' year round demand for fuel.

After narrowing the population of boilers down to the Cambria and Indiana county region the next step was to contact each of the boiler owners and operators to obtain data regarding the size and average utilization of the boilers. During the early stages of this portion of the data collection effort, it became apparent that most of the 462 boilers in the region were too small to be retrofitted. Part of the reason is the economies of scale considerations for the retrofit TCR as described above in Section 4.1.2.5. The number of boilers was reduced to fewer than 35.

The result of canvassing the boilers in the Cambria and Indiana region yielded the 18 candidates for retrofitting as shown in Table 4.1.3. This table includes only those watertube boilers of sufficient size that are not already using coal as a fuel. Most of the boilers shown in this table had the capability of firing either natural gas or No. 2 fuel oil but all were currently using natural gas due to cost advantages. Details as to the size and operating characteristics of these 18 boilers are shown in Table 4.1.4.

The distances between the mines identified in Table 4.1.1 and the boilers identified in this section were determined. This final piece of data for the model is presented in Table 4.1.5. The table shows the driving distances in miles between each mine and the four cities in which the eighteen boilers are located. The program shown in Appendix 4A takes the mileage, as shown in Table 4.1.5, and constructs the distance matrix between each mine and boiler. This result is then multiplied by the mileage dependent portion of the transportation cost Equation 4.1.7 to obtain the costs to deliver MCWM from each mine to each boiler.

Table 4.1.3 Candidate Retrofit Boilers - Location and AWP

Boiler No.	City	Zip	AWP[a] psig	Year Built
1	Indiana	15701	300	UNK[b]
2	Johnstown	15901	350	1982
3	Johnstown	15901	350	1982
4	Johnstown	15901	350	1982
5	Johnstown	15901	350	1983
6	Indiana	15701	300	UNK
7	Johnstown	15901	270	1966
8	Johnstown	15901	270	1966
9	Johnstown	15905	250	1954
10	Johnstown	15905	250	1955
11	Cresson	16330	250	1971
12	Cresson	16330	250	1971
13	Cresson	16630	250	1971
14	Johnstown	15901	200	1957
15	Johnstown	15901	200	1957
16	Johnstown	15901	200	1957
17	Johnstown	15902	200	1953
18	Ebensburg	15931	200	1990

[a] "AWP" is maximum allowable working pressure.
[b] "UNK" indicates that the year boiler was built is unkown.

Table 4.1.4 Candidate Retrofit Boilers Operating Characteristics

Boiler No.	Size MM Btu/h	Avg. Annual Utilization	Fuel Cost $/MM Btu	Annual Fuel Cost
1	68.0	60%	3.62	$ 1,294,703
2	50.4	53%	3.62	$ 840,078
3	50.4	53%	3.62	$ 840,078
4	50.4	53%	3.62	$ 840,078
5	50.4	53%	3.62	$ 840,078
6	68.0	60%	3.62	$ 1,294,703
7	19.4	50%	3.62	$ 307,029
8	19.4	50%	3.62	$ 307,029
9	11.6	5%	4.5	$ 22,858
10	11.6	5%	4.5	$ 22,858
11	27.7	30%	3.62	$ 266,692
12	27.7	30%	3.62	$ 266,692
13	27.7	30%	3.62	$ 266,692
14	11.6	30%	3.62	$ 110,329
15	11.6	30%	3.62	$ 110,329
16	11.6	30%	3.62	$ 110,329
17	53.2	1%	3.62	$ 16,872
18	94.5	5%	3.62	$ 150,014

Table 4.1.5 Driving Mileage From Mine to Boiler Zip Code

Mine	Boiler Zip Code			
No.	15701	15901	16330	15931
1	30	23	9	3
2	22	35	32	20
3	20	40	33	25
4	40	44	32	22
5	45	15	35	29
6	30	42	57	51
7	14	44	43	36
8	23	19	33	26

4.1.3 Results and Conclusions

4.1.3.1 Market Penetration Model Results

The results of the equilibrium market penetration model are summarized in Table 4.1.6. The results indicate that six of the eighteen candidate retrofit boilers could be profitably retrofitted. While these six boilers constitute only one-third of the retrofit candidates, they are responsible for 75.5% of the annual fuel demand. The total annual savings due to retrofitting is $3.58 million per year as compared to the six boilers continuing to fire natural gas. The total capital requirement (TCR) to retrofit all six boilers is $26.9 million. The combined annual savings and capital required result in an overall rate of return of 11.9%.

The optimal mine location was found to be the Heshbon mine (Table 4.1.1). The total fuel savings results in approximately 69,000 tons per year (tpy) of additional coal demand. This amount of coal would be equivalent to 24.4% of total annual production for that mine.

Table 4.1.7 shows the optimal retrofit results broken out by the individual boilers. The table shows that there are two types of boilers that are amenable to retrofitting. Boiler nos. 1 and 6, termed "large" boilers, each require $5.01million TCR in order to generate a $788,000 annual savings per boiler resulting in a 14.7% rate of return. Boiler nos. 2, 3, 4, and 5 are "small" boilers that each require $4.22 million TCR in order to generate a $501,000 annual savings per boiler resulting in a 10.1% rate of return.

The fuel costs (f.o.b. boiler) shown in Table 4.1.7 for the "large" and "small" boilers are $1.42 per MM Btu and $1.48 per MM Btu, respectively. These costs include all costs necessary to fire MCWM except annualized capital charge in order for the rate of returns to be calculated. Adding in the annualized capital charges results in MCWM costs of $2.45 per MM Btu and $2.81 per MM Btu respectively.

Figures 4.1.5 and 4.1.6 show the relative MCWM costs for "large" and "small" boilers, respectively. Capital charges represent the largest cost component associated with retrofitting the boiler, followed by costs associated with producing MCWM at the mine. Transportation and Operations & Maintenance (O&M) combined to contribute about 20% to costs. Ash disposal charges constitute only 0.4% of costs.

The optimal mix of retrofitted boilers and non-retrofitted as presented above, was determined by solving the nonlinear program as described in Section 4.1.3. Solving this problem presented certain challenges that deserve further mention.

Table 4.1.6 Summary of Optimal Retrofit Results

Number of candidate boiler retrofits	18
Annual total boiler fuel demand	2,188 thousand MM Btu/ year
Number of boilers that are optimal to retrofit	6
Retrofitted boiler's annual fuel demand	1,652 thousand MM Btu/ year
Percentage of total annual fuel demand by retrofitted boilers	75.5 %
Retrofitted boilers' estimated additional coal consumption	69,332 tons/ year
Total Capital Requirement (TCR) to effect boiler retrofits	26.9 million $
Total annual savings due to retrofitting	3.58 million $/ year
Retrofit project aggregate rate of return	11.90 %

Notes:

1. Optimal mine location for base case is the Heshbon Mine (mine no. 8).
2. Annual additional boiler coal consumption estimated by assuming coal higher heating value of 12,810 Btu/ lb and a moisture content of 7%.
3. Total annual savings are calculated without annualized capital charges.
4. Retrofit rate of return calculated as annual savings realized over a 20 year boiler life.

Table 4.1.7 Detailed Optimal Retrofit Results

Boiler No.	Optimal Fuel Choice	Fuel Costs f.o.b. Boiler $/MM Btu	TCR M$	Fuel Demand thousand MM Btu/y	Annual Fuel Cost M$/y	Annual Retrofit Savings M$/y	Retrofit Rate of Return
1	MCWM	1.416	5.01	357.7	0.506	0.788	14.7%
2	MCWM	1.482	4.22	234.2	0.347	0.501	10.1%
3	MCWM	1.482	4.22	234.2	0.347	0.501	10.1%
4	MCWM	1.482	4.22	234.2	0.347	0.501	10.1%
5	MCWM	1.482	4.22	234.2	0.347	0.501	10.1%
6	MCWM	1.416	5.01	357.7	0.506	0.788	14.7%
7	N.G.	3.62	N.R.	85.0	0.308	-	-
8	N.G.	3.62	N.R.	85.0	0.308	-	-
9	N.G.	4.50	N.R.	5.1	0.023	-	-
10	N.G.	4.50	N.R.	5.1	0.023	-	-
11	N.G.	3.62	N.R.	72.8	0.264	-	-
12	N.G.	3.62	N.R.	72.8	0.264	-	-
13	N.G.	3.62	N.R.	72.8	0.264	-	-
14	N.G.	3.62	N.R.	30.5	0.110	-	-
15	N.G.	3.62	N.R.	30.5	0.110	-	-
16	N.G.	3.62	N.R.	30.5	0.110	-	-
17	N.G.	3.62	N.R.	4.7	0.017	-	-
18	N.G.	3.62	N.R.	41.4	0.150	-	-
		TOTALS	26.90	2,188.3	4.352	3.516	11.6%

Notes:

1. Optimal mine location for base case is the Heshbon Mine (Sequence No. 8).
2. N.G. is Natural Gas.
3. N.R. indicates that retrofitting is not performed on the boiler.
4. Fuel Costs (f.o.b. boiler) does not include annualized capital charges.
5. Retrofit rate of return calculated as annual savings realized over 20 year boiler life.

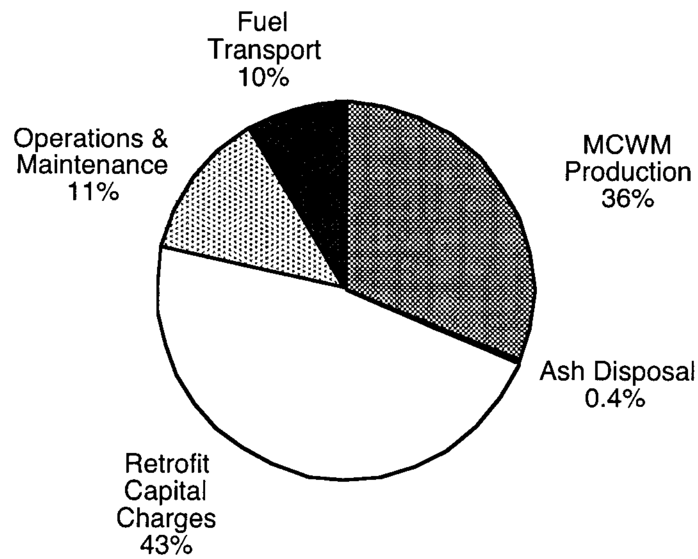

Figure 4.1.5 DISTRIBUTION OF "LARGE" BOILER MCWM COSTS

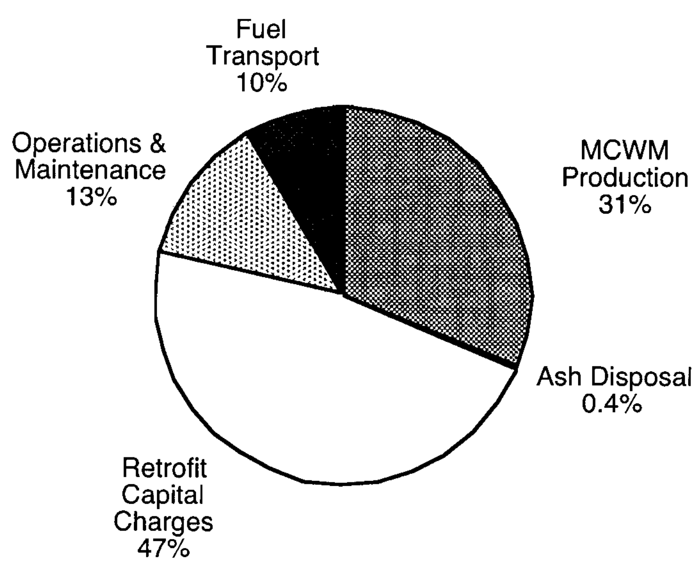

Figure 4.1.6 DISTRIBUTION OF "SMALL" BOILER MCWM COSTS

The programming language chosen to compile the nonlinear programming model was GAMS release 2.5 (Brooke et al., 1992). The specific solver used was the MINOS 5.3developed by Gill et al., (1990). The solver uses an "heuristic" method to find an optimal solution. The solution of nonlinear problems is difficult, particularly in models where the nonlinearity, in this case the MCWM production costs, is one of the constraints. There are two issues to consider. The first issue involves finding an optimal solution. The second issue is that a particular solution may only be "locally" optimal. That is, there may exist other, perhaps better, solutions with notably different conditions.

In this light, the difficulty of solving the nonlinear problem presented in Section 4.1.3 becomes clearer. The main difficulty involves the economies of scale inherent in MCWM production needing to be considered at eight different potential locations. Locally optimal solutions were found that called for MCWM production to be split up among two or more coal mines. However, limiting production to one coal field produces the best solution. The MINOS 5.3 solver could find this optimal solution through the judicious selection of initial conditions of flows of coal and natural gas from the supply points to the boilers. The same result can be obtained by adding a constraint that all MCWM production must occur at only one of the eight mines. Even with this limiting constraint in place, however, it was necessary to run the solver multiple times to produce the optimal solution. The results from one, non-optimal, run would serve as initial conditions for the next until an acceptable optimal solution was found.

4.1.3.2 Sensitivity Analysis

Sensitivity to MCWM Supply Location

A consideration in the model results is the sensitivity of MCWM supply location on the optimal results. Since the nonlinear programming model minimizes costs, of which transportation costs represent one component, then the solution to this model minimizes the transportation costs given the spatial distribution of potential MCWM production plant locations and of candidate retrofit boilers.

One method of showing the sensitivity of MCWM production plant location upon the optimal results is to find solutions to the nonlinear problem that force MCWM production to occur at each location, in turn, and compare the results. Table 4.1.8 shows the results of this analysis. This table shows the marginal costs of MCWM supply to each boiler, on a $/MM Btu basis, that is conditional upon a particular location being selected to provide all MCWM to the boilers that are optimal to retrofit. The table then gives the additional costs to MCWM supply that arise due to the increased transportation costs associated with locating the production plant at other than the optimal location (mine no. 8). For instance, locating the MCWM production plant at mine no. 6 results in an additional \$0.03/MM Btu for boiler nos. 1 and 6, and an additional \$0.09/MM Btu for boiler nos. 2 through 5. A negative marginal cost (e.g., mine no.7 supplying boiler no.1) indicates that MCWM could be delivered to that particular mine at lower than the optimal case results. This result occurs because other boilers in the group are at such a cost disadvantage given that mine location. Boiler nos. 7 through 18 are not optimal to retrofit. Therefore, the marginal costs shown for these boilers shows the marginal cost to supply that boiler with MCWM if retrofitting of that boiler is insisted upon.

Table 4.1.8 also shows the sensitivity of the results to changes in the price level of natural gas. For instance, the price of natural gas would have to fall \$0.81/MM Btu to \$2.81/MM Btu before boiler nos. 2 to 5 would no longer be economical to retrofit. Likewise, long term increases in natural gas prices would increase the number of boilers that would be economical to retrofit. For example, with MCWM production located at mine no. 8 higher natural gas prices of approximately \$0.18/MM Btu would result in boiler nos. 7 and 8 becoming economical to retrofit.

It is clear from the results shown in Table 4.1.8 that MCWM siting does not greatly effect the optimal solution. Boilers that were economical to retrofit under optimal conditions would still be economical to retrofit even if the MCWM production location were to be sited at any of the other seven mines.

Another way of demonstrating this result is to show how the aggregate annual retrofit savings and rate of return varies with selecting a different mine location. Such an analysis is presented in Table 4.1.9. As can be seen by inspecting the table, the annual retrofit savings vary between \$3.4 to \$3.6 million resulting in a variation of rate of returns of 11.3% to 11.9%. With such a small variation in return, other factors, such as coal quality or technical expertise, may be considered when deciding where to locate the MCWM production plant in the two-county region.

Table 4.1.8 Marginal Cost of Fuel Supply Conditional Upon MCWM Siting ($/MM Btu)

Boiler	Fuel Origin								
No.	N.G.	1	2	3	4	5	6	7	8
1	1.17	0.03	0.00	-0.01	0.06	0.08	0.03	-0.03	-
2	0.81	0.02	0.06	0.08	0.09	-0.01	0.09	0.09	-
3	0.81	0.02	0.06	0.08	0.09	-0.01	0.09	0.09	-
4	0.81	0.02	0.06	0.08	0.09	-0.01	0.09	0.09	-
5	0.81	0.02	0.06	0.08	0.09	-0.01	0.09	0.09	-
6	1.17	0.03	0.00	-0.01	0.06	0.08	0.03	-0.03	-
7	-	0.19	0.24	0.25	0.27	0.16	0.26	0.27	0.18
8	-	0.19	0.24	0.25	0.27	0.16	0.26	0.27	0.18
9	-	29.95	30.00	30.02	30.03	29.92	30.02	30.03	29.94
10	-	29.95	30.00	30.02	30.03	29.92	30.02	30.03	29.94
11	-	1.31	1.39	1.40	1.39	1.40	1.48	1.43	1.40
12	-	1.31	1.39	1.40	1.39	1.40	1.48	1.43	1.40
13	-	1.31	1.39	1.40	1.39	1.40	1.48	1.43	1.40
14	-	3.07	3.11	3.13	3.15	3.04	3.14	3.15	3.05
15	-	3.07	3.11	3.13	3.15	3.04	3.14	3.15	3.05
16	-	3.07	3.11	3.13	3.15	3.04	3.14	3.15	3.05
17	-	84.81	84.85	84.87	84.89	84.78	84.88	84.89	84.79
18	-	11.13	11.20	11.22	11.20	11.23	11.31	11.26	11.22

Notes:

1. Optimal MCWM fuel supply siting for boiler nos. 1 to 6 is coal mine no. 8, the remaining boilers are optimally supplied by natural gas.
2. Values shown are marginal costs as compared to the optimal case conditional upon the mine (column) supplying all the fuel for boiler nos. 1 to 6.
3. N.G. is Natural Gas.
4. Fuel prices (f.o.b. boiler) include annualized capital charges.

Table 4.1.9 Sensitivity of Aggregate Project Results to MCWM Plant Siting

Mine No.	Aggregate TCR M$	Annual Retrofit Savings M$/y	Aggregate Retrofit Rate of Return
1	26.9	3.546	11.8%
2	26.9	3.526	11.7%
3	26.9	3.514	11.6%
4	26.9	3.447	11.3%
5	26.9	3.534	11.7%
6	26.9	3.480	11.5%
7	26.9	3.516	11.6%
8	26.9	3.579	11.9%

Sensitivity to Number of Retrofits Performed

The equilibrium results found here assume that all boiler owners instantaneously retrofit their boilers if there exists an economic benefit to doing so. As explained in Section 4.1.3, however, the adoption of the retrofit technology may be slow or not happen at all.

A sensitivity analysis of the optimal results investigated the effects of fewer than six boilers being retrofitted. The results of this analysis are shown in Table 4.1.10. As expected, lowering the number of retrofits lowers both the total TCR necessary and the aggregate annual retrofit savings. The aggregate retrofit rate of return does not follow a smooth decreasing rate. This is mainly due to the "lumpy" form of capital investment. For instance, when one of the "small" boilers is excluded, this concentrates the capital investment, as a percent, with the larger boilers that provided a larger rate of return. The other effect at work is the increased MCWM costs associated with decreasing aggregate MCWM demand in the region. This effect is responsible for lowering the retrofit rate of return but is not a particularly significant effect until only one of the "small" boilers is retrofitted.

Breakeven Radius of MCWM Supply

Another analysis considered is determination of the effective radius that a retrofitted boiler could be economically served from a single MCWM production plant. This radius is determined by

Table 4.1.10 Sensitivity of Aggregate Project Results to Number of Retrofits

Number of "Large" Boilers	Number of "Small" Boilers	Aggregate MCWM Demand thousand MM Btu/y	Fuel Price f.o.b. Prep Plant $/MM Btu	Total TCR M$	Aggregate Annual Retrofit Savings M$/y	Aggregate Retrofit Rate of Return
2	4	1,652	0.872	26.9	3.58	11.9%
2	3	1,418	0.904	22.7	3.03	12.0%
1	4	1,294	0.926	21.9	2.72	10.9%
2	2	1,184	0.948	18.5	2.49	12.1%
1	3	1,060	0.980	17.7	2.18	10.7%
0	4	937	1.019	16.9	1.87	9.1%
1	2	826	1.063	13.5	1.63	10.5%
1	1	592	1.212	9.2	1.09	10.0%
1	0	358	1.552	5.0	0.55	8.9%
0	1	234	1.998	4.2	0.24	1.1%

varying the distance of one of the "large" boilers from its current location out to a distance that would result in retrofitting to be a breakeven proposition as compared to continuing o fire natural gas. This type of analysis is sensitive to the interest rates when considering whether to expend the capital needed to effect the retrofit.

The breakeven retrofit radius analysis that considers both distance and interest rates is presented in Table 4.1.11. This table shows that at an interest rate of 4% the maximum distance a "large" boiler can be located from the mine for retrofitting to remain economical is 338 miles. At an interest rate of 10% that breakeven radius drops to 173 miles. At just over a 14% interest rate the breakeven retrofit radius drops to zero miles.

4.1.4 Conclusions

A market penetration model was formulated to find the equilibrium optimal mix of boiler retrofit technology adoption among a sample population of 462 water tube boilers located in the Pennsylvania counties of Cambria and Indiana. This region was selected so that detailed information could be collected to allow the analysis to be carried out. It was found that six of

Table 4.1.11 Breakeven Retrofit Radius for "Large" Boiler

Interest Rate %	Annual Capital Charges $	Annual Retrofit Savings Less Transportation $	Annual Boiler Fuel Demand thousand MM Btu	Breakeven Retrofit Radius miles
2	306,395	512,572	357.7	384
4	368,645	450,322	357.7	338
6	436,795	382,172	357.7	286
8	510,280	308,687	357.7	231
10	588,473	230,494	357.7	173
12	670,733	148,234	357.7	111
14	756,440	62,527	357.7	47
16	845,022	-26,055	357.7	-

Notes:

1. Analysis considers boiler no. 1 requiring $5.01M TCR.
2. Annual capital charges are determined by amortizing TCR over 20 years.
3. Annual retrofit savings are $819,000 (f.o.b. mine).
4. Mileage dependent transportation rate is $0.00373/MM Btu/mile.

these boilers would benefit economically from adopting the retrofit technology. Retrofitting these six boilers would result in a total cost savings of $3.58 million annually for an aggregate rate of return of 11.9%. This equilibrium result leads to 69,000 tons per year (tpy) additional coal consumption in the region.

It was also found that the study region could be expanded to other portions of the state out to 173 miles assuming that industrial boiler owners use 10% interest rates when considering capital investments. Considering the distribution of boilers throughout Pennsylvania, as described in Section 4.1.2.8, it can be concluded that the boilers located in the eastern part of the state could not be served from the coal producing regions of the west central to south western part of the state. With this consideration in mind, it is estimated that only 40% of Pennsylvania's 6,936 water tube boilers are located in areas that could consider retrofitting as a viable option. It is estimated that 36 Pennsylvania boilers would benefit from adopting the retrofit technology. This estimate assumes that the ratio of boiler retrofits to total water tube boilers in the study

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capital investments. Considering the distribution of boilers throughout Pennsylvania, as described in Section 4.1.2.8, it can be concluded that the boilers located in the eastern part of the state could not be served from the coal producing regions of the west central to south western part of the state. With this consideration in mind, it is estimated that only 40% of Pennsylvania's 6,936 water tube boilers are located in areas that could consider retrofitting as a viable option. It is estimated that 36 Pennsylvania boilers would benefit from adopting the retrofit technology.

Pennsylvania is not the only major potential market for the boiler retrofit technology. Ohio, Indiana, and Illinois are also states that have the combination of a large industrial base near extensive deposits of coal. An estimated total number of retrofits for each of these states is given in Table 4.1.12. The estimates for Ohio, Indiana, and Illinois use the ratio of industrial sector energy consumption in each state, as compared to Pennsylvania, as a proxy for the relative number of boilers in each state. In addition, the other states are likely to suffer less from geographic isolation between boilers and coal fields than is the case for Pennsylvania. It was assumed that 60% of the boilers in each of these states would be near enough to coal fields to justify considering adoption of the retrofit technology.

The estimates presented in Table 4.1.12 indicate that the total market for the boiler retrofit technology is some 186 boilers comprising 3,400 tpy of coal consumption. Again, these are rough estimates only. For example, it may be the case that no Ohio coal is of sufficient quality to allow its use in a retrofitted boiler. It can be concluded, however, that the total market potential for the retrofit technology in Pennsylvania, Ohio, Indiana, and Illinois is likely to be at least 90 boilers but less than 200 boilers. This range of retrofitted boilers would constitute about 1,700 to 3,700 tpy of coal consumption.

4.2 Selection of Incentives for Commercialization of the Coal-Using Technology

4.2.1 Motivation and Aim of the Study

The results of the Phase II work indicated that there are social, economic and political benefits of substituting clean burning coal-based fuels for oil and gas (Miller et al., 2000). A

Table 4.1.12 Estimated Number of Boiler Retrofits and Coal Consumption

State	1992 Industrial Sector Energy Consumption trillion Btu	1992 Industrial Sector Bituminous & Lignite Coal Consumption thousand tons	Estimated Number of Retrofits	Estimated Retrofit Fuel Consumption thousand MM Btu	Estimated Retrofit Coal Consumption thousand tons
Pennsylvania	1,357	13,859	36	15,779	662
Ohio	1,377	50,358	55	24,017	1,008
Indiana	1,154	11,416	46	20,128	845
Illinois	1,237	6,050	49	21,575	906
TOTALS	5,125	81,683	186	81,499	3,420

Notes:

1. Consumption data is from U.S. DOE/EIA "State Energy Data Report, 1992: Consumption Estimates."
2. Coal assumed to have a higher heating value of 12,810 Btu/lb and 7% moisture content.

heavy reliance on imported oil makes the United States vulnerable to price shocks, i.e., periods of increased price volatility, and disruptions in the supply of oil. Clearly, price shocks and disruptions in supply may have significant economic and political effects in the U.S. As previous studies document, the infamous oil embargo of 1973-1974 by OPEC resulted in approximately a 2% rise in unemployment and a 2% increase in the rate of inflation.

The world has been witnessing a downtrend in oil prices, on average, since 1989; nevertheless, due to the concentrated political and highly volatile nature of the oil market, it is not an easy task to predict how oil prices would fare over the next decades. On the other hand, coal prices have been exhibiting one of the smallest price fluctuations in energy markets over the last one and a half decades. This consistent and statistically significant difference in the volatilities of the two price series, oil and coal prices, may be viewed as indicating that there are advantages to switching to a coal-based technology from a oil-based one for risk management purposes.

The Phase II Final Report addressed the question of estimating the net costs of this technology switch at the firm level (Miller et al., 2000). Specifically, the report addressed the estimate of the magnitude of the gross costs and benefits associated with the suggested retrofitting. As it was remarked, the "success (of the new technology) will most likely be achieved through those technologies that can achieve the margin of economic viability by reducing capital costs and not through 'serendipitous' changes in oil price alone." (Miller et al., 2000). This finding clearly shows that even though there may be significant advantages in substituting clean-burning coal-based fuels for oil and gas at the macroeconomic level, at the microeconomic level, e.g., firm level, the costs of retrofitting are considerably high for individual firms, so that managers may be tempted to decide against it. Consequently, in the conclusions of the Phase II Final Report, it is suggested that "those technologies that can reach that marginal level of viability could make their market entry by highlighting fuel flexibility as quantified by option pricing methods." Even though there exist undeniable benefits -in terms of options- by adopting the new technology, it is not possible to come up with an estimate of an option value for this "technological investment" due to the complex nature of the problem at hand and lack of data. Thus, the net cost figures were provided that are based on the discounted cash flow technique (Miller et al., 2000).

The initial premise of the study was that the new coal-using technologies offer significant macroeconomic benefits in terms of fuel price differentials and managerial, economic and political options (some of which are to be quantified by a further study) and that the sum of positive externalities outweigh the negative externalities, which are associated with the differential environmental damage and so forth. The previous research showed that the adoption of the coal-based technology, i.e., the investment in the new technology, had a significant cost component attached to it, which may induce the managers at the firm level to be hesitant or even unwilling to undertake it (Miller et al., 2000). Recognizing the net positive externalities, the government may decide that it is appropriate to offer incentives for firms, which have a potential use for it, to facilitate the use and commercialization of the new technology.

Economic and financial incentives in general, and those provided to manufacturing enterprises in particular, have become accepted tools for the implementation of preferred government policies. These incentives not only affect the size of investments, but also alter the basic parameters of design and operation of industrial firms. However, the combined result of implemented incentives and particularly, the quantitative decision about the choice of the incentives have not been analyzed in depth in the literature.

Typical examples of government incentives that are employed as policy tools are: investment tax credits, reduced or no-interest loans, capital subsidies and tax incentives through accelerated depreciation. These policy tools have been subject to academic research on several occasions, recently, for instance, the discussion on the effectiveness of tax rates on business investment by Chirinko (1985), the debate on the impact of investment tax credit on investment behavior and value of the firm by Auerbach and Kotlikoff (1982), Auerbach (1986) and Lyon (1988) can be mentioned as examples of research involving assessment of effectiveness of these tools in achieving objectives set forth by the government.

The studies conducted on the effectiveness of the policy tools mentioned above remain highly macroeconomics oriented and have little to say about the consequences of them in a given sector, or sub-sector in a given economy. This deficiency was addressed in two sector-oriented studies: Cone et al. (1978) and more recently, Rose and Mor (1993). Nevertheless, all previous studies attempted to estimate the impact of incentives by using aggregate market data and have ignored the response generated by the economic agents operating in those markets, i.e., the firms. This study, therefore, is aimed at filling that gap in the literature and focuses on the microeconomic responses generated by the firms to the incentives. The study examines firm-specific data on firms that are potential customers of the new coal-using technology where the optimal incentive or combination of incentives is determined based on the empirically estimated reactions of firms.

A careful inspection of the government incentives mentioned above reveals that they are designed at fostering projects with different characteristics. In other words, one incentive may be optimal with projects with characteristic "A", whereas another may be of choice if the project has characteristic "B". For example, tax incentives, such as direct tax cuts, accelerated depreciation and so forth, can be thought to be more effective on projects that require a big initial capital outlay. On the other hand, reduced or no-interest loans are more useful on projects which are highly sensitive to interest rate fluctuations in the market, e.g., due to the nature of their cash flow stream.

Modern finance theory has shown that, under realistic assumptions, project selection and project financing decisions are not independent from the current financial attributes of the firm. In other words, risk exposure of firms becomes crucial in project selection and financing decisions, e.g., the same project can be regarded as profitable and desirable by one firm and not so by another.

The switch to a new technology can be thought as an investment in technology, and thus an "investment project" by itself. The importance of this is self-explanatory: if firms are given incentives, regardless of their financial and operational risk exposures, the result may be suboptimal or even off the policy target set forth by the government in some cases. The distortion of prices and the market mechanism may even produce undesirable outcomes in those industries: for instance generous capital subsidies may induce the firms to take projects with an -otherwise- unacceptable levels of risk exposure.

In sum, devising a government incentive scheme that aims at widespread commercialization of the new coal-using technology is a complex task. On the one hand, a miscalculation or negligence of firm characteristics and behavior may lead to suboptimal or even unwanted outcomes. On the other hand, calculation of the optimal mix of incentives presents another challenge for the policy makers. This task addresses both of these issues by taking individual firm characteristics into consideration in assessing the optimal strategy that should be implemented by the government.

4.2.2 Data

A list of 6,823 watertube boiler locations in the Commonwealth of Pennsylvania was generated from a database obtained from the Pennsylvania Department of Labor and Industry (PDL&I). These locations were then cross referenced against the names of publicly traded corporations or their subsidiaries for the entire United States. A total of 128 corporations or their subsidiaries were identified as having watertube boiler locations in the Commonwealth of Pennsylvania.

The latest and past one, three and five year annual financial statements, i.e., income statements and balance sheets, and key financial and operating ratios for the aforementioned 128 corporations were obtained from a CD-ROM provided by the Compact Disclosure Database Company. A closer inspection of the individual characteristics of these boilers revealed that only 57 firms (and subsidiaries), some with multiple boiler locations, fit into the category of boilers for which the new technology is developed. A list of firms included in this study is presented in Table 4.2.1.

Based on the balance sheets and income statements, the following financial ratios are calculated according to their standard definitions as follows: quick ratio (acid test), i.e., (current assets - inventory)/current liabilities; current ratio, i.e., currents assets/current liabilities; net sales/cash; net sales/working capital; net sales/current assets; net sales/assets; total liabilities/total assets (D/A); liabilities/equity (D/E); total net income/net sales; measure of operating leverage (MOL), i.e., percentage change in EBIT per 1% change in sales; measure of financial leverage (MFL), i.e., percentage change in net income per 1% change in EBIT; and finally, measure of total leverage (MTL), i.e., MOL multiplied by MFL.

The data about the new coal-based technology costs are taken from the Phase II Final Report (Miller et al., 2000). Similarly, boiler-specific costs and benefits are estimated using the same algorithm that is utilized in the aforementioned sections. The data were then tabulated and organized into a convenient format to facilitate quantitative analysis of the impacts of various government incentives for commercialization of the new technology. For given levels of boiler capacity the switch in technology is treated as a real investment and the net return on investment is calculated. Tables 4.2.2 and 4.2.3 display some selected balance sheet items and calculated financial ratios for the firms in the sample.

Table 4.2.1 List of Firms Included in the Sample

[illegible]
- ACF INDUSTRIES INC
- ALCAN ALUMINUM LTD
- ALCOA INTERNATIONAL HOLDINGS COMPANY
- ALLEGHENY LUDLUM CORP
- ALLIED SIGNAL INC
- ALUMINUM CO OF AMERICA
- AMERICAN HOME PRODUCTS CORP
- ANGELICA CORP
- ARCO CHEMICAL CO
- ARMCO INC
- ASHLAND OIL INC
- AT&T CORP
- BEATRICE FOODS INC
- BETHLEHEM STEEL CORP
- BETZ LABORATORIES INC
- BORDEN INC
- CABOT CORP
- CARBIDE GRAPHITE GROUP INC
- CATERPILLAR INC
- CHEVRON CORP
- CONSOLIDATED CIGAR CORP NEW JERSEY
- EXXON CORP
- GENCORP INC
- GENERAL ELECTRIC CO
- GENERAL SIGNAL CORP
- GUILFORD MILLS INC
- H J HEINZ CO
- HANOVER FOODS CORP
- HERCULES INC
- INDSPEC CHEMICAL CORP
- J&L SPECIALTY STEEL INC
- KRAFT GENERAL FOODS INC
- LTV STEEL CO INC
- LUKENS INC
- MASLAND CORP
- MERCK & CO INC
- MINNESOTA MINING & MANUFACTURING
- NATIONAL GYPSUM CO
- OCCIDENTAL PETROLEUM CORP
- PPG INDUSTRIES INC
- PROCTER & GAMBLE CO
- RHONE POULENC SA
- ROHM & HAAS CO
- SEARS ROEBUCK & CO
- SMITHKLINE BEECHAM PLC
- SONOCO PRODUCTS CO
- SPS TECHNOLOGIES INC
- ST JOE PAPER CO
- TEMPLE INLAND INC
- USX CORP
- VALSPAR CORP
- WARNER LAMBERT CO
- WEST PENN POWER CO
- WESTINGHOUSE ELECTRIC CORP
- WESTVACO CORP
- WITCO CORP
- YORK INTERNATIONAL CORP

Table 4.2.2 Selected Items from the Balance Sheets of Included Firms

COMPANY NAME	TOT CUR ASSETS	TOTAL ASSETS	INCOME TAXES	CURRENT LIABILITY	TOTAL LIABILITY	COMMON STOCK	RETAINED EARNINGS	TOT LIAB-NET WORTH
ACF INDUSTRIES INC	640,603.00	1,706,454.00	8,336.00	469,213.00	1,388,925.00	76,573.00	(18,453.00)	1,706,454.00
ALCAN ALUMINIUM LTD	2,402,000.00	9,810,000.00	16,000.00	1,335,000.00	5,291,000.00	1,183,000.00	2,813,000.00	9,810,000.00
ALCOA INTL HOLDINGS COMPANY	1,111,800.00	3,872,600.00	181,900.00	571,700.00	1,243,500.00	0.00	1,827,800.00	3,872,600.00
ALLEGHENY LUDLUM CORP	469,788.00	1,174,049.00	20,634.00	210,877.00	770,627.00	7,288.00	152,258.00	1,174,049.00
ALLIED SIGNAL INC	4,567,000.00	10,829,000.00	0.00	3,489,000.00	8,439,000.00	358,000.00	1,023,000.00	10,829,000.00
ALUMINUM CO OF AMERICA	3,702,500.00	11,596,900.00	0.00	2,092,900.00	6,623,900.00	88,800.00	2,946,100.00	11,596,900.00
AMERICAN HOME PRODUCTS CORP	4,807,684.00	7,687,353.00	171,404.00	1,584,411.00	3,612,235.00	103,442.00	2,884,244.00	7,687,353.00
ANGELICA CORP	210,255.00	332,861.00	5,530.00	53,067.00	140,868.00	9,448.00	190,301.00	332,861.00
ARCO CHEMICAL CO	943,000.00	3,502,000.00	28,000.00	487,000.00	1,803,000.00	100,000.00	703,000.00	3,502,000.00
ARMCO INC	625,400.00	1,904,700.00	0.00	353,000.00	2,208,100.00	1,000.00	(1,450,300.00)	1,904,700.00
ASHLAND OIL INC	1,973,001.00	5,551,817.00	41,560.00	1,618,913.00	4,097,023.00	60,022.00	1,008,264.00	5,551,817.00
AT&T CORP	29,738,000.00	60,766,000.00	0.00	25,334,000.00	46,334,000.00	1,352,000.00	857,000.00	60,766,000.00
BEATRICE FOODS INC	137,062.00	655,641.00	4,157.00	113,772.00	491,942.00	155,140.00	4,226.00	655,641.00
BETHLEHEM STEEL CORP	1,591,100.00	5,876,700.00	0.00	914,200.00	5,180,100.00	93,400.00	(939,900.00)	5,876,700.00
BETZ LABORATORIES INC	208,635.00	521,129.00	6,838.00	92,041.00	221,810.00	3,365.00	394,726.00	521,129.00
BORDEN INC	1,290,200.00	3,871,700.00	56,500.00	1,371,500.00	3,117,000.00	121,900.00	835,100.00	3,871,700.00
CABOT CORP	544,206.00	1,489,473.00	26,314.00	354,221.00	1,047,200.00	33,887.00	861,803.00	1,489,473.00
CARBIDE GRAPHITE GROUP INC	102,693.00	171,870.00	213.00	32,665.00	115,314.00	70.00	42,869.00	171,870.00
CATERPILLAR INC	6,071,000.00	14,807,000.00	111,000.00	4,671,000.00	12,608,000.00	835,000.00	1,234,000.00	14,807,000.00
CHEVRON CORP	8,682,000.00	34,736,000.00	782,000.00	10,606,000.00	20,739,000.00	1,069,000.00	13,955,000.00	34,736,000.00
CONSOLIDATED CIGAR CORP NEW JERSEY	49,748.00	205,906.00	0.00	15,771.00	173,027.00	1.00	2,879.00	205,906.00
EXXON CORP	14,859,000.00	84,145,000.00	2,359,000.00	18,590,000.00	46,958,000.00	2,822,000.00	49,365,000.00	84,145,000.00
GENCORP INC	430,000.00	1,164,000.00	14,000.00	341,000.00	929,000.00	3,000.00	229,000.00	1,164,000.00
GENERAL ELECTRIC CO	195,240,000.00	251,506,000.00	0.00	178,638,000.00	224,026,000.00	584,000.00	28,613,000.00	251,506,000.00
GENERAL SIGNAL CORP	594,545.00	1,224,841.00	7,385.00	325,848.00	699,655.00	77,082.00	583,099.00	1,224,841.00
GUILFORD MILLS INC	248,638.00	506,742.00	0.00	96,644.00	287,003.00	393.00	244,066.00	506,742.00
H J HEINZ CO	2,291,530.00	6,381,146.00	130,535.00	1,692,362.00	4,042,595.00	71,850.00	3,633,385.00	6,381,146.00

HANOVER FOODS CORP	73,013.00	124,646.00	1,092.00	50,734.00	81,656.00	21,042.00	26,371.00	124,646.00
HERCULES INC	1,226,523.00	3,161,961.00	0.00	884,211.00	1,793,754.00	31,198.00	1,955,005.00	3,161,961.00
INDSPEC CHEMICAL CORP	32,269.00	237,125.00	0.00	23,571.00	230,874.00	1.00	8.00	237,125.00
J&L SPECIALTY STEEL INC	209,384.00	626,038.00	165.00	99,120.00	358,522.00	387.00	(36,959.00)	626,038.00
KRAFT GENERAL FOODS INC	6,982,000.00	32,669,000.00	428,000.00	6,577,000.00	18,602,000.00	0.00	1,529,000.00	32,669,000.00
LTV STEEL CO INC	1,350,900.00	4,584,100.00	0.00	716,600.00	8,399,500.00	100.00	(5,239,100.00)	4,584,100.00
LUKENS INC	307,739.00	817,178.00	0.00	161,705.00	550,424.00	158.00	193,977.00	817,178.00
MASLAND CORP	101,924.00	203,774.00	0.00	79,629.00	129,503.00	132.00	34,755.00	203,774.00
MERCK & CO INC	5,734,600.00	19,927,500.00	1,430,400.00	5,895,700.00	8,761,400.00	4,576,500.00	9,393,200.00	19,927,500.00
MINNESOTA MINING & MANUFACTURING	6,363,000.00	12,197,000.00	290,000.00	3,282,000.00	5,685,000.00	6,512,000.00	0.00	12,197,000.00
NATIONAL GYPSUM CO	196,480.00	774,340.00	10,868.00	67,144.00	1,428,135.00	1.00	(744,195.00)	774,340.00
OCCIDENTAL PETROLEUM CORP	1,934,000.00	17,123,000.00	110,000.00	2,048,000.00	13,152,000.00	61,000.00	(1,883,000.00)	17,123,000.00
PPG INDUSTRIES INC	2,025,900.00	5,651,500.00	4,700.00	1,281,000.00	3,126,500.00	242,100.00	3,436,800.00	5,651,500.00
PROCTER & GAMBLE CO	9,988,000	25,535,000	0	8,040,000	16,703,000	684,000	7,496,000	25,535,000
RHONE POULENC SA	41,813,000.00	114,481,000.00	0.00	31,492,000.00	64,730,000.00	6,271,000.00	13,155,000.00	114,481,000.00
ROHM & HAAS CO	1,200,000.00	3,524,000.00	3,000.00	701,000.00	2,012,000.00	197,000.00	1,444,000.00	3,524,000.00
SEARS ROEBUCK & CO	25,549,800.00	90,807,800.00	0.00	57,290,200.00	76,809,700.00	293,800.00	8,162,800.00	90,807,800.00
SMITHKLINE BEECHAM PLC	3,393,000.00	5,438,000.00	0.00	2,178,000.00	3,608,000.00	335,000.00	831,000.00	5,438,000.00
SONOCO PRODUCTS CO	513,110.00	1,707,125.00	3,071.00	303,178.00	918,761.00	7,175.00	623,500.00	1,707,125.00
SPS TECHNOLOGIES INC	161,010.00	285,979.00	646.00	66,527.00	183,152.00	6,362.00	60,516.00	285,979.00
ST JOE PAPER CO	283,856.00	1,491,271.00	2,737.00	93,399.00	348,940.00	8,714.00	851,511.00	1,491,271.00
TARKETT INTERNATIONAL GMBH	13,048.00	13,048.00	0.00	12,998.00	12,998.00	50.00	0.00	13,048.00
TEMPLE INLAND INC	4,671,243.00	11,959,260.00	0.00	9,021,256.00	10,259,080.00	61,390.00	1,482,093.00	11,959,260.00
USX CORP	3,180,000.00	17,374,000.00	0.00	3,334,000.00	13,510,000.00	366,000.00	(831,000.00)	17,374,000.00
VALSPAR CORP	197,480.00	336,798.00	11,412.00	113,481.00	140,280.00	13,330.00	223,483.00	336,798.00
WARNER LAMBERT CO	2,218,700.00	4,828,100.00	180,300.00	2,015,900.00	3,438,500.00	160,300.00	2,287,700.00	4,828,100.00
WEST PENN POWER CO	229,283.00	2,544,763.00	11,533.00	184,109.00	1,501,086.00	425,994.00	412,288.00	2,544,763.00
WESTINGHOUSE ELECTRIC CORP	4,774,000.00	10,553,000.00	0.00	3,925,000.00	9,474,000.00	393,000.00	1,401,000.00	10,553,000.00

WESTVACO CORP	609,284.00	3,927,837.00	15,574.00	365,325.00	2,103,849.00	545,166.00	1,294,130.00	3,927,837.00
WITCO CORP	792,573.00	1,838,998.00	0.00	341,338.00	1,125,583.00	254,089.00	488,241.00	1,838,998.00
YORK INTERNATION AL CORP	702,775.00	1,335,181.00	35,072.00	521,699.00	878,214.00	188.00	36,227.00	1,335,181.00

Table 4.2.3 Selected Financial Ratios for the Firms in the Sample

COMPANY NAME	QUICK RATIO	CURRENT RATIO	LIABILITY/EQUITY	INCOME/SALES	INCOME/ASSETS	INCOME/EQUITY
ACF INDUSTRIES INC	1.24	1.37	4.37	(0.05)	(0.01)	(0.06)
ALCAN ALUMINIUM LTD	0.86	1.80	1.31	(0.01)	(0.01)	(0.03)
ALCOA INTERNATIONAL HOLDINGS COMPANY	1.33	1.94	1.22	0.07	0.05	0.18
ALLEGHENY LUDLUM CORP	0.99	2.23	1.91	0.06	0.06	0.18
ALLIED SIGNAL INC	0.64	1.31	3.53	0.03	0.04	0.17
ALUMINUM CO OF AMERICA	0.90	1.77	3.10	0.00	0.00	0.00
AMERICAN HOME PRODUCTS CORP	2.28	3.03	0.98	0.18	0.19	0.40
ANGELICA CORP	1.32	3.96	0.73	0.03	0.03	0.06
ARCO CHEMICAL CO	1.01	1.94	1.24	0.07	0.06	0.15
ARMCO INC	0.99	1.77	(4.34)	(0.39)	(0.34)	1.26
ASHLAND OIL INC	0.75	1.22	3.53	0.01	0.03	0.12
AT&T CORP	0.94	1.17	3.49	(0.06)	(0.06)	(0.29)
BEATRICE FOODS INC	0.80	1.20	3.01	0.00	0.00	0.01
BETHLEHEM STEEL CORP	0.80	1.74	7.59	(0.06)	(0.05)	(0.39)
BETZ LABORATORIES INC	1.59	2.27	0.75	0.10	0.13	0.22
BORDEN INC	0.32	0.94	(11.86)	(0.11)	(0.16)	2.40
CABOT CORP	0.84	1.54	2.83	0.01	0.01	0.03
CARBIDE GRAPHITE GROUP INC	0.00	3.14	2.24	0.02	0.03	0.11
CATERPILLAR INC	0.79	1.30	5.73	0.06	0.04	0.30
CHEVRON CORP	0.55	0.82	1.48	0.03	0.04	0.09
CONSOLIDATED CIGAR CORP NEW JERSEY	0.78	3.15	5.26	0.03	0.01	0.09
EXXON CORP	0.46	0.80	1.48	0.05	0.06	0.17
GENCORP INC	0.55	1.26	3.95	0.02	0.04	0.18

GENERAL ELECTRIC CO	1.07	1.09	9.27	0.07	0.02	0.18
GENERAL SIGNAL CORP	0.79	1.82	1.33	0.02	0.03	0.07
GUILFORD MILLS INC	1.56	2.57	1.31	0.04	0.06	0.13
H J HEINZ CO	0.56	1.35	1.73	0.09	0.09	0.26
HANOVER FOODS CORP	0.49	1.44	1.94	0.03	0.05	0.15
HERCULES INC	0.83	1.39	1.31	(0.01)	(0.01)	(0.02)
INDSPEC CHEMICAL CORP	0.71	1.37	36.93	0.00	0.00	0.00
J&L SPECIALTY STEEL INC	0.68	2.11	1.34	0.03	0.03	0.07
KRAFT GENERAL FOODS INC	0.54	1.06	1.32	0.02	0.02	0.05
LTV STEEL CO INC	0.00	1.89	(2.20)	(0.08)	(0.06)	0.07
LUKENS INC	0.78	1.90	2.35	(0.06)	(0.06)	(0.21)
MASLAND CORP	0.84	1.28	2.06	0.05	0.10	0.33
MERCK & CO INC	0.62	0.97	0.99	0.21	0.11	0.24
MINNESOTA MINING & MANUFACTU RING	1.00	1.94	0.87	0.09	0.10	0.19
NATIONAL GYPSUM CO	1.99	2.93	(2.18)	(0.15)	(0.09)	0.11
OCCIDENTAL PETROLEUM CORP	0.34	0.94	3.90	0.03	0.02	0.08
PPG INDUSTRIES INC	0.87	1.58	1.29	0.00	0.00	0.01
PROCTER & GAMBLE CO	0.72	1.24	2.42	0.07	0.09	0.32
RHONE POULENC SA	0.60	1.33	3.19	0.01	0.01	0.05
ROHM & HAAS CO	0.91	1.71	1.63	0.03	0.03	0.09
SEARS ROEBUCK & CO	0.38	0.45	9.89	0.05	0.03	0.31
SMITHKLINE BEECHAM PLC	1.04	1.56	2.08	0.13	0.15	0.47
SONOCO PRODUCTS CO	0.93	1.69	1.49	0.06	0.07	0.19
SPS TECHNOLOGI ES INC	0.84	2.42	1.78	(0.10)	(0.11)	(0.30)
ST JOE PAPER CO	2.02	3.04	0.53	0.02	0.01	0.02
TARKETT INTERNATIO NAL GMBH	0.00	1.00	259.96	0.00	0.00	0.00
TEMPLE INLAND INC	0.35	0.52	6.03	0.04	0.01	0.07
USX CORP	0.36	0.95	3.60	(0.01)	(0.01)	(0.07)
VALSPAR CORP	0.94	1.74	0.71	0.06	0.12	0.20

WARNER LAMBERT CO	0.66	1.10	2.47	0.06	0.07	0.24
WEST PENN POWER CO	0.64	1.25	1.68	0.09	0.04	0.11
WESTINGHO USE ELECTRIC CORP	0.51	1.22	9.45	(0.04)	(0.03)	(0.33)
WESTVACO CORP	0.77	1.67	1.15	0.04	0.03	0.06
WITCO CORP	1.53	2.32	1.58	0.01	0.01	0.03
YORK INTERNATIO NAL CORP	0.64	1.35	1.92	0.00	0.00	0.01

4.2.3 Methodology

In order to assess firms' responsiveness to alternative incentives and financial ratios, the following regression equation is estimated:

$$y_i = \alpha + \sum_j \beta_j Z_{ji} + \varepsilon_i \qquad (4.2.1)$$

where y_i stands for the net income of the i-th firm, α is a constant, Z_j is the j-th vector of the Z-matrix which includes the explanatory variables, and finally β_j is the estimated coefficient of Z_j and ε_i is a white-noise error term. The Z_j matrix includes variables such as, cost of goods sold, research and development expenses, fixed costs, depreciation, interest expenses, taxes, measures of financial, operational and total leverages, and other aforementioned financial ratios, e.g., debt-equity ratio, current ratio, quick ratio, etc.

In order to determine the explanatory variables in the model, in the regression equation, a stepwise regression procedure is applied. Stepwise regression can adopt a forward selection criterion, where variables are added to the model sequentially until none of the remaining would have t-statistics with a P-value (significance level) smaller than a threshold value. Alternatively, it can also adopt a backward criterion, where starting from the full set of regressors, variables are deleted sequentially as long as their t-statistics produce a P-value larger than a threshold value. In this study, variables are added to the model sequentially; at each stage in this forward selection procedure, the backward selection algorithm is run to delete variables that now have small t-statistics.

It is known that ordinary least squares (OLS) provides a consistent estimator for β in the regression model $Y = X\beta + u$ in a large number of settings where the standard assumption that the residuals satisfy: $V = E(uu') = \sigma^2 I$. If this assumption is violated and the form of V is known, it may be possible to obtain a more efficient estimator by some form of generalized least squares (GLS). However, in certain cases, GLS for serially correlated residuals produces inconsistent parameter estimates (See Hayashi and Sims 1983). Moreover, in the case of heteroscedasticity, it may not always be clear what form V should take. Hansen (1982) demonstrated that it is possible to compute consistent estimators for the covariance matrix of estimators in a wide range of situations using a procedure that imposes little structure upon matrix V. An alternative method for calculating consistent covariance matrices for the estimated coefficients is provided by Newey and West (1987). Hence, to assure the reliability of the reported test statistics of estimated coefficients the regressions are performed with the Newey and West method.

Once the model is determined and estimated the coefficients can be translated to elasticity measures (at the averages), such that the sensitivity of firms' income with respect to 1% change in any of the explanatory variables can be determined. For example, the coefficient of the tax variable, once converted into an elasticity, will reveal how firms income will respond to a 1% change in taxes.

The net cost of the technological investment is estimated for each particular boiler in the sample; the framework developed in Sections 4.1 and 4.2 of the Phase II Final Report is utilized for this task (Miller et al., 2000). The net cost is divided by the current income of the firm in order to express the necessary increase in income in percentage points.

Consequently, the ratio of the percentage increase in income, which is necessary to induce the firms to adopt the new technology, to the elasticity of income to explanatory variables (incentives) reveals the amount of percentage change in incentive variables. Next, these percentage increases necessary to induce the desired change are converted into dollar amounts. The relationship between the induced change in income and the required amount of incentives is expressed as the "rate of return" of the incentive. Similarly, the variance-covariance matrix of estimated coefficients is employed to calculate the "standard deviations" and "correlation matrix" of incentives.

The financial theory of investments is based on the assumption that the essential characteristics of individual investment opportunities and portfolios are captured by information about their expected rate of return and the standard deviation of the return, i.e., the first two moments of the rate of return on the investment. Accordingly, any individual project or combination of projects, i.e., portfolios, can be represented in the "mean-variance (or standard deviation)" space. Modern portfolio theory suggests that individual investment opportunities (or portfolios) can be combined into further portfolios. Depending on the risk-return characteristics of the original investment opportunities, i.e., portfolios, and their correlation structure, the investors will end up with a set of portfolios that cannot be dominated by any other combination of portfolios. This set of portfolios is termed as "the efficient frontier" (see Figure 4.2.1). In the absence of a risk-free investment opportunity, the optimal portfolio of choice for the investors will be determined by their "risk tolerance" and it will be a point that is located on the efficient frontier. If, on the other hand, a risk-free investment alternative is allowed in the model, then portfolio theory suggests that, irrespective of their attitude towards risk, it is in the best interest of all investors to hold a combination of the "market portfolio" (M in Figure 4.2.1) and the risk-free asset. The market portfolio is simply the point of tangency of a ray to the efficient frontier which originates from the point of risk-free rate of return (RF in Figure 4.2.1) on the y-axis which measures the return.

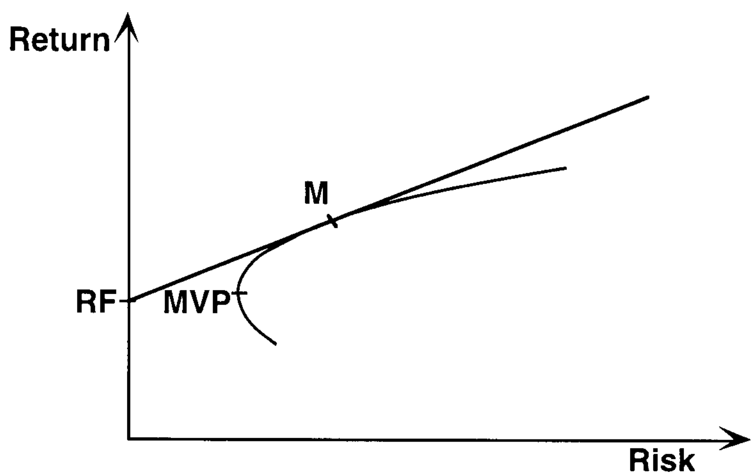

Figure 4.2.1 EFFICIENT FRONTIER AND THE MARKET PORTFOLIO

Once the incentives can be expressed in their first two moments, i.e., mean and variance, the standard Markowitz mean-variance portfolio analysis can be applied to the present context. Accordingly, one is able to determine: (i) the combination of incentives, which would require the least amount of risk-taking possible at the expense of a low return the minimum-variance portfolio, i.e., the minimum-variance portfolio (MVP in Figure 4.2.1); (ii) the efficient frontier, i.e., the set of combinations of portfolios which stochastically dominate others in terms of their moments; and finally, (iii) given the rate of return on a risk-free investment opportunity (real or financial), one can also calculate the optimal combination of incentives to induce the desired outcome, i.e., point M in Figure 4.2.1. In other words, the portfolio theory provides a useful decision-making tool in determining the optimal mix of incentives.

The risk-free rate of return in the present context can be understood as the ratio of the increase in firms' revenues (in terms of dollars) per dollar of incentives offered. For example, if the government were to pay *directly* for the costs of technological switch, the amount of increase in firms' revenues (or reduction in their costs) would be exactly equal to the amount of transfer. Thus, in such an event, the risk-free rate of return is simply equal to zero. Clearly, based on familiar welfare- or profit-maximization motives, one may suggest that the risk-free rate of return, in our context, should be set at a positive rate by the government. On the other hand, if there are significant positive externalities attached to the project, even moderate negative returns may be acceptable from the point of welfare maximization. In this study, a conservative approach was taken and consider non-negative risk-free rates of return, e.g., 0%, 3% and 5% were considered.

4.2.4 Empirical Results

As suggested in the previous section, a stepwise regression equation is performed as a first step in order to determine the correct model to be estimated. For this purpose *all* of the available RHS (right-hand-side) candidates are entered into the model and are held subject to sequential elimination where P (significance level) is set at 0.20. Out of the entire set of variables the following succeeded to remain in the model: cost of goods sold (COGS), research and development expenses (RDEXP), fixed costs (FIXED), depreciation allowances (DEPR), taxes (TAX), and measure of operating leverage (MOL).

After determining the estimation model, the regression equation is estimated by the method developed by Newey and West (1987). The results of the estimation and the calculated elasticities are reported in Table 4.2.4. The estimated equation has an R^2 of 0.80 and an adjusted R^2 of 0.76.

Table 4.2.4 Results of the Regression Equation

Variables	Coefficients	Elasticity	Absolute t-statistics
COGS	-0.0638	-1.1731	3.08
RDEXP	-1.9589	-0.8002	4.14
FIXED	0.0368	0.35265	5.09
DEPR	0.3344	0.20273	2.58
TAX	-2.4695	-1.9847	4.88
MOL	-33923.0837	-	3.06
Constant	273296.7198	-	3.02

Next, the magnitude of costs is calculated which is necessary to induce the desired technological change for each of the boilers in the sample (some firms have multi-boiler sites) using the framework that was reported the Phase II Final Report (Miller et al., 2000). The results about boiler-size, required capital costs and operating and maintenance costs are summarized in Table 4.2.5.

Table 4.2.5 Boiler-Specific Costs

Company Name	Boiler Size	Capital Costs	O&M Costs	TOTAL
ACF INDUSTRIES INC	50.0	1,677,521	(175,516)	1,502,005
ALCAN ALUMINUM LTD	5.0	298,310	(12,329)	285,981
ALCOA INTERNATIONAL HOLDINGS COMPANY	60.0	1,923,330	(214,207)	1,709,123
ALCOA INTERNATIONAL HOLDINGS COMPANY	60.0	1,923,330	(214,207)	1,709,123
ALCOA INTERNATIONAL HOLDINGS COMPANY	40.0	1,419,010	(137,333)	1,281,677
ALCOA INTERNATIONAL HOLDINGS COMPANY	40.0	1,419,010	(137,333)	1,281,677
ALLEGHENY LUDLUM CORP	50.0	1,677,521	(175,516)	1,502,005
ALLEGHENY LUDLUM CORP	50.0	1,677,521	(175,516)	1,502,005
ALLEGHENY LUDLUM CORP	36.0	1,311,195	(122,236)	1,188,959
ALLIED SIGNAL INC	60.0	1,923,330	(214,207)	1,709,123
AMERICAN HOME PRODUCTS CORP	20.0	843,748	(63,297)	780,452
AMERICAN HOME PRODUCTS CORP	27.6	1,074,292	(90,953)	983,339
AMERICAN HOME PRODUCTS CORP	125.0	3,335,208	(473,134)	2,862,074
AMERICAN HOME PRODUCTS CORP	125.0	3,335,208	(473,134)	2,862,074
ANGELICA CORP	20.0	843,748	(63,297)	780,452
ARCO CHEMICAL COMPANY	27.6	1,074,292	(90,953)	983,339
ARCO CHEMICAL COMPANY	27.6	1,074,292	(90,953)	983,339
ARMCO INC	30.0	1,143,619	(99,825)	1,043,794
ARMCO INC	30.0	1,143,619	(99,825)	1,043,794
ASHLAND OIL INC	17.0	746,925	(52,613)	694,313
ASHLAND OIL INC	23.0	936,993	(74,124)	862,869
AT&T CORP	60.0	1,923,330	(214,207)	1,709,123
AT&T CORP	60.0	1,923,330	(214,207)	1,709,123
AT&T CORP	30.0	1,143,619	(99,825)	1,043,794
AT&T CORP	60.0	1,923,330	(214,207)	1,709,123
BEATRICE FOODS INC	24.0	967,384	(77,761)	889,623
BEATRICE FOODS INC	24.0	967,384	(77,761)	889,623

BETHLEHEM STEEL CORP	16.0	713,724	(49,088)	664,636
BETHLEHEM STEEL CORP	16.0	713,724	(49,088)	664,636
BETHLEHEM STEEL CORP	16.0	713,724	(49,088)	664,636
BETHLEHEM STEEL CORP	30.0	1,143,619	(99,825)	1,043,794
BETHLEHEM STEEL CORP	30.0	1,143,619	(99,825)	1,043,794
BETHLEHEM STEEL CORP	100.0	2,821,243	(372,384)	2,448,859
BETZ LABORATORIES INC	40.0	1,419,010	(137,333)	1,281,677
BORDEN INC	10.0	501,696	(28,456)	473,240
BORDEN INC	10.0	501,696	(28,456)	473,240
BORDEN INC	25.0	997,460	(81,410)	916,050
CABOT CORP	30.0	1,143,619	(99,825)	1,043,794
CABOT CORP	30.0	1,143,619	(99,825)	1,043,794
CARBON GRAPHITE GROUP INC	50.0	1,677,521	(175,516)	1,502,005
CARBON GRAPHITE GROUP INC	50.0	1,677,521	(175,516)	1,502,005
CATERPILLAR INC	40.0	1,419,010	(137,333)	1,281,677
CHEVRON CORP	25.0	997,460	(81,410)	916,050
CHEVRON CORP	25.0	997,460	(81,410)	916,050
CONSOLIDATED CIGAR CORP NEW JERSEY	150.0	3,823,921	(574,894)	3,249,027
CONSOLIDATED CIGAR CORP NEW JERSEY	150.0	3,823,921	(574,894)	3,249,027
EXXON CORP	35.0	1,283,783	(118,481)	1,165,302
EXXON CORP	35.0	1,283,783	(118,481)	1,165,302
GENCORP INC	60.0	1,923,330	(214,207)	1,709,123
GENCORP INC	60.0	1,923,330	(214,207)	1,709,123
GENERAL ELECTRIC COMPANY	8.5	444,124	(23,480)	420,645
GENERAL ELECTRIC COMPANY	150.0	3,823,921	(574,894)	3,249,027
GENERAL ELECTRIC COMPANY	150.0	3,823,921	(574,894)	3,249,027
GENERAL SIGNAL CORP	30.0	1,143,619	(99,825)	1,043,794
GENERAL SIGNAL CORP	30.0	1,143,619	(99,825)	1,043,794
GUILFORD MILLS INC	5.0	298,650	(12,353)	286,297
GUILFORD MILLS INC	12.0	575,210	(35,220)	539,990
GUILFORD MILLS INC	35.0	1,283,783	(118,481)	1,165,302
H J HEINZ COMPANY	44.0	1,524,158	(152,537)	1,371,621
H J HEINZ COMPANY	44.0	1,524,158	(152,537)	1,371,621
H J HEINZ COMPANY	40.0	1,419,010	(137,333)	1,281,677
H J HEINZ COMPANY	150.0	3,823,921	(574,894)	3,249,027
HANOVER FOODS CORP	34.0	1,256,174	(114,733)	1,141,441
HANOVER FOODS CORP	34.0	1,256,174	(114,733)	1,141,441
HERCULES INC	12.0	575,210	(35,220)	539,990
HERCULES INC	12.0	575,210	(35,220)	539,990
INDSPEC CHEMICAL CORP	40.0	1,419,010	(137,333)	1,281,677
INDSPEC CHEMICAL CORP	40.0	1,419,010	(137,333)	1,281,677
INDSPEC CHEMICAL CORP	50.0	1,677,521	(175,516)	1,502,005
INDSPEC CHEMICAL CORP	50.0	1,677,521	(175,516)	1,502,005
INDSPEC CHEMICAL CORP	100.0	2,821,243	(372,384)	2,448,859
INDSPEC CHEMICAL CORP	150.0	3,823,921	(574,894)	3,249,027
J&L SPECIALTY STEEL INC	40.0	1,419,010	(137,333)	1,281,677
KRAFT GENERAL FOODS INC	50.0	1,677,521	(175,516)	1,502,005
LTV STEEL CO INC	60.0	1,923,330	(214,207)	1,709,123
LTV STEEL CO INC	77.5	2,330,326	(282,843)	2,047,483
LTV STEEL CO INC	77.5	2,330,326	(282,843)	2,047,483
LTV STEEL CO INC	77.5	2,330,326	(282,843)	2,047,483
LTV STEEL CO INC	80.0	2,386,481	(292,728)	2,093,753
LTV STEEL CO INC	80.0	2,386,481	(292,728)	2,093,753
LUKENS INC	18.0	779,641	(56,156)	723,485
LUKENS INC	18.0	779,641	(56,156)	723,485
LUKENS INC	47.5	1,614,212	(165,918)	1,448,295

LUKENS INC	47.5	1,614,212	(165,918)	1,448,295
MACK TRUCKS	55.0	1,801,824	(194,806)	1,607,019
MACK TRUCKS INC	55.0	1,801,824	(194,806)	1,607,019
MACK TRUCKS INC	55.0	1,801,824	(194,806)	1,607,019
MACK TRUCKS INC	55.0	1,801,824	(194,806)	1,607,019
MASLAND CORP	75.0	2,273,717	(272,977)	2,000,740
MASLAND CORP	60.0	1,923,330	(214,207)	1,709,123
MERCK & COMPANY INC	80.0	2,386,481	(292,728)	2,093,753
MERCK & COMPANY INC	80.0	2,386,481	(292,728)	2,093,753
MERCK & COMPANY INC	80.0	2,386,481	(292,728)	2,093,753
MINNESOTA MINING & MANUFACTURING	45.0	1,550,065	(156,353)	1,393,712
NATIONAL GYPSUM CO	53.0	1,752,457	(187,076)	1,565,381
OCCIDENTAL PETROLEUM CORP	60.0	1,923,330	(214,207)	1,709,123
OCCIDENTAL PETROLEUM CORP	100.0	2,821,243	(372,384)	2,448,859
OCCIDENTAL PETROLEUM CORP	100.0	2,821,243	(372,384)	2,448,859
OCCIDENTAL PETROLEUM CORP	100.0	2,821,243	(372,384)	2,448,859
PPG INDUSTRIES INC	40.0	1,419,010	(137,333)	1,281,677
PPG INDUSTRIES INC	50.0	1,677,521	(175,516)	1,502,005
PPG INDUSTRIES INC	50.0	1,677,521	(175,516)	1,502,005
PPG INDUSTRIES INC	125.0	3,335,208	(473,134)	2,862,074
PROCTER & GAMBLE CO	99.0	2,800,057	(368,379)	2,431,678
PROCTER & GAMBLE CO	99.0	2,800,057	(368,379)	2,431,678
RHONE POULENC SA	50.0	1,677,521	(175,516)	1,502,005
RHONE POULENC SA	50.0	1,677,521	(175,516)	1,502,005
RHONE POULENC SA	50.0	1,677,521	(175,516)	1,502,005
RHONE POULENC SA	50.0	1,677,521	(175,516)	1,502,005
RHONE POULENC SA	50.0	1,677,521	(175,516)	1,502,005
RHONE POULENC SA	50.0	1,677,521	(175,516)	1,502,005
ROHM & HAAS COMPANY	30.0	1,143,619	(99,825)	1,043,794
ROHM & HAAS COMPANY	30.0	1,143,619	(99,825)	1,043,794
ROHM & HAAS COMPANY	30.0	1,143,619	(99,825)	1,043,794
ROHM & HAAS COMPANY	110.0	3,030,296	(412,545)	2,617,750
ROHM & HAAS COMPANY	110.0	3,030,296	(412,545)	2,617,750
ROHM & HAAS COMPANY	125.0	3,335,208	(473,134)	2,862,074
ROHM & HAAS COMPANY	125.0	3,335,208	(473,134)	2,862,074
ROHM & HAAS COMPANY	125.0	3,335,208	(473,134)	2,862,074
ROHM & HAAS COMPANY	125.0	3,335,208	(473,134)	2,862,074
ROHM & HAAS COMPANY	125.0	3,335,208	(473,134)	2,862,074
SEARS ROEBUCK & CO	40.0	1,419,010	(137,333)	1,281,677
SEARS ROEBUCK & CO	40.0	1,419,010	(137,333)	1,281,677
SEARS ROEBUCK & CO	40.0	1,419,010	(137,333)	1,281,677
SEARS ROEBUCK & CO	40.0	1,419,010	(137,333)	1,281,677
SMITHKLINE BEECHAM PLC	40.0	1,419,010	(137,333)	1,281,677
SONOCO PRODUCTS COMPANY	80.0	2,386,481	(292,728)	2,093,753
SPS TECHNOLOGIES INC	55.0	1,801,824	(194,806)	1,607,019
SPS TECHNOLOGIES INC	55.0	1,801,824	(194,806)	1,607,019
ST JOE PAPER CO	40.0	1,419,010	(137,333)	1,281,677
ST JOE PAPER CO	40.0	1,419,010	(137,333)	1,281,677
TARKETT INTERNATIONAL GMBH	75.0	2,273,717	(272,977)	2,000,740
TEMPLE INLAND INC	40.0	1,419,010	(137,333)	1,281,677
USX CORP	8.6	449,014	(23,891)	425,123
USX CORP	50.0	1,677,521	(175,516)	1,502,005
USX CORP	50.0	1,677,521	(175,516)	1,502,005
USX CORP	56.0	1,826,339	(198,677)	1,627,662
USX CORP	56.0	1,826,339	(198,677)	1,627,662
USX CORP	60.0	1,923,330	(214,207)	1,709,123
VALSPAR CORP	20.7	865,801	(65,811)	799,990

WARNER LAMBERT COMPANY	27.0	1,056,728	(88,744)	967,984
WARNER LAMBERT COMPANY	30.0	1,143,619	(99,825)	1,043,794
WARNER LAMBERT COMPANY	30.0	1,143,619	(99,825)	1,043,794
WEST PENN POWER COMPANY	32.0	1,200,336	(107,261)	1,093,075
WEST PENN POWER COMPANY	32.0	1,200,336	(107,261)	1,093,075
WESTINGHOUSE ELECTRIC CORP	10.3	514,809	(29,629)	485,179
WESTINGHOUSE ELECTRIC CORP	80.0	2,386,481	(292,728)	2,093,753
WESTINGHOUSE ELECTRIC CORP	20.0	843,748	(63,297)	780,452
WESTINGHOUSE ELECTRIC CORP	20.0	843,748	(63,297)	780,452
WESTINGHOUSE ELECTRIC CORP	20.0	843,748	(63,297)	780,452
WESTVACO CORP	85.0	2,497,495	(312,549)	2,184,946
WESTVACO CORP	85.0	2,497,495	(312,549)	2,184,946
WITCO CORP	50.0	1,677,521	(175,516)	1,502,005
WITCO CORP	50.0	1,677,521	(175,516)	1,502,005
WITCO CORP	60.0	1,923,330	(214,207)	1,709,123
WITCO CORP	60.0	1,923,330	(214,207)	1,709,123
WITCO CORP	60.0	1,923,330	(214,207)	1,709,123
WITCO CORP	65.0	2,042,328	(233,709)	1,808,619
WITCO CORP	65.0	2,042,328	(233,709)	1,808,619
WITCO CORP	75.0	2,273,717	(272,977)	2,000,740
WITCO CORP	90.0	2,606,888	(332,435)	2,274,453
YORK INTERNATIONAL CORP	30.0	1,143,619	(99,825)	1,043,794
YORK INTERNATIONAL CORP	46.0	1,575,828	(160,174)	1,415,654
			SUM =	$ 249,600,082
			AVERAGE =	$ 1,531,289

The firms in the sample have boilers of an average size of 54.4 million Btu/h and total size of 8,868 million Btu/h. The capital costs of retrofitting for all boilers is estimated to be $281.4 million; the operation and maintenance cost(+) / benefit(-) ratio is estimated to be -$31.8 million, which is due to fuel savings. Thus, the total cost of retrofitting all of the boilers in the sample amounts to $249.6 million.

The boiler-specific cost figures are expressed as percentages of firms' net income. This represents the amount that needs to be induced by means of government incentives. The desired increase in firms' income combined with the calculated elasticities (taken from Table 4.2.4) - which measure the sensitivity of firms' net income to a 1% change in the value of incentives- to obtain the dollar amounts of each of the incentives required to generate the desired outcome. The findings are presented in Table 4.2.6.

Table 4.2.6 Factors and their Effectiveness

Incentive	Amount Needed	Standard Deviation	Rate of Return
Cogs (VAT)	$ 3,912,226,000	2.1%	-93.62%
R&D Subsidy	$ 127,418,400	47.4%	95.9%
Depr.Allowance	$ 746,411,720	13.0%	-66.6%
Tax Cut	$ 101,073,100	50.5%	+146.95%

The results of the stepwise regression estimation (given in Tables 4.2.4 and 4.2.6) show that the relationship between interest payments and firms' net incomes are not statistically significant. This result indicates that interest rate-related government incentives, such a reduced or zero-interest loan, will not necessarily induce the desired increase in net income needed for technology adoption.

On the other hand, it is observed that the net income of firms in the sample are responsive to fluctuations in the cost of goods sold, the amount paid for research and development expenses, depreciation allowances, and taxes. Table 4.2.6 presents the estimated dollar amounts of change needed to induce the desired increase in firms' income, i.e., $249.6 million, to induce them to undertake the technological investment at each and every boiler site in the sample. Accordingly, declines in the cost of goods sold, research and development expenses, and tax burdens by 3,912.2, 127.4 and 101.1 million dollars, respectively, and an increase in their depreciation allowances by $746.4 million will induce an increase in their profits by the targeted amount.

In Table 4.2.6, the necessary changes are also expressed in terms of "rate of return" in order to obtain an understanding about their effectiveness. The "rate of return" is achieved by taking the ratio of the target change in income to the required change in the aforementioned factors and subtracting one from it. Clearly, this approach assumes that there are no externalities (one way or another) attached with any of the incentives under consideration and hence, the "return" of the incentive is measured as the monetary increase in firms' profits. The results are striking. It turns out that only tax cuts and reductions in research and development expenses provide positive returns. Magnitudes of required changes in cost of goods sold and depreciation allowances exceed the 'benefits', i.e., the increase in firms' profits by a significant amount.

If one were to choose only one investment incentive, the best candidates appear to be tax cuts or subsidies that are specifically aimed at covering research and development expenses. The empirical findings indicate that interest-related incentives, such as reduced or no-interest loans, will not generate the desired outcome for the firms studied. On the other hand, an incentive that will reduce the cost of goods sold or to increase the depreciation allowance is statistically significant on firms' profits, and thus present feasible alternatives. However, analyzing their effectiveness yields the result that they are inferior when compared with the other two alternatives: tax cuts and subsidies extended for research and development.

Nevertheless, someone who is familiar with the benefits of portfolio analysis may wonder whether a combination of these alternatives can yield a superior result. To explore possible benefits from portfolio analysis the reported rates of return (see Table 4.2.7), their volatilities (which are based on the standard errors of estimated coefficients), and the correlation matrix of estimated parameters are utilized to perform a standard, Markowitz type, portfolio analysis.

Table 4.2.7 The Correlation Matrix of Estimated Coefficients

	RDEXP	DEPR	TAX
VAT(Subsidy)	0.08	-0.28	0.85
R&D Subsidy	1.00	-0.22	0.22
Depr. Allowance	-0.22	1.00	0.08
Tax Cut	0.22	0.08	1.00

In the case of depreciation allowance and taxes, it is relatively obvious how they are linked to a government incentive scheme. An increase in depreciation allowances or a decrease in tax rates works as an incentive for firms. The link of cost of goods sold and research and development taxes to government incentives of is less obvious. The government can affect the cost of goods sold by means of a subsidy/tax that depends on the sales volume. A good example for this scheme is the value-added tax (VAT). An incentive, in the current context, can simply be thought as a negative VAT. Similarly, an incentive through research and development expenses can be imagined as a specific government subsidy that is meant to cover a portion or the entire amount of firm's research and development expenses.

One may argue that introduction of a (negative) VAT-like schedule would require institutional changes, and thus, in the short- to middle-run its feasibility is questionable. Recognizing this potential criticism, the portfolios were stimulated with and without the COGS (cost of goods sold) variable to account for both possible states of the world.

Portfolio return and volatility calculations are performed assuming a wide range of rate of return that varies between 0 and 100%. In addition, the characteristics of the minimum variance portfolio are calculated for both sets of portfolios. Furthermore, the tangent of the straight line (ray) originating from the locus of the risk-free return, i.e., the market rate of return, is calculated, as well. According to the theory this is the portfolio that investors of all types of risk aversion would hold to maximize their expected utility. The results of the portfolio simulations with COGS variable and without it are presented in Tables 4.2.8 and 4.2.9, respectively.

Table 4.2.8 Risk and Return of Various Portfolios (with COGS)

MVP	1	2	3	4	5	6	7	8	9	10	11
VAT	96.2	7	4.2	2.4	-2.1	-11.1	-20.1	-29.1	-38.2	-60.7	-83.3
R&D	1	19.8	20.3	20.7	21.7	23.6	25.5	27.4	29.3	34	38.8
DEPR	6.5	56.3	57.8	58.8	61.3	66.3	71.3	76.4	81.4	94	106.5
TAX	-3.7	17	17.7	18.1	19.1	21.2	23.3	25.4	27.5	32.7	38
Return	-98.9	0	3	5	10	20	30	40	50	75	100
Risk	0.6	15.2	15.7	16	16.8	18.3	19.8	21.4	22.9	26.8	30.6

Table 4.2.9 Risk and Return of Various Portfolios (without COGS)

MVP	1	2	3	4	5	6	7	8	9	10	11
R&D	11.1	19.7	20.3	20.7	21.6	23.5	25.4	27.3	29.1	33.8	38.5
DEPR	87.8	64.1	62.6	61.5	59.0	53.8	48.7	43.6	38.4	25.6	12.8
TAX	1.1	16.1	17.1	17.8	19.4	22.7	25.9	29.2	32.4	40.6	48.7
Return	-46.1	0	3	5	10	20	30	40	50	75	100
Risk	11.5	15.3	15.7	16	16.7	18.4	20.1	21.9	23.8	28.6	33.6

Tables 4.2.8 and 4.2.9 display the analysis of eleven portfolios based on their return and risk characteristics. The MVP portfolio, in both tables, refers to the minimum-variance portfolio, i.e., the combination of risky assets that generate the portfolio with lowest possible level of risk. Portfolios 1-10 stand for portfolios with expected rates of returns varying between 0% (Portfolio 1) and 100% (Portfolio 10). All of the entries are reported as percentages and the figures next to the variables simply indicate their portfolio weights. For example, according to Table 4.2.8, in order to establish an incentive portfolio which generates a rate of return of 0% (Portfolio 1), the value added tax (subsidy) should have a weight of 7%, research and development subsidies should have a weight of 19.8%, depreciation allowances 56.3% and finally tax incentives 17%. This represents a particular mix of risky incentives, which are combined into a portfolio which offers exactly a 0% rate of return, just as a direct subsidy would which is offered to the firm which reimburses all of the costs (of the switch) directly. A comparison of the results presented in the two tables yields that the risk-return relationship for portfolios 1-10 is not significantly different from each other, i.e., for a given rate of return the portfolio volatility seems to be very similar.

In Table 4.2.8, it is observed that the weights of research and development subsidies and taxes increase as the resulting portfolios allow for more risk. The risk is controlled by the combination of VAT (subsidy) and depreciation allowances. It is interesting to note that after a certain level of risk the weight of VAT (subsidy) becomes negative, i.e., it suggests that after a certain level of risk it is beneficial from a portfolio analysis point of view for the government to introduce a positive value-added tax, which is to be compensated by the increase of depreciation allowances.

In Table 4.2.9, which excludes the cost of goods (COGS) variable, it is observed that as the expected rate of return increases the research and development subsidies and tax incentives move in opposite directions, i.e., the weight of taxes increases and the other one decreases. Depreciation allowances, which counterbalances the other two in the degree of risk, loses its importance in the portfolio greater risk is allowed, whereas, its weight becomes larger for portfolios which are exposed to a lesser degree of uncertainty.

Having calculated the risk-return relationships and the weights of each incentive in different portfolio mixes, the next relevant question to focus on is the location of the "market portfolio". In the presence of a risk-free rate of return, the risk-free rate and the market portfolio span the so-called "capital-market line", which is the locus of efficient and dominant portfolios in the market; accordingly any position on the capital-market line can be achieved by combining the risky market portfolio and the risk-free security.

Under the presumption that the government can with 100% probability achieve its goal of spreading the commercial usage of the new technology by extending direct subsidies, which cover all of the required switching costs to firms which are willing to undertake the necessary technological investment, the direct subsidy incentive can be regarded as a no-risk, i.e., *risk-free* incentive alternative. Hence, direct subsidies are introduced to the analysis as the risk-free security and solve for the point of tangency to find the market portfolio. In both scenarios, i.e., with and without the COGS variable (Tables 4.2.8 and 4.2.9, respectively), the optimal tangency portfolio coincides with a portfolio which is formed 100% by the tax incentive.

Furthermore, in order to account for values which are not accounted for by the standard discounted cash flow analysis, e.g., externalities and option values, the rate of return for the risk-free incentive for -3% and -5% is set and the optimal market portfolio is solved under these assumptions. The results, once again depict the 100% tax incentive portfolio as the optimal market portfolio.

In other words, provided that the direct subsidies can be viewed as risk-free, i.e., the government is 100% confident that it can initiate any marginal technological investment behavior in the industry by undertaking all of the necessary cost by its own if it chooses to do so, it is in government's, and all taxpayers' best interest to offer government incentives in the form of tax cuts, only. Furthermore, even if the risk-free incentive, i.e., direct subsidies generate a subzero rate of return, due to externalities, or some other reasons, the result of the analysis remain unaffected and the 100% tax incentive emerges as the optimal portfolio incentive. In sum, the preceding analysis clearly shows that the tax incentives are the most effective incentives the government can offer to induce increases in firms' profits and thus to induce them to adopt the desired technological changes.

4.2.5 Conclusion

The initial premise of the study was that there are social, political and economic benefits (in market and non-market value) that can be gained by the widespread adoption and commercialization of the new coal-based technology. The adoption of the new technology will most likely be achieved through measures that reduce capital costs and not through serendipitous changes in oil price alone. Thus, the findings can be interpreted as if to indicate that even though the adoption of the new technology may have macroeconomic advantages for the economy, additional incentives may be needed to induce such an adoption at the microeconomic level, i.e., at the firm level.

Economic and financial incentives have become accepted tools for the implementation for preferred government policies. Typical examples range from investment tax credits and reduced or zero-interest loans to capital subsidies and direct and indirect (such as accelerated depreciation) tax incentives. The existing studies on the effectiveness of policy incentives, on average, remain highly macroeconomics oriented and have little to say about the consequences in a given sector in the economy.

This study focused on the microeconomic responses generated by the firms to the incentives. Firm-specific data were examined that have a potential use for the new technology. The optimal incentive and policy mixes determined are based on empirical estimation of firms' reactions to various factors. It needs to be emphasized that one incentive may be optimal with projects with characteristic "A", whereas another may be more suitable if the project has characteristic "B". For example, tax incentives can be thought to be more effective on projects which require a big initial capital outlay, whereas, reduced or zero-loan incentives may prove to be more useful in the case of projects which are highly sensitive to interest rate fluctuations in the market.

The adoption of the new technology can be viewed as an "investment" in the new technology and thus, tools of modern finance and portfolio theory can be applied to the problem at hand. First, the sensitivity of firms' net income to various factors is estimated. The required increases in a firms' income is estimated by adopting a framework in the Phase II Final Report. It turns out that the cost of technology adoption (net of fuel savings benefits) is $249.6 million for all 163 boilers in the sample (or $1.5 million, on average). Consequently, based on the sensitivities (expressed in terms of percentage responses) to induce a 1% change in income, and the required change in income, the dollar amounts a set of incentives are calculated which are needed to generate the desired outcome. Accordingly, a decline of $3,912.2 million in the cost of goods sold, $127.4 million in research and development expenses, $101.1 million in firms' tax burden, or an increase of $746.4 million in firms' depreciation allowances, induce the desired increase in the net income of the firms in the sample.

Recognizing that incentives, on average, do not induce the desired outcome with 100% certainty, the benefits of offering the incentives as a portfolio rather than individually are investigated. The effectiveness of incentives is expressed in terms of their rate of return and risk. Consequently, the composition of optimal portfolios is calculated for several rates of return ranging from 0-100% and for the minimum risk portfolio. The results are estimated for two different cases: with and without cost-of-goods (COGS) as an incentive variable. Noting that the government can affect the cost of goods sold by imposing a value-added tax or subsidy, one may argue that COGS can be viewed as a possible incentive variable. Table 4.2.8 presents the optimal portfolios for this case. On the other hand, the introduction of a value-added tax/subsidy scheme can be viewed as technically difficult in the short to medium-term. Thus, alternatively, another set of optimal portfolios is calculated for the same set of returns, excluding the COGS variable (Table 4.2.9).

It appears that the risk-return relationship is not significantly altered by the inclusion/exclusion of that variable. Tables 4.2.8 and 4.2.9 show that for low risk-low return portfolios depreciation incentive has a significant weight in both portfolios and that its weight decreases as the portfolios become riskier. In contrast, tax and research and development expense incentives appear to have lower weight for low-risk portfolios, which increases gradually as portfolios are aimed at higher return. In addition, an interesting finding of the analysis is that the firms in the sample are not sensitive to interest-rate based incentives, such as a reduced or zero-rate loan.

Finally, given a risk-free investment opportunity in the economy the 'market portfolio' can be estimated. In theory this is the only risky portfolio, which will be held by all investors, irrespective of their attitude towards risk. If one makes the assumption that direct capital subsidies that cover the full cost of the technological investment are literally risk-free in achieving the desired changes, it can be incorporated in the model to estimate the market portfolio that dominates all other risky portfolios in the existence of a risk-free investment opportunity. The direct capital subsidies, by definition, offer a rate of return of 0%. However, to account for externalities and so forth which are not incorporated in the analysis directly, two negative rates of return of -3% and -5% are allowed for on the risk-free alternative. Notably, the point of tangency in all three cases happens to be a portfolio that consists of only the tax incentive, i.e., the weight of the tax incentive is 100%. This result shows that in the existence of a no-risk opportunity, the tax incentive is the best alternative to offer to the industry to induce an increase in their profits.

It should be added that a precise answer about the *best* incentive portfolio varies depending on the shape of government's indifference curves, which depict information about how the risk-return tradeoff is viewed by the government at various levels of returns. The *best* portfolio is determined simply at the point of tangency between the indifference curves and the efficient frontier that is formed by the combination of the risk-free investment alternative and the market portfolio (or just by the locus of efficient risky portfolios in the absence of a risk-free alternative). Thus, for the selection of the best suitable incentive mix, the findings and results provided by this study will provide valuable insights to the policy makers.

4.3 Community Sensitivity to Coal Fuel Usage: Economic Valuation of Risk Perceptions: Measuring Public Perceptions and Welfare Impacts of Electric Power Facilities

4.3.1 Introduction

This activity developed methods that integrate economic valuation with the techniques used in psychology to characterize risk perceptions to value the welfare impacts due to the presence of energy production facilities. A contingent valuation survey, designed with cognitive survey design methods, was administered to elicit quantitative information regarding individuals' perceptions of the risks associated with fossil fuel-based electric power facilities and, the individuals' willingness to pay to prevent or change risk exposure levels. The quantitative measures of risk perceptions are related to the willingness to pay values using maximum likelihood estimation.

The underlying conceptual rationale for valuing changes in perceived risk combines findings from the risk perception literature with expected utility theory. Using an economic model of individual willingness to pay to avoid risks, this study identifies factors that contribute to individual willingness to prevent energy production facilities. Specific focus is placed on developing quantitative measures of perceived risk that can be utilized to derive welfare changes induced by such facilities.

This research measures the individual's *ex ante* marginal willingness to pay to prevent or change their (perceived) risk exposure level from an electric power facility, determined, in part, by the perceived risk attributes. Obtaining the value of individual preferences of risk levels can assist in facility siting decisions by measuring how much individuals will pay to influence decisions or to what extent they will willingly bear the costs of a more expensive, but more desirable fuel.

Results show that welfare impacts, as measured by option price, depend on an individual's perceptions of the health, environmental, aesthetic, and economic impacts as well as their socio-demographic characteristics. Individuals seemed to have difficulty distinguishing between the probability and the severity of a risk in the manner suggested by the definition of risk, although the survey instrument may have been unable to capture the difference. Perceived environmental, health, and aesthetic impacts play a larger role than potential economic impacts in determining option prices, explaining in part why residents may oppose a facility even when it will likely bring economic benefits to an area.

Risk has long been an important focus in psychology. According to Slovic (1987), a professor of psychology, "[t]he ability to sense and avoid harmful environmental conditions is necessary for the survival of all living organisms." Economists also recognize that individuals place an implicit value on risk, but have only recently begun to incorporate such values in the public decision-making process. This study integrates the economics of welfare measurement with the psychological characterization of risk perceptions. Using methods from cognitive psychology (Jabine, et al., 1984), a contingent valuation survey is developed to elicit quantitative information about individuals' perceptions of the risks associated with locally sited fossil-fuel electric power facilities, including utility generators, and independent power producers. Psychometric scales are used to quantify risk perceptions, which are then related to the option price for eliminating or reducing risks. This research extends prior work from the psychology literature by focusing on a specific hazard scenario rather than general "risk" and by examining perceptions of different components making up a risk. The study estimates individuals' marginal willingness to pay (WTP) as a function of these risk perceptions as well as sociodemographic characteristics conventionally modeled as determinants of WTP. Empirically, the model considers multiple perceived risk components identified through focus groups and cognitive interviews. An implicit factor analysis identified four risk components: health risks, aesthetic risks, environmental risks, and beneficial or detrimental economic changes resulting from facility construction and operation.

The field of risk assessment has only recently been extended into economic valuation, so that values can be assigned to the welfare changes resulting from changes in risk exposure. An industrial facility such as an electric power plant can expose a community to a wide variety of hazards, including environmental and health hazards, amenity or aesthetic effects, and changes in traffic patterns and congestion. In addition, their construction and operation can induce economic impacts in the host community such as changes in employment, price levels, and tax revenues. An associated probability distribution characterizes the likelihood that each consequence due to a facility will actually occur. Individuals make behavioral decisions based upon their perceptions of the probability and severity of impacts from such facilities. In this manner, welfare is based upon each individual's perception of risk.

Regulatory changes in the 1980s and 1990s have prompted a significant increase in the location of small energy generation facilities close to residential communities. The Energy Information Agency (U.S. Department of Energy, 1993) predicts a 15% increase in new coal-fired generation capability (170 250-MW plants) and a 31% increase in oil and natural gas-fired generation capability (925 100-MW facilities) by the year 2010. Some proposed facilities have been vehemently opposed by local residents, regardless of experts' attempts to communicate that the benefits could significantly outweigh any associated risks. Such opposition to otherwise economically efficient projects may arise, in part, because layperson or non-expert risk perceptions related to energy generation facilities differ from those of "experts."

Risk assessments by experts are likely to differ from risk assessments by ordinary citizens (Fisher 1991). Laypeople often react to potential hazards or undesirable facilities in a way that is considered disproportionate to the risks involved. Experts have made substantial progress in identifying and measuring "objective" risks but understand less well how individuals perceive risks and how they value changes in risk. Because an individual's behavior and values are based on risk perceptions, a better understanding of risk perceptions and how they influence individual values needs to be developed. Improved understanding of risk perceptions will provide a basis for understanding and anticipating responses to hazards and undesirable facilities and aid in designing risk communication programs to increase understanding of such facilities.

Results from this study show that individuals' willingness to pay for risk prevention or reduction is a function of their perceptions of the health, environmental, aesthetic, and economic impacts as well as their socio-demographic characteristics. Individuals appear unable to distinguish between the probability and the severity of a risk in the manner suggested by the definition of the risk. Perceived environmental, health, and aesthetic impacts play a larger role in determining option prices than potential economic impacts, explaining in part why residents may oppose a facility even when it will likely bring economic benefits to an area.

4.3.2 Background And Previous Research

4.3.2.1 Risk Perceptions

Associated with any hazard are a variety of consequences. Risk is a quantitative measure of the likelihood and severity of those consequences, usually expressed in terms of conditional probabilities or other technical and quantitative measures. Scientists and engineers must assign probabilities to the occurrence of hazardous events in order for risk mitigation policy decisions to be made. Expert risk assessments are based upon quantitative and technical data that are often not readily understood by the general public. Perceived risk, though, is a function of the actual impacts of a hazard in addition to many unquantifiable and unique cognitive dimensions that are derived from personal experiences and preferences (Bostrom et al., 1992).

Risk perception research entails understanding, from a layperson's point of view, what is known about a hazard, what is thought to cause it, and its perceived impacts. The objective is to learn what people know about a particular hazard and how they incorporate risk information into their personal knowledge set or "mental model." Risk perceptions are then defined as a function of the "true" risk and the differential between layperson and expert mental models. Past research has revealed that laypersons rank as most serious risks that are catastrophic, involuntary, unfamiliar, dreadful, uncontrollable, or having an uncertain and inequitable distribution of consequences. In general, laypersons tend to have greater concern for and overestimate "small" risks and less concern for and underestimate "large" risks (Slovic et al., 1985; Slovic 1987; Covello et al., 1993).

Slovic (1987) mapped the perceived risk of 81 hazards over the factors unknown risk and dread risk. Non-nuclear power generation, coal combustion, and fossil fuels appear in the upper-right quadrant of the perceived risk mapping, that includes risks characterized as "unobservable," "unknown to those exposed," "delayed effect," "new risk unknown to science," "uncontrollable," "catastrophic," "inequitable," "not easily reduced," "of high risk to future generations," and "involuntary." Risks located in this quadrant can be thought of as those most difficult to mitigate through regulatory channels and presenting the greatest challenges to risk communicators and mitigators.

Cognitive dissonance explains systematic differences in the interpretation of information, as well as in individuals' receptivity to new information according to preferences and beliefs (Akerlof and Dickens, 1982). Cognitive dissonance theory has also been useful in explaining why a differential between lay and expert risk judgments persists and why individuals may not believe risk information provided by experts. Studies have revealed that risk communication is more effective and more likely to be understood by the targeted public when lay risk perceptions are identified *a priori* (Fisher et al., 1991). Effective risk communication requires that the *relevant* risk information be presented so that it is most likely understood by the public in the manner in which it was intended.

The study and characterization of risk perceptions are an established precursor to developing effective risk communication. More recently, the field of risk assessment has been extended into economic valuation of the welfare changes resulting from changes in risk exposure. Determining the welfare impacts of undesirable land uses should include the value individuals place on perceived changes in risk. This study measures laypersons' *ex ante* WTP (or option price) to decrease or completely eliminate a particular risk exposure level, determined in part by the perceived attributes of a risk.

4.3.2.2 Valuation and Perceived Risks

Slovic's (1987) characterizations of perceived risk according to the degree of voluntariness, immediacy of effect, familiarity, controllability, likelihood of catastrophic consequences, dread, and severity of consequences have provided a solid foundation for many subsequent studies. Slovic et al. (1985) found the following: (i) different groups, including laypersons and experts, have very different attitudes towards risks, (ii) experts tend to rate risks according to annual fatalities or other technical and quantitative measures, (iii) laypersons rate risks on different criteria than experts, and (iv) laypersons tend to want stricter regulation of the hazards they perceive as most risky.

Empirical studies have tended to value welfare shifts induced by changes in risk for a range of hazards. A few studies have developed a methodology to evaluate changes in the risk of a specific hazard. Although the studies differ in many regards, all combine a quantitative component, such as Slovic's psychometric scales, with a contingent valuation instrument (CVM) to elicit willingness to pay for changes in the risk levels of one or more hazards. The conceptual framework underlying these studies assumes that an individual's utility is a function of socioeconomic characteristics and some variant of risk attributes or risk levels. Applying the theory of cognitive dissonance to economic theory, Akerlof and Dickens (1982) incorporated a subjective assessment of risk into an economic valuation of hazardous jobs in the labor market. Römer and Pommerehne (1994) developed a contingent valuation instrument to elicit WTP for the reduction of hazardous waste risk in West Berlin; they consider private averting activities and strategic behavior. Savage (1993) evaluated risk judgments and their influence on relative WTP values to reduce the exposure levels of four "cognitively different" risks. The study found that people are most likely to have different values for reducing different types of risks.

McDaniels et al. (1992) model a household's option price for decreased risk exposure ("safety") as a function of the household's socioeconomic characteristics and perceived attributes of each of ten common risks. The perceived characteristics component consists of a household's familiarity with the risk, perceived exposure, and the degree of dread associated with each risk, which are essentially the factor composites Slovic derived in his 1987 study (Slovic 1987). A CVM instrument using psychometric scales and open-ended valuation questions elicited respondent's willingness to pay for decreases in risk exposure. Their analysis suggests that perceived risk characteristics, perceived exposure levels, age, and income all significantly affect an individual's valuation for a reduction in risk across a range of hazards. In their model with only well-defined risks, personal exposure to the risk was an important determinant, while dread and severity were important factors for the less-defined risks. McDaniels et al. (1992) consider general risks such as air safety rather than specific risks, and do not separate risk into components such as health and environment.

Smith and Desvousges (1987) consider hazardous wastes to explore how marginal valuations of risk changes vary with the size of the baseline risk and the direction of the risk change (i.e., either a decrease or increase in risk levels). Individual risk judgments are related to WTP for changes in perceived risk exposure, income, and other socio-economic characteristics. Marginal valuations to *avoid risk increases* declined with increases in the risk level; the mean valuations to *reduce baseline risk* were greater than the valuation to *avoid risk increases.* The results could imply that valuations to reduce the risk imply a different property right than valuations to avoid a risk increase. Valuations to reduce risk and to avoid a risk increase are essentially measuring two different types of changes in utility.

Psychological methods to characterize perceived risk have contributed to improved risk communication methods and provided a solid foundation for risk valuation studies. Studies based upon cognitive psychology have found that a differential exists between expert and non-expert risk judgments and that risk attributes influence risk perceptions. Economic models that incorporate perceived risk have shown that income and perceived risk are strong determinants of WTP to reduce/change risk exposure. In addition, research has found that the stated baseline risk level may be a determinant of WTP values, and that cognitively different risks are likely to generate different values for reducing risk exposure. However, nearly all studies in this area exclude non-health risks and focus on how hazards influence values to change personal exposure to risks. This study extends previous studies to include risks to the environment, the economy, and aesthetics, in addition to human health.

4.3.3 Theory

Expected utility theory is based upon "objective" or true probabilities and the certainty of future states of the world (von Neumann and Morgenstern, 1944). Savage (1954) and Anscombe and Aumann (1963) extended expected utility theory by incorporating subjective probabilities into the expected utility model. Subjective probability is extensively discussed in the economics literature, though little is said about the perceptions of the magnitude or severity of risk consequences. This research assumes that individuals make choices within an expected utility framework according to their perceptions of the probabilities and the consequences; the expected utility model is naturally inclusive of this concept.

The contingent valuation survey used for this analysis elicits individuals' WTP to avoid or reduce exposure risks due to a facility that burns either coal or natural gas to generate electricity. Individuals are uncertain with regard to the likelihood and severity of risk consequences as a result of a particular facility or fuel type. The risks of such a facility can be disaggregated into probability and severity characteristics to emphasize their individual effects on option price.

Let *EN* measure the environmental consequences of an adverse event and *X* the bundle of consumption goods over which the individual maximizes utility. Utility (*U*) is a state-dependent function of environmental quality and consumption,

$$U = U(X, EN), \quad \text{where} \quad \frac{\partial U}{\partial X} > 0, \; \frac{\partial U}{\partial EN} < 0. \qquad (4.3.1)$$

Maximizing utility subject to a budget constraint, with *I* denoting income and *P* denoting a price vector, results in the *ex post* indirect utility function, $u = v(I, P, EN)$.

Consistent with a framework where policy decisions are made and associated welfare impacts measured, individuals are assumed to make ex ante decisions when facing a risk. An individual may be willing to pay, *ex ante*, to reduce or eliminate a risk, regardless of which state of the world is realized, *ex post*. An *ex ante* payment made independent of the future outcome is referred to as a state-independent payment or an option price (*OP*).

Let p represent the probability of an adverse event occurring and 1-p the probability of the event not occurring. If $EN = 0$, the event has no negative environmental consequence. The level of a negative environmental impact associated with the event is measured by $EN = EN^*$. The corresponding option price for reducing EN^* to zero is the solution to

$$\begin{aligned}&(\pi)v(I,\mathrm{P},EN^*)+(1-\pi)v(I,\mathrm{P},0)=\\&(\pi)v(I-OP,P,0)+(1-\pi)v(I-OP,\mathrm{P},0)=v(I-OP,\mathrm{P},0).\end{aligned} \quad (4.3.2)$$

If p=0, the event does not occur. The corresponding option price for reducing p to zero is the solution to

$$\begin{aligned}&(\pi)v(I,\mathrm{P},EN^*)+(1-\pi)v(I,\mathrm{P},0)=\\&(0)v\left(I,\mathrm{P},EN^*\right)+(1-0)v(I-OP,\mathrm{P},0)=v(I-OP,\mathrm{P},0).\end{aligned} \quad (4.3.3)$$

The option price defined in equation 4.3.2 reduces the severity of the adverse impact to zero. Freeman (1993) defines this as *risk reduction.* In equation 4.3.3, the probability of the risky event occurring (π) is reduced to zero, which is termed *risk prevention.* In theory, the option price is identical for either a reduction of EN or π to zero. As the utility of expected value and expected utility generally differ, marginal changes in severity are likely valued differently than marginal probability changes which result in equivalent changes in expected value. For this reason, decomposing risk into severity and probability is worthwhile for measuring welfare impacts of risk changes.

Assume individuals facing the construction of an electric power producing plant perceive n possible impacts, EN_i, and associated probabilities, p_i, where $i = 1, ..., n$. Individuals do not know, *ex ante*, the true severity or the true probability of risk consequences due to the plant and must rely upon their perceptions of future states of the world to make utility maximizing decisions. Expected utility takes the form

$$E[U]=\sum_{i=1}^{n}(\pi_i|y)U[X,EN_i|y] \quad \text{where} \quad \sum_{i=1}^{n}\pi_i=1 \quad (4.3.4)$$

Individuals may conceivably state perceived probabilities that sum to greater than or less than one. This is a relevant topic in dealing with perceptions based on incomplete information, but is not considered here. Judgments of the probabilities, $\pi_i|y$, and the severity of the risk, $EN_i|y$, are likely to be conditional upon y, the individual's experience, familiarity, and knowledge of the risk and its consequences. Previous studies have found an individual more familiar with hazard consequences is more likely to perceive a higher probability of being exposed to the hazard (Slovic 1987). This does not imply that individuals with pre-existing knowledge or familiarity will always perceive risk to be greater than individuals without previous experience. Perceived severity may be less for individuals with prior experience than those without. The influence of prior experience and knowledge on perceived risk and valuation of risk changes is not explicitly addressed in this study, although such issues were addressed in a preliminary manner in a debriefing questionnaire.

Using the indirect utility representation, $\overline{V}$ is the maximum expected utility given market prices, income, and perceived probability and severity of the risks created by the power plant:

$$V = \sum_{i=1}^{n} (\pi_i|y) v[P_x, I, EN_i|y]\,. \tag{4.3.5}$$

The option price (or *ex ante* WTP) to prevent the power plant from being built or to reduce its environmental impacts to zero, even when operating, will be

$$\overline{V} = \sum_{i=1}^{n} (\pi_i|y) v[P_x, I, EN_i|y] = v(P_x, I - OP, 0)\,. \tag{4.3.6}$$

Solving for OP yields the individual's value for the perceived level of environmental risk of the power plant, holding prices and income constant. The individual's option price, or willingness to pay as elicited from a contingent valuation survey, to change or eliminate perceived risks due to an electric power producer will be a function of prices P_X, income I, and the individual's perceptions of the probabilities and severity of the risk consequences, conditional on the individual's knowledge and experience with the risk:

$$OP = OP(P_x, I, \pi_i|y, EN_i|y)\,. \tag{4.3.7}$$

In estimation, the model will be expanded to include multiple perceived risk components, including health, aesthetic, and environmental risks, and economic impacts resulting from facility construction and operation.

4.3.4 Survey Design

Deriving the values individuals place on risk level changes requires the integration of methods for characterizing perceived risk with contingent valuation methods. Advances in cognitive psychology, survey design, contingent valuation, and econometric techniques provide an opportunity to analyze the relationship between an individual's risk perceptions and the value corresponding to changes in risk.

Contingent valuation is considered the most appropriate method for non-market valuation of public goods (Mitchell and Carson, 1989) as well as the only method available for measuring non-use values (Freeman 1993). Contingent valuation enables researchers to create a surrogate market, where subjects reveal their values for incremental increases or decreases in the provision of a non-market good. Contingent Valuation Method (CVM) estimates depend upon the researchers' representation of a hypothetical market and are vulnerable to sources of measurement error and the survey's reliability to elicit valid responses. These derived values depend on the entire process of designing, implementing, and analyzing CVM survey instruments.

Many aspects of CVM surveys create cognitive challenges. For example, the survey might involve fairly technical information beyond the respondents' understanding, leading to problems at the comprehension stage. Cognitive psychology methods, including focus groups and verbal protocols, provide a potential solution to some of the shortcomings of CVM survey design. Complete elimination of all measurement error is impossible, but a systematic approach to survey design with a goal of minimizing measurement error helps. This systematic approach is applicable regardless of the mode of survey administration or the anticipated method of data analysis.

The CVM survey used in this analysis was designed to elicit quantitative measures of perceived risk and the payments that individuals would be willing to make to change the perceived risk levels of an electric power facility. To explore whether perceived risk can be defined as the product of perceived severity and perceived probability (as risk is defined as severity times probability), measures of both perceived severity and perceived probability were necessary. Other measures of perceived risk are also considered. A copy of the survey is given in Appendix 4D.

Ten focus groups and twenty-one cognitive interviews were conducted from June 1995 through April 1996 with subjects recruited through local newspapers. These sessions were intended for survey development, not primary data collection, and the sample participants were not considered representative of the population. The objectives were as follows: (i) to gather insights into how individuals think about the relationships between the combustion of fossil fuels, electric power facilities, their community, their health, and the environment; (ii) to identify lay terminology for technical aspects of energy production; (iii) to identify lay perceptions of both the risks and benefits of energy production and the presence of an energy production facility; and (iv) to determine what information individuals use to form their perceptions of such facilities.

Discussion during the exploratory sessions revealed that individuals may not associate their own use of electricity with the demand for fossil fuels by electric power facilities. Scenario rejection is likely if individuals do not understand the need for and intended purpose of a facility. A hypothetical facility within three miles of a residential area raised numerous concerns, including health, environmental, economic, aesthetic, land use, intergenerational, and equity concerns. Concern about potential health impacts and air pollution from a facility seemed to be greater than concern about other impacts such as noise, traffic, and economic impacts.

Four primary survey design issues were addressed throughout survey development: implicit factor analysis to determine risk categories, scale format, survey vocabulary, and overcoming survey bias. A two-step process served as an implicit factor analysis to derive composite risk categories. During focus groups and interviews, participants were asked what they thought the future risks might be from a proposed electric power facility three to five miles from their house. Participants then categorized the list into four main groups, as shown in Table 4.3.1. The subjects labeled the resulting composite risk categories as human health risks, environmental risks, aesthetic risks, and economic impacts.

Scales are used to elicit quantitative measures of qualitative variables. The scale questions were designed to quantify perceptions of the four risk categories. Scale range and

Table 4.3.1 Specific Concerns and Composite Risk Categories

Specific Concerns	Composite Risk Category
Cancer Safety (of workers in the facility) Respiratory problems Transmission lines	Human Health Risks
Ozone depletion Mining—strip mining, water impacts Water quality—mine seepage Air quality, pollution Wildlife impacts Disposal of facility waste such as ash, waste heat, and steam Land use—location of the facility, land requirements Coal economically important to PA	Environmental Risks
Cost of pollution control technology Property values Cost of electricity (retail) Taxes Need for additional capacity Cost of fuel Funding of project development Creation of local jobs	Economic Impacts
Odor—diesel trucks Appearance of the facility Noise Transportation of fuel to the facility Truck traffic Dirty emissions Transmission lines	Aesthetic/ Amenity Risks
Concern for future generations Equity—distribution of costs and benefits Regulatory compliance and enforcement Full disclosure of information Fuel choice and characteristics Coal—dirty, polluting, environmental damage from coal mining, dust, trucks, acid rain, Natural Gas—clean burning, gas leaks and explosions	Affecting Multiple Categories

units can be varied and depend upon the desired quantitative accuracy and the subject's cognitive ability to distinguish between choices.

Vocabulary refers to the wording of survey text, questions, and scale labels. Focus groups and interview discussions revealed that subjects anchored their interpretation of scale questions on the scale labels and format more than on the actual question. Survey text, question wording, and scale labels were iteratively revised until the subjects' interpretations of the questions concurred with their intended interpretation.

Finally, survey bias refers to the extent to which subjects felt the survey was encouraging them to respond in a particular way. Scales and scenario descriptions were iteratively revised to minimize the extent of bias in the survey. Debriefing questions were also used to check for bias.The final survey is composed of five sections (see Appendix 4D). The introduction to the survey contains a brief description of the nature of the survey and "warm-up" questions to assess the participant's awareness of their own consumption and expenses for electricity, their proximity to an energy generating facility, and how they rate the risk of an electric power facility relative to other "industrial" hazards. The next two sections provide a hypothetical description of the respondent's community, the growing need for electricity in the community, general features of the proposed power plant (size, land requirements, life of project), and regulatory compliance. One section proposes a coal-fired plant and the other a natural gas-fired plant (U.S. Department of Energy, 1993). A set of four scale questions for each risk category follows each scenario to quantify the respondents' perception of the possible risks and impacts resulting from the proposed facility. Following the scale questions, subjects rate their concern for each of the four risk components.

The valuation sections asks respondents to vote in favor of or against the proposed facility, and the maximum amount extra they would pay each month on their electricity bill to *prevent* the proposed facilities in their community. The question specifically states why the respondents need to pay their utility company extra to prevent construction of the proposed power plant: "*If the supplier is not able to build this power plant, it will have to increase the price you pay for electricity because the much needed electricity must be purchased at a higher cost from other power producers elsewhere in the state.*" Subjects were reminded of their budget constraint prior to answering the valuation question.

The final section of the survey retrieves socio-demographic information about each respondent. The survey was followed by a debriefing questionnaire to enable researchers to gain additional insight into the respondents' answers and to test sample questions. The final survey contains 63 questions, eight of which are demographic.

Data were collected from written surveys in Harrisburg and State College, Pennsylvania. Subjects were recruited via random digit dialing; the adult with the last birthday was asked to participate. Two hundred and twenty surveys were administered. The sample is evenly split by gender, with a mean age of 44 years, a mean education level of 15.6 years, and a mean household income of $46,300.

4.3.5 Estimation And Results

The mean values of the perceived risk attributes for the coal and natural-gas fired plants are presented in Table 4.3.2. Participants responded to these questions after reading the hypothetical proposals for each plant. In general, a majority of respondents believed both plants would create risks, coal more so than natural gas. Their perceptions of severity and probability of health, environmental, and aesthetic impacts were also more negative for coal than for natural gas. The coal facility generated greater feelings of dread or fear, as well. The differences in perceptions between health, environmental, and aesthetic risks from coal and natural gas were significant at the 1% level for all the measures. The difference in perceptions of the significance or the probability of economic impacts arising from a coal or natural gas plant was not significant, although if economic impacts did occur, participants expected the impacts to be greater for natural gas. Comparisons between perceptions of health, environmental, and aesthetic risks or economic impacts within one fuel are not possible. Given the unique nature of these risk components, the scales are not likely to be comparable, and thus mean measures between factors do not have any ordinal meaning.

The seriousness, probability, and dread variables are all significantly correlated with each other within and between each facility type. Severity and probability are positively correlated with dread and positively correlated with each other. Correlations are generally less prominent for the natural gas-fired plant than the coal-fired plant. The perceived severity, probability, and dread measures for the coal-fired facility are positively correlated with respective measures for the natural gas-fired facility.

Table 4.3.2 Mean Values of Perceived Risk Attributes

	Believe Plant Will Create Risk		Perceived Impact		Perceived Severity		Perceived Probability		Dread	
	Coal	Gas	Coal	Gas	Coal	Gas	Coal	Gas	Coal	Gas
Health	82.3	48.2*	-1.07	-0.19*	3.89	2.45*	50.45	29.41*	-1.19	0.03*
Environmental	94.5	76.3*	-1.57	-0.68*	4.57	3.09*	63.73	44.36*	-1.72	-0.59*
Aesthetic	92.3	76.4*	-1.71	-0.80*	4.42	3.11*	62.27	48.86*	-1.61	-0.34*
Economic	90.4	91.3	0.62	1.54*	4.40	4.38	62.15	59.95	0.08	0.86*
Scale	0-100%		very negative = -4 no impact = 0 very positive = +4		not serious = 1 very serious = 7		0-100%		afraid = -4 neutral = 0 comfort = +4	

*The difference between the coal and natural gas figure is significant at 1%.

A measure of perceived risk can be calculated by multiplying perceived severity by perceived probability. Table 4.3.3 reports the mean and standard deviation of this perceived risk measure for each of the four risk categories. Average perceived risk is higher for the coal-fired plant than the natural gas plant in all four categories. Health risks from a natural gas plant are perceived as almost nonexistent.

The dependent variables are the respondent's WTP to prevent a coal-fired and natural gas-fired electric power plant. The values range from \$0.00 to \$120.00 for coal with a mean of \$16.98 and from \$0.00 to \$70.00 with a mean of \$13.37 for natural gas. The difference in means is significant at the 1% level. Summary statistics for all variables are found in Tables 4.3.3 and 4.3.4. The sociodemographic variables included in all models are income, education, age, gender, and an interaction term between income and education. The interaction term implies that the effect of education on WTP depends on the level of income, that is the relationship between WTP and education depends on income.

The actual model estimated is

$$WTP_j = \beta_0 + \beta_1 INC_j + \beta_2 EDUC_j + \beta_3 INC_j * EDUC_j + \beta_4 GENDER_j + \beta_5 AGE_j + \beta_6 VERSION_j + \beta_7 HEALTH_j + \beta_8 ECON_j + \beta_9 ENVIR_j + \beta_{10} AESTH_j + \varepsilon_j \quad (4.3.8)$$

where j indexes individuals, VERSION is a dummy variable referring to whether the coal or natural gas section came first, and HEALTH, ECON, ENVIR, and AESTH are measures of the four perceived risk categories considered. Three different measures were used for the risk attributes. In Model 1, risk is measured as the *perceived seriousness* (e.g., CHLTSERI) of each of the four impacts, which is a measure of the severity of the consequences. Model 2 uses the constructed *perceived risk* (e.g., CHLTPRSK) measure of perceived severity times perceived probability, which is closest to the standard definition of risk. Model 3 uses a *weighted measure of perceived seriousness* (e.g., CHLTWSER), constructed by multiplying perceived seriousness CHLTWSER), constructed by multiplying perceived seriousness times a value from 0 to 1 that reflects the relative importance of each impact to the respondent. Tobit estimation is the appropriate estimation choice because the dependent variables, WTP, are censored at zero (27% of the coal valuations and 45% of the natural gas valuations were zero). Ordinary least squares estimates would be biased upward and inconsistent.

Table 4.3.3 Perceptions Measures

PERCEPTION SCALE	FUEL TYPE	VARIABLE NAME	MEAN	STD. DEV.
Seriousness of health impacts	COAL	CHLTSERI	3.89	1.75
	GAS	GHLTSERI	2.45	1.45
Significance of economic impacts	COAL	CECNSERI	4.40	1.34
	GAS	GECNSERI	4.38	1.39
Seriousness of environmental impacts	COAL	CENVSERI	4.57	1.59
	GAS	GENVSERI	3.09	1.59
Seriousness of aesthetic impacts	COAL	CAESSERI	4.42	1.59
	GAS	GAESSERI	3.11	1.57
Probability of health impacts	COAL	CHLTPROB	0.50	0.28
	GAS	GHLTPROB	0.29	0.24
Probability of economic impacts	COAL	CECNPROB	0.62	0.24
	GAS	GECNPROB	0.59	0.24
Probability of environmental impacts	COAL	CENVPROB	0.63	0.27
	GAS	GENVPROB	0.44	0.28
Probability of aesthetic impacts	COAL	CAESPROB	0.62	0.26
	GAS	GAESPROB	0.49	0.28
Health risk = SERIOUSNESS*PROBABILITY	COAL	CHLTPRSK	2.36	1.87
	GAS	GHLTPRSK	0.99	1.23
Economic risk = SIGNIFICANCE *PROBABILITY	COAL	CECNPRSK	2.28	1.56
	GAS	GECNPRSK	1.34	1.23
Environmental risk = SERIOUSNESS*PROBABILITY	COAL	CENVPRSK	3.22	1.98
	GAS	GENVPRSK	1.68	1.63
Aesthetic risk = SERIOUSNESS*PROBABILITY	COAL	CAESPRSK	3.04	1.92
	GAS	GAESPRSK	1.79	1.56
Weighted seriousness of health impacts	COAL	CHLTWSER	1.08	0.56
	GAS	GHLTWSER	0.67	0.44
Weighted seriousness of economic impacts	COAL	CECNSWER	-0.33	1.11
	GAS	GECNWSER	-0.72	0.86
Weighted seriousness of environmental impacts	COAL	CENVWSER	1.28	0.53
	GAS	GENVWSER	0.87	0.49
Weighted seriousness of aesthetic impacts	COAL	CAESWSER	1.03	0.54
	GAS	GAESWSER	0.73	0.47

Table 4.3.4 WTP and Socio-Demographic Summary Statistics

VARIABLE NAME	VARIABLE DESCRIPTION	MEAN	STD. DEV.	MINIMUM	MAXIMUM
CWTP	Willingness to pay to prevent coal plant ($0.00 bids-26.8%)	$13.72	16.98	$0.00	$120.00
GWTP	Willingness to pay to prevent gas plant ($0.00 bids-45.0%)	$8.41	13.37	$0.00	$70.00
INCOME	Midpoint of income range	$46,300	31,026	$4,999.50	$189,999.50
GENDER	Dummy variable for gender, 1 = Male	0.5091	0.5011	0	1
EDUC	Years of education completed	15.64	3.12	9	31
AGE	Age of respondent (years)	44.03	17.07	18	87
VERSION	Dummy variable for survey version, 1 = ???	0.53	0.50	0	1

The regression results are listed in Table 4.3.5 for all six models estimated. Income is positive and significant in all models, consistent with the hypothesis that individuals with more disposable income are willing to pay more for normal goods of this type. Education is also positive for all models, a common result in nonmarket valuation studies. Age and gender do not seem to play a role in determining an individual's WTP. Version is insignificant in all models, indicating that an individual's stated WTP is independent of the order in which the coal and natural gas valuation questions were presented. Some have suggested that a second WTP question will be invalid, but these results indicate otherwise. It further provides a measure of the reliability of the survey instrument.

When risk perceptions are measured by *seriousness* in Model 1, economic impacts and environmental risks significantly impact the respondents' WTP to prevent a coal-fired facility. All four risk components significantly affect the WTP to prevent a natural gas-fired plant. The results are less appealing when risk is measured by the constructed *risk perception* variable. In Model 2, only environmental risk for coal and health and aesthetic risks for natural gas are significant. Although this *risk perception* variable most closely resembles the accepted definition of risk, it may be difficult for respondents to differentiate between severity and probability. Alternatively, the survey may not have been able to adequately elicit the difference.

In Model 3, risk is measured by a constructed measure which weights perceived seriousness by the importance of each impact to the respondent. The parameter estimates are larger than in Model 1 because the size of the independent variables has been reduced by multiplying them by a number between zero and one. The results for natural gas are similar to Model 1. For coal, aesthetic and health risks become significant but economic impacts become insignificant.

The negative coefficient on economic impacts indicates individuals are less willing to pay to prevent the plant the larger the economic impacts are perceived. This result suggests that separately identifying positive impacts (economic benefits) from negative impacts (health, environment, or aesthetics) can improve interpretation of individuals' responses to CVM scenarios. It may also provide more detailed information to planning officials and improve risk communication methods.

Table 4.3.5 Tobit Regression Results (Standard Errors in Parentheses)

	Model 1		Model 2		Model 3	
	Coal	Gas	Coal	Gas	Coal	Gas
CONSTANT	-67.07* (15.73)	-60.7642* (14.5966)	-51.087* (14.7202)	-44.0057* (14.0162)	-60.0099* (15.3419)	-58.7228* (14.7563)
INCOME	0.00068* (0.00023)	0.0005317* (0.000215)	0.00064* (0.00023)	0.00051* (0.000214)	0.000608* (0.000232)	0.00052* (0.000217)
EDUC	2.5328* (0.8674)	1.8537* (0.8117)	2.333* (0.856)	1.6029* (0.8164)	2.2007* (0.8652)	1.7198* (0.8226)
INC* EDUC	-0.00004* (0.000014)	-0.0000283* (0.000013)	-0.0000356* (0.000014)	-0.0000261* (0.000013)	-0.0000335* (0.000014)	-0.0000266* (0.000013)
AGE	0.0715 (0.0872)	0.0737 (0.08336)	0.0999 (0.0882)	0.0808 (0.08413)	0.0699 (0.0869)	0.0976 (0.0844)
GENDER	-3.8579 (2.9098)	-3.2056 (2.8561)	-4.612 (2.8758)	-3.2451 (2.8976)	-3.1938 (2.9077)	-3.0391 (2.8505)
VERSION	3.1739 (2.9123)	3.0252 (2.6994)	4.0784 (2.9719)	3.6096 (2.7691)	4.1425 (2.8416)	2.8529 (2.7178)
HLTSERI	1.5892 (1.2835)	2.6205* (1.1761)				
ECNSERI	-0.5388* (0.3222)	-0.7591* (0.3983)				
ENVSERI	3.6424* (1.4159)	2.0495* (1.2174)				
AESSERI	1.7048 (1.1954)	3.5338* (1.0934)				
HLTPRSK			1.1753 (1.22)	4.2369* (1.4411)		
ECNPRSK			-0.6964 (0.4365)	-0.7092 (0.5374)		
ENVPRSK			2.7631* (1.206)	0.4883 (1.2977)		
AESPRSK			1.4865 (1.0549)	3.3587* (1.1137)		
WHLTSER					7.0531* (3.1846)	8.5007* (3.7048)

WECNSER	-1.2322 (1.3437)	-2.6873* (1.6251)
WENVSER	10.2932* (3.3579)	11.6373* (3.4963)
WAESSER	6.9441* (2.6495)	9.2607* (3.0972)

*Significant at 5%.

Overall, regardless of model specification, the evidence is strong that the perception of environmental risks influences a respondent's willingness to pay to avoid a coal-fired electric utility in their community. The results are less strong but suggest health, aesthetic, and economic impacts also influence WTP. For the natural gas-fired facility, health and aesthetic risks influence WTP in all models. The evidence is also strong that environmental risks and economic impacts influence WTP.

4.3.6 Conclusions

Results show that welfare impacts, as measured by option price, depend on an individual's perceptions of the health, environmental, aesthetic, and economic impacts as well as their socio-demographic characteristics. Individuals seemed to have difficulty distinguishing between the probability and the severity of a risk in the manner suggested by the definition of risk, although the survey instrument may have been unable to capture the difference. Perceived environmental, health, and aesthetic impacts play a larger role than potential economic impacts in determining option prices, explaining in part why residents may oppose a facility even when it will likely bring economic benefits to an area. Although this study focused on fossil-fuel electric power facilities, the methodology developed here is transferable to a multitude of hazards imposing welfare impacts which are a function of perceived risk.

The results confirm that CVM values are sensitive to the information set and perceptions of a participant (see Fischhoff and Furby, 1988 for additional evidence). While the general approach in contingent valuation methodology has been to mold or correct those perceptions in line with "expert" information, this study has explicitly measured those perceptions and related them to willingness to pay. A correct measure of welfare impacts requires consideration of the participants' perceptions rather than the researcher's perceptions of the commodity.

The potential exists to gather comparable data from "experts" to define levels of "true" risk. These could then be compared to laypersons' perceptions to estimate the welfare impacts from a divergence of expert and layperson risk judgements associated with a facility. The survey could also be administered at different phases of a project's life, from proposal through operation or defeat, to examine changes in perceptions and welfare impacts over time. A further extension could examine the determination of an individual's perceptions as a function of prior experience, y. This approach is implicit in programs to identify the impact or value of public information efforts and is of considerable importance in risk communication programs.

4.4 Regional/National Economic Impacts of New Coal Utilization Technologies

4.4.1 Introduction

Energy conservation is almost universally considered a prime strategy for mitigating greenhouse gases. At present, 97.9 and 70.6% of the CO_2 emitted from industrial and developing countries, respectively, stems from fossil fuel combustion (World Resources Institute 1994). Of course, this anthropogenic emission is only a small fraction of the carbon exchange between the atmosphere and terrestrial ecosystems. Efforts to alter atmospheric concentrations through climate engineering are still only on the drawing board. With any potential major shift to renewables many years away, outright reduction in the utilization of coal, oil, and natural gas is an obvious strategy. It appears even more appealing when one considers that a good deal of conservation can be attained at a cost-savings when less energy is used outright, or at a zero net cost when, for example, energy-saving equipment must be installed. These factors have led to energy conservation being placed in the category of "no regrets" strategies, which refers to measures that do not incur added costs even if projected warming trends are not forthcoming (Cline 1992)

Clearly, production cost-savings and preservation of energy resources are pluses. However, to date, very few studies have focused on the potential down-side. For example, there are jobs and profits at stake in the energy industries. Moreover, declines in fossil fuel sectors will lead to declines in output in successive rounds of upstream suppliers (e.g., mining equipment, fuel service companies), as well as some downstream customers (e.g., railroads, electric utilities). It is not clear whether these negative effects will be offset by the increased efficiency of the economy, various factor substitutions, purchasing power improvements for consumers, or any multiplier effects stemming from increased production of energy-saving equipment.

The purpose of this review is to estimate the effects on the U.S. economy and its energy sectors of conservation strategies to reduce CO_2 emissions. The analysis is undertaken with a 20-sector computable general equilibrium (CGE) model by simulating various responses to command and control, carbon tax, and carbon emission permit policies.

The results indicate that the characterization of energy conservation as a "no regrets" strategy is too strong. In all of the simulations, energy sectors stand to lose, though, in some cases, not anywhere near as much as would be expected. Each of the simulations of mandated conservation also leads to a decline in output and employment for the U.S. economy. In contrast, some of the price-induced conservation response strategies also simulated have a neutral impact on the overall economy.

This review is divided into five sections. In the first section, basic features of the conservation strategy and some overlooked issues are discussed. Then the model used in the simulations is summarized. Next, basic results are presented, as well as some sensitivity tests. The review is concluded with a summary and a discussion of policy implications.

4.4.2 Basic Features of the Conservation Strategy

Many proposals have been put forth to combat potential global warming. One that has received considerable attention calls for a 20% reduction in current greenhouse gas (GHG) emission levels for industrialized countries and a stabilization of developing country emissions at current levels. Several policy instruments are available to implement this reduction, the carbon tax being the most widely supported and most thoroughly analyzed (Manne and Richels, 1991; Nordhaus 1993). In the U.S., however, strong support exists for a marketable permits approach (Winer 1991).

Actually, the conservation response to a carbon tax and a marketable permit system can be modeled in the same manner. First, the optimal carbon tax rate would be equivalent to the equilibrium permit price (Weitzman 1974; Pezzey 1992). Second, the two instruments would result in the same efficient response, in which each polluter equates its marginal cost of abatement to the tax rate or permit price. Third, even though polluters must pay for each unit of

GHG emissions under a tax regime, these emissions are usually free (entitlements) under a permit system and this does not affect the response in the short-run. That is, the tax payments or permit revenues/expenditures affect a firm's average cost but not its marginal cost and thus only bear upon long-run considerations such as exit and entry. Moreover, these conclusions pertain to the application of these instruments at both the international level in relation to total GHG reductions and within national boundaries.

In a recent study, Rose and Stevens (1993) estimated an equilibrium permit price of \$38.35 that would be associated with an agreement to limit *global* CO_2 emissions at 20% below year 2000 levels. The 20% reduction stems from an oft-espoused policy pronouncement that would contribute to the stabilization of CO_2 concentrations. Emissions for the year 2000 are projected based on population and economic growth factors. The year 2000 was chosen as a base rather than, for example, 1990, since the former is likely to be closer in time to when an agreement on CO_2 mitigation might actually be reached. The optimal response of the U.S. to this price is a reduction of 12.8% of baseline emissions. Moreover, given the uniqueness of the outcome of the Coase Theorem, this abatement level is not sensitive to how the permits are initially distributed across countries. Also, within the U.S., there would be a unique optimal response though control levels would vary across polluters (e.g., economic sectors) given differences in marginal abatement costs.

The various tactics that can be applied to the mitigation of CO_2 are depicted in Figure 4.4.1, utilizing a step function to highlight their usual relative marginal cost positions. The first step of the cost function refers to *no regrets* (costless or even cost-saving) conservation. This could stem from either a technological innovation or a move toward the efficiency frontier as a result of correcting a misallocation (e.g., eliminating energy-wasting practices). There is considerable disagreement in the literature about the extent of conservation potential. Manne and Richels (1992) refer to it as *autonomous energy efficiency improvement* (AEEI), which they estimate to be on the order of 0.5% to 1.0% per year. More optimistic estimates of costless conservation in the range of 20% to 30% total for the near term are offered by OTA (no date), NAS (no date), Lovins and Lovins (1991) and Jaccard et al., (1993). This holds open the possibility that the optimal U.S. CO_2 emission reduction could be met entirely by this tactic.

Another major form of conservation is *price-induced*, e.g., decreasing energy use in response to a change in the price of energy relative to the price of other inputs, as would be caused by a carbon tax or permit regime. There are several types of input substitutions that could take place and we categorize them under the headings below following Cline (1992):

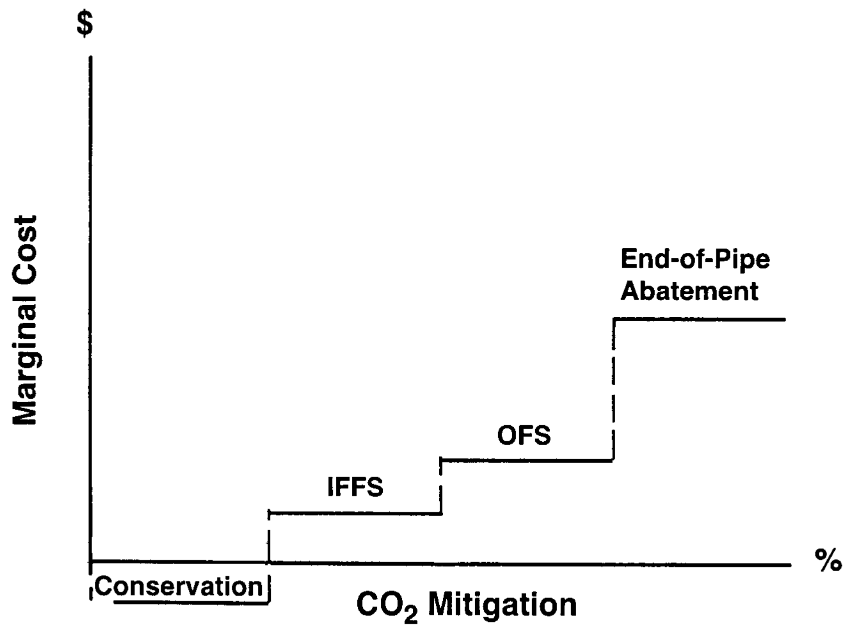

Figure 4.4.1 CO_2 COST FUNCTION

OFS—Other factor substitution

IFFS—Inter-fossil fuel substitution

NFFS—Non-fossil fuel substitution

PMS—Product mix substitution

Thus, if the tax is based on carbon content of fuels, there are optimal substitution responses within the class of fossil fuels (coal emits approximately 1.26 times as much carbon per unit as oil and 1.86 times as much as natural gas) and between the class of fossil fuels and other sources (e.g., nuclear, hydro, solar). All of these responses incur some costs unless the elasticity of substitution is infinite.

The final category of mitigation tactics shown in Figure 4.4.1, though limited in the near-term, is "end-of-pipe" abatement, such as CO_2 scrubbers. Of course other measures, such as climate engineering and carbon absorption through tree planting, might be used but are beyond the scope of this study.

The discussion above pertains only to a first set of adjustments for any decision-maker. If the price of energy inputs decreases because of improved efficiency, ironically energy then becomes more attractive, and there will be some offsetting increase through substitution of energy for other inputs. There is also the question of whether cost-savings will be passed along to industrial and/or final consumers or whether they will increase the returns to labor and/or capital. Similar possibilities arise with respect to responses that incur positive costs, though in terms of price increases and decreases in profits and wages.

The presentation thus far has been limited to partial equilibrium analysis, but a host of general equilibrium effects could potentially further enhance or offset these effects. First, if energy conservation savings were passed on to other industrial customers, there would be the possibility of further rounds of price reductions. This could potentially change the mix of material inputs in favor of those that are energy-intensive. The overall price reduction would increase the purchasing power of consumers and provide a stimulus to the entire economy. This would also take place, but to a different degree, if price decreases were foregone in favor of increasing wages or profits.

At the same time, the reduction in energy use would lower production levels in the coal, oil, gas, refined petroleum, and electric and gas utility industries. This will touch off a chain of negative multiplier effects to upstream suppliers, such as mining equipment, field service, and finance industries, as well as downstream customers, such as railroads, pipeline companies, and electric utilities. These negative impacts would be reinforced by declines in wages and profits in all of these sectors as well. Interestingly, all of these negative effects engender additional energy conservation, though through reduction in economic growth rather than an improvement in energy efficiency. On the positive side, the resources released from the energy industries would stimulate economic activity elsewhere, though it is unlikely that they would be fully employed. Also, any increased demand for energy-saving equipment will have positive multiplier effects analogous to those mentioned in the previous paragraph. At the same time, this increased economic activity will result in increased energy use, partially offsetting conservation efforts.

Obviously, there are a sizable number of expansionary and contractionary influences. It is impossible to ascertain the net outcome a priori, and hence the need for empirical analysis based on a general equilibrium model.

4.4.3 The U.S. CGE Model

An updated version of a 20-sector CGE model, developed by Lin (1991) and similar in nature to most SAM-based CGE models (Dervis et al., 1982; Shoven and Whalley, 1992), was utilized. A brief summary of the model is presented. Domestic producers, being profit-maximizers, produce goods and services using two primary factors, as inputs i.e., labor and capital, and intermediate goods. Intermediate goods are either produced domestically or imported, and are assumed to be qualitatively different (the Armington assumption). The utilization of inputs follows a two-stage decision process in which intermediate goods are modeled as a nested function of aggregates and components. Specifically, the energy aggregate consists of individual fuels (both primary and secondary energy), while the materials aggregate consists of goods such as plastics, glass, metals, etc., and the remaining input aggregate consists of all other intermediate goods. Inter-fuel and inter-material substitutions are allowed within their respective aggregates, which is a feature that is fundamentally required in evaluating environmental quality regulations (Hazilla and Kopp, 1990). The two-stage decision involves finding the optimum combination of components within energy and material aggregates, and then optimizing the levels of capital, labor, energy, and materials.

To take account of inter-fuel and inter-material substitution and substitution among aggregates, flexible functional form cost functions are used to represent the technology of production sectors and it is assumed that these functions are homothetically weakly separable. The relationships between aggregates, and within the energy and material aggregates with flexible functional forms, and the relationship between other intermediate inputs in terms of fixed proportions are specified. For the current application, the Generalized Leontief (GL) functional form is used for all the flexible cost functions.

The demand component of the model includes both intermediate and final demands. The intermediate demand is determined by the cost-minimizing process discussed above. Final demand includes private consumption, government expenditures, and investment.

The modeling framework is general enough to incorporate several alternative views of equilibrium. In one version of the model the total employment is exogenously given so full employment is achieved. Furthermore, the investment level is determined by savings, with savings rates being fixed. These specifications would have the model belong to the "classical" category. However, in the analysis below, an alternative (Keynesian) formulation of the labor