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VERTICAL INTEGRATION AND LONG TERM CONTRACTS:
THE CASE OF COAL BURNING ELECTRIC
GENERATING PLANTS

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" Buyers will construct, own and operate a coal fired steam-electric generating plant ...adjoining coal lands of Seller, based upon the assurance of a dependable supply of coal of specified quality and characteristics for the useful life of the plant.

" The Buyers would not design and construct a plant of this type [at this site] ...but for the availability of a dependable supply of coal from seller through December 31, 2019...

" It is essential to the Seller, because of the substantial capital investment it must make in order to have the capability to supply Buyers' requirements, that buyers purchase all of their coal requirements for said plant from Seller."

(From a coal supply agreement between the five joint-owners of units 3 and 4 of the Colstrip generating plant in Montana and Western Energy Company, dated July 2, 1980. Western Energy Co. is a wholly-owned subsidiary of Montana Power which is one of the joint-owners of the plant)

"An 'ideal agreement' should provide ... for the Buyer to receive a continuous, uniform-quality, efficiently-produced fuel supply over the life of the contract, and for the Seller to recover necessary production costs and an adequate return on his capital. All of these objectives should be met with a minimum of contention through the routine, diligent application of the agreement's written provisions."

(From <u>How To Negotiate And Administer a Coal Supply Agreement</u>, McGraw-Hill (1981), page 508.)

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Paul L. Joskow*

Introduction

What factors determine the institutional arrangements that govern supply relationships between input suppliers and their customers? Why are some transactions internalized through vertical integration ? Why are many market transactions governed by complex long term contracts ? What determines the structure of such contracts and why are they used instead of simple spot market transactions? Over the past several years, a substantial amount of theoretical work has been forthcoming which tries to answer these questions. A much smaller quantity of empirical work devoted to testing alternative theories and expanding our understanding of vertical integration and contracting has appeared. Most of the empirical work has focused on examining the choice between vertical integration and "the market."[1] Empirical analysis of contracts has been minimal. Aside from Macaulay's classic paper, and a recent paper by Goldberg and Erickson most of the empirical analysis of contracts has been limited to examples based on interpretations of facts obtained from court decisions or secondary sources.[2] In this paper I provide a theoretical and empirical analysis of the structure of vertical arrangements governing coal supply transactions between electric utilities and coal suppliers.[3] The paper examines coal supply arrangements between electric utilities and coal suppliers in general, but focuses on the structure of these vertical relationships for mine-mouth coal plants.

Theoretical work devoted to the analysis of vertical arrangements has taken a number of different approaches.[4] I am particularly interested in what has been called the "transactions cost approach," which I attribute to Coase, Williamson, Klein, Goldberg and others working in their tradition.[5] My plan in this paper is to use the transactions cost framework developed by these authors as the theoretical basis for analyzing coal supply arrangements and to make use of the empirical results to "test" the validity of the theory as a framework for understanding the structure of vertical relationships.

The paper proceeds in the following way. The next section provides a synthesis of what I take to be the analytical approach, assumptions and implications of transaction cost theory. The theory requires a lot of detailed information about various characteristics of the buyers, the sellers and the product to generate meaningful empirical predictions. The section following the theoretical discussion therefore provides background information on coal demand, supply, and transportation. This material is followed by a general discussion of the "neoclassical" demand and cost considerations that affect utility decisions to invest in coal plants and choose particular supply and transportation strategies. This discussion focuses on the importance of transaction specific sunk investments associated with various types of coal plants and the alternative coal procurement strategies that may be chosen for them. It suggests that there is likely to be wide variation in the importance of transaction specific sunk investments and that that the nature of the governance structure supporting coal supply relationships is likely to vary as well, but in a systematic way. I then present empirical evidence on the extent to which vertical integration, long term contracts and spot markets are used to govern coal supply relationships for the electric utility industry as a whole.

I turn next to a more detailed analysis of a particular subset of coal using power plants---mine mouth plants. This analysis leads to predictions about the nature of vertical relationships between a mine-mouth plant and its coal suppliers and the structure of market contracts when vertical integration is not used. I go on to examine the actual structure of vertical relationships for all mine-mouth plants built since 1960. This includes a breakdown of supply relationships into vertical integration, contract and spot markets as well as a detailed analysis of the provisions of the actual contracts that govern transactions. A discussion of the empirical results and their implications for the validity of the theory of vertical relationships advanced concludes the paper.

Potential Biases

Before proceeding further it is useful to answer a question that is likely to be in the reader's mind. Why study coal supply arrangements involving electric utilities ? Since the buyers in this case are subject to economic regulation by state and federal regulatory agencies we are confronted with a potentially complicating set of incentives that would not arise in studying the supply arrangements of unregulated firms. My reasons are quite simple. Detailed knowledge of a variety of characteristics of buyers and sellers seems essential for applying and testing transactions cost theory empirically. I already know a lot about electric utilities, power plants and coal markets as a consequence of previous research. Furthermore, in part because they are regulated, there is a lot of information available about particular utilities, their power plants and their coal supply arrangements. It is even possible to obtain a large set of actual coal supply contracts and related documents. The opportunity to analyze data at this level of microeconomic detail is extremely rare.

Nevertheless, it is necessary to be sensitive to potential biases in supply arrangements that may be caused by economic regulation. It is my sense that economic regulation of electric utilities (including both the incentive created by price regulation as well as direct restrictions on mergers and acquisitions imposed by state and federal law) tends to discourage vertical integration. State regulators tend to be hostile to vertical integration and both state and federal regulators have, especially in recent years, treated the recovery of costs from captive (integrated) mines quite harshly.[6] There may be a similar bias against long term contracts. The prospect of "automatic" pass-through of fuel costs through fuel adjustment clauses may also make electric utilities less responsive to the kinds of costs that motivate unregulated firms to adopt vertical arrangements that minimize costs.

I argue below that especially for mine-mouth plants, transaction cost theory implies that vertical integration or complex long term contracts will be used to support exchange. Thus, data involving electric utilities are more likely to lead to rejection of the transactions cost theory than might otherwise be the case if one side of the transaction were not regulated. In an effort to at least partially control for any regulatory biases, I make an effort below to make comparisons between different types of electric generating plants. By making comparisons between supply arrangements for different types of plants with different transaction characteristics but subject to the same types of regulatory restrictions I should be able to get a feeling for whether regulation is driving the results (in which case there should be no differences) or whether the transaction cost considerations hypothesized are important.

Vertical Supply Arrangements: An Overview of the Transactions Cost Approach

In this section I provide a synthesis of what I take to be the primary theoretical foundations and implications of the transaction cost literature that I attribute to Coase, Williamson, Klein, Goldberg, etc. I have integrated ideas developed over time and across commentators and added my own interpretations.[7]

The Basic Theory

Economic institutions (or governance structures) emerge to minimize the costs of making transactions. These costs include both "ordinary" production costs (land, labor, capital, materials and supplies) that make up the components of a neoclassical cost function as well as certain transactions costs associated with establishing and administering an ongoing business relationship. These transactions costs (which are identified more completely below) are real economic costs that must be taken into account along with "ordinary" production costs in structuring cost minimizing economic institutions.

There exists a continuum of potential governance structures for vertical relationships. At one extreme we have vertical integration. At the other extreme we have Walrasian auction markets. In between we have a wide array of potential contracting institutions that mediate transactions through the market, but involve the use of a variety of specialized contractual provisions that arise as a consequence of efforts by firms to minimize the total cost of transactions over time. The nature, magnitude and institutional response to transactions costs depends upon particular identifiable characteristics of the transactions involved. Thus, specific combinations of transactional characteristics, as they interact with more conventional production opportunities, lead to "predictable" cost minimizing organizational and contractual responses.

Transactions Costs and Transaction Characteristics

The transactions costs of interest include the following: The costs of negotiating and writing contingent contracts; the costs of monitoring contractual performance; the costs of enforcing contractual promises; and costs associated with breaches of contractual promises. In each case these costs may include the costs of acquiring and processing information, legal costs, organizational costs, and costs associated with inefficient (in the neoclassical sense) pricing and production behavior.

There appear to be four important characteristics of transactions that have been identified as affecting the nature and magnitude of these transactions costs in important ways.[8] These include:

(a) The extent to which the contemplated transactions are characterized by uncertainty and complexity.

(b) The extent to which cost minimizing transactions (in the neoclassical cost function sense) require one or both parties to a transaction to make durable transaction specific (idiosyncratic) sunk investments.

(c) The extent to which there are diseconomies associated with vertical integration that must be traded off against transactions costs that arise when market transactions are relied upon. These may include economies of scale, scope or learning associated with supplying similar inputs in multiple vertical supply relationships. They also include incentive and command and control costs associated with bringing additional activities inside a firm that would not arise when "market" transactions are relied upon.[9]

(d) The "frequency" of transactions or more generally reputational constraints.

As uncertainty and complexity become more important in a vertical relationship the expected costs of writing, administering and enforcing full contigent contracts increases. When uncertainty and complexity are important it becomes uneconomical to write full contingent contracts and "market contracts" will tend to be incomplete. A contract is incomplete in the sense that it does not specify unambiguously the obligations of each party in every possible state of nature.

Contractual incompleteness sets the stage for ex post performance problems. When contingencies arise that are not fully and unambiguously covered by formal contractual provisions one or both parties to the transaction may have incentives to "behave badly" by taking actions that increase the costs or reduce the revenues that will be obtained by the other party. The anticipation at the contract formation stage that "bad behavior" will occur when certain contingencies arise affects the cost minimizing structure of the initial vertical relationship.

The "bad behavior" that may occur ex post is has been referred to as "opportunism" by Williamson. As I understand it, opportunism refers both to ex post behavior that does not maximize joint profits (and is inefficient) when a particular contingency arises as well as to ex post behavior that involves the appropriation of wealth of one party to the transaction by the other in some states of nature without necessarily inducing distortions in supply or demand. In either case agents anticipate that opportunistic behavior way accur and this in turn affects the governance structure and the terms and conditions of any arrangement chosen ex ante.

The theory generally assumes that markets are competitive ex ante (many buyers and sellers). Opportunism problems can emerge ex post because certain characteristics of the the supply relationship give one or both parties to the transaction some monopoly power when certain contingencies arise. In most of the recent work in this tradition the primary source of ex post monopoly power is the presence of durable transaction specific sunk investments (see below). However, there appears to be a natural relationship between opportunism in this sense and more conventional notions of moral hazard that arise because of information asymmetries.[10] In the latter case, incentive problems arise ex post because one party to the transaction can both affect (uncertain) outcomes by his own behavior and has better (less costly) access to information about the causes of observed outcomes. The agent can exploit an ex post information monopoly to its advantage.

Following the theoretical and empirical work in this tradition I focus on durable transaction specific sunk investments and largely ignore problems associated with information asymmetries and differences in the costs of bearing risk. Williamson (1983: 526) identifies four different types of transaction specific sunk investments:

a. **Site specificity**: Buyer and seller are in a "cheek-by-jowl" relation with one another reflecting ex ante decisions to minimize inventory and transportation expense.

b. **Physical asset specificity**: When one or both parties to the transaction make investments in equipment and machinery that involves design characteristics specific to the transaction and which have lower values in alternative uses.

c. **Human-capital specificity**: arising as a consequence of learning-by-doing, investment and transfer of skills (specific human capital) specific to a particular relationship.

d. **Dedicated assets**: General investments that would not take place but for the prospect of selling a significant amount of product to a particular customer. If the contract is terminated prematurely, it would leave the supplier with significant excess capacity.

Given contractual incompleteness due to uncertainty and complexity, as durable transaction specific investments become more important, the transactions costs associated with mediating vertical relationships using conventional "spot markets" increase. Very simply, the argument is that transaction specific sunk investments generate a stream of potentially appropriable quasi rents equal to the difference between the anticipated value in the use to which the investments were committed and the next best use. The presence of transaction specific investments creates incentives for one party to the transaction to "hold up" the other ex post and can lead to costly haggling. When transaction specific investments are important, governance structures will emerge ex ante to minimize the incentives either party has to exploit them ex post. Considerable emphasis has been placed on the proposition that vertical integration is more likely to emerge when cost minimizing (in the neoclassical sense) transactions involve durable transaction specific sunk investments. Williamson's recent work and a great deal of Klein's work, however, consider contractual alternatives to vertical integration where transactions costs are important. If vertical integration is not economical because of diseconomies associated with internal production, contractual arrangements to govern exchange between independent agents will emerge to economize on these transactions costs. The structure of these market contracts will reflect efforts to build in incentives and restrictions that reflect anticipated performance problems so that agents will perform as initially promised when different contingencies arise.

The theory also assumes that there is a strong incentives to structure contracts so as to minimize reliance on the legal system (which is costly and must confront grave difficulties in distinguishing promised behavior from "bad behavior") and therefore to structure vertical arrangements to achieve a "private ordering" that does not rely on legal enforcement. Nevertheless, people do sue one another for breach of contract and various rules for defining breach and calculating damages exist (Muris). Thus, contractual arrangements should at least evolve in the shadow of the law with recognition that court enforcement remains an option. Opportunities to specify contractual agreements in a clear and unambiguous way so as to strengthen the credibility and reduce the costs and uncertainty of legal sanctions should be taken advantage of.

The reliance on vertical integration is constrained by any diseconomies that may be associated with it. A supplier of some input that involves transaction specific investments, for example, may achieve economies as a consequence of engaging in similar types of transactions with other buyers. There may be economies of scale associated with shared inputs across transactions or learning economies associated with repetitive production in many separate relationships. Internal incentive and command and control problems may limit the economic desirability of vertical integration.

Finally, the market may provide a natural deterrent to agents behaving badly and eliminate the need to rely on either vertical integration or complex "non-standard" contracts. There is a potential cost to breaches of written or implied contractual promises: the loss of future business from either this buyer or other buyers. In markets where buyers and sellers frequently engage in similar types of transactions, and where it is possible at low cost to distinguish "bad behavior" from "promised behavior" (perhaps combined with bad luck), reputational constraints may eliminate hold-up incentives for example, and allow agents to comfortably use simple auction markets recognizing that the market provides penalities for inefficient behavior. These considerations may help to explain MacCaulay's findings regarding the informality of contracts in business.

Overview of U.S. Coal Markets

The primary market for coal today is the electric power industry which accounts for over 80% of domestic coal consumption. The second most important source of coal demand is coke plants (about 10%) which produce coke for the iron and steel industry. All other industrial consumers in the aggregate account for most of the rest of the coal consumed with a small amount of coal continuing to be used in the residential/commercial sectors (See Table 1). Coal is used to generate over 50% of the electricity produced in the U.S. and accounts for over 70% of fossil fuel utilization. **[Table 1 about here]**

Coal reserves are not distributed uniformly across the country in terms of either quantity or quality. The Bureau of Land Management divides the country into over 20 coal producing districts, but the bulk of the coal supplies are conveniently grouped into a handful of areas: The Appalacian region, the Interior Region (midwest), the Western region (often divided into the North Plains and

Mountain regions) and Texas. Historically, most of the coal produced came from the Appalacian and Midwestern regions. Coal production in the Western region has increased dramatically in the past decade reflecting the attractive economics of large strip mining operations, declining productivity and labor problems in the east that increased costs, and an increasing demand for low sulfur coal to meet air pollution restrictions.

There are substantial differences between the regions in terms of coal quality and optimal mining techniques and scale. Coal in the Appalacian region generally has a high BTU content, a sulfur content that generally varies from 1% to 3% and ash content that generally varies from 10% to 15% (see Table 2). The coal in the Interior region generally has a lower BTU content and a generally higher sulfur content. There is relatively little low sulfur (1% or less) coal in the Midwest. Coal in the Western region varies widely in BTU content and ash content, with average BTU content significantly lower than the other regions. But western coal generally has a very low sulfur content and relatively low mining costs (see below) making it especially attractive in midwestern states subject to sulfur emissions restrictions despite high transport costs. The coal being produced in Texas is almost all lignite with low BTU content, low sulfur and high ash content. **[Table 2 about here]**

Topography and the nature of coal deposits affect the optimal type and scale of mining, and these characteristics also vary significantly among the regions. In Appalacia, undergound mining accounts for about 60% of production and underground mines are relatively small (see Table 3). Undeground mines in the east appear to have relatively small minimum efficient scales (MES) (Zimmerman: 17-36) although the observed size distribution is somewhat misleading since it contains a large number of old and marginal mines which are very small. The topography of the Appalacian region makes the use of relatively small mobile machinery necessary for surface mining(Zimmerman:26) and the MES of a strip mining operation here is also relatively small. [Table 3 about here]

In the Midwest, surface mining accounts for about 70% of coal production and both underground and surface mines are much larger in the Midwest than in the Appalacian area. The topography of the Interior region makes it economical to use larger equipment and to better exploit economies of scale in strip mining than in the east. The MES of surface mines is larger in the Midwest as a result. In the Western region almost all of the coal comes from large strip mines (most of the underground mining takes place in Utah and Colorado). The topography and the nature of the deposits makes the use of large draglines and shovels allowing fuller exploitation of surface mining scale economies and larger MES (Zimmerman: 24-35). Surface mines are generally substantially more capital intensive than underground mines and surface mining technology seems to be characterized by substantial scale economies.

The bulk of the coal produced (about 75%) is carried by railroad (sometimes in conjunction with barge transport) (National Coal Association (1984):28). Transportation costs account for a large fraction of the delivered costs of coal on average. About half of the coal transported by rail is shipped by unit trains consisting of 100 or more specialized cars (often owned or leased by the utility buying the coal). Unit train shipments are generally acknowledged to be the most economical way of moving large volumes of coal by train. About 20% of the coal transported is carried by inland barges for at least part of the trip. Trucks account for a small part of the "mine-to-Market" transportation, but are used at both the loading end and the receiving end of the trip to collect and distribute coal (National Coal Association (1984):29). Coal slurry pipelines are a fourth transport option, but only one is currently operating.

Transportation opportunities vary from region to region. Their appears to be more inter and intra mode competition in the east than in the west. For coal produced in the Western Interior and Western regions, rail transportation is essentially the only alternative to mine-mouth operations. Many of these producing areas must rely on one or perhaps two railroads to move coal out of these areas and direct rail linkages between coal fields and potential load centers often do not exist.

Overall, most analysts have concluded that the coal supply market is quite competitive in the ex ante bidding sense used by Williamson (Gordon: 67-69). Concentration in mining and reserve ownership is quite low and entry appears to be relatively easy. Any monopoly problems are generally attributed to the railroads.

Coal Supply Arrangements for Electric Generating Plants and Transaction Specific Investments:Overview

When a utility considers building a new base load generating plant it must make a number of interelated decisions.[11] The most important decisions that must be made are the following:

1. How large should the generating unit(s) be ?
2. What type of fuel should they burn ?
3. Where should the plant be located ?
4. How should the generating unit's boiler be designed to minimize expected fuel costs over the life of the unit ?
5. If a coal burning plant is built, what types of coal will the plant utilize, what is it likely to cost and where is this type of coal likely to come from ?
6. How will the coal be transported from the mine to the plant and what are the expected costs of transportation ?

For purposes of discussion here we will assume that the optimal size of the generating units has been determined and that a decision has been made to utilize coal as the primary fuel for generating electricity in the plants that are built. In the spirit of transaction cost theory we first consider the cost minimizing options that utilities have in each of the remaining dimensions given the "ordinary" or neoclassical cost opportunities they face. We go on to discuss the importance of transaction specific investments associated with four "stylized" cost minimizing investment/coal procurement strategies and the associated implications for the choice of governance structure to support cost minimizing exchange in each case.

A utility considering building a new coal plant can choose between two primary locational strategies. It can build a plant (independently or jointly with other utilities) in or near its own service territory, reflecting the electrical requirements of its system, land and cooling water availability, transportation facilities, etc. and arrange for transportation of the coal from one or more mines to the plant. This has been the approach taken for most operating coal plants. Alternatively, the utility can build (itself or jointly with other utilities) a plant adjacent to coal reserves from which coal will be mined for that plant, with effectively zero coal transportation costs, and then use a high voltage transmission system to transport the power from the supply point to load centers. Such plants are referred to as mine-mouth plants. For utilities whose service territories are far from coal mining areas, the choice between these two alternatives is quite discrete. Obviously, however, a utility whose electric loads are also close to coal producing areas can take advantage of the best of both alternatives.

The decision to choose one locational strategy rather than another (ignoring transactions costs) depends on the prices of coal at the mine in different locations, the availability and costs of coal transport alternatives, the costs and institutional constraints associated with the transmission of electricity, and any institutional constraints affecting the ownership and operation of coal units in states other than those in which the utility is chartered to provide service.

A generating unit is typically designed optimally to burn coal with particular characteristics (btu content, sulfur content, ash content, chemical composition, grindability, etc.). The use of coal which differs from the design specifications of a plant can lead to a loss in thermal efficiency or to increases in plant outages and maintenance costs. Exactly how "tightly" a plant is designed is, within some range, a variable of choice for the utility. The design decision depends on a utility's anticipated fuel procurement strategy, the variation in coal quality in the areas the utility is likely to purchase coal from, the quantities of different types of coal available in these areas and the number of suppliers producing it, and the costs of building more fuel flexibility into the plant. For a mine-mouth plant, the plant design is necessarily governed by the characteristics of the coal in the areas adjacent to the plant since the decision to locate the plant is based on the desire to exploit these sources of coal.

As a general matter, cost minimizing coal procurement strategies and plant design are intimately related. A utility could plan to buy coal for a plant through spot market purchases or short term contracts from a wide variety of different suppliers. If this strategy is chosen, boiler design flexibility is likely to be an important consideration, unless coal quality in the areas where the utility anticipates buying coal in this way is of fairly uniform quality. At the other extreme a utility could plan to purchase all of its coal requirements from one specific mine over the life of the plant. In this case, the plant could be designed optimally to burn coal with the characteristics expected to be available from this mine. Intermediate strategies involving more or less burning flexibility and more or less flexibility in procurement can also be pursued. A utility can choose to purchase from existing mines that are already supplying coal for other utilities and plants or contract in advance from a mine that has not yet been developed.

The cost minimizing coal procurement strategy will depend on a number of factors. The expected fob price of coal in various areas is a primary consideration, along with the expected costs of transporting coal from the mines to the plant. Air pollution restrictions are likely to sharply constrain the kinds of coal that some utilities can burn economically. The economics of mining is likely to affect coal optimal procurement strategies as well. If there are substantial economies of scale in mining, a utility may be able to reduce its coal costs by committing itself to purchase all of its coal from one large mine.[12] If economies of scale in mining are not important, there is little advantage to doing so. The availability of alternative transportation opportunities may also affect the optimal coal procurement strategy.

If the decision is made to build a mine-mouth plant, the location, design and coal procurement strategy generally go hand in hand with one another. The plant is consciously located near specific coal reserves, is designed to optimally to burn coal of the quality that will be mined there and the utility expects to acquire coal for the plant from one or more adjacent mines over a large portion of the expected life of the plant.

There are numerous possible combinations of plant design strategies, coal procurement strategies and transportation strategies that are possible. Let me identify four stylized cases for further discussion.

Case 1: The utility expects to purchase coal from a large number of existing suppliers located at different points in a fairly large geographical area through spot market purchases and simple short term contracts. The elasticity of supply of coal of like quality from this general area is fairly high and numerous utilities are active in purchasing coal there. The identify of the particular mines from which coal is purchased is not of any importance to the utility. It anticipates making transportation arrangement with a variety of railroads and barge companies, contracting for delivery as it contracts for coal. It designs its plant with enough flexibility to accept coal of the variable quality that would be available from any of the mines in this general area.

Case 2: The utility expects to purchase coal from a relatively small number of existing mines located close to one another and producing similar types of coal. The mines currently supply coal to other utilities. To economically meet the anticipated demand the mines must make modest investments to increase their capacity. The utility expects to rely on these mines for several years, but anticipates the possibility of switching suppliers, subject to contractual restrictions, if economic opportunities arise to do so. It anticipates relying on two different railroads to transport the coal, but alternative transportation arrangements can be made at a small cost penalty. Other suppliers of coal of this quality in proximate areas exist, but the elasticity of supply in the short run is very low. The longer run supply elasticity is fairly large, however. The utility designs its boiler to burn coal of the type available from these two mines applying tighter design specificationss than in the case #1. It recognizes that switching suppliers may make it difficult to obtain coal with the same characteristics as its initial suppliers, but coal quality is sufficiently uniform in the areas where alternative suppliers are likely to be located, that coal quality deviations can be accomodated with only small increases in costs.

Case 3: A utility anticipates obtaining supplies from one or two specific mines for the life of the plant. The mines are currently in operation, but will make substantial investments to increase capacity in anticipation of these purchases. The quantities of coal that the utility expects to purchase do not exhaust the economic capacity of these mines and they eventually anticipate making sales to other utilities at similar prices. There are very limited supplies available in the short run from other mines in this area and coal quality varies widely from mine to mine in the same general geographical area. The utility anticipates relying an a single railroad to transport the coal and plans to invest in unit trains to carry the coal on this railroad's tracks. The plant is designed with tight specifications to optimally burn the coal from these mines, including specific investments in pollution control equipment.

Case 4: The utility builds a mine mouth plant and anticipates obtaining all supplies from one or two adjacent mines. The plant is designed specifically to optimally to burn coal from these mines. The mine would not be built but for the existance of the plant and opportunities to sell coal at the same price to other buyers is quite uncertain. The utility makes extensive investments in transmission capacity to move the power from mine to load centers.

These four cases involve very different degrees of transaction specific investments. In the first case, the buyer makes specific investments to design its plant to burn coal of the quality produced in a fairly large geographical area, but the value of the investments would not be reduced by shifting suppliers on short notice since there is an elastic supply of coal of similar quality available from this area. Multiple transport options combined with ease of shifting suppliers does not make the value of the plant economically dependent on the behavior of a particular railroad. Suppliers have not made investments specific to the purchases of this particular plant or utility. None of the four potential types of transaction specific sunk investments seem to be important.

In the second case, transaction specific investments are likely to be somewhat more important. The plant has tighter design specifications than in the first case. Sudden switching of suppliers can be costly because the elasticity of supply is small, although if appropriate notice is given additional mining capacity can be brought into production to satisfy additional demand at approximately the same price. Only two railroads are utilized, but alternative transport options are available at a small increase in cost. The suppliers have made some investments in direct response to the anticipated demand of this utility, but the associated mines are already operating, and alternative purchasers of the coal would probably emerge with some lag. Thus, the power plant investment is characterized by some physical asset specificity and some of the mining investments may fall into the dedicated assets category.

In the third case, transaction specific investments are much more important. The utility has designed its plant to burn coal from a particular mine. It has invested in unit trains to transport that coal. The mine owners will make investments to increase the capacity of the mine almost completely as a result of the expected demand by this utility. The utility effectively ties itself to a single transport option, although by owning the rail cars that will carry the coal it has some control over the availability of transportation and simplifies the problem of writing a contract for transport services with the railroad. In this case the investment in the plant is characterized by a greater degree of physical asset specificity. The mining investment has the character of a dedicated asset. Although the vertical relationship is not of the "cheek-by-jowl" nature implied by the concept of site specificity, the existance of a single railroad and utility investments in rolling stock to be used on that railroad seems to lead to a similar result.

The fourth case is a mine-mouth plant and is characterized by at least three of the four types of asset specificity identified by Williamson:

(a) site specificity-- the plant and mine are consciously located next to one another to minimize costs; (b) physical asset specificity--- the need to design the plant to burn the particular types of coal located in the adjacent reserves and (c) dedicated assets--- The mine would not be built but for the promise of purchases from the adjacent plant. The plant would not be built but for the availability of coal from the adjacent mine.[13] Human (or organizational) asset specificity "that arise in a learning-by-doing fashion" as identified by Williamson may also be important especially with regard to coordination between the plant operator and the mine operator, but I will not rely on this fourth form of asset specificity in this discussion.

Let us consider the implications of asset specificity for the optimal choice of governance structure in each case, assuming for now that contracts will be incomplete and reputational constraints are not important (we look at these issues in more detail below as part of the detailed analysis of mine-mouth plants). According to transaction cost theory, other things equal, the potential for opportunism problems should vary directly with the importance of transaction specific investments. These opportunism problems should in turn affect the nature of the contractual relationships between buyers and sellers. In case 1 opportunism problems should be minimal and reliance on spot market purchases and simple contracts should be quite adequate. In case number 2, there is a potential for opportunistic behavior by the buyer and the seller, but this is sharply constrained since transaction specific investments are modest. Alternatives to spot market transactions and simple short term contracts are likely to be desirable to provide some protection for buyers and sellers from ex-post hold-up problems. Vertical integration is not a viable option, however, given the procurement strategy of the utility. In case 3, both the buyer and the seller make transaction specific investments and opportunism problems are potentially quite serious. The potential for the railroad to act opportunistically is a serious complication. Long term contracts with extensive protection for both the buyer and seller from opportunistic behavior is suggested. Vertical integration is a possibility, although if the utility also sinks investments in the mine, the railroad's incentives to hold it up may be even greater. Long term coal supply contracts with utility performance contingent on performance of the railroad may be desirable.

Asset specificity appears to be of most importance for mine-mouth plants and opportunism problems potentially the most severe. Such plants appear to be prime candidates for the use of complex long term contracts or vertical integration to support exchange.

We can identify mine-mouth plants directly and analyze the governance structures for coal transactions involving such plants in detail below. In these cases we can assume that neoclassical cost considerations led to this locational choice and can examine the choice of governance structures that have been made in response to the associated transaction cost considerations. For other plants, we have no easy way of identifying directly the underlying neoclassical cost conditions that might make one of the other strategies economical for particular plants. However, in light of the general characteristics of coal supply and transportation discussed above, we can make at least some qualitative statements about the likely incidence of each of the three cases discussed above.

For the strategy covered by case #1 to be economical (transaction cost considerations aside), several characteristics of supply and transportation must prevail. The supply areas where the utility can most economically obtain coal should have coal of fairly uniform quality, should have numerous producing mines, and should be supplying quantities of coal that are very large relative to the demands of any particular plant. Economies of scale in coal mining should not be important so that it is not advantageous for a plant to commit itself to long term supplies with a single supplier. In addition, transport cost savings associated with the use of several competing transport alternatives should be greater than the savings associated with the use of unit trains to transport large quantities of coal from a single point to the plant. Alternatively, the mines must be close enough together to economically move the coal to a local point for onward transport by unit trains.

These characteristics of coal supply and transportation do not appear to be satisfied in most areas of the country. To the extent that this extreme case would be an economical coal procurement strategy anywhere, it is likely to be so for some plants located in the east which utilize coal from certain areas in Appalacia and for one reason or another cannot make efficient use of unit trains.[14]

The second case is likely to be more consistent with the supply and transportation opportunities faced by many plants located in the east and especially in the eastern half of the midwest which secure supplies from Appalacia and the eastern Interior region. This reflects potential benefits associated with making at least limited commitments to particular mines, the costs of efficiently operating plants with variable coal quality and economies associated with concentrating coal transportation and investments in unit trains. Longer term contracts with some protection from opportunism would be more likely in this case, although there seems to be little reason for vertical integration.

As we move further west, the advantages of reliance on a small number of mines because of scale economies, transport economies and variations in coal quality become more important. Opportunism problems become more severe and reliance on spot markets or simple contracts more problematical. Long term contracts with appropriate protective provisions become more likely responses to opportunism problems. Utilities in the midwest and west that rely on supplies of coal from the west to satisfy air pollution requirements or which take advantage of cheap lignite and sub-bituinous coal and must make very specific plant investments to burn it effectively, are likely to have arrangements similar to those suggested in case 3. Procurement strategies that lie between cases 2 and 3 are likely to reflect opportunities faced by other plants in the midwest.

Overall, this suggests that (excluding mine-mouth plants) as we move from east to west, we should see less reliance on spot market purchases and more reliance on long term contracts. There should be relatively little reliance on spot market purchases generally since the supply, transportation and generating technology conditions conducive to cost minimizing supply strategies that do not involve at least some asset specificity by either the buyer or the seller are likely to exist for a relatively small fraction of all coal burning power plants. Mine-mouth plants are the prime condidates for complex long term contracts or vertical integration.

Vertical Integration, Spot Markets and Contract Sales: The Industry as a Whole

The previous discussion suggests that we should observe considerable variation in coal supply arrangements. Spot market transactions and simple short term contracts will be economical choices for some plants. They will tend to be older plants located in the east. Vertical integration is most likely for mine-mouth plants, but such plants account for a relatively small fraction of total coal utilization (on the order of 15%---see below). If vertical integration is not chosen to govern supply for mine-mouth plants, contracts will have to be structured to mitigate opportunism problems in the context of a supply relationship governed by complex long term contracts. Most coal burning plants are likely to face economic opportunities that fall somewhere between these two extremes, relying extensively on neither spot markets nor vertical integration or very long and "tight" contracts that "simulate" the opportunism mitigating features of vertical integration.

We now turn to an examination of the extent to which vertical integration, spot markets and other contractual arrangements are utilized to support exchange between coal generating plants and their suppliers for the industry as a whole. In the next section we examine mine-mouth plants in much more detail.

Table 4 lists the utilities that are integrated into coal production in one way or another and their coal subsidiaries (where the latter information is available).[15] The table also provides information on the extent of vertical integration (% of coal requirements provided by coal subsidiaries) for each of these companies. Less than 15% of coal consumed by utilities is supplied to plants by a coal company owned by the owner (or one of the owners in the case of jointly-owned plants) of the plant. Another 3% or so of U.S. coal consumption is produced by coal companies owned by utilities but supplied to plants not owned by the integrated utility in question. The extent of vertical integration into coal production in the electric utility industry is substantial less than in the coking (iron and steel) industry where about 65% of requirements come from integrated coal suppliers. [Table 4 about here]

About half of the utilities owning coal producing subsidiaries are fully integrated, supplying all of their coal requirements (and often supply coal to other utilities as well). The others generally supply only a small fraction of their coal needs. Those utilities that are integrated tend to be relatively large consumers of coal, but over half of the twenty largest utility consumers of coal are not integrated. A few utilities are currently attempting to divest themselves of coal subsidiaries, largely as a consequence of unfavorable regulatory treatment.[16]

Thus, about 85% of the coal used to generate electricity is supplied through some type of market transaction mechanism. Readily available data on coal supply arrangements breaks utility coal transactions down into "spot" transactions and "contract" transactions (see Table 5). Generally, "spot transactions" involve coal supply agreements for relatively small fixed quantities of coal with delivery schedules extending for less than a year. Transactions that involve deliveries extending over a period of more than a year generally fall in the contract category. The proportion of spot transactions varies considerably from year to year (See Table 5). The relatively high values for 1974-75 and 1977-78 appear to reflect coal strikes that took place during portions of these periods. There is also substantial regional variation in the volumes of coal made available through spot market transactions. The spot market accounts for a much larger fraction of transactions in the east than elsewhere and there is essentially no spot market for coal in the west. [Table 5 about here]

The "contract" category includes everything from one year contracts to fifty year contracts and individual contracts vary widely in the annual tonnage provided for. There is probably relatively little difference from a transactional perspective between spot sales and contract sales with deliveries spread over one or two years, so it would be useful to at least break down the contract category further by duration and volumes. Additional information on contract deliveries by the duration and annual quantities is not as easily obtained from standard government sources as the initial breakdown between spot and contract. However, I have analyzed a sample of over 200 coal contracts [17] that accounted for over 30% of contract coal deliveries in 1979 (See Table 6). Over 80% of the coal sold under these contracts involved delivery commitments over more than five years and over 70% involved commitments extending over a period of more than 10 years. This breakdown is roughly equivalent to the survey information Gordon (1969, pp. 55-58) obtained for 1969. Longer contract periods are generally associated with larger annual volumes of coal as well. [Table 6 about here]

These results are broadly consistent with the previous discussion. About 60% of the coal supplied to electric utilities involves relatively long term contracts (more than five years). The spot market is not an important "governance mechanism" for coal supply arrangements between utilities and coal producers. It is most important in the east and essentially non-existant in the west. Vertical integration is not particularly important either, accounting for a somewhat smaller fraction of coal supplied than do spot market transactions.

Coal Supply Arrangements For Mine-Mouth Plants Implied By Transaction Cost Considerations

I argued above that coal supply transactions for mine-mouth plants are characterized by at least three of the four types of asset specificity identified by Williamson (1983, page 26). From a transactional perspective, these plants are distinguished from the "typical" coal plant primarily by the unusual importance of durable transaction specific investments. Transaction cost theory suggests that mine-mouth plants should be much more likely to be integrated or make use of complex long term contracts than the "typical" generating plant. Before proceeding further it is worth considering briefly, the other characteristics of transactions that are likely to affect the governance structure for coal plants generally and mine-mouth coal plants in particular:

<u>uncertainty/complexity</u>: There is no easy way to "measure" the extent to which a particular type of transaction is subject to uncertainty or complexity. Indeed, it is not at all obvious from the literature how one even would conceptualize either a cardinal or ordinal measurement proceedure. Precise measurement is not important, however. Uncertainty and complexity are important to the extent that buyers and sellers cannot write unambiguous and easily enforceable full contingent claims contracts. When full contingent claims contracts cannot be

written, contracts are necessarily incomplete. Contractual incompleteness is not the source of transactional difficulties, but rather sets the stage for contractual difficulties in the presence of transaction specific investments or information asymmetries.

From the perspective of a utility considering investment in a coal plant with an expected life of 35 years or more, it is certainly reasonable to assume that there is enough uncertainty about coal demand in the short run and over the life of the plant to make it difficult to write a full contingent claims contract. Coal demand will vary with the utilization rate of the plant and the thermal efficiency of the plant. Both of these vary over time in a non-deterministic way. As a plant ages and moves higher in the dispatch profile, plant utilization will also vary with total electrical load and with the prices of fuels burned by other plants on a utility's system. Air pollution restrictions and cooling water availability may limit plant utilization and affect both the quantity and types of coal required. Furthermore, because coal quality is very important, and numerous coal characteristics are relevant for plant design and plant performance, the "simple" product "coal" is a much more complex product than first meets the eye.

From the perspective of a mine owner considering investing in a new mine or expanding an existing mine, there is also likely to be considerable uncertainty about mining costs and coal quality over the life of the mine. Ex ante, there is at least some uncertainty about mining costs, cleaning requirements and reserves given prevailing input prices. Over time, the nominal and real costs of mining are enherently uncertain, depending not only on the physical characteristics of the reserves, but also on changes ininput prices, changes in contract work rules, changes in government regulations affecting mining costs and technological change.

For the purposes of examining governance structures for coal supplied to electric utilities I think that it is fair to assume that contracts will necessarily be incomplete. This is especially true for mine-mouth plants where both parties make long term reliance investments contingent on the performance of the other over many years.

reputational contraints: Is it likely that the threat of losing future purchases (in the case of the mining company) or the prospect that buyers will have to pay higher transactions prices in future contracts (reflecting a price for anticipated breaches on the part of the buyer) will deter the kinds of "bad behavior" that the transactions cost literature is concerned with ? Reputational constraints depend primarily on the importance of repeat purchase activity and the ability to distinguish bad (good) outcomes (such as high mining costs or failures to deliver promised quantities) that arise because of inefficient (efficient) behavior from bad (good) outcomes that arise simply because of bad (good) luck. Reputational constraints are likely to be most important when utilities find it economical (in the neoclassical sense) to adopt procurement strategies such as those outlined in case 1 and case 2 above. There is extensive repeat purchase activitiy, sales are made to many sellers from the sames mines and the utility buys from several different sellers. These constraints are not likely to be very important in the case of mine-mouth operations, however.

Individual mine-mouth operations have many idiosyncracies that make it difficult for third parties to distinguish poor performance due to actions by either party from poor performance resulting from exogenous factors that are not subject to control by either party. Especially in the last ten or fifteen years regulatory changes and labor problems have had profound effects on mining costs and production. Many generating units built over the past twenty years have experienced much poorer heat rates and availabilities than had been anticipated.

It is likely to be difficult to determine how much of these changes were do to exogenous factors and how much can be associated with sub-optimal levels of effort by either party. Overall, it seems unlikely that reputational constraints can provide protection from opportunistic behavior in the case of mine-mouth plants.

diseconomies of internal production: I have no way of evaluating objectively whether there are important economies that a large coal producer with production activity and experience from other supply arrangements would bring to a transaction that a utility embarking on coal production itself would not be able to take advantage of. I suspect that there are some economies of scale or experience in this sense that utilities would not be able to take advantage of, but I have seen no evidence that would allow me to make a difinitive statement.[18] Nor is there any way to estimate empirically internal incentive and command and control problems that might increase costs from integrated production compared to the costs of market procurement and necessarily limit the economic extent of vertical integration. There is little reason to believe, however, that these considerations are more important for mine-mouth plants than they are for other types of plants.

In summary, these observations suggest the following: The assumption of incomplete contracts is probably a good one for all types of generating plants. This sets the stage for opportunism problems if transaction specific investments are necessary for structuring a minimum cost supply relationships. Transaction specific sunk investments are very important for mine mouth plants; considerably more important than for other types of plants. Reputational constraints are not likely to be particularly effective in the case of mine-mouth plants. Diseconomies of internal production are likely to affect the economics of vertical integration equally, regardless of the particular type of plant involved. This all implies that that coal supply transactions for a mine-mouth coal operation are prime candidates for the choice of vertical integration as a transaction cost minimizing governance structure. Regulatory considerations, coal supplier economies and other diseconomies of vertical integration may make vertical integration less attractive than alternative contractual governance structure, or even impossible. If vertical integration is not chosen some type of long term contractual arrangement containing provisions that anticipate the kinds of performance difficulties discussed in the literature and designed to effectuate a smooth and efficient relationship between the buyer and the seller should be forthcoming. Reliance on a spot market or even relatively short term contracts are not likely to prove to be a cost minimizing alternative.

Let's assume that for one reason or another a mine-mouth plant operator chooses to secure supplies through contract rather than vertical integration. What are the characteristics of an "efficient" contractual relationship ? What contractual provisions will emerge as the parties negotiate a mutually acceptable supply agreement in response to anticipated transactions costs and contract execution difficulties ? Are the resulting arrangements efficient ?

From a normative (efficiency) perspective we would want to see a coal supply arrangement emerge that has the following attributes:

(a) We want to see the contemplated mine-mouth operation go forward if this is the cost minimizing way for the utility to generate electricity; we want the parties to be able to strike a deal.

(b) Once a plant and mine are built we want to see the plant operator continue to take supplies from the adjacent mine as long as this is the least cost source of supply. We don't want to see (socially) uneconomical supplier switching by the buyer.

(c) We want the seller to produce coal efficiently.

(d) We want the seller to continue to supply the quantities and quality of coal promised as long as it represents the least cost source of supply for the plant. We don't want to see uneconomical shifting of supplies to other buyers.

(e) We want the agreement to be flexible enough to allow supply and demand by the supplier/purchaser to adjust to changes in economic conditions. If the current supplier is not the minimum cost producer the agreement should provide a mechanism to shift suppliers, reduce production, etc.

(f) We want to minimize haggling over price and production levels that may disrupt efficient supply arrangements but may be a natural outcome of the bilateral monopoly situation that emerges once each party sinks costs in reliance on the agreement.

(g) We want to avoid litigation and litigation costs.

The actual provisions that emerge will reflect efforts by each party to maximize profits with due recognition of the costs of writing, monitoring and enforcing contractual promises. A variety of "price" and "non-price" provisions are potentially available to support exchange and mitigate opportunism problems. The optimal price and non-price provisions are likely to be related to one another and it is difficult to discuss them independently. It is even more difficult to discuss them simultaneously.

I proceed in the following way: I assume to start with that the costs of producing coal do not change over time due to changes in input prices, technological change, government regulation, contractual changes in work rules, etc. and that a price (level and structure) is negotiated at the start of the contract and is <u>anticipated</u> to be fixed over the term of the contract, although either party is free to try to exploit any ex post monopoly power to force the other to agree to a higher or lower price after production begins. I assume that other changes in market conditions may take place over time which affect the value of the coal to the buyer and the opportunity cost to the seller of supplying to the adjacent plant. Given these assumptions I suggest the kinds of "non-price" terms that we should expect to find in these contracts to mitigate opportunism problems. I then go on to relax the assumptions about the costs of producing coal and examine alternative patterns for determining prices over the life of the contract.

Non-Price Provisions

a. Given the three types of investment specificity that characterizes this type of production neither the utility nor the coal supplier will want to be the first mover. The utility isn't going to start building a power plant on this site without some supply agreement because it would be subject to hold-up by the owner(s) of adjacent reserves. The same is true of the coal supplier vis a vis the utility. Furthermore, effective design of the mine-mouth operation requires cooperation between both the utility and the coal supplier. Thus, a firm governance structure is likely to be in place before any substantial plant investments are made by either party.

b. I expect to see very long term contracts negotiated which specify purchasing (take) and supply obligations for the plant and the mine over a substantial fraction of the life of the plant---at least twenty years. Neither the power plant owner nor the supplier is likely to want to enter into a relationship which involves frequent renegotiation of terms after each incurs transaction specific sunk investments.

c. I would expect to see extensive use of requirements contracts. The quantity of coal to be delivered under the contract must be specified somehow. Coal requirements will vary from month to month and year to year. Some of this variation can be dealt with through a coal inventory accumulation, although one of the desirable features of a mine-mouth plant is the ability to minimize inventories that might otherwise be necessary to insure against transportation problems. Ideally, the power plant owner would simply like the mine to deliver enough coal to satisfy the requirements of the plant. Since requirements vary, the easiest way to specify quantities from the viewpoint of the plant operator is simply to write the contract as a requirements contract.

There are strategic reasons for the utility to write the contract as a requirements contract as well and to include provisions to restrict sales to third parties. Reducing promised deliveries during the anticipated term of the contract may be perceived as a supplier credible threat as part of an effort to hold up the utility, because the utility's initial investment is larger, longer lived and less easily redeployed than those of the mining company. The mine operator could credibly reduce supplies over time by ceasing to make replacement and expansion investments and use this threat to extract better terms from the utility. Furthermore, depending on the pricing provisions in the contract, changing market conditions could make it profitable for the mining company to breach the contract to supply even if it is not efficient to do so. Clear language that the contract is for plant requirements over a specified period of time makes court enforcement easier if disputes arise between the plant owner and the mine owner that cannot be resolved otherwise. It also suggests that provisions for dealing with sales to third parties and the dedication of specific reserves to the agreement along with the requirements provisions will protect the utility from the threat and potential costs of diverting supplies to other buyers.[19]

A requirements contract serves to protect the seller in similar ways. Threats by the buyer to switch to alternative suppliers are made less credible both because comparable suppliers will not be waiting in the wings to take up the slack and because breach is easier to detect and penalize through legal sanctions.

d. Coal quality is of particular importance to the utility and the mining company is in a position to affect coal quality by its mining practices. The mining company may be able to reduce its costs by mining low quality deposits, shirking on cleaning and increase effective prices (especially in per ton priced contracts) by increasing the quantity of "junk" in the coal. The utility may have difficulty distinguishing coal quality problems that arise because of poor mining practices and coal quality problems that arise because the reserves are of generally lower quality than had been anticipated when the contract is negotiated. The supplier may also have an interest in the precise definition of the expectations about coal quality ex ante since claims of poor coal quality may be used by a utility as an excuse to breach the contract. One would expect substantial ex ante investigation of reserve characteristics to verify that the promised quality specifications can be achieved. I would also expect the contract itself not only to specify minimum acceptable coal quality but also to define clearly the specific reserves on which ex ante quantity/quality evaluations were made and to provide for the dedication of these reserves to production for this plant. To the extent that variations in coal quality can be easily "priced", I would expect pricing provisions expanded to do so.

e. Williamson (1983) discusses the desirability of "protective governance structures" to deal with potential hold-up problems when "hostage arrangements" cannot be structured to eliminate expropriation incentives possesed by one or both parties. Contractual incompleteness and the potential for haggling are a serious potential problem in unintegrated mine-mouth operations. While court enforcement remains an option and coal contract disputes do occasionally lead to litigation, arbitration clearly represents an opportunity to provide a dispute resolution system that does not entail the costs (broadly defined) of litigation.

Thus, I expect to see arbitration provision contained in these contracts as well as other cooperative arrangements that allow for the smooth functioning of a complex agreement and the settlement of disputes without resorting to litigation.

Pricing Provisions

Establishing a pricing formula to govern compensation arrangements for contracts lasting many years that provide incentives to both the buyer and the seller to perform as promised without leading to serious inefficiencies itself is not an easy task. Dealing with the kinds of ex post performance problems addressed in the transactions cost literature and providing mechanisms for smooth adjustments in obligations as various contingencies arise is complicated by the uncertainty governing future costs and market conditions that are inherent in this relationship. Input prices are likely to change over time, technological developments may reduce the current and expected future costs of mining from similar reserves, labor agreements may change work rules and increase or decrease productivity, new government regulations may increase mining costs, unanticipated mining problems may emerge, new property and severence taxes may be applied, etc. General changes in supply and demand are likely to lead to changes in the value of the coal at the mine-mouth operation both from the buyer's perspective and the seller's perspective.

The compensation arrangements should reflect two interelated objectives. First, they should be structured so as to eliminate incentives either party has to behave opportunistically. Second, the pricing provisions should be structured in such a way that efficient demand and supply decisions are made by both the buyer and the seller. It would, for example, be undesirable if a pricing formula gave one or both parties the incentive to breach their purchase and supply promises if this would increase the social costs of supplying coal or producing electricity. Let us examine four different methods for establishing prices over time.

1. **Market price contracts.** If the product under consideration where a homogeneous product some of which were sold in a competitive auction market and which carried a clear "market price," the simplest way of determining prices might be just to stipulate that payments would be made at some fraction of an appropriate market price indicator. This is not likely to be a particularly attractive alternative as the sole determinant of prices for coal supplied for a mine-mouth operation, however.

Coal is not a homogeneous commodity with regard to the characteristics of the coal or the location of the coal. The mine mouth supply price includes both the cost of coal and (implicitly) the cost of transportation. There generally simply will not be any meaningful "market price" for coal of this particular type delivered to the plant. This is especially problematical in the west where there is essentially no spot market to tie anything to. Market price contracts may make a lot of sense for a homogeneous commodity like uranium, or even for coal in some areas of the country and when other types of plants are involved, but not for mine-mouth plants.

2. **Fixed Price Contracts:** An alternative to a market price contract is a simple fixed price contract (as I assumed above) . Risk allocation problems aside, this contract has poor incentive properties with regard to continuing performance. The primary problem that I see with it is that if the supplier's actual costs rise significantly above the fixed price when certain contingencies arise, it will have strong incentives to breach (reduce quantities provided in the short run, cease making investments to expand its capacity to continue to supply, run down the value of the equipment,etc.) even if such behavior is inefficient. Similarly, if the expected price of coal available from alternative suppliers falls below the fixed price (due to cost reductions generally, changing market conditions,

etc.) the plant operator may find it profitable to breach even if it is inefficient to do so.

Expectations of secular increases in input prices, reserve depletion, changes in work rules and government regulations that are likely to reduce productivity, etc., make these problems worse. A long term fixed price contract must satisfy the criterion that the PDV of expected revenues is greater than or equal to the PDV of expected costs or the supplier will not agree to enter into the supply arrangement. Given expectations of nominal cost increases over time, this implies a fixed price that will "front load" the cash flow so that in early years the supplier is getting revenues substantially above current costs while in later years he may receive revenues substantially below the then current cost. At some point the fixed contract price may fall below current incremental costs and the supplier will have an incentive to abandon the mine, substantially reduce production, cease making investments, etc.[20] Fixed prices in long term contracts don't appear to me to be credible because the specification of a fixed price is so likely to provide incentives to one or both parties to threaten to breach and to trigger renogotiation.

3. **Cost Plus Profit Contracts:** A third alternative is to negotiate a cost plus profit contract in which the supplier is compensated for all of the costs incurred in production, including the cost of capital. Risk allocation consideration aside, <u>if it could be assured that the supplier would produce efficiently</u>, such a contract has some desirable properties. It is unlikely that the buyer would have a strong incentive to breach because it is unlikely that he could get the coal more cheaply elsewhere over the duration of the contract unless the market value of the coal increases or decreases faster than production costs, since the mine mouth supplier is presumably facing the same changes in input prices, regulations, technological change, etc. as are other comparable

suppliers.

A cost based price also ensures that prices are high enough so that the supplier does not have an incentive to walk away from the supply arrangement when costs increase due to input price changes, productivity changes due to changes in health and safety regulation, land reclamation costs,etc. as might occur with a fixed price contract. A cost based price of course does not eliminate the incentives a supplier might have to shift supplies to buyers if there is a large unanticipated increase in the value of of the coal, for example, as a result of an increase in the demand for low sulfur coal making it more valuable in "the market" than it is under the contract (i.e. the long run supply function for low-sulfur coal is upward sloping and the economic rent associated with an assumed inframarginal reserve rises). And it is unlikely that it would be efficient for the supplier to shift to another buyer if such a contingency arose. Similar inefficient responses by buyers can be expected if the value of coal falls and the "costs" used in the pricing formula reflect rents generated based on ex ante expectations.

An important problem with a cost plus contract is that it has bad incentive properties with regard to the supplier's incentives to minimize costs. Without more, the supplier has little incentive to produce efficiently. If costs got high enough the buyer would have incentives to switch to other suppliers, but there is likely to be a potentially large wedge for inefficiency since the next best alternative would on average be more costly to the buyer than an efficiently operated mine mouth facility.

4. **Indexed Contracts:** The fourth and final type of contract that I consider is an indexed contract. This is a natural alternative to a fixed price contract. Rather than try to set a fixed price that rolls in revenues for anticipated future changes in input prices, costs of government regulations, changes in union work

rules, etc. we can set a base price that is adjusted over time as input prices rise. For example, the base price can be broken down into components (labor, materials and supplies, depreciation, profit, property taxes, etc.) and then each component escalated according an appropriate input price and productivity index. This type of contract seems to deal with some of the undesirable properties of both the fixed price and cost plus contracts. Prices now rise over time as input prices rise and productivity opportunities change and we do not have to front load cash flow. Prices rise as the supplier's input prices rise and production opportunities change, but are independent of the actual production decisions made by the supplier. If the supplier can increase productivity more than provided for by the index his actual costs will rise by less than the indexed price. If his costs rise, because of bad mining practices for example, his net revenues are reduced as a result. This type of contract provides incentives for the supplier to minimize costs(given coal quantity and quality). Furthermore, the increases in input prices, technological change, etc. will have similar effects on the costs of proximate alternative suppliers as well. Although this type of pricing provision cannot guarentee that contract prices will move in lockstep with the prices that might be charged by competing suppliers over time, it does account for several important causes of changing supply prices. An indexed contract therefore appears to dominate either a fixed price or cost plus contract.

An indexed contract is not without problems, however. It may be difficult to index some components of mining cost that will affect the costs of producing from this mine and "comparable" mines (actual and potential). New labor contracts may change work rules, increasing labor costs. New mining regulations may increase costs substantially. Technological change may reduce costs and substantially alter the cost minimizing weights used to index the price. This kind of adjustment mechanism can also get very complicated if we try to break down the base price into numerous components. The indexed price could move far away from the economic costs of production giving either the buyer or seller increased incentives to breach the agreement. Complexity would encourage haggling and litigation.

In addition to general provisions for adjusting the level of prices, the price structure could be adapted to provide additional financial protection against expropriation and uneconomic buyer/supplier switching. For example, Williamson (1983) and Goldberg and Erickson suggest that non-linear prices may be used as a device to help to insure that the buyer performs. A seller concerned that a buyer will shift to other suppliers might find a fixed annual payment (to cover sunk costs) plus a commodity charge attractive or include minimum take or pay provisions in the contract. We should recognize, however, that "optimally" adjusting non-linear price schedules over time may be even more complicated than adjusting simple (linear) unit prices.

None of the price adjustment mechanisms is ideal in the sense that the method of setting the level and structure of prices alone can deal effectively with all of the performance problems that can arise in a long term coal supply arrangement. Thus, whatever method is used to determine prices, I also expect to see substantial reliance for protection on the kinds of non-price provisions discussed above.

Finally, there is the problem of dealing with "surprises" that affect either the price or non-price terms of a contract. What I mean by surprises are events that where not anticipated with positive probability by either party to the contract when the contract was negotiated. The expected effects of "surprises" are not reflected in the terms of the contract. As I have argued elsewhere (Joskow:157), "bounded rationality" suggests that there are some contingencies that are simply not contemplated by the parties when they negotiate a supply arrangement. These contingencies may involve the effects of unexpected changes in government regulation, dramatic changes in supply or demand in the market, or other changes that would impose a large financial burden on one of the parties if it performed as required by literal interpretation of the contract; a burden that was not reflected, for example, in the base price or adjustment provisions. Both parties to the contract should recognize ex ante that "surprises" will occur and I would expect to find general provisions in contracts, such as force majeur or gross inequity clauses, that specify a process for dealing with such unspecified contingencies if they arise.

Coal Supply Arrangements For Mine-Mouth Coal Plants:General Characteristics

Table 7 lists all of the mine-mouth coal plants with first units that began operating no earlier than 1960 (with one exception)[21] that I was able to identify. The method used to identify these plants is discussed in the Appendix. There are 21 plants all together which accounted for about 15% of electric utility coal deliveries. Most of the plants are multi-unit facilities and over half are jointly-owned by at least two utilities. Only two of the plants used any coal purchased on the spot market and in both cases spot sales accounted for only a small fraction of total consumption. **[Table 7 about here]**

Table 8 provides general information on the coal supply arrangements that have been made for each plant. In 1982, 10 of the plants obtained all of their coal supplies either from a coal mining division or subsidiary of one of the utilities owning the plant (i.e. coal supply arrangements involved some form of vertical integration). One plant (Mt. Storm) obtained part of its supplies from a coal mining subsidiary of the utility (but this accounted for 100% of mine's capacity). In the case of jointly-owned plants with coal supplied by a coal subsidiary of the one of the plant owners there is typically a formal contract written between the owners of the plant and the coal subsidiary. I have noted these in table 8 by using the term "integrated/contract" to reflect this state of affairs. [Table 8 about here]

Together, mine mouth power plants account for about 50 million tons of "integrated" coal supplies per year. This is about 60% of all coal supplied to utilities by coal companies owned by one of the owners of a plant. In other words, mine-mouth plants account for about 15% of total coal utilization, but 60% of all coal supply arrangements governed by some form of vertical integration. A mine mouth plant is thus about 6 times more likely to rely on vertical integration to support exchange than is any other type of coal burning power plant.

The remaining ten plants all rely primarily on long term contracts for the supply of coal.[22] The contracts vary in duration from 20 years to 50 years with 35 years being typical. The "integrated/contract" supply arrangements generally involve long term contracts with 35 year durations as well. Referring back to Table 6 it is clear that very long contracts are far more likely to emerge to govern coal supply arrangements for mine-mouth plants than they are to govern supply arrangements generally in the electric utility industry. On average less than 20% of the coal supplied under the 200 sample contracts had durations of greater than 30 years (and most of this is accounted for by mine mouth plants). Both the extensive reliance on vertical integration and very long term contracts are quite consistent with the predictions of transaction cost theory.

Non-Price Provisions of Long Term Contracts For Mine-Mouth Plants

I was able to obtain the actual contracts governing transactions between the coal supplier and the power plant owners for 16 of the 21 mine-mouth plants on the list.[22] Since some plants have more than one contract, either because separate contracts were written for different units or (in one case) contracts were written with two adjacent mining companies, I have 21 contracts all together, plus amendments and revisions, covering 16 plants. These contracts may be "incomplete", but many of them are very complicated. These are not just documents that were dashed off because the companys' lawyers said thay should have a legal document to "confirm their orders."

Table 9 summarizes the incidence of various non-price provisions of the coal supply contracts reflecting the discussion above. **[Table 9 about here]**

Duration: As indicated above, most of the contracts have durations of thirty years or more with 35 years being most typical. And these are real long term contracts. Sixteen of the contracts have no scheduled renegotiation provisions. Three contracts provide for price renegotiation (subject to certain constraints) after 20 years. One provides for renegotiation of the escalation weights only. One contract allows the buyer to terminate after 6 years, but obligates him to reimburse the mining company for all fixed costs. Short term renogotiation provisions and options to terminate on short notice are generally not provided for as they sometimes are in other coal contracts (McGraw-Hill:352-353). It is also quite clear from reading the contracts that are available that these supply agreements are generally negotiated several years before the initial units for which the coal is to be supplied are placed in service. Neither party moves first, they move together.

Requirements Contracts/dedication of reserves: Almost all of the contracts are full requirements contracts. Of those that are not, we have one contract which simply specifies annual supplies for each of twenty years, one contract which specifies annual quantities (plus or minus 10%) for each of 35 years, one 90% requirements contract and one plant that has two contracts each for 50% of requirements (with flexibility to go down to 40%). In all but one case specific reserves are dedicated to fulfilling the contract as well. Most of the contracts also have explicit restrictions on sales to third parties which require the approval of the plant operator, or most favored nations clauses.

Coal Quality: Coal quality is handled in one or both of two ways. Most of the contracts include "contract" coal quality characteristics and "minimum" coal quality characteristics, often along with various bonus/penalty provisions if certain coal quality specs (usually BTU content) fall above or below those specified in the contract. BTU content of coal, sulfur content, size, moisture and ash content are the most frequently specified characteristics. If coal quality specifications are not included, the contract provides for "run-of-mine" deliveries free of certain impurities from specified reserves. Some contracts have as many as 16 coal quality characteristics specified.

Maximum Delivery Commitments: In addition to providing requirements obligations on the buyer and seller, the contracts typically specify maximimum monthly and annual quantities that the suppliers are commited to deliver. These are often adjustable within some range if the purchasers give adequate notice to the supplier. These provisions sometimes get very complicated, especially when a sequence of generating units is planned. Even if a utility claims its requirements are greater than the maximum, the supplier has no contractual obligation to supply more than the maximum.

Arbitration: All but three of the contracts have specific arbitration provisions to deal with disputes arising under the contracts. Two of the three contracts without these provisions were eventually terminated after utility acquisition of the mines. A few of the contracts also provide for a joint utility/supplier committee to facilitate the smooth operation of the coal supply arrangements and to avoid disputes.

Pricing Provisions in Long Term Contracts

There are two "general" types of formulas used to determine prices in the actual coal contracts that I have reviewed. The predominant form (14 of 21 contracts) of pricing involves the specification of a base price (either per ton or per million btu's) which is broken down into several different components (labor, materials, depreciation, profit, taxes, etc.) with an escalation provision specified for each. Usually some of the components are indexed in some way, while other components are adjusted for changes in actual costs. There is some variation among contracts in this regard. These contracts thus represent a mixture of the indexed and cost plus contracts discussed above. They recognize explicitly that prices will have to be adjusted over time (up or down) to reflect changes in input prices and several categories of real cost changes that are not subject to the control of the mining company. Prices are not, however, formally tied to "market prices" nor do changes in the relationship between contract prices and market prices automatically trigger renegotiation. The older contracts tend to have a fraction of the price which is not escalated and it is quite clear that uncertainty due to inflation and unanticipated exogenous events affecting real mining costs have been of increasing importance in structuring long term contracts between utilities and "independent" suppliers over time.

The second primary type of compensation arrangement (7 contracts plus one indexed contract with a cost plus option) is a cost plus profit contract. These contracts normally specify that the buyer will pay all operating costs, depreciation, amortization, property and severence taxes plus an allowance for profit (normally per ton or per BTU with a couple of exceptions). These contracts generally recognize explicitly that pure cost plus arrangements raise incentive problems and include specific incentive provisions.

Table 10 summarizes a number of the key provisions governing price adjustments over time. We discuss the base price plus escalation contracts first and then turn to the cost plus contracts. [Table 10 about here]

<u>Base Price + Escalation Contracts</u> (14 contracts)

a. **Wages and Benefits:** Labor costs are normally broken down into several categories to reflect wages, benefits, employment taxes, etc. A base hourly wage rate is typically indexed to changes in wage rates (including benefits, taxes, etc.) as specified in collective bargaining agreements applicable to the area in which the mine is located (if it is unionized and sometimes if it is not) or to the average wage rate actually paid to workers at the mine including changes in government mandated tax and benefit payments. I have identified the treatment of wages and benefits as indexed if the wage component had a fixed weight in the base price, excluding adjustments for contractual or legal changes in work rules, and was adjusted only for changes in prevailing wage rates. Several contracts have manning tables attached to indicate how the average wage rate is to be determined. In three of the contracts all increases in labor costs per unit output were passed through, so that changes in labor costs due to both input price changes and changes in realized productivity were reflected in transactions prices. These are denoted as adjustments based on "actual cost."

b. **Materials & Supplies:** The M&S component of the base price is almost always indexed using a weighted average of several components of the WPI. As many as 9 separate components of the WPI are sometimes used. One contract contains a pass through for changes in actual M&S costs. Two contracts adjust M&S costs using the same index used to adjust wages (one contract is very old (1957) and the other has an unusual cost plus option). Explosives and electricity are often indexed separately.

The fraction of the base price attributable to labor costs and materials and supplies varies considerably, but generally falls within the range of 50% to 75% of the base price.

c. **Depreciation/Amortization:** This capital cost component is treated in a variety of ways. In about half the cases it is indexed directly (one case partially indexed and one case fully indexed) using either the WPI or the CPI, or aggregated with a profit component and residual costs and then indexed. In three cases actual costs were passed through and in two cases this component was fixed. One contract had a more complicated treatment of depreciation and profits which used a fixed component unless profits fell below some lower bound, in which cases prices would be adjusted upward.

d. **Profit:** In five cases a specific profit component was indexed either by the WPI or the CPI. In one cases prices were adjusted upward or downward if the rate of return on sales fell above or below some range specified in the contract. In three cases the profit component was fixed. In four cases it was aggregated with depreciation and other residual costs and then indexed in three cases and was fixed in the other.

e. **Costs Due to Changes in Government Regulations:** Costs associated with complying with new government regulations are generally treated as a cost to be passed on to the buyer. The provisions for calculating these costs are sometimes quite vague and are often subject to arbitration. The two contracts which did not contain such a provision were subsequently amended to include it. Both of these contracts were written in the 1960's.

f. **Changes in taxes (excluding income) and royalties:** These cost changes are generally simply passed through. Since they are generally simply changes in tax rates it is like indexing them.

g. **Changes in Contract/Union Work Rules:** In all but one of the contracts, provisions were made to adjust the labor component for changes in contract working hours, overtime pay, vacation time, etc. Several contracts contain detailed examples of the computations that should be made to implement this provision.

<u>Cost Plus Contracts</u> (8 Contracts)

Seven of the 21 contracts were primarily cost plus contracts and an additional contract gave the seller the option to switch from an indexed contract to a cost plus arrangment on six months notice (it is counted twice in the totals). In six of these contracts the profit component is indexed to the CPI or WPI. In two contracts the profit is based on a fair rate of return on investment.

Seven of the eight contracts (including the contract with the cost plus option) have formal incentive provisions. The eighth has vague language in the contract indicating that an incentive plan would be developed through negotiation after three years (the mine involved was subsequently acquired by the utility, before the date which would have triggered this provision). In three of the contracts there is a reward and/or penalty provided for, in the form of an adjustment to the profit component based on a comparison with market prices. In one of these contracts the incentive payment is tied to a comparison between the unit cost increase under the contract and the increase in a weighted average of local, regional and national coal prices. The other two contracts provide for a reward if the coal produced is the lowest cost of any comparable mine in the state.

Three of the contracts provide for a bonus/penalty based on the relationship between the actual costs and an indexed "standard cost." The indexed "standard cost" is constructed in a way similar to the construction of the base price plus escalation prices in the first set of contracts. Components are specified and then either indexed (mostly) or adjusted for some actual cost changes. The indexed standard cost is then compared to the actual cost per ton. There is a sliding scale that adjusts the profit component upward if the actual cost is below the standard cost and vice versa. The sliding scale bonus/penalty adjustment has a minimum and maximum. In each of these contracts explicit provisions are made as well for the utility to acquire the assets of the mines at net book value. In at least two of the three contracts, the utilities financed the initial development of the mines and hold mortgages on the property.[24]

The contract which gives the mining company the option to change from an indexed contract to a cost plus contract also gives the buyers the option to put the mining contract up for competitive bids if the cost plus option is exercised. The contract provides that a new mining company can acquire the assets at depreciated book cost or fair market value whichever is lower.

In these cost plus contracts, the utility frequently has the contractual right not only to audit the books and submit the reasonableness of costs incurred to arbitration, but also has the right to approve mining plans, capital expenditures and and budgets. Indeed, the distinction between vertical integration and "contract" in several of these cost plus contracts becomes almost a matter of semantics rather than a sharp distinction given the joint control, the presence of utility financing and the cost plus nature of the pricing provisions.

Other Provisions

a. **Non-Linear Pricing/Minimum Take or Pay:** Five of the contracts had non-linear price schedules (although one had 10 components with prices increasing as aggregate production increased). Most of the contracts have minimum take or pay provisions. Of the five contracts without minimum take or pay provisions one was a cost plus contract, one had a two-part tariff and one had a minimum take or pay provision added by amendment.

b. **Gross Inequity/Force Majeur:** Many of the contracts recognize explicitly that the pricing provisions specified can track the "prudent" costs incurred by the mining company only imperfectly. While the contracts intend both parties to bear some price/cost risk, it is not the intent of the contract to impose "inequitable" losses on the mining company or (in fewer cases) allow it to earn "inequitable" profits as a result of "surprises." These contracts contain a fairly vague provision that allows one or both parties to reopen the contract by asserting that its continuance constitutes a "gross inequity." Thirteen of the contracts have "gross inequity" provisions and in at least a few cases these provisions were used to reopen the contracts. All of the contracts recognize that certain contingencies may arise that make it impossible for the plant to continue to operate or that make it impossible for it to continue to burn coal from this mine. Fairly standard force majeur provisions are included in all of the contracts. In a few cases considerable detail regarding what does and what does not constitute force majeur and how compensation will be made during force majeur periods is contained in the contracts.

Experience with Contract Execution Over Time

A complete analysis of coal supply arrangements for mine-mouth plants would ideally include a detailed discussion of how these supply arrangements worked out over time. Did one party to the contract try to hold-up the other? Were there haggling problems ? Was there uneconomical supplier switching? Did the contractual provisions allow for smooth adjustments in obligations? Did the parties continue to perform as economic conditions changed ? Did the parties resort to litigation to get contractual promises enforced ?

Most of the information that one would need to do such an in depth analysis is not publicly available. I will discuss the fragments of evidence that I have been able to put together, however.

Most of the initial supply arrangements that were made at the time construction of a mine-mouth plant was planned have continued to govern supply arrangements up until the present time, despite fairly dramatic changes in coal prices, mining costs and air pollution restrictions. However, many of the contracts have been amended, in several cases numerous times, for a variety of reasons. The contracts negotiated in the 1960's and early 1970's often had pricing provisions that did not provide adequate protection to the mining company for the kinds of cost increases that ocurred in the 1970's. Amendments revising the base price and escalation provisions appear to be quite common. Sometimes these amendments are made in the course of negotiating a new supply agreement to accomodate additional generating units on the site. The gross inequity provisions have also been used to adjust prices. In several cases initial provisions for annual price adjustments were amended to provide for semi-annual, quarterly or monthly base price adjustments as the inflation rate increased in the 1970's. In a few cases there were amendments clarifying the operation of the pricing provisions contained in the contracts, no doubt following a dispute between the parties. I was surprised how enduring these relationships have been and how few modifications there have been made to the initial supply arrangements given the many changes that have occurred in coal markets over the last twenty years.

Two of the 21 plants identified experienced significant changes in their initial supply arrangements. The owners of the San Juan plant initially created a jointly-owned coal subsidiary (Western Coal Co.) which owned the reserves and coal cleaning facilities.[25] They contracted with a subsidiary of Utah-International to build and operate a mine to produce coal from these reserves in 1972. The mining contract gave either party the option to terminate the agreement after six years, in which case the plant owners would have to acquire the mining assets. The contract price (apparently) contained a large fixed component. Utah notified the owners that it would exercise its option to terminate after six years since it was losing money. It offered to renegotiate the supply arrangement and preferred a cost plus contract. After determining that they could not produce the coal any cheaper and that an alternative fixed price contract offered by Utah was too expensive, the joint owners of the plant signed a new mining agreement with a cost plus profit pricing formula. Subsequently, Western Coal sold the reserves to the mine operator as well and the utilities signed a revised 37 year cost plus contract with Utah International.

Utah Power & Light initially secured coal supplies for the Hunter and Huntington units under two long term contracts with Peabody Coal. The first contract signed in 1971 provided for the requirements of the first two units of the Huntington plant. The second contract signed in 1974 (involving a second mine) provided for supplying the requirements of the first two units of the Hunter plant. Both contracts were for 35 years. The first used a base price plus escalation formula. The second used a cost plus formula with no explicit incentive provision. They both also contain unusually wide ranges in acceptable coal quality and no bonus/penalty payments tied to coal quality. Both mines were acquired by Utah P&L in 1977 and are operated by an independent operator under a 30 year agreement[26]. The mining agreement does not contain coal quality specs or a bonus/penalty system. The plants encountered serious operating problems due to poor coal quality and wide variations in coal quality both before and after the acquisition of the mines. The utility never rejected any coal under the agreements.

I could find only one supply arrangement in the group where a dispute led to litigation. In 1973 Colorado-Ute Electric Coop signed a long term requirements contract with Utah-International to supply coal for the first two units of the Craig generating station. The contract specified that the units would each have a capacity of 350 Mwe. The requirements contract specified both a minimum take (and associated minimum payments) by the utility and a maximum monthly and yearly delivery obligation by the supplier. Deliveries above the maximum were at the discretion of the seller. Without telling the supplier, Colorado-Ute subsequently increased the actual size of each generating unit by about 20%. The year before deliveries were to commence the supplier sued for breach of contract requesting that it be obligated only to deliver the minimum takes specified in the contract. Colorado-Ute argued that it was entitled to deliveries up to the maximum specified in the contract. The federal district court (425 F.Supp. 1093 (D. Colo. 1976) found for the supplier allowing him to rescind part of the agreement. Deliveries are being made under the contract, but only at the minimum take levels. A commentary on the case suggests that market conditions had changed after the contract was negotiated, that the seller could get higher prices by selling the additional coal to others and perhaps that it could extract a higher price from Colorado-Ute.[27]

Discussion

The empirical results are quite consistent with the "predictions" of the transaction cost theory. Spot markets and short term contracts account for a relatively small fraction of coal supply transactions for electric utilities. For the utility industry as a whole, long term contracts rather than vertical integration is the preferred governance structure. Vertical integration is much more prevalent for mine-mouth plants than it is for other coal-fired generating stations, however. Although mine-mouth plants account for only 15% of total coal consumption by electric utilities, they account for over half of the supplies governed by some form of vertical integration. When contracts are chosen in lieu of vertical integration (or in a sense in addition to it for jointly-owned generating plants) for mine-mouth plants, the parties rely on very long term contracts to support exchange. These contracts, while certainly "incomplete," are often quite complex, containing numerous price and non-price provisions to protect both parties from breach and to help ensure the smooth operation of the supply relationship over time.

Although my research examining coal supply arrangements for non-mine-mouth generating plants is not yet complete, preliminary results suggest that there are important differences, on average, between contracts governing exchange for mine-mouth plants compared to other types of generating plants. The contractual duration of coal supply agreements for mine mouth plants is substantially longer than for other types of plants and involves substantially larger annual delivery commitments (compare table 6 and table 8). Preliminary analysis of about 60 contracts for other coal plants suggests that these figures may understate the differences in length of commitment. Several of the non-mine-mouth contracts contain renegotiation and termination provisions that specifically allow one or both parties to terminate the agreement without paying damages long before the stated term of the contract is reached. This is not generally the case for mine-mouth plants. Contracts for mine-mouth plants are generally written as requirements contracts. This is rarely the case for the other contracts that I have examined.[28]

Although long term contracts establish pricing provisions ex ante, this does not mean that prices are rigid. The pricing formulas used allow for frequent price adjustments based on input price changes and other cost changes that are attributable to exogenous events. While prices will not generally track short term movements in "market" prices, they do respond in the long run to changes in the costs of producing coal. Recent contracts often provide for quarterly or monthly adjustments and some older contracts have been amended to do so.

The pricing provisions, along with certain non-price provisions also reflect an interest by buyers that their suppliers produce efficiently. Two-thirds of the contracts make extensive use of indexing provisions to adjust prices so that the price the seller receives is partially independent of his production decisions. If the seller can beat the index he can increase his profits and if the seller does not mine efficiently his profits will fall. All of the cost plus profit contracts recognize explicitly that pure cost plus pricing has bad incentive properties with regard to efficient production. All but one of these contracts contains additional provisions to give suppliers incentives to produce efficiently.

Overall, I have found the transactions cost framework to be an extremely powerful vehicle for gaining a better understanding of the nature of vertical supply relationships between power plant owners and their coal suppliers.

Table 1

U.S. Coal Consumption By Sector 1980 and 1982

Sector	1980 Tons (millions)	%	1982 Tons (millions)	%
Electric Utilities	569	81%	594	84%
Coke Plants	67	10%	41	6%
Other Industrial	60	9%	64	9%
Resid/Commercial	6	1%	8	1%
	703		707	

Source: Quarterly Coal Report, U.S. Department of Energy (DOE/EIA-0121) September 1983.

Table 2

Regional Coal Characteristics
1982 Production

Region/State/BLM	BTU/lb	% Sulf	% Ash
APPALACIAN:			
Alabama	12,154	1.3	11.8
Georgia	12,338	1.5	11.7
Ohio	11,565	3.3	12.5
Pennsylvania			
1	12,228	1.9	14.5
2	12,233	2.0	12.1
Tennessee			
8	12,349	1.5	10.9
13	12,293	0.9	12.3
Virginia (8)	12,592	1.0	10.9
W. Virginia			
3	12,708	2.3	10.7
6	12,109	3.9	11.4
8	12,213	0.9	11.8
Kentucky/East	12,184	1.1	10.6
INTERIOR:			
Illinois	10,959	2.7	10.2
Indiana	10,942	2.6	10.2
Kentucky/West	11,446	3.2	11.2
Missouri	10,276	4.8	17.1
Kansas	10,463	4.7	20.7
TEXAS:	6,445	0.8	15.5
WESTERN:			
Wyoming	8,686	0.4	6.2
Montana	8,958	0.6	6.8
New Mexico	9,342	0.7	19.0
North Dakota	6,590	0.6	8.2
Utah	11,643	0.5	10.3
Washington	8,100	0.8	15.7
Illinoi			

Source: Cost and Quality of Fuels For The Electric Utility Industry, U.S. Department of Energy (DOE/EIA -0191(82), August 1983 Table 53.

Table 3

Underground and Surface Mining By Region
1982

Region	% Underground	Annual Output Per Mine	
		Underground	Surface
Appalacian	60%	138,900	100,003
Interior	30%	760,590	411,650
Western	11%	441,810	2,646,040
U.S. Total	40%	170,040	242,540

Source: Calculated from Coal Data (1981/82), National Coal Association, pp II-11 and II-12.

Table 4

Vertical Integration By Electric Utilities Into Coal Mining

Utility/Subsidiaries	1980 Production (tons)	(State)	Extent of VI
TEXAS UTILITIES	27,590,768	(TX)	100% Requirements
PACIFIC P&L/NERCO			
Bridger Coal (joint owner)	6,453,302	(WY)	100% requirements by company-owned mines or mines owned by joint-owners of plants + substantial 3rd party sales.
Decker Coal (joint owner)	5,534,429	(MT)	
Glenrock Coal	3,800,000	(WY)	
Sond Mountains Minerals	500,000	(AL)	
Spring Creek Coal	100,000	(MT)	
Bankhead Coal	390,000	(AL)	
TOTAL	16,777,331		
AMERICAN ELECTRIC POWER			~30% of requirements
Windsor Power House			
Southern Ohio Coal			
Central Ohio Coal			
Southern Appalacian Coal			
Cedar Coal			
Central Appalacian			
Simco/Peabody (joint-owner)			
Price River Coal (UT)			
TOTAL	16,057,181		
MONTANA POWER			
Western Energy	10,448,000	(MT)	100% of requirements + 3rd party sales.
WASHINGTON WATER POWER	5,140,000	(WA)	Requirements of Centralia, system's only coal plant.
UTAH P&L	4,600,000	(UT)	~65% of requirements; mines operated by contractor.
MONTANA/DAKOTA UTILITIES			100% of requirements + 3rd party sales.
Knife River Coal	4,788,967	(MT,ND)	
PENNSYLVANIA P&L			
Pennsylvania Mines	2,928,211	(PA)	~50% of requirements
Greenwich Collieries	1,528,807	(PA)	
Lady Jane Collieries	200,963	(PA)	
TOTAL	4,657,981		
BLACK HILLS P&L			100% of requirements incl. all req. of Wyodak Plant.
Wyodak Resources	2,500,000	(WY)	
DUKE POWER			
Eastover Mining Co.	2,084,000	(PA)	~15% of requirements. Sub. up for sale in 1983.
DUQUESNE L&P	900,000	(PA)	~ 20% of requirements
IOWA PS Co.			
Energy Dev. Co.	877,631	(WY)	NA
VEPCO			~15% requirements (Mt. Storm Plant)
Laurel Run Mining	619,981	(WV)	
TAMPA ELECTRIC			
Cal-Glo Coal	388,000	(KY)	~10% of requirements
OHIO EDISON	188,439	(OH)	~5% of requirements
CAROLINA P&L [illegible]			

Table 4 (con't)

TOTAL PRODUCTION BY UTILITY CONTROLLED MINES:		83,000,000 tons
SALES TO THIRD PARTIES (EXCL. JOINT PLANT OWNERS):		13,000,000
NET INTEGRATED PRODUCTION :		70,000,000
% of Total Utility Coal Use (tons):	14%	
% of Total Utility Coal Use (BTU's):	12%	

Source: Compiled from data in 1982 Keystone Coal Manual, Moody's Electric Utility Manual (various years), Annual Reports and 10-K's.

Table 5

Spot and Contract Transactions

Year	% Spot	% Contract
1974	23.8	76.2
1975	18.2	81.8
1976	14.0	86.0
1977	19.4	80.6
1978	21.2	78.8
1979	12.8	87.2
1980	11.5	88.5
1981	13.1	86.9
1982	9.6	90.4

Regional Breakdown: 1982

Region	% Spot
Appalacian	17.4%
Interior	7.4
Texas	8.1
Western	1.6
Total	9.6%

Source: Calculated from Cost and Quality of Fuels For The Electric Utility Industry, U.S. Department of Energy (DOE/EIA-0191(82)) August 1983 Table 53.

Table 6

Distribution of 205 Contracts By Duration and Annual Tonnage

Duration	% of Coal Deliveries	Tons/year/contract
< 5 years	17%	267,000
6 thru 10 years	12%	556,000
11 thru 20 years	37%	885,000
21 thru 30 years	17%	1,309,000
greater than 30	17%	2,411,000

Source: See Text

Table 7

Mine Mouth Coal Plants

Unit Names	Utility/State	Joint/Owners	Units (years)	Capacity (Mwe) 1982	Coal Deliveries (tons)
Big Brown	Texas Util.(TX)	No	71,72	1186	5,963,000
Martin Lake	Texas Util.(TX)	No	77,78,79	2379	11,413,000
Monticello	Texas Util.(TX)	No	74,75	1980	9,797,000
Hunter	Utah P&L (UT)	No	78,80,(83,85)	892	2,525,000
Huntington	Utah P&L (UT)	No	74,77	892	2,492,000
Naughton	Utah P&L (WY)	No	63,68,71	707	2,040,000
Wyodak	Pacific P&L(WY)	Yes	78	331	1,812,000
Centralia	Pacific P&L(WA)	Yes	72,72	1329	4,400,000
Bridger	Pacific P&L(WY)	Yes	74,75,76,77	2034	6,025,000
San Juan	Pub Serv NM (NM)	Yes	73,76,79,82	1708	5,071,000
Colstrip	Montana Power(MT)	Yes	75,76,(84,85)	716	2,103,000
Four Corners[1]	Arizona PS (NM)	Yes	63,63,64,69,70	2269	7,291,000
Young	Minkotta Coop(ND)	Yes	70,77	673	2,983,850
Coyote	Mont/Dakota (ND)	Yes	81	450	1,669,000
Montrose	Kan City P&L(MO)	No	58,60,64	536	1,326,700
Craig	Col-Ute Coop(CO)	Yes	79,80,(83)	894	2,303,000
Asbury	Emp. Dist. (MO)	No	70	212	707,000
Keystone[2]	Penn Elec (PA)	Yes	67,68	1872	3,543,000
Homer City	Penn Elec (PA)	Yes	69,71,77	2012	3,811,000
Conemaugh[2]	Penn Elec (PA)	Yes	70,71	1872	2,668,000
Mt. Storm	VEPCO (WV)	No	65,66,73	1662	3,100,000

[1] Units 4 and 5 jointly-owned

[2] Penn Electric operates plant for joint owners, but has no direct ownership interest. Other GPU subs own part of the plants along with other utilities.

Source: See Appendix

Table 10

Summary of Pricing Provisions in Contracts

GENERAL PRICING PROVISIONS: Base Price + Escalation: 14
Cost + Profit: 7 + 1 with option = 8

A. Escalation Provisions in Base Price + Escalation Contracts

Components of Base Price

Wages/Benefits: Indexed: 11
Actual Costs: 3

Materials & Supplies: Indexed: 13
Actual Costs: 1

Depreciation/Amortization: Indexed: 4 (2 partial, 1 full)
Actual Costs: 3
Fixed: 2
Aggregated with other Components: 4
Other: 1

Profit: Indexed: 5
ROI: 1
Fixed: 3
Aggregated with other components: 4
Other: 1

Residual Aggregate: Indexed: 4
Fixed: 2
None: 8

Taxes/Royalties: Actual Costs: 14

Costs Due to Changes In Gov't Regulations: Actual Costs: 12
Not Mentioned: 2 (subsequently added by amendment)

Changes in Contract/Union Work Rules: Actual Costs: 13
Fixed: 1 (contract has cost + option)

(con't)

Table 9

Summary of Selected Non-Price Provisions of Contracts
(21 contracts)

Duration:	Mean: 35 yrs Median: 35 yrs Mode: 35 yrs Min: 20 yrs Max: 50 yrs
Requirements Contracts:	Full requirements: 16 Partial (%) Req.: 3 Annual Quantities: 2
Min Take/Min Payment:	Yes: 16 Not Mentioned: 5 (2, cost+ or two-part tariff;1, added by amendment)
Arbitration:	Yes: 18 Not Mentioned: 3
Scheduled Renegotion:	Yes: 5 (3, after 20 years;1, escal. weights only;1, buyer pays fixed costs on termination) No: 16
Coal Quality Specs:	Yes: 14 No: 7 (Run of mine for specified reserves)
Specification/Dedication of Reserves:	Yes: 20 Not Mentioned: 1
Specific Restrictions on 3rd Party Sales:	Yes: 13 Not Mentioned: 8
Gross Inequity:	Yes: 12 Not Mentioned: 9 (3, cost+;3, integrated/contract;1,"fair profit" provision)

Source: See Appendix

Table 8

Coal Supply Arrangements For Mine-Mouth Plants

Unit	Supply Arrangements	Initial Contract	Duration
Big Brown	Integrated	None	NA
Martin Lake	Integrated	None	NA
Monticello	Integrated	None	NA
Huntington	Initially long term contract; Util. acquired mines in 1977;	1971	35 yrs
Hunter	Initially long term contract; Util acquired mines in 1977;	1974	35 yrs
Naughton	Long term contract	1957	40 yrs
Wyodak	Integrated/Contract	1977	35 yrs
Centrailia	Integrated/Contract	1970	35 yrs
Bridger	Integrated/Contract	1974	35 yrs
San Juan	Initially coal subsidiary contracted with mining co. to build and operate mine on util. sub. reserves. Reserves later sold to mining co. and supplies now provided under long term contract.	1972,1980	37 yrs
Colstrip	Integrated/contract (units 1,2)	1971	35 yrs
	(unit 3)	1980	36 yrs
Four Corners	Long Term Contracts (units 1,2,3)	1960,1963	35 yrs
	(units 4,5)	1966	35 yrs
Young	Long Term Contract	1966	50 yrs
Coyote	Integrated/Contract	1978	35 yrs
Montrose	Long Term Contracts (units 1,2)	1956	~30 yrs
	(unit 3, different mine)	1959	~35 yrs
Craig	Long Term Contract	1973	35 yrs
Asbury	Long Term Contract + some spot	1966	20 yrs
Keystone	Long Term Contract	1964	~30 yrs
Homer City	Long Term Contracts (2)	1966	~30 yrs
Conemaugh	Long Term Contracts	196?	~30 yrs
Mt. Storm	Initial Supply arrangements unknown; Currently coal comes from adjacent company owned mine (100% of output) plus contract purchases from other suppliers with different durations, plus some spot purchases.	NA	NA

Source: See Appendix

B. Cost Plus Profit Contracts

Treatment of Base Profit per unit: Indexed: 6
ROI: 2 (includes contract with cost+ option)

Incentive Provisions: Bonus/penalty based on "standard cost" comparisons: 3
Bonus/Penalty based on market price comparisons: 3
Option to rebid mining agreement: 1
Contractual Promise to develop incentive provision: 1

C. Non-Linear Rate Structure (in addition to/along with minimum take): 5 of 21

FOOTNOTES

* I am gratefull to Fred Dunbar, Victor Goldberg, Edmund Kitch, Oliver Williamson, Dick Schmalensee, Oliver Hart and Steve Shavell for help and comments. I also want to thank National Economic Research Associates, Inc. for giving me access to its coal contract library.

1. Monteverde and Teece is an excellent example of this type of empirocal work.

2. This is not to say that the examples have not been useful. The example presented by Klein, Crawford and Alchian of the evolution of the supply relationship between General Motors and Fisher Body was instrumental in getting me interested in pursuing this project.

3. This is part of a larger project examining vertical relationships between electric utilities and input suppliers.

4. Some of the alternative approaches are discussed in Williamson (1983: 520-21) and Williamson (1984).

5. These papers include, Coase (1937,1972), Williamson (1971,1975,1979,1983 and 1984), Klein, Crawford and Alchian, Klein, Monteverde and Teece, and Goldberg.

6. See McGraw-Hill, pages 371 -373, <u>Electrical Week</u>, August 23, 1982, page 8, and <u>Electrical Week</u>, April 5, 1982. Some state commissions and the FERC have been paying increasing attention to purchases made from subsidiaries and purchases made under long term contracts.

7. The primary references are contained in note 5.

8. I believe that information asymmetries can and should be further integrated into this literature and added to the list. The transaction cost literature I focus on here has either ignored or placed in the background both information asymmetries and differences between agents in the costs of bearing risks. The principle-agent literature, which is concerned with related problems, relies on assumptions about information asymmetries and risk aversion, but ignores transaction specific investments. See Holmstrom, Shavell, and Hart. It would be productive to integrate the two approaches, but this is well beyond the scope of this paper.

9. Thus there are both costs and benefits associated with internal production. Grossman and Hart provide an interesting analysis of this issue.

10. Holmstrom, Shavell, and Hart are excellent examples of the approach taken in this growing literature.

11. A base load unit is a unit that is designed to operate at full capacity throughout the year, regardless of variations in total system demand. Demand variations are accomodated with "cycling" or "peaking" units. Almost all coal burning units are designed to operate as base load units for a substantial fraction of their useful lives; on the order of twenty years.

12. My reasoning here is related to Williamson's notion of dedicated assets.

The development of a mine requires durable investments. The mine operator chooses both an optimal level of capacity and an optimal mining technique to meet expected demand. Mining techniques vary in capital intensity. More capital intensive techniques are optimal at larger scales, other things equal. Without a long term commitment by buyers to take specific quantities, the mine operator will treat nominal contract demand as being uncertain with an expected value that is less than the nominal contract demand. Mine capacity and mining technique will be chosen to reflect this expected demand and the unit cost of coal and prices determined based on this expected demand. If a buyer can commit itself to a firm demand equal to the nominal demand, it can induce the mine operator to expand capacity, reducing unit costs. Some of the savings can be passed along as a lower price than would otherwise prevail if the contract demand were treated as being uncertain. The more significant are scale economies, the greater the associated price reduction.

13. The importance of dedicated assets is made clearly by one of the contracts for a mine-mouth plant that is analyzed below.
" Buyers will construct, own and operate a coal fired steam-electric generating plant ...adjoining coal lands of Seller, based upon the assurance of a dependable supply of coal of specified quality and characteristics for the useful life of the plant.
" The Buyers would not design and construct a plant of this type [at this site] ...but for the availability of a dependable supply of coal from seller through December 31, 2019...
" It is essential to the Seller, because of the substantial capital investment it must make in order to have the capability to supply Buyers' requirements, that buyers purchase all of their coal requirements for said plant from Seller." (From the coal supply agreement between the five joint-owners of units 3 and 4 of the Colstrip generating plant in Montana and Western Energy Company, dated July 2, 1980.)

14. The age of the plant is also likely to be relevant. Over time, technological change has made it possible to build more efficient plants that produce steam at higher temperatures and pressures. The newer high pressure units, especially supercritical units tend to be more sensitive to variations in coal quality. See Joskow and Rose for a discussion of changes in generating unit technology over time.

15. Exactly what constitutes vertical integration is far from obvious. Some utilities own a plant themselves and have a mining division or subsidiary that operates the mines. Other utilities own plants themselves, own both coal reserves and the mines, but contract with independent operators to produce the coal. Still other utilities own the reserves, but contract with independent contractors to both develop and operate the mines. In other cases, the plant is jointly owned by several utilities, only one of which has an ownership interest in the mines serving the plant. I classify any of these cases as vertical integration and make finer distinctions in the discussion of mine-mouth plants below.

16. A few utilities are trying to divest themselves of coal subsidiaries, largely as a consequence of unfavorable regulatory treatment of coal obtained from captive mines. Duke Power has been actively seeking a buyer for its coal subsidiary. Carolina P&L and Pennsylvania Power and Light are also considering selling their coal subsidiaries. See, for example, Electrical Week, August 23,

1982, p. 8.

17. The contract information was obtained from Pasha Publications, 1980 Guide To Coal Contracts for another project. Data on 270 contracts was collected, but only 205 contained both information on duration and delivered quantities for 1979.

18. The utility owners of Western Coal (formed to supply the San Juan plant) did apparently consider taking over mining responsibilities from Utah-International, the developer and operator of the adjacent mine. Among other things they concluded that Utah could take advantage of some economies associated with its mining operations at Four Corners. See letter from Western Coal Co. to Tucson Gas & Electric and Public Service of New Mexico regarding negotiations between Western (jointly-owned by the two utilities) and Utah-International (dated February 21, 1978, on file).

19. This is especially true if the pricing provisions of the contract have a significant cost plus component.

20. This depends on the length of the contract, the capital output ratio, the durability of the investments, the expected rate of inflation and the discount rate used. I have performed some simulations of the relationship between the fixed price and the incremental costs for a variety of reasonable assumptions. Reasonable assumptions about expected input price inflation suggests that the "abandonment" problem becomes serious for contracts that are longer than fifteen or twenty years. The mines at mine-mouth plants are often organized as separate subsidiaries of larger coal companies and it is possible that a utility would have difficulty making a claim against the parent company.

21. The initial source I used to date the units at different plant sites gave the wrong date for the first unit of the Montrose plant (1960 rather than 1958). I decided to leave it on the list. There are a two or three other utilities with mine mouth plants which pre-date the sample period.

22. Note that the Huntington and Hunter plants were initially supplied under long term contracts, but the utility eventually acquired the mines. Coal supply arrangements for the San Juan plant moved in the opposite direction.

23. This includes the initial contracts and amendments for Hunter and Huntington.

24. This is probably true of Keystone as well, although I was unable to find documents indicating the utility financing had been provided.

25. See letter from Western Coal Co. to Tucson Gas & Electric and Public Service of New Mexico regarding negotiations with Utah-International (dated February 21, 1978, on file).

26. McGraw-Hill, 1981: 392. This publication does not identify the utility and plants by name, but it is clear from the information provided that the utility is Utah P&L and the plants are Hunter and Huntington.

27. McGraw-Hill, 1981: 486. Additional coal was eventuall purchased from another supplier.

28. I have performed a preliminary analysis of 60 contracts that do not involve mine-mouth plants. The average duration of the contracts is about 13 years. Only 4 are requirements contracts. Only 3 involved mines that had not been developed at the time the contract was signed. 18 of these contracts provide for scheduled price renegotiation during the term of the contract.

Appendix

This appendix summarizes the methods used for collecting the information on vertical integration and contracts that is discussed in the text.

Vertical Integration:

I started with lists of captive coal mines contained in the McGraw-Hill Keystone Coal Manual and Gordon. Individual utility entries in Moody's Public Utilities Manual were reviewed to verify the information provided there and to resolve differences between the two lists. Next, Pasha Publications' Guide to Coal Contracts was searched for additional information on utility ownership of mines. Then, the entries for the 25 largest utility consumers of coal in Moody's were reviewed in an effort to identify additional utility-owned mines. Finally, the ownership of all suppliers identified in the contracts with mine-mouth plants was determined from another listing in the Keystone Coal Manual.

Annual production figures by mines and consumption figures for utilities were obtained from the Keyston Coal Manual, the Department of Energy's Cost and Quality of Fuels For Electric Utilities, Moody's and annual reports.

Mine-Mouth Plants:

The definition of a mine-mouth plant is at least partially subjective and no general list of such plants appears to exist. I searched for plants that were consciously located adjacent to specific coal reserves in order to exploit these reserves to generate electricity and where the adjacent mining facilities were built in reliance on these plants. The Guide To Coal Contracts has extensive information on coal transportation modes used to serve many plants. Mine-mouth plants are frequently noted explicitly. In a few cases, mine mouth plants were identified when conveyor belts or short-haul rail spurs were designated as the coal tranportation mode. Gordon contains a discussion of mine-mouth plants and identifies a few. The Keystone Coal Manual also provides information to identify mine-mouth plants. These sources were supplemented by searches of annual reports and various government publications. I identified more plants than appear on the list, but eliminated plants which had first units which began operating before 1960 since I thought that it would be difficult to obtain information on initial supply arrangements for plants that began operating so long ago. One plant (Montrose) that began supplying electricity before 1960 is on the list because the start-date that I initially identified turned out to be incorrect. I left it on the list since I had already collected the information on coal supply arrangements. Almost all of the older plants that were dropped from the list get at least some of their coal from utility-owned coal subsidiaries. In several cases these plants were greatly expanded with large units built in the 1960's or 1970's and rely on contracts for a large fraction of their supplies. It is possible that this selection process did not capture all mine-mouth plants in existance.

Contracts:

General information on the contract characteristics for each plant was obtained from the Guide to Coal Contracts. Individual contracts, amendments, etc. were obtained from the Washington Service Bureau. These contracts in turn were obtained primarily from SEC files. National Economic Research Associates gave me access to their coal contract library where these contracts are filed. In a few cases I was able to obtain additional information by making telephone calls to individual utilities and reviewing 10-K filings.

The contracts are sometimes long and complicated. Just reading them is not very productive. I used a coding sheet which contained entries for a variety of contract characteristics based on the discussion of the implications of transaction cost theory contained in the text. Each contract was read to fill in the relevant characteristics that had been identified. In several cases it is necessary to make interpretations of provisions which are unclear or ambiguous, so the coding of the contracts involves some subjective evaluations as well. I read every contract, amendment and any associated correspondence myself.

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